



Oregon

Kate Brown, Governor

Public Utility Commission

201 High St SE Suite 100

Salem, OR 97301

Mailing Address: PO Box 1088

Salem, OR 97308-1088

Consumer Services

1-800-522-2404

Local: 503-378-6600

Administrative Services

503-373-7394

August 3, 2015

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OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
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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
Utility Program
(503) 378-5763
Email: kay.barnes@state.or.us

CASE: UE 296
WITNESS: JORGE ORDONEZ

**PUBLIC UTILITY COMMISSION
OF
OREGON**

STAFF EXHIBIT 200

Cross-Answering Testimony

August 3, 2015

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

2 A. My name is Jorge Ordonez. I am employed by the Public Utility Commission of
3 Oregon (OPUC) as a Senior Economist in the Energy Resources and Planning
4 Division. My business address is 201 High St. SE, Suite 100, Salem, Oregon
5 97301.

6 **Q. Please describe your educational background and work experience.**

7 A. My Witness Qualification Statement is found in Exhibit Staff/101, filed with my
8 Opening Testimony in this proceeding.

9 **Q. What is the purpose of your testimony?**

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

14 **Q. Did you prepare an exhibit for this docket?**

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

16 **Q. How is your testimony organized?**

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

- 18 I. Issues raised in Staff's Opening Testimony:
19 1) BAAs Nexus Modeling,
20 2) EIM Within-hour Benefits, and
21 3) Day-ahead and Real-time Modeling.
22 II. Issues raised in intervenors' Opening Testimonies:
23 4) EIM Inter-regional Benefits,
24 5) EIM New Participants,
25 6) Reserves / Reliability Metric,
26 7) Reserves / PSE & APS Reserve Diversity,
27 8) Hermiston Prudence and Point-to-point Transmission,
28 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. BAA Nexus Modeling: 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. EIM Within-Hour Benefits: 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. Day-Ahead and Real-Time Modeling: 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

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

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

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

19 6. Reserves / Reliability Metric: Staff generally agrees with PacifiCorp that it
20 "is the Company's responsibility to carry enough reserves to deal with system
21 uncertainty across all hours of the year." Therefore, Staff does not
22 recommend ICNU's NPC downward adjustment of \$11.2 million on a total-
23 Company basis, with \$2.8 million allocated to Oregon.

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

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

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

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

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

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

3 Staff recommends that the Commission adopt an increase of NPC by
4 \$0.2 million on a total-Company basis, with \$52,107 allocated to Oregon.

5 11. Direct Access:

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

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

10 Schedule 200, Costs in Years 6 through 10: Staff believes the

11 Commission's issuance of Order No. 15-195 on June 16, 2015 was too
12 recent to merit changing the methodology used for developing Schedule
13 296. Nevertheless, Staff would like to review the Company's Reply
14 testimony regarding this issue to determine the reasonableness of the
15 positions of the Company and Noble Solutions.

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

20 **1. BAAs Nexus Modeling**

21 **Q. What is Staff's summary recommendation regarding this issue (i.e.,**
22 **BAAs Nexus Modeling)?**
23
24

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

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

6 A. In its Opening Testimony, Staff recommended to the Commission that the
7 Company refine, if possible, its BAAs Nexus Modeling in the GRID model for
8 the next TAM, preferably for the 2017 TAM.¹ Staff also represented that, in the
9 meantime, it would continue to analyze this issue, and that it was developing a
10 specific adjustment to provide in this round of testimony. Staff expected to
11 include the potential benefits of PacifiCorp being able to share reserves
12 between its BAAs due to the availability of 400 MW of DTC between
13 PacifiCorp's BAAs.² Staff further indicated that it had issued Data Request (DR)
14 47 asking the Company to provide actual levels, if any, of reserves shared
15 between its BAAs³ in the past.

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

17 A. In the Company's response to Staff DR 47, which is included as Exhibit
18 Staff/201, Ordonez/1-2, the Company represented that "[o]n limited
19 occasions [emphasis added] since the start of EIM operations, the Company
20 has designated a portion of its [DTC] for transferring contingency reserves from
21 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.

1 transfer is not available for economic dispatch within EIM.” This fact was
2 demonstrated in the confidential portion of the Company’s response to Staff
3 DR 47.

