Oregon
Kate Brown, Governor

Public Utility Commission
201 High St SE Suite 100
Salem, OR 97301-3398
Mailing Address: PO Box 1088
Salem, OR 97308-1088
503-373-7394

June 11, 2018

Via Electronic Filing and U.S. Mail

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

RE: Docket No. UE 339 – In the Matter of PACIFICORP 2019 TRANSITION ADJUSTMENT MECHANISM (TAM)

Enclosed are the following exhibits for Staff Opening Testimony:

Exhibit 100, page 4 is confidential
Exhibit 101, Witness qualification
Exhibit 102, Redacted version of PacifiCorp's presentation.

Exhibit 200, Confidential pages: 2, 7, 8, 13, 14, 16 and page 11 is highly-confidential.
Exhibit 201, Witness qualification
Exhibit 202, Exhibit
Exhibit 203-205, Confidential exhibits

Exhibit 300
Exhibit 301, Witness qualification

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

CERTIFICATE OF SERVICE

UE 339

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 11th day of June, 2018 at Salem, Oregon

Kay Barnes

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

UE 339
Service List (Parties)

ALLIANCE OF WESTERN ENERGY CONSUMERS

MYRALEIGH ALBERTO **(C)** **(HC)** DAVISON VAN CLEVE	1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 maa@dvclaw.com
BRADLEY MULLINS **(C)** **(HC)** MOUNTAIN WEST ANALYTICS	1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 brmullins@mwanalytics.com
TYLER C PEPPLE **(C)** **(HC)** DAVISON VAN CLEVE, PC	1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 tcp@dvclaw.com

CALPINE SOLUTIONS

GREGORY M. ADAMS **(C)** RICHARDSON ADAMS, PLLC	PO BOX 7218 BOISE ID 83702 greg@richardsonadams.com
GREG BASS CALPINE ENERGY SOLUTIONS, LLC	401 WEST A ST, STE 500 SAN DIEGO CA 92101 greg.bass@calpinesolutions.com
KEVIN HIGGINS **(C)** ENERGY STRATEGIES LLC	215 STATE ST - STE 200 SALT LAKE CITY UT 84111-2322 khiggins@energystrat.com

OREGON CITIZENS UTILITY BOARD

OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY, STE 400 PORTLAND OR 97205 dockets@oregoncub.org
MICHAEL GOETZ **(C)** **(HC)** OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY STE 400 PORTLAND OR 97205 mike@oregoncub.org
ROBERT JENKS **(C)** **(HC)** OREGON CITIZENS' UTILITY BOARD	610 SW BROADWAY, STE 400 PORTLAND OR 97205 bob@oregoncub.org

PACIFICORP

PACIFICORP, DBA PACIFIC POWER	825 NE MULTNOMAH ST, STE 2000 PORTLAND OR 97232 oregondockets@pacificorp.com
KATHERINE A MCDOWELL **(C)** **(HC)** MCDOWELL RACKNER & GIBSON PC	419 SW 11TH AVE., SUITE 400 PORTLAND OR 97205 katherine@mcd-law.com
MATTHEW MCVEE **(C)** **(HC)** PACIFICORP	825 NE MULTNOMAH PORTLAND OR 97232 matthew.mcvee@pacificorp.com

STAFF

SCOTT GIBBENS **(C)** **(HC)** PUBLIC UTILITY COMMISSION	201 HIGH ST SE SALEM OR 97301 scott.gibbens@state.or.us
KAYLIE KLEIN **(C)** **(HC)**	1162 COURT STREET NE

PUC STAFF--DEPARTMENT OF JUSTICE
SALEM OR 97301
kaylie.klein@state.or.us

SOMMER MOSER **(C)** **(HC)**
PUC STAFF - DEPARTMENT OF JUSTICE
1162 COURT ST NE
SALEM OR 97301
sommer.moser@doj.state.or.us

CASE: UE 339
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

REDACTED
June 11, 2018

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

A. My name is Scott Gibbens. I am a Senior Economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. I discuss the 2019 TAM filing and Staff's analysis of the issues. Specifically, I will discuss Staff's review of and recommended Commission action regarding: inclusion of wind repowering benefits, wind capacity factors, the Western Energy Imbalance Market benefit forecast, load forecast and allocations, wholesale transactions, Pioneer Wind QF shaping, and revenues from UP 369.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared Exhibit Staff/102, consisting of 27 pages.

Q. How is your testimony organized?

A. My testimony is organized as follows:

2019 TAM BACKGROUND

Q. Please summarize PacifiCorp's 2019 TAM filing.

A. On a system basis, the Company's initial filing requested a 2019 Net Power Cost (NPC) of approximately $1,501,455,411 without adjustments, which represents a decrease of approximately $18.1 million compared to the 2018 NPC.[1]

Q. What is the effect on an Oregon basis?

A. On an Oregon basis, the 2019 NPC of approximately $386.9 million is higher than the 2018 NPC of $365.3 million.[2] This represents a 1.3 percent increase to overall rates on a net basis.[3] I will address the drivers for an increase in Oregon despite a decrease in system power costs later in my testimony.

Q. Did PAC propose any changes from its methodology in the 2019 TAM?

A. Yes. PacifiCorp proposes to:

1. Transfer RECs to the ESS of a direct access customer.
2. Update regulating reserve requirements to be consistent with the flexible reserve study in the 2017 IRP.
3. Economic cycling of certain coal plants.
4. Include variable operations and maintenance costs in the dispatch price of thermal resources.
5. Use capacity factor for company-owned wind based on the historical average capacity factor.

---

[1] See PAC/101 Wilding/1 line 33.
[2] See PAC/101 Wilding/1 line 36.
[3] See PAC/100 Wilding/3 lines 2-5.

6. Forecast energy imbalance market benefits using a linear regression.
7. Change house shape of new wind power purchase agreements, including qualifying facilities (QFs) based on proxy wind resources, which impacts the Pioneer Wind facility in the 2019 TAM.

Q. What topics will Staff's opening testimony address?

A. Staff discusses the following issues in our opening round of testimony:

(Staff/100 - Gibbens)

1. Wind Repowering
2. Wind Capacity Factor Forecasting
3. Western EIM
4. Load Forecast
5. Wholesale Transactions
6. Pioneer Wind QF Wind Shaping
7. Revenues from UP 369

(Staff/200 Kaufman)

8. Model Validation
9. Economic Shutdown of Coal Units
10. Jim Bridger Long Term Fuel Plan
11. Bridger Coal Company Depreciation
12. Direct Access

(Staff/300 Anderson)

13. Qualifying Facilities
14. Renewable Energy Certificates

Q. Please summarize Staff's adjustments in this docket.

A. Below is a table summarizing the Staff adjustments found in Staff testimony.[4]

[BEGIN CONFIDENTIAL]

Adjustment	Amount
EIM net benefits	($14,420,311)
Wind Capacity Factors	($4,644,000)
BCC Depreciation	[redacted]
TOTAL	[redacted]

[END CONFIDENTIAL]

[4] All adjustments are listed on a system basis.

ISSUE 1. INCLUSION OF WIND REPOWERING BENEFITS

Q. Please provide a background for this issue.

A. As part of the Company's 2017 Integrated Resource Plan (IRP), PacifiCorp plans to repower its wind fleet beginning in 2019. New rotors with longer blades and new nacelles with higher-capacity generators are expected to be installed which will increase wind production by roughly 19 percent.[5] Repowering the fleet will also allow the resources to requalify for PTC's, many of which are expiring between 2016 and 2020. The Company has not included the impact of the repowering in the 2019 TAM, and has stated that it expects to include the costs and benefits of repowering in a renewable adjustment clause (RAC) deferral filing in 2019.[6]

Q. Please describe the Company's proposal regarding the treatment of impacts of repowering in the 2019 TAM.

A. The Company has not included the impacts of repowering in its 2019 TAM forecast. The Company notes that "this project will benefit customers by increasing wind production, a zero-cost fuel resource, thus reducing NPC and by requalifying the wind plants for PTCs."[7] The Company states that it "expects to include the costs and benefits of repowering in a renewable adjustment clause deferral filing in 2019."[8]

---

[5] See LC 67 Informational Update filed July 28, 2017.
[6] Staff/102, Gibbens/5.
[7] PAC/100, Wilding/8.
[8] *Ibid.*

Q. Does Staff have any concerns regarding the Company's proposal?

A. Yes. Staff has two main concerns about the Company's decision not to include the NPC and PTC benefits in the 2019 TAM. First, Staff is concerned that the Company's proposed ratemaking treatment is inconsistent with Commission policy and precedent regarding the ratemaking treatment for variable costs and benefits for RPS-compliant resources, including PTCs. Second, Staff is concerned that the Company's proposal inappropriately shifts the risk of under-performance of the wind repowering project to Oregon customers, inconsistent with the Commission's discussion in its LC 67 acknowledgment order.[9]

Commission policy and precedent regarding ratemaking treatment for costs and benefits of RPS compliant resources.

In 2007, SB 838 was passed, creating Oregon Renewable Portfolio Standard. SB 838, Section 13, provides for the recovery of "all prudently incurred costs associated with compliance with a renewable portfolio are recoverable in the rates of an electric utility."[10] SB 838 further directed the Commission to establish an automatic adjustment clause or another method for timely recovery of RPS compliance costs.[11] The Commission subsequently opened docket UM 1330, which investigated the adoption of an automatic adjustment clause or other method for timely recovery of costs as required by SB 838. The Commission adopted the non-contested stipulation filed by Portland General Electric (PGE), PacifiCorp, Oregon Staff, CUB and ICNU.[12]

[9] See Commission Order No. 18-138.
[10] Now codified at ORS 469A.120(1).
[11] ORS 469A.120(2).
[12] Order 07-572 at 10.

The stipulation authorized PGE and PacifiCorp to implement RAC tariffs by which they could recover the costs associated with RPS compliant resources. The stipulation approved by the Commission states that the revenue requirement recovered pursuant to the RAC includes:

- *The return of and on capital costs of the renewable energy source and associated transmission;*
- *Forecasted operation and maintenance costs;*
- *Forecasted property taxes;*
- *Forecasted energy tax credits; and*
- *Other forecasted costs and cost offsets authorized by SB 838* ***and not captured in the Utility's annual power cost update****.*[13]

Therefore, the Commission adopted a stipulation that required costs and benefits of RPS compliant resources not otherwise recovered in the utility's annual power cost proceedings to be recovered in the RAC. In short, the RAC is intended to cover items not otherwise included in the TAM.

Subsequent to Order No. 07-572, the Commission opened a second investigation—docket UM 1662—which considered the recovery of variable costs associated with RPS compliance (i.e., RPS compliance costs subject to forecast in the TAM or AUT, and the PCAM).[14] In that case, PGE and PacifiCorp argued that variations in PTCs and other variable costs and benefits

[13] Order 07-572 at 3 (emphasis added).
[14] Order 15-408.

should be recovered on a dollar-for-dollar basis, rather than on a forecast basis and subject to the PCAM.[15] Staff, CUB and ICNU argued that ORS469A.120(1) did not require dollar-for-dollar recovery of all RPS related costs and benefits.[16] The Commission adopted Staff's, CUB's and ICNU's position, concluding that certain RPS costs would not be subject to dollar-for-dollar recovery, and would need to be recovered through general ratemaking.[17] This includes variable costs and benefits of RPS compliance.

