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June 10, 2019

Via Electronic Filing

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

RE: Docket No. UE 356 – In the Matter of PACIFICORP, dba PACIFIC POWER, 2020 Transition Adjustment Mechanism.

Enclosed for electronic filing are Staff Opening Testimony and Exhibits,
Certificate of Service and UE 356 Service List.

Exhibit 100, confidential pages are 5, 16, 31
Exhibit 101-103 and Confidential Exhibit 104

Exhibit 200, confidential pages are 13, 16
Exhibit 200-202 and Confidential Exhibit 203

Exhibit 300, confidential pages are 2, 6-13, 17, 19-21 and 27-30
Exhibit 301-302 and Confidential Exhibit 303

Exhibit 400, confidential pages are 2, 6, 7-8, 10-13
Exhibit 401-402 and Confidential Exhibit 403

Confidential exhibits are being mailed today via US first class mail to parties who have signed Protective Order No. 16-128.

/s/ Kay Barnes

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CASE: UE 356
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 100

Opening Testimony

Redacted

June 10, 2019

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 2020 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 and new facility benefits, wind capacity factors, PTC forecasts, and the official Forward Price Curve (OFPC) scalar methodology.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared:

- Exhibit Staff/102 (Company Response to DR Nos. 1,2, and 16, and Company Response to DR Nos. 51 from LC 67)
- Exhibit Staff/103 (Staff workpaper and Company Response to Staff DR No. 14)
- Confidential Exhibit Staff/104 (Confidential Company Response to Staff DR No. 10)

Q. How is your testimony organized?

A. My testimony is organized as follows:

2020 TAM Background 3
Issue 1. Inclusion of Energy Vision 2020 Benefits 6

Issue 2. Wind Capacity Factors 14
Issue 3. EV 2020 and PTC Customer Protections 24
Issue 4. Official Forward Price Curve Scalars... 26

2020 TAM BACKGROUND

Q. Please summarize PacifiCorp's 2020 TAM filing.

A. On a system basis, the Company's initial filing requested a 2020 Net Power Cost (NPC) of $1,480,334,955, which represents an increase of approximately $27.7 million compared to the final 2019 NPC.[1] However the increase is more than offset by an approximately $62.3 million increase in forecast production tax credit (PTC) benefits.[2] The net adjustment of the 2020 TAM is a $36 million decrease on a total Company basis.[3]

Q. What is the effect on an Oregon basis?

A. On an Oregon basis, the 2020 TAM of approximately $354.5 million is lower than the 2019 TAM of $364.3 million.[4] When account for load changes this represents a 1.2 percent decrease to overall rates on a net basis.[5]

Q. Did PacifiCorp propose any changes from its methodology in the 2020 TAM?

A. Yes. PacifiCorp proposes to:

1. Update scalar methodology for the OFPC.
2. Update the solar hourly shaping methodology.
3. Update topology splitting Wyoming Northeast Bubble.
4. Update the EIM benefits model.

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[1] PAC/101, Wilding/1 line 38.
[2] *Ibid.* line 41.
[3] *Ibid.* line 42.
[4] *Ibid*.
[5] PAC/100, Wilding/3 line 5.

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 and EV2020
2. Wind Capacity Factor Forecasting
3. PTC Forecasts
4. OFPC Scalar Methodology

(Staff/200 - Soldavini)

5. Other Revenues
6. Load Forecast
7. Solar Hourly Shape
8. Model Validation
9. Coal Contracts
10. Bridger Coal Company Depreciation
11. Company Supply Service Access Charge

(Staff/300 - Enright)

12. EIM Benefits
13. Wholesale Purchases and Sales and Hedging
14. Economic Cycling
15. DA-RT

(Staff/400 - Zarate)

16. Standard Inputs
17. Wheeling Costs

18. Qualifying Facilities Costs

19. DJ Clean Fuels and Hunter Coal Treatment

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

A. Below is a table summarizing the Staff adjustments found in Staff testimony.[6]

[BEGIN CONFIDENTIAL]

Adjustment	Amount
EIM net benefits	[redacted]
Wheeling Expense	[redacted]
QF Forecast	[redacted]
EV 2020 Benefits	$12.2 million
TOTAL	[redacted]

[END CONFIDENTIAL]

[6] All adjustments are listed on an Oregon-allocated basis. Other Staff adjustments have no dollar impact or Staff was unable to calculate the impact.