4 **Q. Does the Company’s response satisfy Staff’s concerns?**

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

8 **Q. Is Staff foregoing an adjustment associated with the increased amount**
9 **of DTC between PacifiCorp’s BAAs?**

10 A. No. Staff would like to clarify that the benefit proposed in its Opening
11 Testimony was labeled “a potential benefit” from the additional 200 MW of DTC
12 between PacifiCorp’s BAAs from 200 MW to 400 MW.

13 **Q. Is Staff proposing another adjustment to reflect this increased amount**
14 **of DTC between PacifiCorp’s BAAs?**

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

17 *“In general, during December 2014 and January 2015 the Company’s*
18 *full 200 megawatts (MW) of [DTC] was made available for use within*
19 *the Energy Imbalance Market (EIM).”*

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

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

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

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

13 **Q. Does that statement appear to be contradictory?**

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

19 PacifiCorp further represented "in Confidential Exhibit PAC/105, [that]
20 the Company's EIM exports [to the CAISO] in December 2014 and January
21 2015 averaged 115 megawatts (MW) and had an estimated margin (transaction

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

1 revenue minus generation expense) totaling approximately \$1.3 million. The
2 transmission available to EIM averaged 278 MW.”⁵

3 **Q. Please elaborate.**

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

12 Based on the above assumption (i.e., that the resources on the margin
13 are located in the PacifiCorp east BAA) and the fact that between December
14 2014 and January 2015 the Company averaged only 115 MW of EIM exports
15 for the 278 MW of transmission available to EIM between PacifiCorp’s west
16 BAA and the CAISO, and approximately 200 MW of DTC between PacifiCorp’s
17 BAAs, increasing the DTC between PacifiCorp’s BAAs would result in doubling
18 the amount of power exported to the CAISO to approximately 230 MW. This
19 would double the \$8.4 million of inter-regional benefits proposed by the
20 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.

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

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

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

5 **3. Day-Ahead and Real-Time Modeling**

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

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

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

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

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

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

3 **Q. Please summarize ICNU's recommendation.**

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

6 *"The Company has proposed a **complex series of adjustments***
7 *[emphasis added] to reflect what it claims to be additional costs*
8 *associated with its **trading activities in forward markets** [emphasis*
9 *added]. [ICNU] generally disagree[s] with the concepts and*
10 *calculations behind the proposed adjustments and recommend[s] that*
11 *the Commission reject the Company's proposal. In connection with the*
12 *Company's proposal, [ICNU] also make[s] an alternative proposal to*
13 *model **market liquidity** [emphasis added] in GRID using a **bid-ask***
14 ***spread** [emphasis added]. The net impact of these recommendations*
15 *will reduce NPC by \$38.2 million on a total-Company basis, with \$9.4*
16 *million allocated to Oregon."*⁹

17
18 ICNU also represented:

19
20 *"The Company's participation in forward markets is tied largely into its*
21 *overall **hedging strategy** [emphasis added]."*¹⁰

22
23 *"[ICNU has] reviewed the power cost modeling of the majority of*
24 *investor-owned utilities located in the Northwest...[y]et, **none has***
25 ***alleged that there is a systematic cost of system balancing not***
26 ***already reflected in their respective power cost model** [emphasis*
27 *added]—let alone proposed the extraneous modeling adjustments that*
28 *the Company has proposed in this proceeding."*¹¹

29
30 *"The principle that forward prices represent an unbiased estimate of*
31 *future spot prices has its origin in **arbitrage pricing theory** [emphasis*
32 *added]. In an **efficient market** [emphasis added] there are assumed to*
33 *be no arbitrage opportunities..."*¹²

34
35 **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.

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

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

23
24 **Q. Please comment on ICNU and CUB's positions.**

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

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

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

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

8
9 Staff proposes that these multiple issues related to the Company's proposed
10 change should be addressed in a docket that is separate from the current UE
11 296 (PacifiCorp 2016 TAM).

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

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

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

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

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

7 A. In Order No. 07-15 of Docket Nos. UE 180,¹⁴ UE 181,¹⁵ and UE 184¹⁶ of
8 Portland General Electric (PGE), the Commission made an adjustment of \$4.6
9 million¹⁷ out of approximately \$857 million¹⁸ of total power costs (i.e., 0.5
10 percent of total power costs) and opened a new generic docket to examine the
11 issue at stake.

12 In this current docket, the adjustment at stake represents
13 approximately \$8 million out of approximately \$375 million¹⁹ of total power
14 costs (i.e., a more significant 2.1 percent of total power costs).