In 2016, the Oregon Legislature passed SB 1547, directing the Commission to allow forecast production tax credits in any variable power cost forecasting process established by the Commission.[18] In response to this directive, in it 2017 TAM, PacifiCorp proposed to include the variance between PTCs currently in base rates, as established in the Company's last general rate case, and the forecast for PTCs in 2017.[19] The Company further proposed to track variances in forecast and actual PTCs through the PCAM.[20] Staff proposed to remove the Company's PTCs from base rates, and to include the full PTC forecast in the TAM, subject to true-up in the PCAM.[21] The Company agreed to Staff's recommended ratemaking treatment.[22] The Commission adopted this ratemaking treatment.[23] Therefore, the Company's failure to

[15] Order 15-408 at 2-3.
[16] Order 15-408 at 3.
[17] Order 15-408 at 6-7.
[18] This provision is codified as ORS 757.264.
[19] UE 307 – PAC/600, Dalley/22.
[20] UE 307 – PAC/600, Dalley/22.
[21] UE 307 – PAC/600, Dalley/23.
[22] UE 307 – PAC/600, Dalley/23.
[23] Order 16-482.

include NPC and PTC benefits Wind Repowering is inconsistent with the ratemaking treatment for PTCs agreed to by the Company, and adopted by the Commission, in the Company's 2017 TAM.

In sum, the Company's proposed approach is inconsistent with the Commission's direction in Order Nos. 07-572, 15-408 and 16-482. Furthermore, Staff will reserve this issue for briefing, but notes that it questions whether the Company's proposal is consistent with ORS 757.264.

Commission direction for Wind Repowering in LC 67

Staff is also concerned that the Company's decision to exclude Wind Repowering project NPC and PTC benefits in the 2019 TAM is inconsistent with the Commission's guidance and intent in Order 18-138, the order acknowledging the Company's Energy Vision 2020 project, which includes the Wind Repowering project. Benefits of the Wind Repowering project, including NPC savings and increased PTCs, were discussed at length in the Company's IRP proceeding (Docket LC 67). In that case, Staff recommended that the Commission not acknowledge the Company's Wind Repowering project, as it was concerned about capacity factor shortfalls, PTC decreases, commercial operation date delays, changes in official forward price curves for energy, and construction cost overruns.[24] The Commission ultimately acknowledged PacifiCorp's Energy Vision 2020, including the Wind Repowering project, but noted that cost recovery "may be conditioned or limited to ensure customer

[24] Order 18-138 at 7.

benefits remain at least as favorable as IRP planning assumptions."[25] The Commission went on to state:

> For uncertainties that may persist beyond commercial operation date (post-COD risks), such as project performance, tax policy changes, and resource value relative to market, we will carefully scrutinize the net benefits during…rate recovery proceedings. We intend to ensure that customer risk exposure is mitigated appropriately, and recovery may be structured to hold PacifiCorp to the cost and benefit projects in its analysis.

PacifiCorp's proposal to exclude Wind Repowering project NPC and PTC benefits from the TAM forecast, and instead subject ratepayers to actual dollar-for-dollar ratemaking treatment of those benefits, shifts the risk the risk that benefits will not materialize from PacifiCorp to customers. Furthermore, such treatment is not consistent with the Commission's discussion in Order 18-138.

Q. What is Staff's recommendation for the treatment of the wind repowering project?

A. Staff recommends that those variable costs and benefits generally reflected in TAM proceedings be included as a forecast in the 2019 TAM. This treatment is consistent with past Commission policy and precedent, and consistent with the Commission's discussion in Order 18-138. Staff continues to believe the TAM is capable of handling the NPC and PTC impacts of the Wind Repowering project. It is able to encompass all non-Schedule 202 costs and all of the direct and indirect benefits, on a forecast basis, consistent with the ratemaking treatment for all other wind projects included in Oregon rates. Staff

[25] Order 18-138 at 8.

recommends that PacifiCorp be directed to include in its 2019 NPC forecast the NPC and PTC benefits of its Wind Repowering project.

ISSUE 2. WIND CAPACITY FACTORS

Q. Please provide a background for this issue.

A. PacifiCorp proposes to change the forecast methodology for the wind farms owned by the Company from the generation forecasts used to determine the prudence of the project to a forecast based on a rolling 48 months of historical generation. The Company states that this will better align forecast NPC with actual power costs. If the wind farm has been operating for less than four years, then the forecast will incorporate the project owner's forecast until actual generation history is available.

Q. Does Staff support the Company's change in methodology?

A. No. The Company's proposal to update its forecast methodology in this way shifts the risk of performance for utility-owned variable resources to customers. Staff believes that the Company should be held accountable to the forecasts it made during the planning of the project, because it ensures that the Company's planning incentives match ratepayer incentives. Although the Commission has allowed updates for capacity factors in the past, Staff believes that the increase in RPS requirements, which is leading to an increase of variable resources, necessitates a reexamination of this treatment in light of the recently increased RPS requirements.

The risk of performance was recently acknowledged by the Commission in PacifiCorp's most recent IRP. As discussed previously, part of the acknowledged action plan was to procure more than 1,100 MW of new Wyoming wind resources. PacifiCorp issued an RFP in order to procure bids for the proposed wind, and the resulting shortlist consisted of approximately 1,100 out of 1,300 MWs of Company owned resources.[26] Staff's report on the Shortlist pointed out that a two percent reduction in capacity factor would result in a $99 million reduction to the net present value for customers. It would require only a 4.5 percent reduction in capacity factor in order to make the projects no longer beneficial to customers. This is only one of a myriad of risks ratepayers face when a Company owned resource is built instead of a PPA. In the IE's report, they noted the higher risk borne by customers due to a large portion of Company owned resources present in the shortlist, and recommended the Commission take actions to insulate ratepayers from these risks.[27] As referenced above, Commission Order 18-138 stated:

> *For uncertainties that may persist beyond project commercial operation date (post-COD risks), such as project performance, tax policy changes, and resource value relative to market, we will carefully scrutinize the net benefits during future shortlist acknowledgement, IRP Update filing, and rate recovery proceedings. We intend to ensure that customer risk exposure is mitigated appropriately, and recovery may be structured to hold PacifiCorp to the cost and benefit projections in its analysis.*[28]

Staff's recommendation in this case is consistent with the Commission's guidance in Order 18-138. If the Company is not required to maintain the original forecasts, it has an incentive to be overly optimistic about the forecast of generation at its own plants. The Commission and legislature have often attempted to mimic market forces and foster competition whenever possible.

---

[26] Two of the projects are Build Transfer Agreements and two were developed by PacifiCorp's benchmark team. See UM 1845, IE's Final Report on the PacifiCorp Shortlist.
[27] UM 1845 IE Final Report.
[28] Commission Order No. 18-138, page 8.

The RFP process is evidence that market competition exists for utility scale renewable generation, but fair competition will only exist if the utility is incentivized to act the same as any other participant. If the PPA over estimates generation, they do not receive payment for the amount not generated. If the utility does and the Commission approves this treatment, there is no consequence.

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

A. Staff recommends that the Commission reject the Company's proposed change to wind forecasting. This would reduce NPC by $4.6 million. Staff also notes that if the Commission declines to adopt Staff's recommendation, the Commission should direct the Company to verify it is in compliance with Commission Order No. 16-482 regarding an avian curtailment adjustment for its Seven Mile Hill and Glenrock wind farms.

ISSUE 3. WESTERN ENERGY IMBALANCE MARKET

Q. What is the Energy Imbalance Market?

A. The Energy Imbalance Market (EIM) is an automated dispatch system that allows for efficient balancing of load and generation resources for participants, which provides both reliability and renewable integration benefits to the grid, and economic benefits to participants. The EIM allows for very efficient and automated re-dispatch of generators to precisely and continuously meet load in a sliding, five-minute window. Generation and load must be balanced within strict parameters at all times in order for the electric grid to remain stable. A large sustained imbalance between generation and load will cause both voltage and frequency instability on the grid. This balancing and coordination of generation assets is performed on several time scales, starting from months or weeks ahead with generation unit planning, to next-day planning, and then to real-time balancing.

Q. Please explain how PacifiCorp includes EIM costs and benefits in the 2018 TAM.

A. PacifiCorp's 2019 net power cost forecast includes a $29.3 million (total-Company) adjustment to reflect the incremental EIM benefits from inter-regional dispatch and reduced flexibility reserves.[29] In the 2018 TAM, PacifiCorp forecast a total benefit of $40.3 million. The updated forecast is the result of an updated methodology which utilizes a basic linear regression to

[29] PAC/100, Wilding/6.

forecast inter-regional benefits. The model utilizes 26 months of historical data, from December 2015 through January 2017.

The Company also included EIM-related costs of approximately $4.8 million (total-Company), which consist of the return on net rate base from the capital investment required to participate in the EIM, depreciation expense, and ongoing operations and maintenance (O&M) expenses and transaction fees.[30] Total-Company net benefits related to EIM included in this case are $24.5 million.

Q. What does Staff like about the proposed methodology?

A. Staff believes that this methodology is an improvement over previous PAC methodologies. It is a similar approach to Staff's proposed methodology in UE 323. A core assumption of the model is that there is a trend present in the EIM data, an assumption not reflected in previous iterations of PacifiCorp's EIM benefit forecast. It is also a mathematical approach which relies on actual data and economic theory to produce the forecast.

Q. Does Staff have concerns related to PacifiCorp's EIM costs and benefits?

A. Yes. Staff has two concerns. First, there is a relatively short amount of historical data from which to make a forecast. Second, Staff found a few discrepancies when comparing data in UE 339 workpapers to data previously supplied by the Company.

[30] PAC/100, Wilding/30.

Q. Please describe Staff's concern with the length of historical data.

A. Staff believes that part of the reason there has been some disagreement among parties regarding the best way to estimate EIM benefits is due to the fact that the Western EIM is a relatively new market that is hard to predict. PacifiCorp began operating in the market in Q4 of 2014 as the sole participant outside of the California Independent System Operator (CAISO). Since that time, seven other entrants have entered the market and at least four more plan to join by April 2020. Staff questions whether excluding all data prior to NV Energy's participation in the EIM (December 2015) has merit. On one hand, as the Company points out, the data may not be a very good representation of the EIM market in 2019. On the other hand, it eliminates over 1/3 of the total available data from which to inform the forecast. This limits the predictive power of potentially the accuracy of the forecast.

Q. What is Staff's proposal to address this concern?

A. Staff believes that the simplest and most straight forward resolution for the issue is to allow the Company to continue to update the forecast to include new data as it becomes available. In response to a Staff data request, the Company provided the first four months of 2018 EIM benefits. Staff added the first four months and compared the resulting regression to PacifiCorp's proposal.

Table 1

	PAC Proposal	With 2018 Data
Slope	18,510	54,531
Intercept	1,630,271	1,281,977
R^2	5.7%	27.9%

F-Stat	1.44	10.45
F-Stat Probability	76%	99.7%
Slope Uncertainty %	83.4%	30.9%
Intercept Uncertainty %	14.6%	22.6%

The inclusion of the 2018 data improves the forecast statistics in almost every manner Staff reviewed. The R^2 is a measure of 'goodness of fit' which in laymen's terms compares the explained variance in the data to the unexplained variance in the data. So including the 2018 data improves the models ability to explain the variance in the data by roughly 22 percent. The F-statistic is another measure which quantifies the goodness of fit. It also compares the explained variance to the unexplained variance but is based on a test that the data is just a random scatter plot of points. PacifiCorp's regression has a 76 percent chance of being 'meaningful' while the full dataset has a near certainty of producing meaningful results.

As evidenced by the results of Staff's analysis, Staff believes that the inclusion of the 2018 data would improve the model overall. The statistical attributes of the regression are better, and more importantly, will provide the model with the data which most closely reflects what the 2019 EIM market will look like.

Q. What is the result of Staff's recommended treatment for the forecast?

Adding the 2018 data to date produces a 2019 forecast of $43.8 million in inter-regional benefits. This number will change as more data becomes available but at this point it would increase EIM benefits by $14.6 million.

