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August 3, 2015

Via Electronic Filing and US Mail

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 1088
SALEM OR 97302-1088

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

Attached for electronic filing is Staff Cross Answering Redacted Testimony, Exhibit 200 in UE 296. Confidential page 9 and 22 of Exhibit 200 are being mailed today to parties who have signed Protective Order 10-069.

Exhibit 201, Certificate of Service and Service List are electronically submitted.

/s/ Kay Barnes
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CASE: UE 296
WITNESS: JORGE ORDONEZ

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 200

Cross-Answering Testimony

August 3, 2015

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

A. My name is Jorge Ordonez. I am employed by the Public Utility Commission of Oregon (OPUC) as a Senior Economist in the Energy Resources and Planning Division. My business address is 201 High St. 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, filed with my Opening Testimony in this proceeding.

Q. What is the purpose of your testimony?

A. The purpose of my Cross-Answering testimony is twofold: first, to provide supplemental information regarding the issues raised in Staff's Opening Testimony, and second, to address certain issues raised in other parties' Opening Testimony.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/201, consisting of 17 pages.

Q. How is your testimony organized?

A. My testimony addresses the following 11 issues categorized in two groups:

I. Issues raised in Staff's Opening Testimony:
   1) BAAs Nexus Modeling,
   2) EIM Within-hour Benefits, and
   3) Day-ahead and Real-time Modeling.

II. Issues raised in intervenors' Opening Testimonies:
   4) EIM Inter-regional Benefits,
   5) EIM New Participants,
   6) Reserves / Reliability Metric,
   7) Reserves / PSE & APS Reserve Diversity,
   8) Hermiston Prudence and Point-to-point Transmission,
   9) Modeling Thermal Plant Forced Outage,

10) Modeling Avian Protection, and
11) Direct access.

Q. What are Staff's recommendations regarding the topics you have referenced above?

A. 1. <u>BAA Nexus Modeling</u>: Staff proposes an increased system-wide value of inter-regional benefits of $12.60 million, which represents $4.2 million in addition to the Company-proposed amount of $8.4 million. The $4.2 million is on a system-wide basis and it is $1.7 million on an Oregon-allocated basis. The rationale for Staff's adjustment lies in the assumption that the increased "dynamic transfer capability" (DTC) between PacifiCorp's BAAs is needed to produce inter-regional exports to the CAISO.

2. <u>EIM Within-Hour Benefits</u>: Staff withdraws its adjustment presented in its Opening Testimony. Staff learned through additional discovery that the new performance paradigm featuring a 30-minute balancing market, on which the Staff adjustment relied, is not yet in operation.

3. <u>Day-Ahead and Real-Time Modeling</u>: Staff continues to recommend that the Commission not accept the Company-proposed change, which reduces the Company's Oregon-allocated NPC by approximately $8 million, until Staff and other parties have had the opportunity to reasonably understand the mechanics of the Company-proposed modeling, as well as the opportunity to analyze GRID run variances and sensitivities to the Company-proposed change. However, Staff recommends that instead of addressing its issues through workshops before the next 2017 TAM, similar to the way in which

parties participated in productive workshops covering the EIM benefits presented in this current 2016 TAM, a separate investigation should be opened to address the issues raised above by Staff, the Industrial Customers of Northwest Utilities (ICNU), and the Citizens' Utility Board of Oregon (CUB), concerning this particular modeling change.

4. <u>EIM Inter-regional Benefits</u>: Staff generally agrees with ICNU and CUB and recommends that the Commission require the Company to include the potential benefits that result from incorporating the summer seasonality in the estimation of EIM Inter-regional Benefits. Should the Company fail to do so, Staff supports ICNU’s adjustment of reducing the Company’s NPC by $1.5 million on a total-Company basis, with $0.4 million allocated to Oregon.

5. <u>EIM New Participants</u>: Staff generally agrees with ICNU and recommends that the Commission require the Company to incorporate a certain level of potential EIM inter-regional benefits that may occur due to new EIM participants (i.e., Nevada Energy (NV Energy), Puget Sound Energy (PSE) and Arizona Public Service Company (APS)). Should the Company fail to do so, Staff supports ICNU’s adjustment of reducing the Company’s NPC by $3.2 million on a total-Company basis, with $0.8 million allocated to Oregon.

6. <u>Reserves / Reliability Metric</u>: Staff generally agrees with PacifiCorp that it “is the Company’s responsibility to carry enough reserves to deal with system uncertainty across all hours of the year.” Therefore, Staff does not recommend ICNU’s NPC downward adjustment of $11.2 million on a total-Company basis, with $2.8 million allocated to Oregon.

7. Reserves / PSE & APS Reserve Diversity: Staff generally agrees with ICNU's recommendation that the Commission require the Company to incorporate the potential benefits of reduced levels of flexibility reserve diversity benefits associated with the entrance of PSE and APS into EIM. Should the Company fail to do so, Staff supports ICNU's proposed adjustment of reducing the Company's NPC by $60,750 on a total-Company basis, with $15,020 allocated to Oregon.

8. Hermiston Prudence and Point-to-point Transmission: Staff recommends that, in the context of the 2016 TAM, the Commission not adopt ICNU's assertion that the Hermiston contract was imprudent. Staff's rationale lies in the fact that, if the Company had renewed this contract, the high costs associated with this contract in the 2016 test year would have been onerous to the Company and ratepayers.

9. Modeling Thermal Plant Forced Outage: Staff does not necessarily disagree with the Company, but supports ICNU's position that, because the UM 1355 methodology underwent extensive review by the parties participating in the UM 1355 investigation, it would be preferable not to adopt a new methodology at this time without undertaking a similarly extensive review.

Staff recommends that the Commission require the Company revert to the UM 1355 methodology, which results in reducing NPC by $0.7 million on a total-Company basis, with $0.2 million allocated to Oregon.

10. Modeling Avian Protection: Although this adjustment is immaterial compared with the overall NPC of the Company, Staff agrees with the

Company in implementing this modeling change because the curtailment of wind facilities was required by a court order.

Staff recommends that the Commission adopt an increase of NPC by $0.2 million on a total-Company basis, with $52,107 allocated to Oregon.

11. Direct Access:

Freed-up RECs: Staff generally agrees with Noble Solutions that Schedules 294, 295, and 296 should reflect the value of freed-up RECs.

Staff recommends that the Commission require the Company to reflect the value of RECs in Schedules 294, 295, and 296.

Schedule 200, Costs in Years 6 through 10: Staff believes the Commission's issuance of Order No. 15-195 on June 16, 2015 was too recent to merit changing the methodology used for developing Schedule 296. Nevertheless, Staff would like to review the Company's Reply testimony regarding this issue to determine the reasonableness of the positions of the Company and Noble Solutions.

Timing of Direct Access Service Requests: It appears to Staff that Noble Solutions' request is not unreasonable. Nevertheless, Staff would like to review the Company's Reply testimony regarding this issue to assess the reasonableness of the positions of the Company and Noble Solutions.

1. BAAs Nexus Modeling

Q. What is Staff's summary recommendation regarding this issue (i.e., BAAs Nexus Modeling)?

A. Staff recommends that the Commission require the Company to include $1.07 million of Oregon-allocated EIM inter-regional benefits that result from the Company having an increased level of DTC of 400 MW between PacifiCorp's BAAs compared to the Company's current 200 MW of DTC.