15 **4. EIM Inter-Regional Benefits**

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

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."

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

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

10 **Q. Has Staff changed its recommendation?**

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

13 **Q. Please summarize ICNU's recommendation.**

14 A. ICNU represented:

15 *"Seasonality. The Company calculated the level of inter-regional EIM*
16 *benefits in the test period using only two months of data—December*
17 *2014 and January 2015. The economic margins used in these two*
18 *winter months, however, are not representative of the margins*
19 *expected to be earned in the summer months. Accordingly, [ICNU*
20 *proposed] a methodology to tie the forecasted economic margins of*
21 *EIM transfers with the Cal-ISO to the seasonal spreads between the*
22 *Mid-Columbia and California-Oregon Border markets, reducing NPC*
23 *by \$1.5 million on a total-Company basis, with \$0.4 million allocated to*
24 *Oregon."*²¹

25
26 **Q. Please summarize CUB's recommendation.**

27 A. CUB represented:

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

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

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.

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

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

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

15 **5. EIM New Participants**

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

18 A. In its Opening Testimony, ICNU recommended:

19 *"New EIM Participants. The Company excluded a provision to account*
20 *for additional inter-regional EIM transfers with new participants,*
21 *including NV Energy, PSE and APS. [ICNU] proposes a methodology*
22 *to account for these additional inter-regional EIM transfers that will*
23 *reduce NPC by \$3.2 million on a total-Company basis, with \$0.8 million*
24 *allocated to Oregon."*²³

25 **Q. Please explain the ICNU-proposed methodology.**

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 1²⁶Inter-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.

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

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

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

9 **6. Reserves / Reliability Metric**

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

12 A. In its Opening Testimony, ICNU recommended:

13 *"Reliability Metric. The reserves in the Company's GRID model are*
14 *calculated based on a 99.7% confidence interval. However, the*
15 *Company's actual historical reliability performance has been measured*
16 *at lower levels based on Control Performance Standard 2 [(CPS 2*
17 *Standard)]. Accordingly, [ICNU recommends] modeling a 90%*
18 *confidence interval, which will reduce NPC by \$11.2 million on a total-*
19 *Company basis, with \$2.8 million allocated to Oregon."²⁷*

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

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

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

1 **Q. What was the Company's response?**

2 A. In DR 49, the Company stated that:

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

15
16 **Q. What is Staff's understanding of the Company's response?**

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

21 **Q. How did the Company respond to DR 54?**

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

23 *"The overall regulating margin reserve requirement is specified in the*
24 *[RBC Standard]. Under this standard any Area Control Error (ACE)*
25 *deviation outside the allowance limit that is contributing [to the] excess*
26 *or deficient interconnection frequency must be corrected within a*
27 *30-minute period... The 2014 Wind Integration Study (2014 WIS)*
28 *estimated the regulating reserves necessary to ensure compliance with*
29 *the RBC standard. By including the regulating reserve amounts from*
30 *the 2014 WIS, GRID also represents compliance with the **RBC***
31 ***[S]tandard.[emphasis added]."***

32
33 **Q. What is Staff's position and recommendation regarding this issue?**

1 A. Staff generally agrees with PacifiCorp that it “is the Company’s responsibility to
2 carry enough reserves to deal with system uncertainty across all hours of the
3 year.”²⁸ Therefore, Staff does not support ICNU’s NPC downward adjustment
4 of \$11.2 million on a total-Company basis, with \$2.8 million allocated to
5 Oregon.

6 **7. Reserves: PSE and APS Reserve Diversity**

7 **Q. Please state which party raised this issue and summarize that party’s**
8 **recommendation to the Commission.**

9 A. In its Opening Testimony, ICNU recommended:

10 *“PSE & APS Reserve Diversity. While the Company included flexibility*
11 *reserve diversity benefits associated with the addition of NV Energy*
12 *into the [EIM], it did not include incremental flexibility reserve savings*
13 *associated with the entrance of [PSE] and [APS]. [ICNU] proposes to*
14 *incorporate this additional reserve savings into the GRID model,*
15 *reducing NPC by \$60,750 on a total-Company basis, with \$15,020*
16 *allocated to Oregon.”*²⁹

17 **Q. What is Staff’s position on this issue?**

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

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

25

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.