Q. Please describe Staff's concern regarding data discrepancies.

A. In the process of analyzing the proposed EIM forecast, Staff noticed that some values from 2015 and 2016 differed from data provided by the Company last year in UE 323. Staff believes that the inter-regional benefit should be relatively fixed over a year after the data occurred, so were surprised to see different values. Although the differences were minor for the most part, they did produce material changes to the forecast of a few million dollars. Staff simply asks that the Company verify the current data used in order to ensure a proper forecast results.

ISSUE 4. LOAD FORECAST AND ALLOCATION

Q. Please provide a background to this issue.

A. Oregon's load is estimated to increase by 4.9 percent from 2018 to 2019, the highest increase relative to all other states.[31] Accordingly, Oregon's allocation of load changes from 24.2 percent to 25.3 percent from 2018 to 2019.[32] This changes the system energy allocation factors by the same amount and the system generation allocation factors from 25.7 percent to 26.7 percent. The Company states the result of the increased allocation is an increase to NPC of $16.4 million, however this is offset by a larger load forecast which reduced NPC by $15.5 million. The net result is a $0.9 million increase in NPC for Oregon.[33] The methodology for calculating allocation factors for costs recovered pursuant to the TAM is governed by the 2017 Protocol.[34]

Q. How did Staff analyze this issue?

A. Staff reviewed the Company's workpapers to ensure proper calculation of the impact. Staff focused on the load forecasts which exhibited the largest changes and relied on Staff's 2017 IRP analysis.

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

A. Staff has no proposed adjustments at this time.

[31] PAC/100, Wilding/4 (Table 1).
[32] *Ibid*.
[33] PAC/100, Wilding/5, line 19.
[34] *In re PacifiCorp*, OPUC Docket No. UM 1050, Order No. 16-319, Appendix A (Aug. 23, 2016).

ISSUE 5. WHOLESALE TRANSACTIONS

Q. Please provide background on this issue.

A. Market sales decreased by 2,191 GWh compared to the 2018 TAM. The average price dropped by approximately 2 percent. Market purchases also decreased compared to the 2018 TAM. Volumes decreased by 2,102 GWh and the average price dropped from $21.30 to $21.10/MWh. QF expense, discussed in Staff/300, increased by $27.2 million on a total company basis. The net impact of all of these changes is an increase to NPC of $47 million.

Q. Please describe Staff's analysis of the issue.

A. Staff reviewed the Company's workpapers on wholesale transactions. In the 2018 TAM overall load decreased and average prices increased. In the 2019 TAM we see the exact opposite where overall load increased and average prices decreased. However, in both circumstances wholesale sales and purchases decreased with a net impact in both cases which increased NPC. Part of the reasoning is likely due to an increase in QF purchases. A core assumption of the model is that GRID is programmed to maximize profits in the wholesale market. Staff found no issues in the data or methodology. How purchases and sales in GRID compare to actual operations in a subject of study in the model validation analysis. For more information on the process, please see Staff/200.

Q. Does Staff have a recommended adjustment?

A. No. Staff has no proposed adjustments.

ISSUE 6. PIONEER WIND QF SHAPING

Q. Please provide a background for this issue.

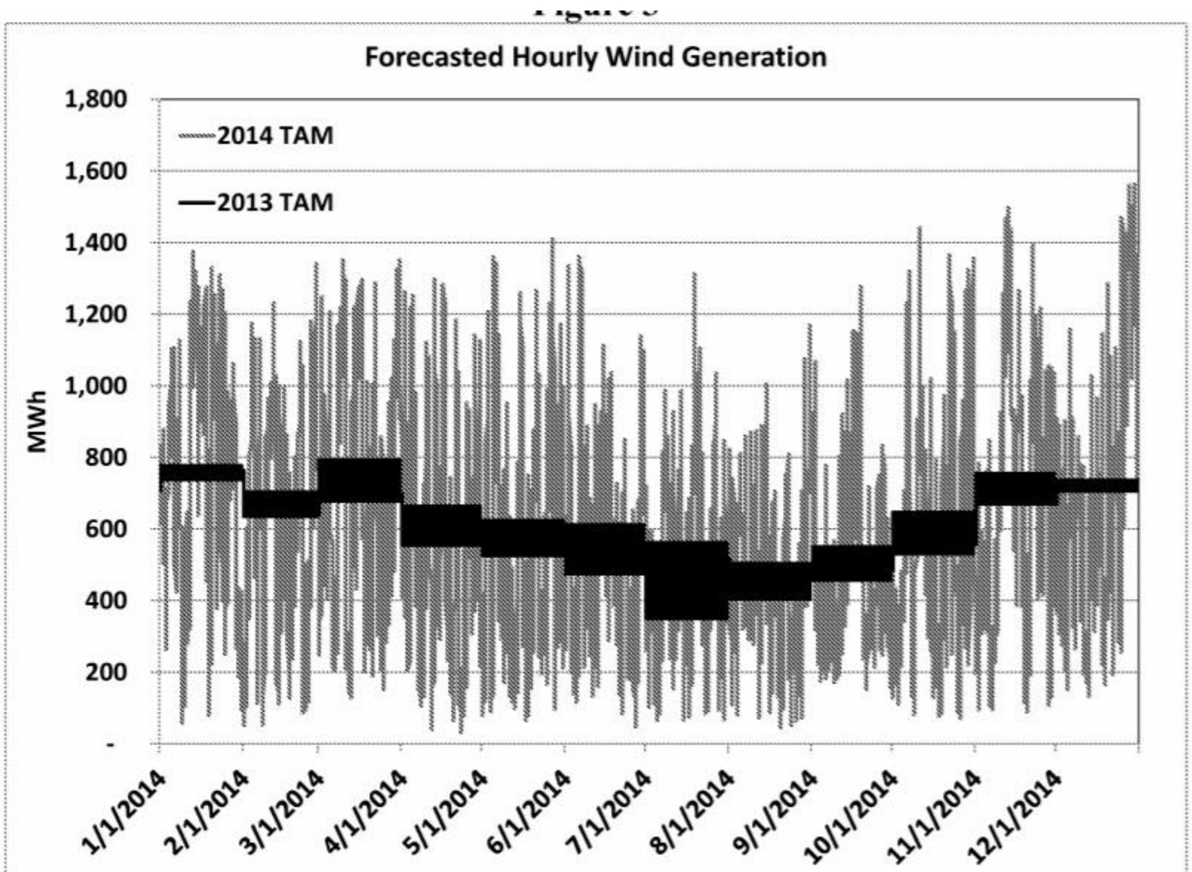
A. In UE 264 (2014 TAM), the Commission approved the use of actual data from the prior year to shape the wind profile of each wind facility before it was input into GRID. Prior to this, the wind was input as six four-hour blocks which were simple averages based on measurements taken prior to the wind facility's operation date. The Pioneer Wind QF is a facility which the company does not have historical data available by which to shape the wind forecast input. The Company is proposing to use the data available from two wind plants geographically close to the Pioneer Wind QF in order to provide a more accurate representation of the wind in the area. This results in an increase to NPC of $0.5 million.

Q. What is Staff's analysis of this issue?

A. Staff began by reviewing the workpapers associated with this update and asking several data requests regarding the methodology. Staff verified that the shaping had not altered the original capacity factor forecast, and reviewed the distance of the two proxy resources and calculations of the shaping mechanism. Staff did find an error in the calculation. The proxy farm wind correlation from March 13, 2016, 3:00 AM until November 6, 2016, 3:00 AM was offset by one hour. This means that for a little over half of the year, the data the model thought corresponded to any given hour was actually the data for the hour prior. Staff does not know if this will have an effect on NPC but Staff recommends the Company rectify the issue. Also, Staff noticed that the Company did not calculate any wind shaping for the final day of the year, which may be intentional but Staff is unsure of the reason.

Q. What is Staff's view of the proposed methodology?

A. Staff understands the need to provide GRID with the most accurate data possible in order to produce a realistic forecast. Below is a figure from PacifiCorp's opening testimony in UE 264 which portrays the difference in prior and current shaping methodology. It is clear that the use of actual data provides a much different profile than averaging in blocks.



Staff's concern is that PacifiCorp has not provided any evidence that the two plants used as a proxy for the Pioneer wind farm are truly representative. Although the dollar impact of this adjustment is a relatively small amount, it could set precedent for the treatment of new QFs which do not have historic wind data available to the Company. Staff was not convinced in discovery or testimony that the wind from the two plants, averaged and weighted by distance reflects the wind profile of Pioneer itself. In researching the topic, Staff found that wind speed and variability can be different even within the distance of 10 miles.[35] Ultimately though, Staff does not believe that getting the wind speed and direction correct in the forecast is the goal; the goal is to provide inputs to the model which accurately produce normalized costs. As shown in the figure above, the variability in the wind is simply not captured by the Company's prior shaping methodology. Utilizing a proxy which approximates the wind variability provides a better estimate of the true cost than other possible solutions.

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

A. Staff recommends that the Company correct the apparent error in its workbook and recalculate the impact of the proposed methodology. Staff has no other recommended adjustments at this time.

[35] Lenhard, R.W., 1973: Variability of Wind Over a Distance of 16.25 km. *J. Appl. Meteor.,* **12**, 1075–1078, https://doi.org/10.1175/1520-0450(1973)012<1075:VOWOAD>2.0.CO;2.

ISSUE 7. REVENUES FROM UP 369

Q. Please provide a background for this issue.

A. PacifiCorp and Tinuum Group, LLC identified an opportunity to install refined coal facilities on the Hunter power plant property in 2018. The refined coal production facility, owned by Tinuum, is qualified to generate tax credits under Section 45 of the U.S. Internal Revenue Code via the sale and purchase of untreated and treated coal within that facility. Tinuum will install a refined coal treatment facility that would "straddle" approximately 6 feet of the moving incoming coal feedstock conveyor belt at the Hunter plant; so that a treatment can be applied as the coal is transported to the plant on the coal conveyor belt. Essentially, PacifiCorp sells its coal to Tinuum who treats the coal and then sells it back to PacifiCorp for approximately the same price. Tinuum makes money off of the tax credit, while PacifiCorp gets a better burning coal product. UP 369 was approved on May 22, 2018, and as part of the approval, the Commission directed the Company to pass the benefits of the better burning coal through to customers in their power cost filings.

Q. How did Staff analyze this issue?

A. Staff looked at the workpapers supplied by PacifiCorp regarding the Hunter plant. Staff was unable to identify any adjustment or benefit as the result of the UP 369 agreement. The coal price increased from last year's TAM to this year.