Q. What was Staff's Opening Testimony position regarding this issue?

A. In its Opening Testimony, Staff recommended to the Commission that the Company refine, if possible, its BAAs Nexus Modeling in the GRID model for the next TAM, preferably for the 2017 TAM.[1] Staff also represented that, in the meantime, it would continue to analyze this issue, and that it was developing a specific adjustment to provide in this round of testimony. Staff expected to include the potential benefits of PacifiCorp being able to share reserves between its BAAs due to the availability of 400 MW of DTC between PacifiCorp's BAAs.[2] Staff further indicated that it had issued Data Request (DR) 47 asking the Company to provide actual levels, if any, of reserves shared between its BAAs[3] in the past.

Q. What was the Company's response to Staff DR 47?

A. In the Company's response to Staff DR 47, which is included as Exhibit Staff/201, Ordonez/1-2, the Company represented that "**[o]n limited occasions** [emphasis added] since the start of EIM operations, the Company has designated a portion of its [DTC] for transferring contingency reserves from its east BAA to its West BAA. The [DTC] designated for contingency reserve

[1] See Exhibit Staff100, Ordonez/2, lines 14-17.
[2] See Exhibit Staff100, Ordonez/2, lines 17-21.
[3] See Exhibit Staff100, Ordonez/10, lines 12-14.

transfer is not available for economic dispatch within EIM." This fact was demonstrated in the confidential portion of the Company's response to Staff DR 47.

Q. Does the Company's response satisfy Staff's concerns?

A. Yes, the Company's response is reasonable. Consequently, Staff no longer supports an adjustment associated with the Company being able to share reserves between its BAAs.

Q. Is Staff foregoing an adjustment associated with the increased amount of DTC between PacifiCorp's BAAs?

A. No. Staff would like to clarify that the benefit proposed in its Opening Testimony was labeled "a potential benefit" from the additional 200 MW of DTC between PacifiCorp's BAAs from 200 MW to 400 MW.

Q. Is Staff proposing another adjustment to reflect this increased amount of DTC between PacifiCorp's BAAs?

A. Yes. In the Company's response to Staff DR 52, which is included as Exhibit Staff/201, Ordonez/3-4, PacifiCorp stated:

> "*In general, during December 2014 and January 2015 the Company's full 200 megawatts (MW) of [DTC] was made available for use within the Energy Imbalance Market (EIM).*"

Therefore, it is Staff's understanding that the DTC between PacifiCorp's BAAs has been used for EIM, contributing to the inter-regional benefits of $8.4 million.

Q. Did Staff ask the Company to update this $8.4 million of inter-regional benefits to account for the increased level of DTC between its BAAs (i.e., 400 MW instead of 200 MW)?

A. Yes. In Staff DR 53, the response to which is included as Exhibit Staff/201, Ordonez/5-6, Staff asked the Company to update the inter-regional benefits to account for the increased level of DTC between its BAAs. The Company responded with the following statement:

> "*The Company's $8.4 million estimate of system-wide Energy Imbalance Market (EIM) inter-regional benefits is a function of transmission available on the California Oregon Intertie (COI) and is not dependent on the level of dynamic transfer capability between the Company's balancing authority areas (BAA).*"

Q. Does that statement appear to be contradictory?

A. Yes, as I will explain. As represented by PacifiCorp, "the Company's forecast EIM export benefit is derived from the results of EIM operation during December 2014 and January 2015 as reflected in the CAISO invoices and the cost of the Company's **resources that were expected to be on the margin** [emphasis added]."[4]

PacifiCorp further represented "in Confidential Exhibit PAC/105, [that] the Company's EIM exports [to the CAISO] in December 2014 and January 2015 averaged 115 megawatts (MW) and had an estimated margin (transaction

[4] See Exhibit PAC/100 Dickman/17, lines 12-15.

revenue minus generation expense) totaling approximately $1.3 million. The transmission available to EIM averaged 278 MW."[5]

Q. Please elaborate.

A. The average cost of the **resources on the margin** for December 2014 and January 2015 is [redacted]$/MW,[6] approximates to the average variable cost of PacifiCorp's coal plants of [redacted]$/MW.[7] Since most of the Company's coal resources are located in the Company's east BAA, it is Staff's understanding that the DTC between PacifiCorp's BAAs might be critical for transmitting power to the west BAA and then to the CAISO. Therefore, achieving the inter-regional benefits of $8.4 million proposed by the Company might be dependent on the DTC between PacifiCorp's BAAs.

Based on the above assumption (i.e., that the resources on the margin are located in the PacifiCorp east BAA) and the fact that between December 2014 and January 2015 the Company averaged only 115 MW of EIM exports for the 278 MW of transmission available to EIM between PacifiCorp's west BAA and the CAISO, and approximately 200 MW of DTC between PacifiCorp's BAAs, increasing the DTC between PacifiCorp's BAAs would result in doubling the amount of power exported to the CAISO to approximately 230 MW. This would double the $8.4 million of inter-regional benefits proposed by the Company to approximately $16.8 million.

[5] See Exhibit PAC/100 Dickman/17, lines 17-20.
[6] This figure is the result of averaging the energy cost presented in Confidential Exhibit PAC/105 Dickman/2 for December 2014 (row "$/MW," and column "Energy Cost") and in Confidential Exhibit PAC/105 Dickman/3 for January 2015 (row "$/MW," and column "Energy Cost").
[7] This figure is the average variable cost of PacifiCorp's coal plants represented in the range E117:E1128 of confidential workpaper "_ORTAM16 NPC Study_2015 03 17 CONF."

Therefore, Staff proposes an increased value of inter-regional benefits of $12.6 million, which is $4.2 million in addition to the Company-proposed amount of $8.4 million.

Q. Why is Staff proposing an upward adjustment of $4.2 million instead of $8.4 million?

A. Staff is making a conservative assumption that only 50 percent of the increased DTC between PacifiCorp's BAAs will be used to produce exports to the CAISO, resulting in the $12.6 Staff-proposed adjustment. The rationale for the 50 percent is based on Staff's judgment that the DTC between PacifiCorp's BAAs will not always result in transactions with the CAISO. The $4.2 million of system-wide basis is expressed in an Oregon-allocated basis of $1.7 million.

2. EIM Within-Hour Benefits

Q. What was Staff's position in the Opening Testimony regarding this issue?

A. In its Opening Testimony, Staff recommended "the inclusion of $1.43 million of Oregon-allocated benefits of reduced reserves due to the fact that EIM allows the Company to schedule wind [and load] resources on a within-hour basis."[8]

Q. Has Staff changed its position regarding this issue?

A. Yes. Staff has performed further discovery regarding this issue. In the Company's response to Staff DR 55, which is included as Exhibit Staff/201, Ordonez/7-11, the Company stated that the new performance paradigm featuring a 30-minute balancing market, on which the Staff adjustment relied, is

[8] See Exhibit Staff100, Ordonez/3, lines 1-3.

not yet in operation. Staff initially understood that EIM embodied this new performance paradigm, but now understands that it does not.