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

3 A. In its Opening Testimony, ICNU recommended:

4 *"Prudence. The Company's analysis of whether to extend the*
5 *Hermiston Purchase contract demonstrates a fundamental flaw in the*
6 *Company's Integrated Resource Plan ('IRP'). [ICNU recommends] that*
7 *the Commission make a finding that the Company's analysis of the*
8 *Hermiston Purchase contract was not prudent because the Company*
9 *did not evaluate the benefits of the contract on the winter peak."*³⁰

10 *"Point-to-Point transmission. The Company includes in NPC*
11 *transmission costs necessary to deliver the full output of the Hermiston*
12 *facility onto its system. A portion of these costs will no longer be used*
13 *and useful when the Hermiston Purchase contract expires. [ICNU*
14 *proposes] to remove from NPC the unused portion of the Hermiston*
15 *point-to-point transmission contract, resulting in a \$0.2 million*
16 *reduction of NPC on a total-Company basis, with \$54,336 allocated to*
17 *Oregon."*³¹

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

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

26 Staff's rationale lies in the fact that, if the Company had renewed this
27 contract, the high costs associated with this contract in the 2016 test year
28 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.

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

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

4
5 **9. Modeling: Thermal Plant Forced Outage**

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

8 A. In its Opening Testimony, ICNU recommended:

9 *"Outage Modeling: The Company's new methodology to develop a*
10 *schedule of forced outages in GRID results in a pattern of frequent,*
11 *short outages that is not representative of actual operations.*
12 *Accordingly, [ICNU recommends] that the Company continue to use*
13 *the methodology approved in Docket No. UM 1355, reducing NPC by*
14 *\$0.8 million on a total-Company basis, with \$0.2 million allocated to*
15 *Oregon."*³²

16 ICNU also represented:

17 *"The Company has proposed to model outages dynamically based on*
18 *discrete events over the four-year base period. Based on the historical*
19 *data, the Company developed an hourly schedule of outages for each*
20 *plant, which it modeled in GRID in the test period. This is in contrast to*
21 *the methodology approved in Docket No. UM 1355 [(UM 1355*
22 *Methodology)] [emphasis added], where the Capacity and heat rates*
23 *of plants are derated to simulate cost impacts of outages over the*
24 *course of the test period. The impact of the Company's new*
25 *methodology is a \$0.7 million increase to NPC on a total-Company*
26 *basis, relative to the methodology approved in Docket No. UM 1355."*³³

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

29 A. The Company's direct testimony quoted the following statement made by the
30 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.

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

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

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

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

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

18 **10. Modeling: Avian Protection**

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

21 A. In its Opening Testimony, ICNU recommended:

22 *"Avian Protection. The Company has proposed to reduce the output*
23 *from several Wyoming wind resources to account for avian protection*
24 *curtailments. This adjustment is immaterial and will not improve the*
25 *accuracy of the Company's overall wind forecast. [ICNU proposes] to*
26 *remove this adjustment, reducing NPC by \$0.2 million on a total-*
27 *Company basis, with \$52,107 allocated to Oregon."*³⁵

28 **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.

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

8 **Q. What is Staff’s position on this issue?**

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

12 **Q. What is Staff’s recommendation regarding this issue?**

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

15 **11. Direct Access Issues**
16

17 **Q. Please state which party raised this issue and summarize that party’s**
18 **recommendation to the Commission.**

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

21 **Q. What is Noble Solutions’ first conclusion and recommendation?**

22 A. Noble Solutions first considered a topic known as “Freed-Up RECs”.
23 Specifically, Noble Solutions represented:

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

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

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

11 A. Yes. The Company responded as follows:

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

21
22 **Q. What is Staff's position regarding this issue?**

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

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

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

29 **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.

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

3 *"In calculating the Schedule 296 Consumer Opt-Out charge, Schedule*
4 *200 costs should not be escalated in Years 6 through 10 as proposed by*
5 *PacifiCorp. Rather, Schedule 200 costs used in this calculation should*
6 *decline each year from Year 6 through Year 10 to reflect the decline in*
7 *the Company's return on generation rate base attributable to the*
8 *departed customers' loads, due to the effects of accumulated*
9 *depreciation and amortization. The effects of this decline in return*
10 *should be passed through to the Consumer Opt-Out charge."*³⁹

11
12 **Q. On what basis is Noble Solutions requesting the change to the**
13 **calculation in Schedule 296?**

14 A. Noble Solutions represented:

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

23
24 **Q. What is Staff's position regarding this issue?**

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

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

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

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).