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

A. Staff asks that the Company verify that the 2019 TAM forecast reflects the benefits of the agreement from UP 369. If the benefits are not included, Staff requests a narrative explanation as to why that is the case.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 339
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

June 11, 2018

WITNESS QUALIFICATION STATEMENT

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

CASE: UE 339
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

June 11, 2018

2019 Oregon TAM

Workshop

May 25, 2018






Redacted Version

PACIFIC POWER
POWERING YOUR GREATNESS

2019 TAM Summary

- Initial NPC - $1.502 billion ($25.46/MWh), $386.9 million Oregon allocated
- Oregon rate increase of $16.9 million, or approximately 1.3 percent
- TAM increase largely due to PTCs expiration and federal tax rate change:
  - $11.2 million revenue requirement increase, Oregon allocated, compared to PTCs in 2018 TAM
  - $9.9m due to expiration of PTCs at Glenrock, Glenrock III (Jan 2019), High Plains (Oct 2019), Marengo II, McFadden (Oct 2019), Seven Mile, and Seven Mile II and generation levels at remaining plants
  - $1.3m due to change in federal tax rate
- EIM benefits and costs included
  - $29.3 million total company benefits ($7.6 million Oregon allocated), $4.8 million total company costs ($1.3 million Oregon allocated)
  - EIM-related costs treated consistent with previous TAM filings

PACIFIC POWER
POWERING YOUR GREATNESS

2019 TAM vs 2018 TAM

- Initial 2019 TAM rate increase of $16.9 million, or approximately 1.3 percent

	Total Company		Oregon Allocated	
($millions)	UE-323 Final TAM CY 2018	TAM CY 2019	UE-323 Final TAM CY 2018	TAM CY 2019
Sales for Resale	$ (431.5)	$ (323.6)	$ (111.1)	$ (86.5)
Purchased Power	702.1	640.8	180.3	171.0
Wheeling Expense	145.2	136.4	37.3	36.4
Fuel Expense	1,067.5	1,047.9	258.2	265.3
Total NPC	$ 1,483.3	$ 1,501.5	$ 364.7	$ 386.2
Oregon Situs	0.6	0.6	0.6	0.6
EIM Costs	5.0	3.4	1.3	0.9
PTCs	(66.6)	(22.2)	(17.2)	(5.9)
Total TAM	$ 1,422.3	$ 1,483.3	$ 349.4	$ 381.8
TAM Increase Before Load Change				$ 32.4
Change Due to Load				(15.5)
Other Revenue Change				-
Total TAM Increase				$ 16.9

PACIFIC POWER
POWERING YOUR GREATNESS

2019 TAM Drivers

- Change in PTCs is the single largest driver of the TAM increase:
  - Expiration of PTC eligibility
  - Decreased federal income tax rate
- Change in NPC from 2018 TAM is approximately one percent.
- Net impact of loads in the 2019 TAM is $0.9 million:
  - Higher than expected Oregon load resulting in increased collections.
  - Oregon load growth relative to other states is driving an increase in Oregon allocation factors.

TAM Drivers	***($ millions)***
Change in NPC	$ 5.2
Change in Allocation Factors	16.4
Change Due to Load Variance	(15.5)
Change in PTCs	11.2
Change in Non-NPC EIM Costs	(0.4)
Total Increase	**16.9**

PACIFIC POWER
POWERING YOUR GREATNESS

Production Tax Credits

- The impact of repowering is not included in the 2019 TAM.
- To match the regulatory treatment of the costs, the NPC and PTC benefits of repowering will be deferred as part of a RAC.
- Due to the timing of the 2018 TAM, the impact of tax reform on the value of PTCs was not captured in the 2018 TAM.
  - PacifiCorp's federal tax deferral filing will address the PTCs included in the 2018 TAM.

PACIFIC POWER
POWERING YOUR GREATNESS

2018 vs 2019 TAM: Oregon Allocation Factors

- The increase in Oregon allocation factors is driven by load forecast changes across the system.
- The 2019 TAM load forecast is 0.21% higher, total company, than the forecast load used in 2018 TAM. Oregon forecasted load is 700 GWh (4.9%) higher than the forecasted load in 2018 TAM.
- Proportionately larger increases in Oregon and Washington compared to load reductions in Utah and Wyoming are causing higher Oregon allocation factors in the 2019 TAM.

Oregon Factors	2018	2019	Incr/(Decr)
System Generation (SG)	25.74%	26.72%	3.82%
System Energy (SE)	24.19%	25.32%	4.70%

PACIFIC POWER
POWERING YOUR GREATNESS

2019 TAM vs 2018 TAM
Total Company NPC

Net Power Cost Reconciliation

	($ millions)	$/MWh
OR TAM 2018	**$1,483**	**$25.20**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	71	
Purchased Power Expense	(24)	
Coal Fuel Expense	(92)	
Natural Gas Fuel Expense	73	
Wheeling and Other Expense	(9)	
Total Increase/(Decrease) to NPC	**18**	
OR TAM 2019	**$1,501**	**$25.46**

PACIFIC POWER
POWERING YOUR GREATNESS

2019 TAM Step Log

	2019 TAM Step Log		
ORTAM18			$ 1,483,317,604
	Description	Detail	Impact
	Routine Updates		18,456,806
Step 1	Transmission link capacity updates	APS --> Mead (150 MW new) COB --> West Main (from 206 to 222 MW in average)	(1,692,504)
Step 2	Varible O & M Cost in Dispatching Tier prices		1,796,024
Step 3	a. new QF contract	New QFs: Sage Solar I, II, III	1,022,157
	b. Contract Delay Rate (CDR)	CDR for QFs coming online after 2018	(290,039)
Step 4	2017 Flexble Reserve Study in 2017 IRP		(3,223,732)
Step 5	Wind Capacity Factor Methodology Change		4,644,500
Step 6	DA/RT (starting EIM)	DART historicial period based on the months joining EIM	(2,245,827)
Step 7	Coal Plant Economic Cycling		(740,681)
Step 8	Thermal Attributes updates	**Minimum Operationa Level Change:** Hunter 1: 121.9MW (was 112.5MW) Hunter 2 :78.4MW (was 72.4MW) Huntington 1 :100MW (was 120MW) Huntington 2 :100MW (was 120MW) Naughton 1 :30MW (was 35MW) Wyodak :144MW (was 176MW) Current Creek :264MW (was 280MW) Lake Side 2 : 365MW (was 354MW)	(111,184)
Step 9	Pioneer Wind Shape		522,288
ORTAM19			$ 1,501,455,411

Routine Updates include:

- Base period moved from 48month ending June 2016 to 48month ending June 2017
- Forward price curve moved from Nov 8th 2017 to December 29th 2017
- Test period moved from CY2018 to CY2019
- Load Forecast Update

PACIFIC POWER
POWERING YOUR GREATNESS

Changes to the 2019 TAM

- Notice of Methodology Changes sent to parties March 1, 2018
  - The Company will transfer RECs to the ESS of a direct access customer.
  - The regulating reserve requirements are updated to be consistent with the flexible reserve study in 2017 integrated resource plan.
  - Certain coal plants are allowed to cycle for economics during the spring season.
  - Variable operations and maintenance costs are included in the dispatch price of thermal resources.
  - The capacity factors used for Company-owned wind generation are based on the historical average capacity factor.

PACIFIC POWER
POWERING YOUR GREATNESS

Economic Cycling of Coal Plants

- In the 2019 TAM, GRID was allowed to cycle certain coal plants for economics during the Spring.
- The economic cycling hours in the 2019 TAM are greater than any prior year.

Year	Economic Cyclying Hours	Avoided MWh *	Economic Cycling Units
2015	653	245,313	Cholla 4, Dave Johnston 1,2, Jim Bridger 2 and Wyodak
2016	6,596	2,964,760	Cholla 4, Dave Johnston 1,2,3,4, Hayden 1,2, Jim Bridger 1,2,3, Huntington 1,2, and Hunter 3
2017	3,761	1,346,760	Cholla 4, Dave Johnston 1,2,3,4, Jim Bridger 2,4 and Hunter 1
2018 Jan - Apr	1,662	684,243	Cholla 4, Hunter 1 & 3, Jim Brdiger 3
2019 Forecast	7,636	2,744,391	Cholla 4, Hunter 1 & 2

**: Lost MWh is calculated based on plant avaliablity at the time of the event*

PACIFIC POWER
POWERING YOUR GREATNESS

EIM Benefits

- Inter-regional benefits = $29.2 million
  - The margin on EIM inter-regional transfers included as a reduction to NPC based on actual results from December 2015 – December 2017
    - Using EIM inter-regional benefits by month, a linear trend based on actual EIM benefits beginning in December 2015 was extrapolated forward to produce an estimate for 2019.
    - The time period used to form the extrapolation includes the entry of NVE in December 2015, APS and PSE in October 2016 and PGE in October 2017.
    - Benefits will be updated with NPC update in July, and will reflect additional information available at the time.
- Flex reserve benefit = $0.1 million, 106 MW reduction in reserves
- EIM costs of $4.8 million include return on net capital investment, depreciation, ongoing operation and maintenance expenses, CAISO fees (split between NPC and non-NPC).

PACIFIC POWER
POWERING YOUR GREATNESS

REC Transfers

PacifiCorp proposed to transfer RECs to an energy service supplier to account for the migration of direct access load:

- RECs transfers will begin following the first year of direct access.
- Based on the prior year compliance obligation, a transfer of Oregon RPS-eligible RECs would take place by May 1 of each year.
- For one-year and three-year direct access customers the RECs transferred will be based on the prior year's actual load.
- For five-year/permanent opt-out direct access customers, the REC transferred will be based on actual load for years 1-5 and average load of 1 to 5 year for years 6-10.

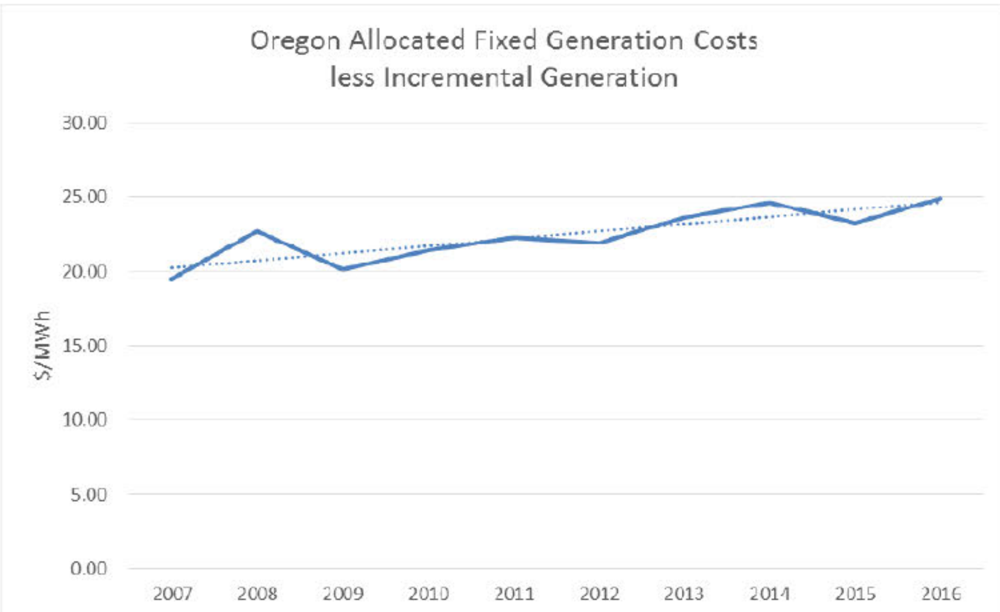
PACIFIC POWER
POWERING YOUR GREATNESS

REC Transfers Cont.

- The specific RECs transferred would be from RPS-eligible resources, at PacifiCorp's discretion, and may vary from year to year.
- At least 80 percent of the transferred RECs will be RECs that, before the transfer, were considered bundled. PacifiCorp makes no representation and does not warranty that after the transfer any of the RECs transferred to the ESS's WREGIS account qualify as bundled RECs for the purposes of RPS compliance requirements.
- PacifiCorp is not responsible for the retirement of RECs or claims made about the RECs on behalf of the direct access consumer or ESS, or any RPS compliance of the direct access consumer or ESS.

PACIFIC POWER
POWERING YOUR GREATNESS

Fixed Generation Costs



- The Company examined a ten-year historical time series of fixed generation costs after accounting for depreciation and removing incremental generation.
- The increasing trend continues supports the reasonableness of the five year opt-out charge calculation.