Q. What is Staff's position in this round of testimony?

A. Staff withdraws the recommendation it presented in its Opening Testimony.

3. Day-Ahead and Real-Time Modeling

Q. What was Staff's position in the Opening Testimony regarding this issue?

A. In its Opening Testimony, Staff recommended that the Commission not accept the Company-proposed change, which would reduce the Company's Oregon-allocated NPC by approximately $8 million, until Staff and other parties had the opportunity to reasonably understand the mechanics of the Company-proposed modeling, as well as the opportunity to analyze GRID run variances and sensitivities to the Company-proposed change. This could be facilitated through workshops before the next 2017 TAM, similar to the way the parties participated in productive workshops covering the EIM benefits presented in this current 2016 TAM.

Q. Please summarize Staff's rationale for its recommendation in its Opening Testimony.

A. In its Opening Testimony, Staff testified that although Staff appreciated the computational support of the GRID team in navigating the massive level of data in workbooks, worksheets, GRID inputs, etc. associate with the modeling change, the complexity of the computational mechanics for implementing this modeling change presents challenges.

Q. Did other parties raise issues regarding this modeling change?

A. Yes. ICNU and CUB raised issues regarding this modeling change.

Q. Please summarize ICNU's recommendation.

A. ICNU opposes the Company-proposed modeling change. In its summary recommendation regarding this issue, ICNU represented:

> "*The Company has proposed a* ***complex series of adjustments*** *[emphasis added] to reflect what it claims to be additional costs associated with its* ***trading activities in forward markets*** *[emphasis added]. [ICNU] generally disagree[s] with the concepts and calculations behind the proposed adjustments and recommend[s] that the Commission reject the Company's proposal. In connection with the Company's proposal, [ICNU] also make[s] an alternative proposal to model* ***market liquidity*** *[emphasis added] in GRID using a* ***bid-ask spread*** *[emphasis added]. 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.*"[9]

ICNU also represented:

> "*The Company's participation in forward markets is tied largely into its overall* ***hedging strategy*** *[emphasis added].*"[10]

> "*[ICNU has] reviewed the power cost modeling of the majority of investor-owned utilities located in the Northwest…[y]et,* ***none has alleged that there is a systematic cost of system balancing not already reflected in their respective power cost model*** *[emphasis added] –let alone proposed the extraneous modeling adjustments that the Company has proposed in this proceeding.*"[11]

> "*The principle that forward prices represent an unbiased estimate of future spot prices has its origin in* ***arbitrage pricing theory*** *[emphasis added]. In an* ***efficient market*** *[emphasis added] there are assumed to be no arbitrage opportunities…*"[12]

Q. Please summarize CUB's recommendation.

[9] See Exhibit ICNU/100, Mullins/2, lines 5-13.
[10] See Exhibit ICNU/100, Mullins/7, lines 5-6.
[11] See Exhibit ICNU/100, Mullins/9, lines 16-22.
[12] See Exhibit ICNU/100, Mullins/11, lines 5-7.

A. CUB also opposes the Company-proposed modeling change. CUB represented:

> "*The Company admits that it is asking for the current [modeling] changes because it did not get the dollar-for-dollar recovery that it requested in the PCAM. Specifically, PacifiCorp states that it has consistently under-recovered power costs 'because of the* ***restrictions on NPC recovery in the PCAM design*** *[emphasis added].' The Company is thus introducing modeling changes in order to avoid under-recovery of actual NPC in future years. In order to do this, the Company adjusts its forward market prices 'to reflect historical variation from average actual market prices for purchases and sales.' CUB does not agree that this is the proper solution for ameliorating what the Company claims is GRID's consistent and systematic under-forecasting of NPC. CUB is concerned that that* ***incorporating 'historical variations' into a weather normalized power cost forecast*** *[emphasis added] will lead to a forecast that is less accurate and could put ratepayers at risk of overpaying power costs.* ***The TAM is not designed to forecast actual power costs –it is designed to dispatch PacifiCorp's system in a weather normalized manner to establish a forecast of power costs*** *[emphasis added]. Because it is weather normalized, it is not expected to accurately account for actual costs.*"[13]

Q. Please comment on ICNU and CUB's positions.

A. As emphasized in the ICNU and CUB quotations above, multiple issues have been raised regarding the Company-proposed day-ahead and real-time modeling change, such as:

- The complexity of the computational mechanics for implementing this modeling change (Staff and ICNU),
- The Company's trading activities in forward markets (ICNU),
- The concept of market liquidity (ICNU),
- The concept of bid-ask spread (ICNU),
- The Company's hedging strategy (ICNU),
- The notion that none of the investor owned utilities in the Pacific Northwest has alleged that there is a systematic cost of system balancing not already reflected in their respective power cost model (ICNU),
- The concept of arbitrage pricing theory (ICNU),

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[13] See Exhibit UE 296/CUB/100, Jenks-Hanhan, 6-CNU/100, Mullins/5-6.

- The concept of market efficiency (ICNU),
- Restrictions on NPC recovery in the PCAM design (CUB),
- The incorporation of historical variations into a weather normalized power cost forecast (CUB), and
- The motion that the TAM might be designed not to forecast actual power costs, but rather to dispatch PacifiCorp's system in a weather normalized manner to establish a forecast of power costs (CUB).

Staff proposes that these multiple issues related to the Company's proposed change should be addressed in a docket that is separate from the current UE 296 (PacifiCorp 2016 TAM).

Q. Does Staff's proposal in this round of testimony differ from its proposal in its Opening Testimony?

A. Yes. Staff continues to recommend that the Commission not accept the Company-proposed change, which reduces the Company's Oregon-allocated NPC by approximately $8 million, until Staff and other parties have had the opportunity to reasonably understand the mechanics of the Company-proposed modeling, as well as the opportunity to analyze GRID run variances and sensitivities to the Company-proposed change. However, Staff recommends that instead of addressing Staff issues through workshops before the next 2017 TAM, similar to the way in which parties participated in productive workshops covering the EIM benefits presented in this current 2016 TAM, an investigation should be opened to address the issues raised above by Staff, ICNU, and CUB, specifically concerning this particular modeling change.

Q. Please explain Staff's rationale for recommending an investigation to address the issues raised by Staff and other parties regarding this modeling change?

A. Staff's rationale is twofold. First, Staff is concerned about the number of issues raised. Second, Staff notes that, in the past, the Commission has opened investigations to address power cost issues with a smaller dollar value at stake.

Q. Please cite dockets in which the Commission has opened investigations to address power cost issues with a smaller dollar value at stake.

A. In Order No. 07-15 of Docket Nos. UE 180,[14] UE 181,[15] and UE 184[16] of Portland General Electric (PGE), the Commission made an adjustment of $4.6 million[17] out of approximately $857 million[18] of total power costs (i.e., 0.5 percent of total power costs) and opened a new generic docket to examine the issue at stake.

In this current docket, the adjustment at stake represents approximately $8 million out of approximately $375 million[19] of total power costs (i.e., a more significant 2.1 percent of total power costs).

4. EIM Inter-Regional Benefits

Q. What was Staff's position in the Opening Testimony regarding this issue?

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[14] Request for a General Rate Revision.
[15] Annual Adjustments to Schedule 125 (2007 RVM Filing)
[16] Request for a General Rate Revision relating to the Port Westward Plant.
[17] See page 15 of Order No. 07-15 of Docket Nos. UE 180, UE 181, and UE 184 at http://apps.puc.state.or.us/orders/2007ords/07-015.pdf
[18] See Exhibit UE 180/PGE/400, Less – Niman/4, line 18 in Docket No. UE 180 at http://edocs.puc.state.or.us/efdocs/HTB/ue180htb12256.pdf
[19] See Exhibit PAC/101, Dickman/1, line "42," column "Oregon Allocated: TAM CY 2016."