1 *“PacifiCorp’s proposal for handling a [Direct Access Service Request*
2 *(DASR) that arrives after the 13-business-day advance deadline for a*
3 *customer to start the five-year opt-out program on January 1 is to deny*
4 *participation in the program for a full year. This approach, which is*
5 *unstated in the tariff, is unreasonable. Instead, the customer should*
6 *have the option to enter the five-year program by paying PacifiCorp all*
7 *applicable five-year opt-out charges that would have applied between*
8 *January 1 and the effective date of the DASR in excess of the amount*
9 *that the customer is charged by PacifiCorp under the default*
10 *participation in Schedule 220 during that period.”*⁴¹
11

12 **Q. What is Staff’s position regarding this issue?**

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

18 **Q. Does it conclude your testimony?**

19 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



825 NE Multnomah, Suite 2000
Portland, Oregon 97232

July 6, 2015

Kay Barnes
Oregon Public Utility Commission
201 High St. SE
Salem, OR 97301-3612
puc.datarequests@state.or.us (C)

Michael Weirich
Department of Justice
1162 Court St NE,
Salem, OR 97301-4096
jmichael.weirich@state.or.us (C)

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,

A handwritten signature in cursive script that reads "Erin Apperson".

Erin Apperson
Manager, State Regulatory Affairs

Enclosures

C.c.: S. Bradley Van Cleve bvc@dvclaw.com (C)
Jesse Cowell/ICNU jec@dvclaw.com (W)
Bradley G. Mullins/ICNU brmullins@mwanalytics.com (C)
Gregory M. Adams/NAES greg@richardsonadams.com (C)
Kevin C. Higgins/NAES khiggins@energystrat.com (C)
Greg Bass/NAES gbass@noblesolutions.com
Nadine Hanhan/CUB Nadine@oregoncub.org dockets@oregoncub.org (C)

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.



825 NE Multnomah, Suite 2000
Portland, Oregon 97232

July 17, 2015

Kay Barnes
Oregon Public Utility Commission
201 High St. SE
Salem, OR 97301-3612
puc.datarequests@state.or.us (C)

Michael Weirich
Department of Justice
1162 Court St NE,
Salem, OR 97301-4096
jmichael.weirich@state.or.us (C)

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,

A handwritten signature in cursive script that reads "Erin Apperson".

Erin Apperson
Manager, State Regulatory Affairs

Enclosures

C.c.: S. Bradley Van Cleve bvc@dvclaw.com (C)
Jesse Cowell/ICNU jec@dvclaw.com (W)
Bradley G. Mullins/ICNU brmullins@mwanalytics.com (C)
Gregory M. Adams/NAES greg@richardsonadams.com (C)
Kevin C. Higgins/NAES khiggins@energystrat.com (C)
Greg Bass/NAES gbass@noblesolutions.com
Nadine Hanhan/CUB Nadine@oregoncub.org dockets@oregoncub.org (C)

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 MW¹ 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.



825 NE Multnomah, Suite 2000
Portland, Oregon 97232

July 16, 2015

Kay Barnes
Oregon Public Utility Commission
201 High St. SE
Salem, OR 97301-3612
puc.datarequests@state.or.us (C)

Michael Weirich
Department of Justice
1162 Court St NE,
Salem, OR 97301-4096
jmichael.weirich@state.or.us (C)

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,

A handwritten signature in cursive script that reads "Erin Apperson/km".

Erin Apperson
Manager, State Regulatory Affairs

Enclosures

C.c.: S. Bradley Van Cleve bvc@dvclaw.com (C)
Jesse Cowell/ICNU jec@dvclaw.com (W)
Bradley G. Mullins/ICNU brmullins@mwanalytics.com (C)
Gregory M. Adams/NAES greg@richardsonadams.com (C)
Kevin C. Higgins/NAES khiggins@energystrat.com (C)
Greg Bass/NAES gbass@noblesolutions.com
Nadine Hanhan/CUB Nadine@oregoncub.org dockets@oregoncub.org (C)

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 MW¹ 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:

- 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
- 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;
- 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.



825 NE Multnomah, Suite 2000
Portland, Oregon 97232

July 24, 2015

Kay Barnes
Oregon Public Utility Commission
201 High St. SE
Salem, OR 97301-3612
puc.datarequests@state.or.us (C)

Michael Weirich
Department of Justice
1162 Court St NE,
Salem, OR 97301-4096
jmichael.weirich@state.or.us (C)

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,

A handwritten signature in cursive script that reads "Erin Apperson / uen".