PACIFIC POWER
POWERING YOUR GREATNESS

GRID MODEL VALIDATION

GRID Model Validation - Scope

PacifiCorp and parties agreed that the GRID model validation be based on the 2016 Oregon TAM Final Study. The following inputs were replaced by 2016 actual data:

- Electricity and Natural Gas Prices
- Load
- Outage and Derates
- Wind and Hydro Generation
- Long Term Contract, Purchased Power Agreements and Qualifying Facilities Prices and Generations
- Heat Rate

Other Sensitivity Analysis:

- Market Capacity based on 4 year Historical Average
- Actual market transactions of duration greater than seven days
- Jim Bridger costing tier prices
- Economic shutdowns

PACIFIC POWER
POWERING YOUR GREATNESS

GRID Model Validation - Results

- The results of the model validation analysis show the GRID model was able to reasonably and accurately simulate historical NPC for the period of 2016.
  - The GRID model estimated total company 2016 NPC to be $1,466.3 million compared to actual costs of $1,465.9 million, a variance of $0.4 million or 0.03 percent.
  - The GRID model estimated total resources at 71.8 million MWh compared to 65.0 million MWh in actual 2016, a difference of 6.9 million MWh or 11 percent.
- Load is the main driver of NPC differences. Actual 2016 load is 4% lower than the load used in OR TAM 2016, which results in $55.3 million reduction to forecast NPC on total company basis.
- Re-running GRID using actual data inputs changes NPC in both directions which provided information on how each data input change is related to the total company NPC forecast.

PACIFIC POWER
POWERING YOUR GREATNESS

GRID Model Validation – Results

	NPC ($)	
	TAM 2016	**Actual 2016**
	1,521,069,669	1,465,887,270
GRID Model Validation	**Variance to TAM**	**Variance to Actual**
Cumulative Study	**(54,744,487)**	**437,913**
- Actual Hourly Prices - Powerdex	6,857,042	62,039,441
- Actual Hourly Prices - Historic Monthly Prices shaped using scalers	(5,404,889)	49,777,510
- Actual Natural Gas Prices	(9,804,827)	45,377,572
- Actual Load	(55,334,258)	(151,859)
- Actual Outages and Derates	2,619,634	57,802,033
- Actual Wind Generation	(10,017,868)	45,164,531
- Actual Hydro Generation	1,421,903	56,604,302
- Actual Long Term Contracts/QFs	(4,685,746)	50,496,653
- Actual Heat Rate	5,007,992	60,190,391
Sensitivity Analysis (Impact is based on Cumulative Study)		
Market Cap based on 4 year average	6,371,202	
Actual Short Term Firm	(5,504,050)	
Jim Bridger Average Costing Tier Prices	10,545,358	
Cumulative Study - screened	(4,482,448)	

PACIFIC POWER
POWERING YOUR GREATNESS

GRID Model Validation – Results

- Actual hourly prices from Powerdex shows that wholesale electricity prices are 7 percent lower than the prices used in TAM, which results an increase of $6.9 million to total company NPC. The increase is driven by lower coal and gas generation, lower prices for system balancing sales, and higher system balancing purchase volumes.
  - Prices from Powerdex captures counterparty transaction from companies that participant with Powerdex. PacifiCorp counterparty transactions may or may not be included in prices from Powerdex.
- Actual hourly price from monthly historical prices shaped by scalers used in TAM 2016. On average, the wholesales electricity prices are 4 percent lower than what's in the TAM. Lower prices reduced total company NPC by $5.4 million. The reduction is a result of lower gas generation which replaced by system balancing purchase at lower cost.
  - Monthly historical prices are based on ICE day ahead index, which captures all transactions in the market including PacifiCorp transactions.

PACIFIC POWER
POWERING YOUR GREATNESS

GRID Model Validation – Results

- Actual natural gas prices are 4.9 percent lower as compared to the natural gas prices in 2016 TAM. With lower natural prices, gas generation volume increased about 1.7 percent and the total gas generation expense decreased by 2.8 percent. Additional savings are due to lower coal generation expense and extra wholesale sales revenue.
- Compared to normalized outages schedule in TAM, actual thermal availability includes more coal availability and less gas availability in 2016, which increased NPC by $2.6 million.
- Actual wind generation in 2016 was lower than wind generation forecasted in TAM resulting in $10 million reduction to NPC due to avoided purchases from wind Qualifying Facilities.

PACIFIC POWER
POWERING YOUR GREATNESS

GRID Model Validation – Results

- Actual hydro generation is slightly lower than the forecasted hydro generation in 2016 TAM. Using actual hydro generation for 2016 TAM, the total company NPC increased by $1.4 million.
- Actual long term contract and actual purchased powers energy are lower than the forecast values used in OR TAM 2016. Lower purchase power generation reduced the total Company NPC by $4.7 million.
- Actual Heat Rate in 2016 is unfavorable to OR TAM 2016 NPC. This change increased total Company NPC by $5 million.

PACIFIC POWER
POWERING YOUR GREATNESS

GRID Model Validation – Sensitivity Analysis

- Using the 48 month historical average market capacity increased NPC by $6.4 million. The increase is driven by lower purchase and sales volumes and the loss of system balancing transaction benefits.
- Actual Short Term Firm (STF) transactions at a given market hub with greater than 7 days delivery span from 2016 are incorporated as executed STF. Market capacity is adjusted to represent the STF transaction less than 7 days delivery span which allow GRID to balance the system up to the historical level. The study shows the total company NPC reduced by $5.5 million.
- After removing $20 million Joy Longwall impact, Jim Bridger 2016 actual costing tier prices is $26.93/MWh, higher than the costing tier prices used in OR TAM 2016 as of $24.14/MWh. The price differences increased the total company NPC by $10.5 million.
- Screening of the cumulative study reduced the total Company NPC by $4.3 million.

PACIFIC POWER
POWERING YOUR GREATNESS

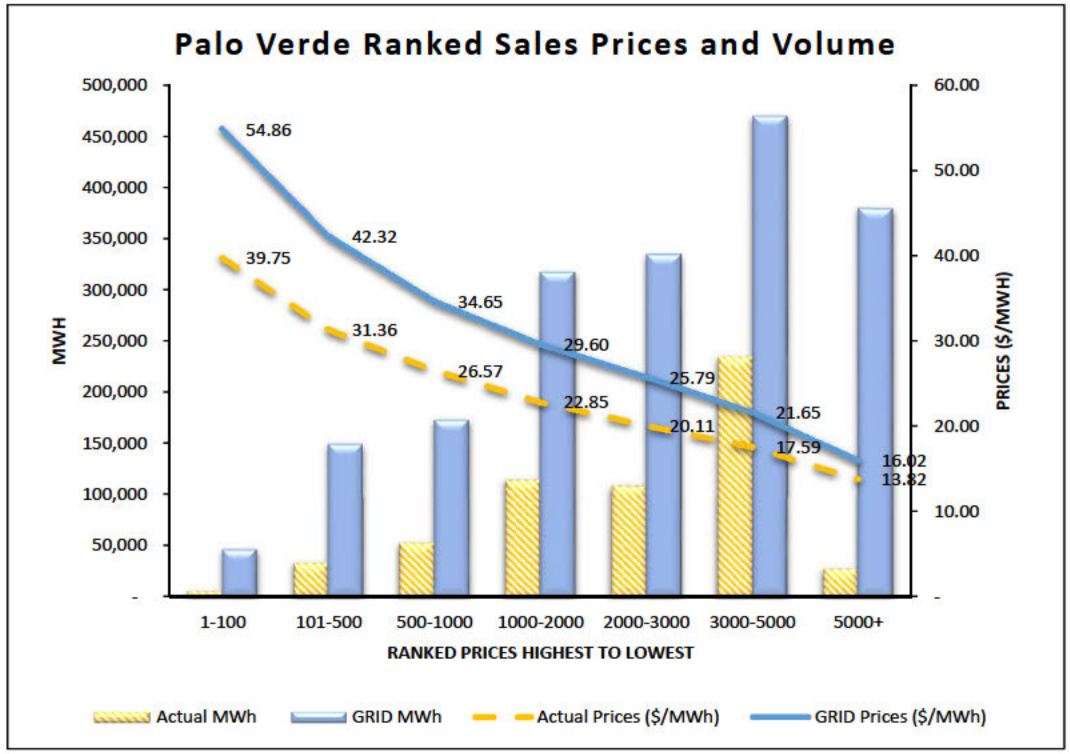
GRID Model Validation – DA/RT

- DA/RT results show that the pricing component is -$23.1 million and the volume component is $51.0 million.
  - The pricing component value is negative, which implies GRID transacts at more favorable hourly price points than the transactions in real time. This results in cost savings in GRID compared to actuals.
  - The GRID model is able to transact in higher volumes at more favorable prices points than real time at the same price points.
- The following two slides show the GRID and actual transaction volumes at different prices points based on the ranked order from the most favorable to least favorable prices in 2016.

PACIFIC POWER
POWERING YOUR GREATNESS

GRID Model Validation – DA/RT

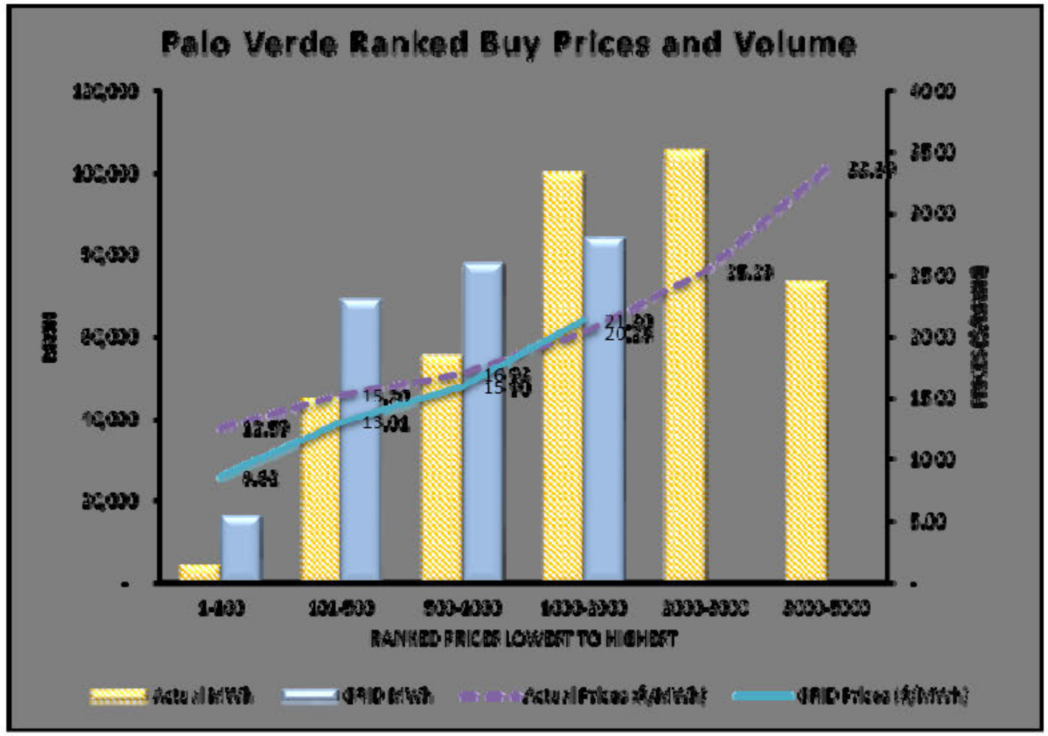
- Hours are ranked and grouped by sales price with the highest sales price first.
- In the first group, hours ranked one to 100, GRID makes off system sales at an average price of $54.86/MWh, but actual off-system sales are at an average price of $39.75/MWh, 38 percent lower than GRID.



PACIFIC POWER
POWERING YOUR GREATNESS

GRID Model Validation – DA/RT

- Hours are ranked and grouped by purchase price with the lowest sales price first.
- In the first group, hours ranked one to 100, GRID purchases at an average price of $8.62/MWh, but actual purchases are at an average price of $12.59/MWh, 32 percent higher than GRID.