A. Staff's position in its Opening Testimony was that the Company's approach regarding the Company-estimated EIM inter-regional benefits was not unreasonable. Staff further stated:

> *"Staff looks forward to the Company's updates of these [EIM Inter-Regional Benefits] estimates based on additional historical information. As the Company represented in response to Staff DR 20, which [was] incorporated in Exhibit Staff/104, Ordonez/1-2, PacifiCorp will update the estimates in its Reply Testimony on August 3, 2015, which will incorporate historical results for December 2014 through June 2015."*[20]

Q. Has Staff changed its recommendation?

A. No. Staff continues to support its Opening Testimony recommendation. However, Staff would like to address ICNU and CUB's positions on this issue.

Q. Please summarize ICNU's recommendation.

A. ICNU represented:

> *"<u>Seasonality.</u> 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, [ICNU proposed] 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."*[21]

Q. Please summarize CUB's recommendation.

A. CUB represented:

> *"CUB also believes that forecasting EIM benefits with such little data [(i.e., December 2014 and January 2015)) is problematic."*[22]

Q. Please comment on ICNU and CUB's positions.

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[20] See Exhibit Staff/100, Ordonez/13 (lines 19-21) and Ordonez/14 (lines 1-3)
[21] See Exhibit ICNU/100, Mullins/3, lines 4-12.
[22] See Exhibit UE 296/CUB/100, Jenks-Hahhan/2, lines 1-2.

A. Staff finds that ICNU and CUB's positions are not unreasonable. ICNU and CUB concerns will be partially addressed when the Company includes additional historical months while projecting benefits; the Company has represented that it will do so in response to Staff DR 20, which was incorporated in Exhibit Staff/104, Ordonez/1-2, where the Company said the period of December 2014 through June 2015 would be included in a future update. However, any potential benefits from the summer may not be reflected in such a future update.

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

A. Staff generally agrees with ICNU and CUB and recommends that the Commission require the Company to incorporate the potential benefits that result from incorporating summer seasonality. Should the Company fail to do so, Staff supports ICNU's adjustment of reducing the Company's NPC by $1.5 million on a total-Company basis, with $0.4 million allocated to Oregon.

5. EIM New Participants

Q. Please state which party raised this issue and summarize that party's recommendation to the Commission.

A. In its Opening Testimony, ICNU recommended:

> *"<u>New EIM Participants.</u> The Company excluded a provision to account for additional inter-regional EIM transfers with new participants, including NV Energy, PSE and APS. [ICNU] proposes 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."*[23]

Q. Please explain the ICNU-proposed methodology.

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[23] See Exhibit ICNU/100, Mullins/3, lines 13-17.

A. ICNU first estimated the transfer capability between the new participants (NV Energy, PSE, and APS) and PacifiCorp: 430 MW between NV Energy and PacifiCorp, between 300 MW and 900 MW between PSE and PacifiCorp, and 600 MW between APS and PacifiCorp. To address a range of transfer capability, ICNU assumed the lower value of transfer capability (i.e., 300 MW between PSE and PacifiCorp). Finally, ICNU assumed that only one third of such transfer capabilities would be utilized to effectuate sub-hourly energy transfers in EIM. [24]

As for the pricing of the sub-hourly energy transfers, ICNU assumed a $1.66 /MWh economic margin, which represents the economic margins that the Company actually earned on sub-hourly transfers with the CAISO in the first months of EIM operations, discounted by one-half to reflect uncertainty.[25] The results of this analysis are presented in the following table.

Table 1[26]

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. What is Staff's position on this issue?

[24] See Exhibit ICNU/100, Mullins/37-38.
[25] See Exhibit ICNU/100, Mullins/38, lines 9-17.
[26] See Exhibit ICNU/100, Mullins/39.

A. Staff generally agrees with ICNU that a certain level of EIM inter-regional benefits due to new participants in EIM should be incorporated into the Company's 2016 NPC.

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

A. Staff recommends that the Commission require the Company to incorporate EIM inter-regional benefits due to new EIM participants. Should the Company fail to do so, Staff supports ICNU's adjustment of reducing the Company's NPC by $3.2 million on a total-Company basis, with $0.8 million allocated to Oregon.

6. Reserves / Reliability Metric

Q. Please state which party raised this issue and summarize that party's recommendation to the Commission.

A. In its Opening Testimony, ICNU recommended:

> *"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 [(CPS 2 Standard)]. Accordingly, [ICNU recommends] 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."*[27]

Q. Did Staff perform discovery regarding this issue? If so, please present Staff's findings.

A. Yes. In DRs 49 and 54, the responses which are included as Exhibit Staff/201, Ordonez/12-16, Staff asked the Company to explain why it did not use a 90 percent confidence standard instead of the 99.7 percent confidence standard, which would have complied with the CPS2 Standard.

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[27] See Exhibit ICNU/100, Mullins/2, lines 20-25.

Q. What was the Company's response?

A. In DR 49, the Company stated that:

> *"As of March 1, 2010, the Company began operating under the Reliability-Based Control (RBC) Proof-of-Concept Field Trial under Project 2007-18 for the Western Electricity Coordinating Council (WECC) [(RBC Standard)] and is* ***no longer subject [emphasis added]*** *to North America Electric Reliability Corporation (NERC) [CPS2 Standard]. This new WECC standard [i.e.,* ***RBC Standard****], is tied to changes in PacifiCorp's Area Control Error (ACE) as they affect interconnection frequency. Any ACE deviation outside the allowable limit that is contributing excess or deficient frequency must be corrected within a 30-minute period.* ***All deviations must be corrected within 30-minutes 100 percent of the time or the Company is in violation and non-compliant [emphasis added]****."*

Q. What is Staff's understanding of the Company's response?

A. Staff understands that the Company is no longer subject to the CPS2 Standard, but instead is subject to the RBC Standard. Therefore, the historical CPS2 values are not relevant for establishing compliance with reliability standards.

Q. How did the Company respond to DR 54?

A. In response to Staff DR 54, the Company represented that:

> *"The overall regulating margin reserve requirement is specified in the [RBC Standard]. Under this standard any Area Control Error (ACE) deviation outside the allowance limit that is contributing [to the] excess or deficient interconnection frequency must be corrected within a 30-minute period… The 2014 Wind Integration Study (2014 WIS) estimated the regulating reserves necessary to ensure compliance with the RBC standard. By including the regulating reserve amounts from the 2014 WIS, GRID also represents compliance with the* ***RBC [S]tandard****.[emphasis added]."*

Q. What is Staff's position and recommendation regarding this issue?

A. Staff generally agrees with PacifiCorp that it "is the Company's responsibility to carry enough reserves to deal with system uncertainty across all hours of the year."[28] Therefore, Staff does not support ICNU's NPC downward adjustment of $11.2 million on a total-Company basis, with $2.8 million allocated to Oregon.