ISSUE 1. INCLUSION OF ENERGY VISION 2020 BENEFITS

Q. Please provide a background for this issue.

A. As part of the Company's 2017 Integrated Resource Plan (IRP), PacifiCorp is in the process of repowering the majority of its wind fleet. In the 2019 TAM, PacifiCorp agreed to include the benefits of repowering in the TAM in the form of increased PTCs and reduced power costs.[7] In conjunction with that, parties agreed to propose an expedited schedule in a subsequent Renewable Adjustment Clause (RAC) filing in order to have rates effective closer to the project in-service date, and to address the Commission's decision in docket UM 1909 regarding the deferral of capital. In the 2020 TAM, PacifiCorp is proposing to include the benefits of Glenrock III in a similar manner, but to not include any other Energy Vision 2020 new wind projects. Timing of when each project will provide benefits to customers, as proposed by the Company, is in the figure below.

Previously Built	
Leaning Jupiter	2019 TAM
Goodnoe Hills	2019 TAM
Marengo I	2019 TAM
Marengo II	2019 TAM
Glenrock I	2019 TAM
McFadden Ridge I	2019 TAM
Seven Mile Hill I	2019 TAM
Seven Mile Hill II	2019 TAM
High Plains	2019 TAM
Glenrock III	2020 TAM
Dunlap I	2021 GRC
New Build	
TB Flats I	2021 GRC
TB Flats II	2021 GRC
Ekola Flats	2021 GRC

[7] Order No. 18-421.

Cedar Springs II	2021 GRC
PPAs	
Cedar Springs I	2021 TAM
Cedar Springs III	2021 TAM

The exclusion of the noted plants until the 2021 general rate case (GRC) or 2021 TAM results in the omission of roughly $8 million of PTCs and $4.3 million of NPC savings on an Oregon allocated basis from the 2020 TAM.[8]

Q. Does the Company provide an explanation for the proposed treatment?

A. Yes. The Company states that the majority of the projects will come online in late 2020, and plans to include the impacts of the projects in an upcoming GRC with an effective date of January 1, 2021.[9] Cedar Springs 1 and 3 are PPAs which the Company states rely on the completion of the Aeolus-to-Bridger transmission line in order to provide benefits to the Company's system. As the transmission line will not be completed until late 2020, the Company proposes a similar treatment along similar lines of cost/benefit matching.[10]

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

A. Yes. In addition to legal concerns, which Staff will address in briefing, Staff has two main concerns about the Company's decision not to include the NPC and PTC benefits in the 2020 TAM. The concerns mirror concerns Staff had in the 2019 TAM when PacifiCorp proposed to exclude the NPC and PTC benefits. First, Staff is concerned that the Company's proposed ratemaking treatment is one-sided and inconsistent with Commission policy and precedent regarding

[8] Staff/102, Gibbens/1-2.
[9] PAC/100, Wilding/9.
[10] *Ibid.* at 9-10.

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.[11]

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."[12] SB 838 further directed the Commission to establish an automatic adjustment clause or another method for timely recovery of RPS compliance costs.[13] 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.[14] 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:

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

- *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****.*[15]

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).[16] In that case, PGE and PacifiCorp argued that variations in PTCs and other variable costs and benefits should be recovered on a dollar-for-dollar basis, rather than on a forecast basis and subject to the PCAM.[17] Staff, CUB and ICNU argued that ORS469A.120(1) did not require dollar-for-dollar recovery of all RPS related costs and benefits.[18]

[15] Order 07-572 at 3 (emphasis added).
[16] Order 15-408.
[17] Order 15-408 at 2-3.
[18] *Ibid*.

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.[19] This includes variable costs and benefits of RPS compliance.