PACIFIC POWER
POWERING YOUR GREATNESS

DA/RT Conclusions

- GRID is able to optimize the system to sell when prices are high and buy when prices are low. This is because GRID balances the system differently than it is balanced in actual operations.
  - GRID balances the system at a single hourly transactions. Actual operations balances the system by month, then day-ahead, and lastly real-time transactions.
  - GRID balances the system at one megawatt (MW) increments and up to any volume within the market caps. In actual operations, monthly and day-ahead transactions are made at 25MW increments which could require additional transactions during the shoulder periods at potential less than cost.
- In the model validation, the total company NPC derived from the backcast study is 0.03 percent higher than 2016 actual NPC. Without the DA/RT adjustment the backcast study would be 3.45 percent lower than 2016 actual NPC.
- The DA/RT adjustment is a needed to accurately forecast NPC.

PACIFIC POWER
POWERING YOUR GREATNESS

GRID Model Validation Conclusions

- When actual data is used as inputs, GRID is able to produce the 2016 NPC within a very reasonable range compared to actual 2016 NPC.
- GRID is designed to produce a forecasted normalized NPC.
- GRID optimizes the system simultaneously within the established constraints of the inputs.
- The differences between actual NPC and backcast study in each balancing resource category are due to how GRID and real time operation select each balancing resources category differently when facing a different set of operational constraints.

PACIFIC POWER
POWERING YOUR GREATNESS

CASE: UE 339
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

REDACTED
June 11, 2018

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

A. My name is Dr. Lance Kaufman. I am a Senior Utility Analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/201.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarize Staff's analysis and recommendations regarding PacifiCorp's 2019 Transition Adjustment Mechanism filing, Docket No. UE 339.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

Staff/201: Witness Qualification Statement
Staff/202: Non-Confidential Data Responses
Staff/203: Confidential Data Responses
Staff/204: Bridger Coal Company Depreciation
Staff/205: Summary of Reserve Shutdowns

Q. How is your testimony organized?

A. My testimony is organized as follows:

Q. Please summarize your recommendations and adjustments.

A. I propose the following recommendations and adjustments:

- TAM Model Validation
  - Wait until the 2020 TAM before drawing conclusions from the model validation results.
- Economic Cycling of Coal Plants
  - Direct PacifiCorp to provide additional justification for the decision to limit economic cycling of coal plants as proposed.
  - Direct PacifiCorp present evidence addressing the prudence of PacifiCorp's actual cycling decisions as part of PacifiCorp's next PCAM filing.
- Jim Bridger Long Term Fuel Plan
  - Direct PacifiCorp to address the cost effectiveness of the fuel plan under a 2030 life for Jim Bridger plant.
- Bridger Coal Company Depreciation
  - Exclude depreciation expense of Bridger Coal Company plant that has not been included in rate base. This reduces Oregon's share of the net power cost forecast by approximately **[BEGIN CONFIDENTIAL]** $[redacted]. **[END CONFIDENTIAL]**
  - Include Bridger Coal Company assets in PacifiCorp's next depreciation study.
- Direct Access
  - No recommendation at this time.

ISSUE 1. TAM MODEL VALIDATION

Q. Please summarize this issue and Staff's recommendation.

A. In PacifiCorp's 2018 TAM proceeding, Docket No. UE 323, Staff and Alliance of Western Energy Consumers (AWEC, formerly Industrial Customers of Northwest Utilities) proposed that PacifiCorp perform a model validation procedure to verify that the TAM modeling produces reasonable results. In Order No. 17-444, the Commission directed PacifiCorp to perform the requested analysis.

PacifiCorp's testimony provides details on recent Model Validation workshops and process.[1] In addition to the workshops noted by PacifiCorp parties met on Friday, May 25, 2018, to discuss the initial the Model Validation results as they were unable to do so prior to PacifiCorp's filing of the results in this TAM proceeding.

Q. Please summarize Staff's thoughts on the Model Validation process, results, next steps, and conclusions.

A. Staff has the following observations:

1. Process:
    a. PacifiCorp was cooperative and responsive to parties' suggestions regarding the appropriate inputs for the Model Validation.
    b. PacifiCorp was concerned about time limitations and was not responsive to parties' request to evaluate more than one historic year.

[1] PGE/100, Wilding/17-19.

   c. PacifiCorp indicated a willingness to consider additional historic years after performing a first round analysis on a single year.
   d. PacifiCorp was open to input regarding which historic year to use.
   e. PacifiCorp did not engage parties in the model validation process beyond establishing inputs and providing results.
2. Results
   a. The initial Model Validation results are encouraging, but require additional analysis in order to leverage the full value of the process.
   b. The scope of the current proceeding is too limited for Staff to effectively evaluate and interpret the Model Validation results.
   c. The results indicate that the TAM forecast process captures much of the inefficiencies of actual operations despite the unrealistic advantages of perfect foresight and the ability to perfectly optimize dispatch in every hour of the year.
3. Next Steps
   a. Staff should devote resources during the following year to analyzing the initial results.
   b. PacifiCorp should leverage the knowledge and skills developed in the initial Model Validation exercise by performing the validation process using several additional years of historical actuals.
4. Conclusions

a. The Commission should not use the results to draw conclusions regarding the TAM modeling until PacifiCorp validates additional years and until parties have had time to analyze the results.

b. If PacifiCorp improves the efficiency of actual dispatch, then PacifiCorp should reduce the out-board cost adders used in the TAM to bring forecasts closer to actuals.

ISSUE 2. ECONOMIC CYCLING OF COAL PLANTS

Q. Please summarize this issue and Staff's recommendation.

A. In PacifiCorp's 2018 TAM proceeding, Docket No. UE 323, Staff noted that recent changes in market conditions have resulted in some PacifiCorp coal units being un-economic to operate during certain periods. This occurs when PacifiCorp's forecasted market price is lower than the marginal cost of operating a coal unit for an extended period. In such a scenario, it is economic to cycle the coal plant (i.e., temporarily stop generating). Economic cycling of coal plants results in lower net power costs. The Commission directed parties to discuss economic cycling of coal plants in a coal workshop. PacifiCorp developed a proposal for economic cycling of coal plants and presented this proposal to parties at a February 23, 2018 workshop.

PacifiCorp proposes allowing economic cycling of plants within GRID for a limited set of coal plants and for limited months.

1. PacifiCorp does not model cycling of minority owned plants due to limited control;
2. PacifiCorp does not model cycling of EIM participating coal plants becase EIM participation increases the value of dispatching coal plants;
3. PacifiCorp only models coal plant cycling from February to May, because this is a period when power prices are typically low.[2]

Staff raised concerns at the workshop that PacifiCorp's proposal was limited to too few plants and to too few months. Staff asks that PacifiCorp provide

---

[2] PAC/100, Wilding/35, lines 5 to 13.

additional justification for its decision to limit plant cycling in the TAM during periods where it may still be feasible and likely for the plants to cycle.

Q. Please explain why Staff is concerned that the PacifiCorp proposal is too limited.

A. PacifiCorp's historic economic cycling of coal plants includes plants and periods that are outside the limits that PacifiCorp proposes for modeling economic shut-down in the 2019 TAM. These actual operations include. For example:

[redacted] **[BEGIN CONFIDENTIAL]** [redacted]

3. [redacted] **[END CONFIDENTIAL]**[3]

Staff does not agree with PacifiCorp's rationale for its proposed modeling limitations for several reasons[4]

1. While participation in EIM may provide some incremental benefit to operating a coal plant, if this benefit is lower than the benefit of cycling the plant, then it is still economic to cycle the plant.
2. While PacifiCorp may not have operational control of minority plants, some entities or groups of entities do have operational control, and should be evaluating the economics of cycling plants.

---

[3] See Exhibit Staff 205, Confidential Summary of Reserve Shutdowns.

[4] Exhibit Staff/203.

3. Market conditions drive the economic value of cycling coal plants. If fall market conditions support the economic cycling of plant, these plants should be allowed to cycle.

Q. Do any factors mitigate Staff's concerns about PacifiCorp's limitations?

A. The number of hours of economic cycling in PacifiCorp's forecast is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** PacifiCorp's historic cycling hours.[5] This lends credibility to PacifiCorp's forecast, but raises additional concerns that PacifiCorp's actual cycling decisions may be less than optimal. However, PacifiCorp's actual cycling decisions are a PCAM issue, not a TAM issue, and parties should address PacifiCorp's actual operation cycling decisions in the next PCAM.

Q. What is your recommendation related to this issue?

A. Staff recommends that PacifiCorp provide additional justification for the decision to limit economic cycling of coal plants as proposed. Staff also recommends that PacifiCorp present evidence addressing the prudence of PacifiCorp's actual cycling decisions as part of PacifiCorp's next PCAM filing.

---

[5] PAC/100, Wilding/36

ISSUE 3. JIM BRIDGER LONG TERM FUEL PLAN

Q. Please summarize this issue and Staff's recommendation.

A. In Docket No. UE 307, Staff raised concerns with the prudence of PacifiCorp's continued reliance on Bridger Coal Company coal as a fuel source for Jim Bridger plant. Staff provided evidence that PacifiCorp's 2016 long term fuel plan did not include sufficient analysis of fuel alternatives.[6] In Order No. 16-482, the Commission directed PacifiCorp to delay updating its long term fuel plan and to meet with parties to discuss the information and analysis that parties need to meaningfully evaluate the Jim Bridger plant fueling options.

Staff has completed a preliminary review of the 2018 fuel plan. Staff considered the following items:

1. Assumption of useful life no later than 2030,
2. Sufficient range of alternatives,
3. Assumptions and inputs,
4. Cost analysis, and
5. Risk analysis.

Staff's preliminary review finds the updated plan to be an improvement over the initial long term fuel plan; however, Staff has some recommendations and intends to continue to evaluate the plan.

Q. What are your findings related to the useful life assumed?

A. SB 1547 requires that "For the purposes of evaluating the prudence of an investment decision regarding a coal-fired resource… the useful life of the coal-

[6] Docket No. UE 307, Staff/200. Kaufman/27.

fired resource may not be considered to be any later than January 1, 2030, unless the Commission determines otherwise."[7] Therefore, Staff finds that PacifiCorp's long term fuel plan should be based on a useful life of Jim Bridger plant of no later than January 1, 2030. However, the long term fuel plan contemplates continued operation of Jim Bridger until 2037.[8]

Staff raised this as a concern with PacifiCorp during preliminary discussions of the updated long term fuel plan. While PacifiCorp's analysis contemplates a 2037 useful life for Jim Bridger, the fuel option selected by PacifiCorp appears to have a minimal amount of capital investment for both BCC and Jim Bridger coal unloading facilities after 2028. In general, plans with lower capital investments become more economic as lives are shortened, relative to plans with high capital investment. Therefore, while the analysis of the plan is not consistent with a useful life of no later than 2030, the preferred plan has minimal capital investment beyond 2030.

Q. What are your findings related to sufficient range of alternatives?

A. PacifiCorp evaluated a reasonable number of options to evaluate coal on a going-forward basis. However, PacifiCorp did not provide analysis of PacifiCorp's failure to transition to Powder River Basin Coal beginning in 2019. A prudence evaluation of PacifiCorp's 2019 fuel costs requires consideration of what 2019 fuel costs would have been, had PacifiCorp made timely investments in order to receive PRB coal in 2019.

[7] Codified as ORS 757.518.
[8] PAC/205, Ralston/5.

Staff recommends that PacifiCorp provide evidence that the 2019 fuel purchase from Black Butte and BCC is less expensive than purchasing fuel from PRB, had PacifiCorp made investments on a time line that would have allowed receipt of PRB coal in 2019.

Q. What are your conclusions related to assumptions and inputs?

A. At this time, Staff notes several concerns that PacifiCorp should address:

1. The heat content selection of PRB coal was not supported with financial analysis.
2. The PRB rail transportation costs continue to appear unreasonably high.
3. **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**

Q. What are your conclusions related to cost analysis?

A. Staff is continuing to evaluate the cost analysis in the fuel plan.

Q. What are your comments related to risk analysis?

A. Staff appreciates the Company's efforts to address risk in the long term fuel plan. However, Staff does not agree with some of the risk metrics used. For example, PacifiCorp rates the incremental capital cost of **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]** Most of the risk metrics used by the Company are various measures of risk related to the dispatch level of Jim Bridger plant. One important risk that is not considered is the risk that Black Butte coal will not be available for purchase.