7. Reserves: PSE and APS Reserve Diversity

Q. Please state which party raised this issue and summarize that party's recommendation to the Commission.

A. In its Opening Testimony, ICNU recommended:

> *"<u>PSE & APS Reserve Diversity</u>. While the Company included flexibility reserve diversity benefits associated with the addition of NV Energy into the [EIM], it did not include incremental flexibility reserve savings associated with the entrance of [PSE] and [APS]. [ICNU] proposes 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."*[29]

Q. What is Staff's position on this issue?

A. Staff generally agrees with ICNU and recommends that the Commission require the Company to incorporate the potential benefits of reduced levels of flexibility reserve diversity benefits associated with the entrance of PSE and APS into EIM. Should the Company fail to do so, Staff supports ICNU's adjustment of reducing the Company's NPC by $60,750 on a total-Company basis, with $15,020 allocated to Oregon.

8. Hermiston: Prudence and Point-to-point Transmission

[28] See the first paragraph of the Company response to DRs 49, included as Exhibit Staff/201, Ordonez/12-14.
[29] See Exhibit ICNU/100, Mullins/2, lines 26-32.

Q. Please state which party raised this issue and summarize that party's recommendation to the Commission.

A. In its Opening Testimony, ICNU recommended:

> *"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'). [ICNU recommends] 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."*[30]

> *"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. [ICNU proposes] to remove from NPC the unused portion of the Hermiston point-to-point transmission contract, resulting in a $0.2 million reduction of NPC on a total-Company basis, with $54,336 allocated to Oregon."*[31]

Q. What is Staff's position on this issue?

A. Staff disagrees with ICNU. In Staff DR 51, Staff asked the Company to run a GRID scenario assuming the Hermiston Contract is in effect in 2016. The Company's response to Staff DR 51 is included in Exhibit Staff/201, Ordonez/17. The Company represented that running such a scenario resulted in approximately [redacted] million of higher NPC in the 2016 test year. This figure is the result of netting the variable portion benefit of approximately [redacted] million with the fixed portion cost of approximately [redacted] million.

Staff's rationale lies in the fact that, if the Company had renewed this contract, the high costs associated with this contract in the 2016 test year would have been onerous to the Company and ratepayers.

[30] See Exhibit ICNU/100, Mullins/3, lines 19-24.
[31] See Exhibit ICNU/100, Mullins/3, lines 25-31.

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

A. Staff recommends that, in the context of the 2016 TAM, the Commission not adopt ICNU's recommendation.

9. Modeling: Thermal Plant Forced Outage

Q. Please state which party raised this issue and summarize that party's recommendation to the Commission.

A. In its Opening Testimony, ICNU recommended:

> *"<u>Outage Modeling</u>: 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, [ICNU recommends] 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."*[32]

ICNU also represented:

> *"The Company has proposed to model outages dynamically based on discrete events over the four-year base period. 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. This is in contrast to the **methodology approved in Docket No. UM 1355 [(UM 1355 Methodology)]** [emphasis added], 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."*[33]

Q. What was the Company's rationale for presenting this modeling change?

A. The Company's direct testimony quoted the following statement made by the Commission in Order No. 10-414 of Docket No. UM 1355:

[32] See Exhibit ICNU/100, Mullins/3, lines 32-37.
[33] See Exhibit ICNU/100, Mullins/43, lines 17-23.

> *"When modeling forced outages using capacity deration approach, utilities are directed to derate a unit's capacity over its entire range of operation…We note that ICNU points out that the current deration approach to modeling forced outages is outdated and that there are more sophisticated methods of representing forced outages in production cost models. We encourage the utilities, ICNU, CUB, and Staff to explore these modeling alternatives in future rate cases involving net variable costs."*[34]

Q. What is Staff's position on this issue?

A. Staff does not necessarily disagree with the Company, but supports ICNU's position that the UM 1355 Methodology underwent extensive review by the parties participating in the UM 1355 investigation, so any change should be subject to extensive review.

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

A. Staff recommends that the Commission require the Company to revert to the UM 1355 Methodology, which results in reducing NPC by $0.7 million on a total-Company basis, with $0.2 million allocated to Oregon.

10. Modeling: Avian Protection

Q. Please state which party raised this issue and summarize that party's recommendation to the Commission.

A. In its Opening Testimony, ICNU recommended:

> *"<u>Avian Protection.</u> 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 forecast. [ICNU proposes] to remove this adjustment, reducing NPC by $0.2 million on a total-Company basis, with $52,107 allocated to Oregon."*[35]

Q. What was the Company's rationale for this modeling change?

---

[34] See Exhibit PAC/100, Dickman/31 (lines 21-26) and Dickman/32 (lines 1-3).
[35] See Exhibit ICNU/100, Mullins/4, lines 2-7.

A. In its Direct Testimony, PacifiCorp represented that the "Company recently received an order from the United States District Court for the District of Wyoming (Court Order) that included the requirement to curtail [two wind sites] to reduce the risk of eagle interaction with wind turbines. As part of the Court Order, an on-site observer will use their professional judgment to identify risky eagle flight behavior/pathways during specific time periods and notify plant personnel to implement turbine curtailment."[36]

Q. What is Staff's position on this issue?

A. Although this adjustment is immaterial compared with the NPC of the Company, Staff agrees with the Company in implementing this modeling change because it is required by a court order.

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

A. Staff recommends that the Commission adopt an increase of NPC by $0.2 million on a total-Company basis, with $52,107 allocated to Oregon.

11. Direct Access Issues

Q. Please state which party raised this issue and summarize that party's recommendation to the Commission.

A. In its Opening Testimony, Noble Solutions presented three primary conclusions and recommendations.

Q. What is Noble Solutions' first conclusion and recommendation?

A. Noble Solutions first considered a topic known as "Freed-Up RECs". Specifically, Noble Solutions represented:

[36] See Exhibit PAC/100, Dickman/39, lines 10-16.

> *"The Schedule 294, 295, and 296 transition adjustments should be adjusted to reflect the value of freed-up Renewable Energy Certificates ('RECs'). Otherwise, direct access customers will unreasonably pay for Renewable Portfolio Standard ('RPS')-related resources twice: once from their Electricity Service Supplier ('ESS') and a second time from PacifiCorp, which banks the RECs paid for by direct access customers for future use by cost-of-service customers."*[37]

Q. Did Noble Solutions ask PacifiCorp whether the Company agrees that the calculation of transition adjustment schedules does not reflect the value of RECs that are freed up as a result of direct access?

A. Yes. The Company responded as follows:

> *"The calculation of the Schedule 294, 295, and 296 transition adjustments accurately reflects the fact that election of direct access service by a customer does not result in "freed-up" renewable energy credits (RECs). Under Oregon's [RPS], unlimited banking of RECs is allowed. Thus, if the Company's retail load is lowered as the result of a customer electing direct access service, **RECs that may have otherwise been necessary if the customer did not elect direct access are retained in the Company's REC bank for use towards RPS compliance in future years** [emphasis added]."*[38]

Q. What is Staff's position regarding this issue?

A. Staff generally agrees with Noble Solutions. The fact that the "freed-up" RECs are not immediately sold, but "banked," does not recognize the value of the freed-up RECs in the TAM calculation.