In 2016, the Oregon Legislature passed SB 1547, directing each public utility to forecast, on an annual basis, projected state and federal production tax credits received by the public utility due to variable renewable electricity production, and directing the Commission to allow those forecasts to be included in any variable power cost forecasting process established by the Commission.[20]

In response to this directive, in its 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.[21] The Company further proposed to track variances in forecast and actual PTCs through the PCAM.[22] 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.[23] The Company agreed to Staff's recommended ratemaking treatment.[24] The Commission adopted this ratemaking treatment.[25] Therefore, the Company's failure to include NPC and PTC benefits Wind Repowering is

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

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 and ORS 757.269.

Commission direction for EV2020 in LC 67

Staff is also concerned that the Company's decision to exclude EV 2020 project NPC and PTC benefits in the 2020 TAM is inconsistent with the Commission's guidance and intent in Order 18-138 (2017 IRP Order), the order acknowledging the Company's Energy Vision 2020 project. Benefits of EV 2020 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 EV 2020 projects, 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.[26] The Commission ultimately acknowledged PacifiCorp's Energy Vision 2020, but noted that cost recovery "may be conditioned or limited to ensure customer benefits remain at least as favorable as IRP planning assumptions."[27] 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

[26] Order 18-138 at 7.
[27] Order 18-138 at 8.

> 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 EV2020 NPC and PTC benefits from the TAM forecast, results in PacifiCorp retaining reduced NPC and PTC benefits for plant that is in-service during the TAM year, and subjects ratepayers to actual dollar-for-dollar ratemaking treatment of those benefits, thus shifts the risk that benefits will not materialize from PacifiCorp to customers.

Q. What is Staff's recommendation for the treatment of the EV 2020 projects?

A. Staff recommends that all EV 2020 variable costs and benefits generally reflected in TAM proceedings be included as a forecast in the 2020 TAM, including the inclusion of partial year benefits. This treatment is consistent with the Company's treatment of EV 2020 benefits for the 2019 TAM, past Commission policy and precedent, and 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 Energy Vision 2020 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 recommends that PacifiCorp be directed to include in its 2020 NPC forecast the NPC and PTC benefits of its EV 2020 project (for both repowered wind and new wind). The impact of Staff's recommended adjustment is a $12.2 million reduction to the final TAM value.

Staff also notes that additional adjustments in future ratemaking proceedings, including a future TAM, may also be appropriate if the Company does not qualify for PTCs generated from either the repowered wind projects or the new wind projects.

ISSUE 2. WIND CAPACITY FACTORS

Q. Please provide a background for this issue.

A. In UE 339, PacifiCorp proposed 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.[28] Ultimately, parties settled on a 50/50 methodology which utilizes fifty percent historical actuals, and fifty percent original P50 forecast, for a one-year basis.[29] In the current TAM, the Company is proposing the continued use of the 50/50 approach.[30]

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

A. No. Staff believes that the 50/50 approach is a proper way to share performance risk between ratepayers and shareholders, generally, because it provides a good balance between aligning Company and ratepayer incentives in a RFP and forecast accuracy. However, this is not a reasonable approach for EV 2020 wind projects. Staff believes that the EV 2020 projects present are unique for two reasons. The first is that EV 2020, as discussed in the previous section, was acknowledged with significant discussion regarding ratepayer risk—for both the wind repowering and the new wind resources—and indicating desire from the Commission to condition or limit cost recovery in order "to ensure customers benefits remain at least as favorable as IRP planning

[28] PAC/100, Wilding/34.
[29] Order 18-421 at 4.
[30] PAC/100, Wilding/35.

assumptions."[31] Post-COD project performance was specifically called out as a risk to ratepayers. PacifiCorp's proposal would shift the risk of project performance to ratepayers. The second is that EV 2020 was built mainly for economic opportunity and not customer need, so the benefits associated with the project become of the utmost importance.

Q. How can Staff assert that the projects were built for economic purposes and not need?

A. Staff's position dates back to the recommendation it made regarding EV 2020 in PacifiCorp's 2017 IRP. Staff recommended the Commission not acknowledge the EV 2020 action items stating "the new wind and transmission resources proposed by PacifiCorp were not needed."[32]

PacifiCorp's date by which the Company needs additional renewable resources for purposes of RPS compliance has moved around. Staff, in the Staff Report prepared for the December 5, 2017 Public Meeting, documented five different expressions regarding the amount and timing of PacifiCorp's capacity needs,[33]

Staff noted PacifiCorp's assertion that "it has a current RPS compliance shortfall forecasted for 2025."[34] PacifiCorp's assertion was: "[t]he Energy Vision 2020 projects have the added benefit of allowing PacifiCorp to defer its

[31] Order 18-138 at 8.
[32] *Ibid.* at 20.
[33] *Ibid.* at 15-19.
[34] *Ibid.* at 14.