Erin Apperson
Manager, State Regulatory Affairs

Enclosures

C.c.: S. Bradley Van Cleve bvc@dvclaw.com (C)
Jesse Cowell/ICNU jec@dvclaw.com (W)
Bradley G. Mullins/ICNU brmullins@mwanalytics.com (C)
Gregory M. Adams/NAES greg@richardsonadams.com (C)
Kevin C. Higgins/NAES khiggins@energystrat.com (C)
Greg Bass/NAES gbass@noblesolutions.com
Nadine Hanhan/CUB Nadine@oregoncub.org dockets@oregoncub.org (C)

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:

- 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
- 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;
- 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.



825 NE Multnomah, Suite 2000
Portland, Oregon 97232

July 9, 2015

Kay Barnes
Oregon Public Utility Commission
201 High St. SE
Salem, OR 97301-3612
puc.datarequests@state.or.us (C)

Michael Weirich
Department of Justice
1162 Court St NE,
Salem, OR 97301-4096
jmichael.weirich@state.or.us (C)

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,

A handwritten signature in cursive script that reads "Erin Apperson/han".

Erin Apperson
Manager, State Regulatory Affairs

Enclosures

C.c.: S. Bradley Van Cleve bvc@dvclaw.com (C)
Jesse Cowell/ICNU jec@dvclaw.com (W)
Bradley G. Mullins/ICNU brmullins@mwanalytics.com (C)
Gregory M. Adams/NAES greg@richardsonadams.com (C)
Kevin C. Higgins/NAES khiggins@energystrat.com (C)
Greg Bass/NAES gbass@noblesolutions.com
Nadine Hanhan/CUB Nadine@oregoncub.org dockets@oregoncub.org (C)

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

CITIZENS' UTILITY BOARD OF OREGON	
OPUC DOCKETS	610 SW BROADWAY, STE 400 PORTLAND OR 97205 dockets@oregoncub.org
ROBERT JENKS (C)	610 SW BROADWAY, STE 400 PORTLAND OR 97205 bob@oregoncub.org
SOMMER TEMPLET (C)	610 SW BROADWAY, STE. 400 PORTLAND OR 97205 sommer@oregoncub.org
DAVISON VAN CLEVE	
JESSE E COWELL	333 SW TAYLOR ST., SUITE 400 PORTLAND OR 97204 jec@dvclaw.com
DAVISON VAN CLEVE PC	
S BRADLEY VAN CLEVE (C)	333 SW TAYLOR - STE 400 PORTLAND OR 97204 bvc@dvclaw.com
ENERGY STRATEGIES LLC	
KEVIN HIGGINS (C)	215 STATE ST - STE 200 SALT LAKE CITY UT 84111-2322 khiggins@energystrat.com
MCDOWELL RACKNER & GIBSON PC	
KATHERINE A MCDOWELL (C)	419 SW 11TH AVE., SUITE 400 PORTLAND OR 97205 katherine@mcd-law.com
MOUNTAIN WEST ANALYTICS	
BRADLEY MULLINS (C)	333 SW TAYLOR STE 400 PORTLAND OR 97204 brmullins@mwanalytics.com
NOBLE AMERICAS ENERGY SOLUTIONS, LLC	
GREG BASS	401 WEST A ST., STE. 500 SAN DIEGO CA 92101 gbass@noblesolutions.com

PACIFICORP	
MATTHEW MCVEE	825 NE MULTNOMAH PORTLAND OR 97232 matthew.mcvee@pacificorp.com
PACIFICORP, DBA PACIFIC POWER	
OREGON DOCKETS	825 NE MULTNOMAH ST, STE 2000 PORTLAND OR 97232 oregondockets@pacificorp.com
PUBLIC UTILITY COMMISSION OF OREGON	
JORGE ORDONEZ (C)	PO BOX 1088 SALEM OR 97308-1088 jorge.ordonez@state.or.us
PUC STAFF--DEPARTMENT OF JUSTICE	
MICHAEL T WEIRICH (C)	BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4096 michael.weirich@state.or.us
RICHARDSON ADAMS, PLLC	
GREGORY M. ADAMS (C)	PO BOX 7218 BOISE ID 83702 greg@richardsonadams.com

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