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

A. Staff recommends that the Commission require the Company to reflect the value of RECs in Schedules 294, 295, and 296.

Q. What are Noble Solutions' second conclusion and recommendation?

[37] See Exhibit Noble Solutions/100, Higgins/4, lines 4-11.
[38] See Exhibit Noble Solutions/100, Higgins/18, lines 22-29.

A. Noble Solutions considered the costs in years 6 through 10 in Schedule 200 as follows:

> *"In calculating the Schedule 296 Consumer Opt-Out charge, Schedule 200 costs should not be escalated in Years 6 through 10 as proposed by PacifiCorp. Rather, Schedule 200 costs used in this calculation should decline each year from Year 6 through Year 10 to reflect the decline in the Company's return on generation rate base attributable to the departed customers' loads, due to the effects of accumulated depreciation and amortization. The effects of this decline in return should be passed through to the Consumer Opt-Out charge."*[39]

Q. On what basis is Noble Solutions requesting the change to the calculation in Schedule 296?

A. Noble Solutions represented:

> *"In Order 15 195 [, entered recently on June 16, 2015], denying the motion of Noble Solutions and other parties for clarification or reconsideration, the Commission noted that, 'As PacifiCorp notes, if in the future the joint parties believe that they have new evidence or arguments demonstrating that the customer opt-out charge is unjust or unreasonable, they may seek our review at [that] time.' [Noble Solutions believes] that some refinements to the Opt-Out charge calculations are necessary in this case for the rate to be just and reasonable."*[40]

Q. What is Staff's position regarding this issue?

A. Staff believes the Commission's issuance of Order No. 15-195 (June 16, 2015) is too recent to be included in the methodology used for developing Schedule 296. Nevertheless, Staff will review the Company's Reply testimony regarding this issue and further consider the matter.

Q. What are Noble Solutions' third conclusion and recommendation?

A. Regarding Noble Solutions' third-considered topic addressed the timing of direct access service requests as follows:

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[39] See Exhibit Noble Solutions/100, Higgins/4, lines 12-19.
[40] See Exhibit Noble Solutions/100, Higgins/22 (lines 20-23) and Higgins/23 (lines 1-3).

> *"PacifiCorp's proposal for handling a [Direct Access Service Request (DASR) that arrives after the 13-business-day advance deadline for a customer to start the five-year opt-out program on January 1 is to deny participation in the program for a full year. This approach, which is unstated in the tariff, is unreasonable. Instead, the customer should have the option to enter the five-year program by paying PacifiCorp all applicable five-year opt-out charges that would have applied between January 1 and the effective date of the DASR in excess of the amount that the customer is charged by PacifiCorp under the default participation in Schedule 220 during that period."*[41]

Q. What is Staff's position regarding this issue?

A. Staff finds that Noble Solutions' request is not unreasonable, because giving more time to potential direct access customers, without causing detriment to the Company, is reasonable. Nevertheless, Staff would like to will review the Company's Reply testimony regarding this issue and further consider the matter.

Q. Does it conclude your testimony?

A. Yes.

[41] See Exhibit Noble Solutions/100, Higgins/4 (lines 20-23) and Higgins/5 (lines 1-3).

CASE: UE 296
WITNESS: JORGE ORDONEZ

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Exhibits in Support
Of Cross-Answering Testimony

August 3, 2015

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July 6, 2015

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RE: OR Docket No. UE 296
OPUC Data Request (47)

Please find enclosed PacifiCorp's Response to OPUC Data Request 47. Provided on the enclosed Confidential CD is Confidential Attachment OPUC 47. 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.

If you have any questions, please call me at (503) 813-6642.

Sincerely,

Erin Apperson/car

Erin Apperson
Manager, State Regulatory Affairs

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OPUC Data Request 47

For the period from January 2012 through December 2014, please provide the actual monthly average of contingency reserves and regulating margin reserves that the Company has shared between its east and west balancing authority areas (BAAs).

Response to OPUC Data Request 47

The Company objects to this request as not reasonably calculated to lead to the discovery of admissible evidence and as requiring development of a special study or information not maintained in the ordinary course of business. Without waiving these objections, the Company responds as follows:

The Company does not have the requested information.

Prior to the start of Energy Imbalance Market (EIM) operations the Company held contingency reserves and regulating margin reserves separately for its east balancing authority area (BAA) and west BAA. During an hour the Company could dispatch west resources to meet an east regulating reserve requirement or vice-versa, up to its dynamic transfer limits. This allowed the Company to effectively transfer part of the regulating margin requirement from one BAA to the other.

Under EIM operations the Company continues to hold contingency reserves and regulating margin reserves separately for its east and west BAAs. During an hour the California Independent System Operator's (CAISO) EIM model dispatches the most economic resources to meet regulating requirements, subject to transfer limits. However, the Company's BAA's are each required to meet the CAISO's hourly flexible resource requirement independently. As a result, the regulating margin requirement can no longer be transferred from one BAA to the other.

On limited occasions since the start of EIM operations, the Company has designated a portion of its dynamic transfer capability for transferring contingency reserves from its east BAA to its West BAA. The dynamic transfer capability designated for contingency reserve transfer is not available for economic dispatch within the EIM. Please refer to Confidential Attachment OPUC 47 for details.

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.

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RE: OR Docket No. UE 296
OPUC Data Request (52-56)

Please find enclosed PacifiCorp's Response to OPUC Data Request 52.

If you have any questions, please call me at (503) 813-6642.

Sincerely,

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OPUC Data Request 52

Regarding Table 2 of PacifiCorp Exhibit PAC/100, Dickman/9, where the Company presented $8.4 million of system-wide EIM Inter-regional benefits that resulted from an assumed average of 278 MW[1] of available transmission capacity between PacifiCorp and the California Independent System Operator's (CAISO) BAAs, please:

Provide the average of available transmission capacity between PacifiCorp's BAAs in the same period as the period used to estimate the 278 MW referred above; please provide the work papers used to respond to this question in electronic spreadsheet format with cell references and formulae intact.

Response to OPUC Data Request 52

In general, during December 2014 and January 2015 the Company's full 200 megawatts (MW) of dynamic transfer capability between its balancing authority areas (BAA) was made available for use within the Energy Imbalance Market (EIM). The Company has not yet gathered the data to measure the precise capability in all hours, and will supplement this response when it becomes available.

[1] See Exhibit PAC/100, Dickman/17, lines 17-22.

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July 16, 2015

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RE: OR Docket No. UE 296
OPUC Data Request (52-56)

Please find enclosed PacifiCorp's Responses to OPUC Data Requests 53-56. The response to OPUC 52 will be provided separately. Also provided are Attachments OPUC 56 –(2, 5, 7). Provided on the enclosed Confidential CD are Confidential Attachments OPUC 56 –(1, 3, 4, 6). The information provided in the Confidential Attachments is designated as confidential under the protective order in these proceedings and may only be disclosed to qualified persons as defined in that order.

If you have any questions, please call me at (503) 813-6642.