Q. What is your recommendation for this issue?

A. Staff recommends that the Commission direct PacifiCorp to evaluate the long term fuel plan alternatives under an assumed life of Jim Bridger no later than January 1, 2030.

ISSUE 4. BRIDGER COAL COMPANY DEPRECIATION

Q. Please summarize this issue and Staff's recommendation.

A. PacifiCorp's NVPC includes depreciation expense of Bridger Coal Company. A large portion of this depreciation expense is associated with plant that has not been deemed prudent by the Commission. PacifiCorp should not recover plant investment from customers prior to the Commission making a prudence determination for the investment. Staff recommends excluding depreciation of plant that has not been deemed prudent by the Commission.

Prudence decisions of BCC plant investments are typically made in PacifiCorp's general rate cases. PacifiCorp's most recent general rate case filing was in 2013. Staff's recommendation removes BCC depreciation expense for plant added after December 31, 2013. This results in a reduction to PacifiCorp's Oregon 2019 NVPC forecast of approximately **[BEGIN CONFIDENTIAL]** $[redacted]. **[END CONFIDENTIAL]**

Staff also observed that the depreciable lives of BCC plant are not supported by a depreciation study. As a result, BCC depreciation rates may be too high. Staff recommends that BCC plant be included in PacifiCorp's next depreciation filing.

Q. What is BCC's relationship to PacifiCorp?

A. BCC is a joint venture of Idaho Power and PacifiCorp. PacifiCorp, through a wholly owned subsidiary, operates BCC. BCC charges PacifiCorp for coal at cost. PacifiCorp also receives a return on net plant invested in BCC through

PacifiCorp's base rates. This means that PacifiCorp recovers some BCC costs through base rates and some BCC cost through NVPC rates.

Q. Is BCC plant subject to prudence review by the Commission?

A. Yes, as part of general rate cases, BCC plant is subjected to a prudence review by the Commission.

Q. Depreciation is not normally included in power costs. Please explain why PacifiCorp is including BCC depreciation expense in power costs.

A. BCC is operated as an affiliated interest of PacifiCorp. The price that BCC charges PacifiCorp for coal is based on the actual operating costs of BCC, including depreciation expense. Fuel cost is included in NVPC as a variable power cost. As a result, depreciation expense for BCC is included in this filing.

Q. Please summarize BCC post rate case plant and depreciation expense.

A. PacifiCorp filed its last general rate case on March 1, 2013. Rates became effective January 1, 2014. Bridger Coal Company is including **[Begin Confidential]** [redacted] **[End Confidential]**[9] in gross plant additions between January 1, 2014 and December 31, 2019 in this filing. **[Begin Confidential]** [redacted] **[End Confidential]**[10] of 2014 plant additions will be depreciated by the end of 2019. None of this plant has received a prudence review by parties or a prudence determination by the Commission.

Q. Should depreciation expense associated with post rate case plant additions be included in rates?

[9] Staff Exhibit 204.
[10] Staff Exhibit 204.

A. No. Post rate case plant has not been subjected to a prudence review. It is not appropriate to recover capital costs from customers for plant that is not in rate base and has not yet been determined by the Commission to be prudent. The problem with including depreciation expense in rates for plant that has not been deemed prudent is that it circumvents the prudence examination process that the Commission has in place to evaluate plant investments. For example, PacifiCorp has recovered $20.1 million in costs related to the Joy Longwall purchase.[11] The Commission will never review the prudence of the Joy Longwall because it is no longer in service. This illustrates why depreciation should not be included for plant that has not been deemed prudent by the Commission.

Q. Should PacifiCorp have the opportunity to recover prudently incurred BCC expenses?

A. Yes, it is reasonable for PacifiCorp to have the opportunity to recover prudently incurred expense. However, the TAM does not currently include a process for reviewing rate base investments. Staff encourages PacifiCorp to work with the Staff and other interested parties to develop an appropriate process for reviewing these expenses and including prudent amounts in rates.

Q. What is the impact of excluding the depreciation expense for post rate case plant additions from power costs?

A. PacifiCorp is a two third owner of BCC, and approximately one third of annual BCC depreciation expense is included in this case. BCC has annual

[11] Docket No. UE 327, ICNU/102.

depreciation expense of **[Begin Confidential]** [redacted]**[End Confidential]**[12] associated with post rate case plant additions. PacifiCorp's share of this is **[Begin Confidential]** [redacted]. **[End Confidential]**[13] Oregon's allocation of this cost is **[Begin Confidential]** [redacted] **[End Confidential]**[14]

Q. What do you recommend regarding Bridger Coal Company.

A. Staff recommends that:

1. Depreciation expense associated with BCC plant added after PacifiCorp's last rate case be excluded from rates.
2. The Company include BCC assets in subsequent depreciation studies.

---

[12] Staff Exhibit 204.
[13] Staff Exhibit 204.
[14] Staff Exhibit 204.

ISSUE 5. DIRECT ACCESS

Q. Please summarize this issue and Staff's recommendation.

A. PacifiCorp's long term direct access customers transition adjustments for 10 years worth of fixed generation costs. In Docket No. UE 335, PGE noted that there is a difference between the length of time that PGE direct access customers pay for fixed generation costs and the length of time that PacifiCorp customers pay for fixed generation costs.[15] In UE 335, Staff recommend that PGE maintain its current method of including five years of fixed generation costs in long term direct access transition adjustments. In UE 335, Staff also noted that expected capacity shortfalls may provide a reason to revisit the method of calculating fixed transition adjustments and proposes a workshop related to the potential for avoided capacity costs from direct access. Staff may make a recommendation related to PacifiCorp's direct access services in a future TAM depending on the outcome of this issue in UE 335.

Q. Does this conclude your opening testimony?

A. Yes.

[15] PacifiCorp collects ten years of fixed generation costs over a five year period. PGE proposes to collect ten years of fixed generation costs over a ten year period.

CASE: UE 339
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualification Statement

June 11, 2018

WITNESS QUALIFICATION STATEMENT

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

CASE: UE 339
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

June 11, 2018

OPUC Data Request 1

Please refer to PAC/100, Wilding/35. What changes were required to the GRID model to allow for economic coal cycling? Please provide direction for how to allow cycling, how to restrict the date of cycling, and how to limit the number of unit starts.

Response to OPUC Data Request 1

In the Generation and Regulation Initiative Decision Tool (GRID) Graphic User Interface (GUI), the thermal unit screen, use the time attribute drop down box to select "Can Cycle." On this GUI screen, a "Can Cycle" value equal to "1" means the specific thermal plant is allowed for cycling. The "Start" value specifies the starting date of cycling and restricted by duration and repeat frequency GUI entries where indicates the length of the cycling period. GRID does not have the functionality to limit the number of unit starts, so the number of start-ups during the cycling period for each cycling coal plant is checked after GRID is run to make sure the number of starts is under the start limit. The confidential work paper to check the number of starts during the cycling period for each cycling coal plant was provided with the company's 5-day confidential work papers supporting the direct testimony of company witness, Michael G. Wilding, specifically file "ORTAM19w_Thermal Dispatch Check.xlsx."

OPUC Data Request 2

Please refer to PAC/100, Wilding/35. What coal plants are eligible for economic cycling? For each restriction limiting the eligible units, please explain why PacifiCorp includes the restriction.

Confidential Response to OPUC Data Request 2

In the Oregon 2019 transition adjustment mechanism (TAM), the eligible coal units for economic cycling are [redacted]. The restrictions to determine the economic cycling eligibility are:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Confidential information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 3

Please refer to PAC/100, Wilding/36. Please provide the data used to generate Table 4. Please update the data to include economic cycling outages that have occurred prior to May 31, 2018.

Response to OPUC Data Request 3

Please refer to Confidential Attachment OPUC 3, which provides Confidential Table 4 from the Direct Testimony of company witness, Michael G. Wilding, updated to April 30, 2018.

Note: data for May 2018 is not available at this time. The company will supplement this response with May 2018 data, when it becomes available.

Confidential Attachment OPUC 3 is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 4

Please refer to PAC/200, Ralston/10.

(a) Please provide the new Black Butte coal contract and the UPRR transportation contract.

(b) Please provide the date that PacifiCorp began negotiating the Black Butte contract.

Response to OPUC Data Request 4

(a) This information is highly confidential and commercially sensitive. Please refer to Highly Confidential Attachment OPUC 4.

(b) Discussions and negotiations with Lighthouse Resources Inc. began in January 2017.

Highly Confidential Attachment OPUC 4 is provided subject to Modified Protective Order No. 18-106 and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 5

Please provide all analysis supporting the volume selected for the Black Butte coal contract.

Confidential Response to OPUC Data Request 5

[redacted]

PacifiCorp's generation forecast, the basis for assumed coal consumption of approximately [redacted] tons/year, was taken from PacifiCorp's 2017 budget Generation and Regulation Initiative Decision Tool (GRID) results while taking into account the plant coal stockpile level and the ability to maintain some flexibility. The assumptions and analyses used to derive PacifiCorp's budget GRID was discussed in a recent workshop held in Portland, Oregon held on February 23, 2018. Please refer to the company's response to OPUC Data Request 7 for the information provided by PacifiCorp at that workshop. PacifiCorp cannot comment on the derivation of IPC's expected annual coal consumption of approximately [redacted] tons/year.

In terms of annual coal deliveries, the Black Butte mine provided five proposals with differing terms (contract lengths) and annual coal delivery volumes. The annual coal delivery volumes provided in the proposals ranged from [redacted] tons/year to [redacted] tons/year. BCC prepared complementary mine plans of 4.2 million tons/year and [redacted] tons/year. Please refer to Confidential Attachment OPUC 5, which provides the analysis supporting PacifiCorp's decision to select the [redacted] ton/year Black Butte proposal.

Confidential Information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 6

Please provide all analysis supporting the terms of the UPRR contract supplying Jim Bridger.

Confidential Response to OPUC Data Request 6

The Jim Bridger plant is captive to Union Pacific for all rail transportation services. There is no other means of transporting coal via rail into the plant other than by the Union Pacific Railroad. Discussions and negotiations with the Union Pacific Railroad began in January 2017. The new four year (2018 through 2021) rail agreement effectively represents an extension of the prior three year (2015 through 2017) rail agreement. The new rail agreement provides for rail transportation services from the Black Butte mine to the Jim Bridger power plant. Additionally, the new rail agreement provides terms and pricing for three additional alternative coal supply sources; the Kemmerer mine in southwest Wyoming, southern Powder River Basin (PRB) mines in Wyoming, and the Twentymile mine in Colorado. The new rail agreement provides benefits with an increased volume range between a minimum of [redacted] and a maximum of [redacted] per calendar year. The new rail agreement was negotiated with a minimal price increase of [redacted] as calculated from fourth quarter 2017 to first quarter 2018.

Confidential information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 7

Please refer to PAC/200, Ralston/9 at line15. Please identify the date of each workshop and provide all handouts and presentations distributed at each workshop. If this information is already provided, please provide a reference to where it is located.

Response to OPUC Data Request 7

Please refer to the following workshops listed below with dates and reference where handouts were previously provided (excluding Fueling Plan Workshop #3, which is provided in Confidential Attachment OPUC 7-2).

- Jim Bridger Plant, Long-Term Fueling Discussion – January 12, 2017 (docket UE 323 (2018 TAM), direct testimony of company witness, Dana M. Ralston, Confidential Exhibit PAC/201). For ease of reference, a copy of this presentation is provided as Confidential Attachment OPUC 7-1.