Sincerely,

Erin Apperson/

Erin Apperson
Manager, State Regulatory Affairs

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OPUC Data Request 53

Regarding Table 2 of PacifiCorp Exhibit PAC/100, Dickman/9, where the Company presented $8.4 million of system-wide EIM Inter-regional benefits that resulted from an average 278 MW[1] of available transmission capacity between PacifiCorp and the California Independent System Operator's (CAISO) BAAs, please:

Please re-estimate the $8.4 million of system-wide EIM Inter-Regional Benefits assuming 400 MW of dynamic transfer capability (DTC) between PacifiCorp's BAAs that result from Docket No. UP-315 (In the matter of PacifiCorp, dba Pacific Power and Idaho Power Company's Joint Application for an Order Authorizing the Exchange of Certain Transmission Assets) approved by the Commission in Order No. 15-184;[2] please include the work papers used to respond to this question in electronic spreadsheet format with cell references and formulae intact.

Response to OPUC Data Request 53

The Company's $8.4 million estimate of system-wide Energy Imbalance Market (EIM) inter-regional benefits is a function of transmission available on the California Oregon Intertie (COI) and is not dependent on the level of dynamic transfer capability between the Company's balancing authority areas (BAA).

[1] See Exhibit PAC/100, Dickman/17, lines 17-22.
[2] See http://apps.puc.state.or.us/orders/2015ords/15-184.pdf

OPUC Data Request 55

Regarding PacifiCorp 2012 Wind Integration Study filed with the Company's 2013 IRP, where the Company represented:

"*A **new control performance paradigm featuring a 30-minute balancing market** [emphasis added] is under regional evaluation. Per current operational practice, the 60-min market and operational paradigm is the base of the Wind Study design. However, to assess the potential benefits of a 30-minute clearing market for PacifiCorp's customers, an alternate calculation has been prepared by reducing the load and wind forecasting time interval to 30 minutes for wind and load demands. Table H.20 [below] compares the regulation reserves for the 30-min balancing market scenario and the default 60-minute balancing market case for PACE and PACW. This calculation assumes **adequate market depth at all 30-minute intervals such that the Company can rebalance system deviations from the market** [emphasis added].The ramp obligation is assumed to remain supplied by the Company's hourly generation planning.*"

Table H.20 - 30-minute Balancing Interval Scenario Results (MW)

	Regulation West	Regulation East	Ramp	Total
Scenario	105	233	128	466
2012 Study	149	302	128	579

Please respond the following questions:

(a) Does the **new control performance paradigm featuring a 30-minute balancing market** that was under consideration as of the date of the time of the 2012 WIS was embodied by the current functioning Energy Imbalance Market (EIM) between PacifiCorp and the California Independent System Operator (CAISO) that was launched in November 2014? Please explain the Company's response;[1]

(b) If the response to part "a" of this question is "yes," please explain whether or not the EIM has an **adequate market depth at all 30-minute intervals such that the Company can rebalance system deviations from the market?** Please explain the Company's response;

(c) Regarding part "b" of this data request, please provide for the period of December 2014 through May 2015, the percentage of 30-min intervals from all intervals when there was an adequate market depth such that the Company could rebalance system variations from the market;

[1] PacifiCorp and the California Independent System Operator launched the Energy Imbalance Market in November 2014. The EIM uses a sophisticated system to automatically balance demand every five minutes with the lowest cost energy available across the initial six-state combined grid. See http://www.pacificorp.com/about/eim.html

(d) If the response to part “a” of this question is “yes,” please explain whether or not the EIM has an adequate market depth at all 15-, 10-, 5-minute, or other intervals, from all intervals, such that the Company can rebalance system deviations from the market?; Please explain the Company’s response;

(e) Regarding part “d” of this data request, please provide for the period of December 2014 through May 2015, the percentage of 15-min, 10-min, 5-minute, or other interval, where there was an adequate market depth such that the Company could rebalance system variations from the market.

Response to OPUC Data Request 55

(a) No. The current Energy Imbalance Market (EIM) market does not incorporate the 30 minute market balancing paradigm considered in the 2012 Wind Integration Study (2012 WIS). The 2012 WIS was predicated on the Company being able to buy or sell for the bottom half of each hour to free up any regulation reserves that had been deployed in the top half of the hour. This is not how the EIM functions. To participate in the EIM, the Company must demonstrate to the California Independent System Operator (CAISO) that it has sufficient flexible resource capacity for the entire hour. The Company’s and CAISO’s flexible resources are then dispatched if they provide the lowest cost means of balancing the overall EIM requirements (subject to transmission constraints). As a result, the EIM does not reduce the Company’s regulation reserve requirement, other than through the flexibility reserve diversity benefit.

(b) Not applicable.

(c) Not applicable.

(d) Not applicable.

(e) Not applicable.

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July 24, 2015

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RE: OR Docket No. UE 296
OPUC Data Request (52-56)

Please find enclosed PacifiCorp's 1st Supplemental Response to OPUC Data Request 55.

If you have any questions, please call me at (503) 813-6642.

Sincerely,

Erin Apperson/ksw

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Manager, State Regulatory Affairs

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OPUC Data Request 55

Regarding PacifiCorp 2012 Wind Integration Study filed with the Company's 2013 IRP, where the Company represented:

"A ***new control performance paradigm featuring a 30-minute balancing market*** *[emphasis added] is under regional evaluation**.** Per current operational practice, the 60-min market and operational paradigm is the base of the Wind Study design. However, to assess the potential benefits of a 30-minute clearing market for PacifiCorp's customers, an alternate calculation has been prepared by reducing the load and wind forecasting time interval to 30 minutes for wind and load demands. Table H.20 [below] compares the regulation reserves for the 30-min balancing market scenario and the default 60-minute balancing market case for PACE and PACW. This calculation assumes* ***adequate market depth at all 30-minute intervals such that the Company can rebalance system deviations from the market*** *[emphasis added].The ramp obligation is assumed to remain supplied by the Company's hourly generation planning."*

Table H.20 - 30-minute Balancing Interval Scenario Results (MW)

	Regulation West	Regulation East	Ramp	Total
Scenario	105	233	128	466
2012 Study	149	302	128	579

Please respond the following questions:

(a) Does the **new control performance paradigm featuring a 30-minute balancing market** that was under consideration as of the date of the time of the 2012 WIS was embodied by the current functioning Energy Imbalance Market (EIM) between PacifiCorp and the California Independent System Operator (CAISO) that was launched in November 2014? Please explain the Company's response;[1]

(b) If the response to part "a" of this question is "yes," please explain whether or not the EIM has an **adequate market depth at all 30-minute intervals such that the Company can rebalance system deviations from the market?** Please explain the Company's response;

(c) Regarding part "b" of this data request, please provide for the period of December 2014 through May 2015, the percentage of 30-min intervals from all intervals when there was an adequate market depth such that the Company could rebalance system variations from the market;

[1] PacifiCorp and the California Independent System Operator launched the Energy Imbalance Market in November 2014. The EIM uses a sophisticated system to automatically balance demand every five minutes with the lowest cost energy available across the initial six-state combined grid. See http://www.pacificorp.com/about/eim.html

(d) If the response to part "a" of this question is "yes," please explain whether or not the EIM has an adequate market depth at all 15-, 10-, 5-minute, or other intervals, from all intervals, such that the Company can rebalance system deviations from the market?; Please explain the Company's response;

(e) Regarding part "d" of this data request, please provide for the period of December 2014 through May 2015, the percentage of 15-min, 10-min, 5-minute, or other interval, where there was an adequate market depth such that the Company could rebalance system variations from the market.