- Fueling Plan Workshop #2 – March 1, 2017 2017 (docket UE-323 (2018 TAM), direct testimony of company witness, Dana M. Ralston, Confidential Exhibit PAC/201). For ease of reference, a copy of this presentation is provided as Confidential Attachment OPUC 7-1.

- Fueling Plan Workshop #3 – January 11, 2018. Please refer to Confidential Attachment OPUC 7-2.

- Workshop on Long-Term Coal Contract and Variable Operations and Maintenance (O&M) in Oregon TAM – February 23, 2018 (docket UE 339 (2019 TAM), direct testimony of company witness, Dana M. Ralston, Exhibit PAC/201).

Confidential Attachments OPUC 7-1 and OPUC 7-2 are designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 8

Please provide the following data for each PacifiCorp affiliate that has power cost related transactions with PacifiCorp that impact the 2019 NPC Forecast in the TAM by greater than $100,000 on a total company basis.

(a) Name of affiliate.

(b) Percent of common ownership interest if any.

(c) Affiliated interest agreement on file, if any.

(d) Indicate if the transactions are cost based or market based transactions.

(e) Type of power cost related transactions.

Response to OPUC Data Request 8

For purposes of this request, the company reviewed calendar year 2017 transactions to identify PacifiCorp affiliates that likely impact the 2019 net power costs (NPC) forecast by greater than $100,000 on a total company basis.

(a) Please refer to Attachment OPUC 8-1.

(b) Please refer to Attachment OPUC 8-1.

(c) Please refer to Attachment OPUC 8-2, Confidential Attachment OPUC 8-3, and Highly Confidential Attachment OPUC 8-4.

(d) Please refer to Attachment OPUC 8-1.

(e) Please refer to Attachment OPUC 8-1.

Confidential Attachment OPUC 8-3 is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

Highly Confidential Attachment OPUC 8-4 is provided subject to Modified Protective Order No. 18-106 and may only be disclosed to qualified persons as defined in that order.

OPUC Data Request 9

Please refer to PAC/100, Wilding/7. Please explain how the Tax Cuts and Jobs Act has impacted PacifiCorp's forward price curves and fuel contracts.

Response to OPUC Data Request 9

The Tax Cuts and Jobs Act of 2017 (TCJA) was signed into law by President Donald J Trump on December 22, 2017.

PacifiCorp's official forward price curve (OFPC), which reflects its wholesale marginal cost of power and natural gas, is composed of 72 months of market forward prices followed by 12 months of a forwards -fundamental blend that transitions to a pure fundamentals forecast in month 85. Consequently, the first seven years of the December 2017 OFPC reflects or is influenced by observed market forwards as of December 29, 2017. Forwards for Henry Hub natural gas and Mid-Columbia (Mid-C) power, traded daily throughout December 2017, show no material change occurring when the TCJA was signed into law. In addition, since the TCJA was signed into law, the company has not seen a material impact to natural gas contracts it has entered into. Likewise, PacifiCorp's coal supply agreements (CSA) typically have fixed or variable pricing. There has been no impact to the fixed-priced coal contracts as a result of the TCJA. The variable-priced contracts are typically based on an index or basket of indices. Changes or movements in these indices are driven by a variety of variables, therefore, the ability to identify, isolate or quantify the impacts of the TCJA on the variable-priced coal contracts is indeterminable.

CASE: UE 339
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits in Support
Of Opening Testimony

June 11, 2018

STAFF EXHIBIT 203

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 18-106

CASE: UE 339
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 204

Exhibits in Support Of Opening Testimony

June 11, 2018

STAFF EXHIBIT 204

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 18-106

CASE: UE 339
WITNESS: LANCE KAUFMAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 205

Exhibits in Support
Of Opening Testimony

June 11, 2018

STAFF EXHIBIT 205

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 18-106

CASE: UE 339
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony

June 11, 2018

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

A. My name is Rose Anderson. I am a Senior Utility Analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/301.

Q. What is the purpose of your testimony?

A. My testimony discusses the application of a Contract Delay Rate (CDR) in PacifiCorp's 2019 TAM. I also discuss PacifiCorp's REC transfer proposal for direct access customers.

Q. Did you prepare an exhibit for this docket?

A. My previously mentioned witness qualification statement is the only exhibit I prepared for this docket.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, PURPA CONTRACT DELAY RATE

Q. Please explain the issue with forecasting the Commercial Operation Date (COD) of new Qualifying Facilities (QF) under the Public Utility Regulatory Policies Act of 1978 (PURPA).

A. Part of forecasting power costs for a future test year is forecasting generation from new QFs. The date at which a new QF is forecast to begin commercial operation may have a significant impact on the amount of generation forecast from the new QF and the resulting expenses attributable to the new QF. For example, if a utility forecasts a COD of January 1, 2019 in the test year, and then the COD is delayed by ten months, customers will pay for an entire year of generation from that QF. In reality, that QF was not in operation for ten months of the year, and the utility purchased power from a different source to meet the same load that was expected to be met by the delayed QF. This creates a discrepancy between what was forecasted and actual power costs.

Q. What process has PacifiCorp agreed to that can help to mitigate this potential source of inaccuracy in the Transition Adjustment Mechanism (TAM) power cost forecast?

A. In the 2018 TAM (Docket UE 323), the Commission adopted CUB's proposal for the treatment of QF costs in the TAM, and ordered PacifiCorp to calculate and apply a Contract Delay Rate (CDR) based on a three-year history of delays for new QFs.[1] The Commission also directed PacifiCorp to weight the CDR by QF size to more accurately reflect the rate impact of forecast errors.[2]

In compliance with the Commission's direction, PacifiCorp compares a three-year history of actual CODs to the CODs forecast in the applicable year's TAM. PacifiCorp then weights these delays by the capacity of each delayed facility in MW. Finally, PacifiCorp applies the weighted average of these historical delays to each new QF's COD in the forecast Test Year and uses the adjusted forecast as an input to the GRID power cost model.

Q. Has Staff reviewed PacifiCorp's calculation and application of the CDR in the 2019 TAM?

A. Yes. Staff has reviewed Company workpapers and participated in a phone conference with the Company. The Company's workpapers demonstrate that the Contract Delay Rate has been calculated appropriately and applied to the QF CODs in the Company's 2019 TAM as described in Order No. 17-444.

[1] *In re PacifiCorp*, OPUC Docket No. UE 323, Order No. 17-444 at 17 (Nov. 1, 2017).
[2] *Ibid.*

ISSUE 2, REC TRANSFERS

Q. Please explain the issue of Renewable Energy Certificate (REC) transfers in the TAM.

A. Direct access customers who depart PacifiCorp's service to purchase energy from an Electricity Service Suppler (ESS) are subject to a transition adjustment pursuant to PacifiCorp's Schedules 294, 295, and 296, depending on the direct access program. These schedules are for two-, three-, and five-year opt-outs respectively. Each schedule contains a transition adjustment designed to recover all or a portion of an uneconomic utility investment and to return to a direct access customer all or a portion of the benefits from an economic utility investment. The transition adjustment can be a charge or a credit, depending on the economic and uneconomic utility investments included.

When a customer leaves for direct access, the Company's Renewable Portfolio Standard (RPS) compliance requirement is reduced proportionate to the direct access customer's load for the period of time in which the customer is subject to transition adjustments. Put another way, the transition adjustment calculation includes a calculated value for freed-up energy, and with that energy there are corresponding freed-up RECs.

In PacifiCorp's three most recent TAM proceedings, Calpine has argued that PacifiCorp should include in the transition adjustment the value of

PacifiCorp's reduced RPS compliance obligation—freed-up RECs—that were acquired to serve direct access load.[3]

In the 2017 TAM, the Commission acknowledged that freed-up RECs may benefit cost-of-service customers.[4] In the 2018 TAM, the Commission directed PacifiCorp to present its best proposal for REC transfers in the 2019 TAM as a way to build a full record on this issue, enabling the Commission to decide whether REC transfers are practical and feasible.[5]

Q. What is PacifiCorp's REC transfer proposal?

A. PacifiCorp proposes to transfer RECs on an annual basis to the direct access customer's ESS.[6] RECs will be transferred to a WREGIS account identified by the direct access customer's ESS.[7] Transfers will begin following the first year of direct access, to meet the ESS's RPS compliance obligation.[8] Transfers would take place by May 1 of each year based on the prior year's compliance obligation.[9]

For one- and three-year direct access customers, the RECs transferred will be based on the prior year's actual load for that customer.[10] For the five-year/permanent opt-out direct access customers, the RECs transferred will be

[3] *In re PacifiCorp*, OPUC Docket No. UE 296, Order No. 15-394 at 10-12 (Dec. 11, 2015); *In re PacifiCorp*, OPUC Docket No. UE 307, Order No. 16-482 at 21-22 (Dec. 20, 2016); *In re PacifiCorp*, OPUC Docket No. UE 323, Order No. 17-444 at 17-19 (Nov. 1, 2017).
[4] Order No. 16-482 at 21-22.
[5] Order No. 17-444 at 17-19.
[6] PAC/100, Wilding/46.
[7] *Ibid.*
[8] *Ibid.*
[9] *Ibid.*
[10] *Ibid.*

calculated differently for years one through five, and years six through ten.[11] This is because five-year opt-out customers only have a transition adjustment for the first five years after departure, although the adjustment reflects costs and benefits to cost-of-service customers over a ten year period. In PacifiCorp's proposal, customers would be credited with RECs for years six through ten on the basis of average load over years one through five.

The specific RECs transferred would be from RPS-eligible resources, at PacifiCorp's discretion, and may vary from year to year.[12] At least 80 percent of the transferred RECs will be RECs that, before the transfer, were considered bundled.[13] PacifiCorp makes no representation and does not warranty that after the transfer, any of the RECs transferred to the ESS's WREGIS account will qualify as bundled RECs for the purposes of RPS compliance.[14] Finally, PacifiCorp will not be responsible for the retirement of RECs or claims made about the RECs on behalf of the direct access customer or ESS, or any RPS compliance of the direct access customer or ESS.[15]

Q. What is Staff's position on PacifiCorp's REC transfer proposal?

A. Staff generally supports PacifiCorp's REC transfer proposal as addressing the issues and concerns raised by Calpine in recent TAM proceedings, and finds that it is consistent with the Commission's direction in OPUC Order No. 17-444. The REC transfer will reduce the likelihood of direct access customers'

[11] PAC/100, Wilding/46-47.
[12] *Ibid.* at 47.
[13] *Ibid.*
[14] *Ibid.*
[15] *Ibid.*

subsidization of cost-of-service customers for RPS compliance by returning the RECs associated with the customer's load to the customer. Staff recommends the Commission provide guidance to ESSs as to whether the bundled RECs transferred from PacifiCorp to an ESS will be considered as bundled RECs in the context of an ESS' requirement to meet the RPS with 80% bundled RECs beginning in 2021.[16]

Q. Does this conclude your opening testimony?

A. Yes.

[16] ORS 469A.145(4)

CASE: UE 339
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualification Statement

June 11, 2018

WITNESS QUALIFICATION STATEMENT

NAME:	Rose Anderson
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Renewal Energy Analyst Energy Resources and Planning Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Master of Science, Agriculture and Resource Economics, University of California Davis, Davis, CA Bachelor of Arts, International Political Economy University of Puget Sound, Tacoma, WA
EXPERIENCE:	I have been employed at the Public Utility Commission of Oregon since September of 2016. My position is Senior Utility Analyst in the Energy Resources and Planning Division. My current responsibilities include review of load forecasting, advertising, and Renewable Portfolio Standards. I perform economic analysis in Rate Cases, Integrated Resource Plans and Rulemaking dockets. Prior to working for the PUC I was a Research Associate at McCullough Research for two years. My responsibilities included economic analysis of energy markets and utilities.