1st Supplemental Response to OPUC Data Request 55

Further to the Company's response to OPUC Data Request 55 dated July 16, 2015, the Company provides the following supplemental information:

Since the development of the 2012 Wind Integrated Study (2012 WIS), a 30-minute balancing market has not emerged that would enable PacifiCorp to rebalance system deviations from the market at less than 60-minute intervals.

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July 9, 2015

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RE: OR Docket No. UE 296
OPUC Data Request (49-51)

Please find enclosed PacifiCorp's Responses to OPUC Data Requests 49 and 51. Also provided is Attachment OPUC 49. Provided on the enclosed Confidential CD are Confidential Attachments OPUC 51 –(1-3). The information provided in the Confidential Attachments is designated as confidential under the protective order in these proceedings and may only be disclosed to qualified persons as defined in that order.

If you have any questions, please call me at (503) 813-6642.

Sincerely,

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OPUC Data Request 49

Regarding Exhibit ICNU/100, Mullins/27, lines 2-6:

"*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 90.0% confidence interval, or a 95% confidence interval.*"

And,

Regarding Exhibit ICNU/100, Mullins/28, lines 8-14:

"*While I believe there would be merit in using a confidence interval corresponding to the Company's historical Control Performance Standard 2 (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 performed 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*."

Please:

(a) Explain why the Company did not use a 90 percent confidence interval, which is consistent with the lower bound of the CPS2 standard, instead of the 99.7 percent used for estimating reserves given the fact that, on average, CPS2 measures from 2012 through 2014 were 61.7 percent for the west balancing authority and 65.2 for the east balancing authority; and

(b) Explain how PacifiCorp modeled in GRID the 99.7 confidence interval metric referred above.

Response to OPUC Data Request 49

(a) It is the Company's responsibility to carry enough reserves to deal with system uncertainty across all hours of the year, 100 percent of the time. Establishing a 99.7 percent confidence interval (3 standard deviations) is done to remove outliers in the historical data.

As of March 1, 2010, the Company began operating under the Reliability-Based Control (RBC) Proof-of-Concept Field Trial under Project 2007-18 for the Western Electricity Coordinating Council (WECC) and is no longer subject to North America

Electric Reliability Corporation (NERC) Critical Performance Standards (CPS) 2. This new WECC standard is tied to changes in PacifiCorp's Area Control Error (ACE) as they affect interconnection frequency. As frequency fluctuates, real-time operators use Company assets to maintain or correct ACE to support system frequency. Any ACE deviation outside the allowable limit that is contributing excess or deficient frequency must be corrected within a 30-minute period. All deviations must be corrected within 30-minutes 100 percent of the time or the Company is in violation and non-compliant. For further information, please refer to page 120 of Volume II, Appendix H of the 2015 Integrated Resource Plan (IRP), as well as the following website link:

http://westernenergyboard.org/reliability/reliability-based-control-rbc/

(b) The Company's 2014 Wind Integration Study (2014 WIS) produced reserve requirements as a function of load and wind based on a 99.7 percent confidence level. Because the Generation and Regulation Initiative Decision Tool (GRID) forecast is based on these requirements, the same confidence level is expected to be achieved. For additional details on calculations based on the 2014 WIS results, please refer to the Company's response to ICNU Data Request 0011, provided here as Attachment OPUC 49. For additional details on the modeling of the reserve requirement in GRID, please refer to the Company's 1st Supplemental response to OPUC Data Request 29.

OPUC Data Request 54

Please provide a comprehensive explanation of how GRID models reserves and **reconcile** such modeling with the real life reserves that the Company is required to hold such as the types of reserves mentioned in the Company's 2014 Wind Integration Study (WIS) filed as Appendix H of PacifiCorp 2015 Integrated Resource Plan (e.g., Operating Reserve, Contingency Reserve, Regulating Margin, Ramp Reserve, Regulation Reserve including Regulation Reserve *per se* and Following Reserve).

Please note for your response that by "**reconcile"**, Staff means that the Company should include an explanation of how the GRID modeling reflects the real life reserve requirement as described in the Company's 2014 WIS. (Staff is cognizant of the fact that no model will reflect faultlessly real life aspects of power system operations).

Response to OPUC Data Request 54

For a comprehensive explanation of how the Generation and Regulation Initiative Decision Tool (GRID) models reserves, please refer to the Company's 1st Supplemental response to OPUC Data Request 29.

As described in the above referenced response, there are two basic categories of reserve requirements: (1) contingency reserves, and (2) regulating margin reserves.

The contingency reserve requirement in GRID is based on the same calculation as the requirement in actual operations, in accordance with the current BAL-002-WECC-2 reliability standard.

The overall regulating margin reserve requirement is specified in the Reliability-Based Control (RBC) Proof-of-Concept Field Trial under Project 2007-18 for the Western Electricity Coordinating Council (WECC). Under this standard any Area Control Error (ACE) deviation outside the allowable limit that is contributing excess or deficient interconnection frequency must be corrected within a 30-minute period. Please refer to the Company's response to OPUC Data Request 49 for more details. The 2014 Wind Integration Study (2014 WIS) estimated the regulating reserves necessary to ensure compliance with the RBC standard. By including the regulating reserve amounts from the 2014 WIS, GRID also represents compliance with the RBC standard.

The 2014 WIS broke down the regulating margin reserves into two components:

(1) The ramp reserve requirement represents the minimum amount of reserves necessary for the system to transition from the net area load in one hour to the net area load in the next hour, assuming both were known precisely and the change occurred uniformly and continuously. GRID contains the same ramp reserve calculation employed in the 2014 WIS.

(2) The regulation reserve requirement consists of regulating reserves, which represent the uncertainty in the reserve need over 10 minute intervals, and following reserves, which represent the reserve need over sixty minute intervals. GRID contains the same hourly regulation reserve calculation employed in the 2014 WIS, with adjustments for incremental wind capacity not evaluated in the 2014 WIS and for flexibility reserve diversity credits resulting from the Company's participation in Energy Imbalance Market (EIM).

OPUC Data Request 51

Please provide a GRID scenario assuming that Hermiston Power Purchase Agreement is in effect the entire 2016 year instead of the Company-assumed operation of only half of the 2016 year. Please provide the GRID scenario results including the work papers associated with the requested run.

Response to OPUC Data Request 51

Please refer to Confidential Attachment OPUC 51-1, which provides the net power costs (NPC) results of assuming the Hermiston Power Purchase Agreement (PPA) was extended under the terms of the contract. NPC is higher as a result of the fixed costs under the contract, as shown on tab "Hermiston Purchase Summary." Please refer to Confidential Attachment OPUC 51-2, which provides calculations supporting the NPC result. Please refer to Confidential Attachment OPUC 51 -3, which provides the Generation and Regulation Initiative Decision Tool (GRID) project containing the requested scenario. Please refer to the Company's response to ICNU Data Request 0054; specifically Confidential Attachment ICNU 0054, which provides additional information about the terms of the Hermiston PPA extension option. A copy of the Company's response to ICNU Data Request 0054 was provided with the Company's response to OPUC Data Request 50.

The information provided in the Confidential Attachments 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 - SERVICE LIST

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CERTIFICATE OF SERVICE

UE 296

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

Dated this 3rd day of August, 2015 at Salem, Oregon

Kay Barnes

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