RPS compliance shortfall, which is currently forecasted to occur in 2025."[35] This "shortfall in 2025" forecast is **[Begin Confidential]** [redacted] **[End Confidential]**[36] PacifiCorp's assertion of a 2025 compliance need, in a October 30, 2017 filing, seems inconsistent with the timing of compliance need in the 2017 IRP, as it "...was prepared with information *consistent with the Company's most recently filed Integrated Resource Plan—the 2015 IRP and 2015 IRP Update,* unless stated otherwise."[37]

Q. What did PacifiCorp include in its 2017 IRP regarding a compliance shortfall with respect to Oregon's RPS?[38]

A. PacifiCorp included a modeling sensitivity (RE-1a) that accommodated Oregon's RPS by adding additional renewables to physically comply with

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35 Page 27 of PacifiCorp's Response Comments filed on October 30, 2017 in Docket No. LC 67, citing its Initial Application in its 2017-2021 Renewable Portfolio Standard Implementation Plan in Docket No. UM 1790, which was filed on July 15, 2016.

36 Page 2 of Confidential Appendix A to PacifiCorp's Initial Application in its 2017-2021 Renewable Portfolio Standard Implementation Plan, filed on July 15, 2016 in Docket No. UM 1790.

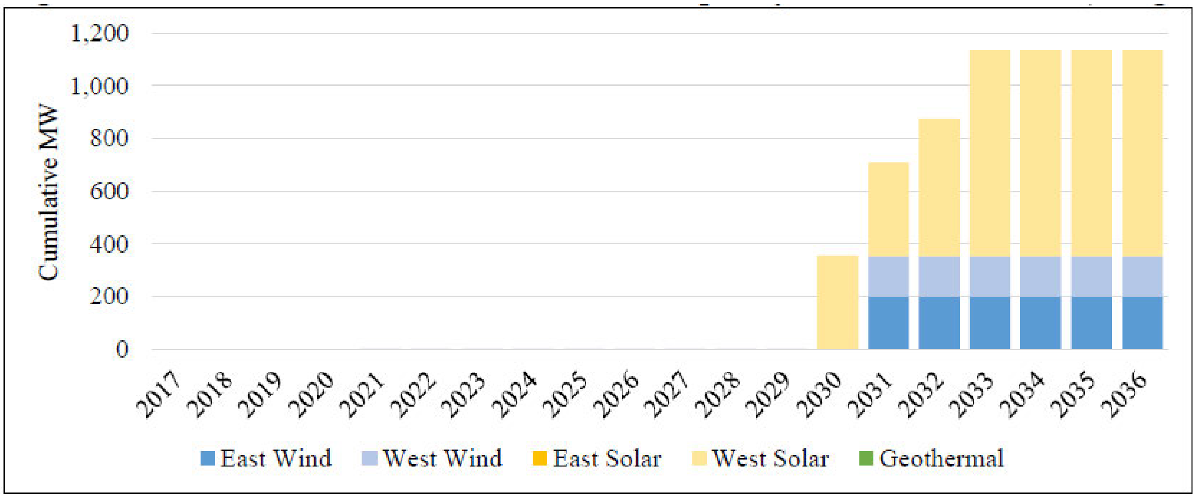
37 *Ibid.* at 2. Emphasis added.

38 Staff documented five different expressions of capacity need PacifiCorp presented in course of the 2017 IRP process. See pages 15 – 20 of the Staff Report dated November 21, 2017 and prepared for a December 5, 2017 Public Meeting regarding PacifiCorp's 2017 IRP.

Oregon's RPS on a just-in-time (JIT) basis.[39] Figure 1 below is the Company's figure in the 2017 IRP depicting the results of this sensitivity.

Figure 1: Cumulative Situs Renewable Capacity

Core Case RE-1a (Oregon RPS)



As can be seen in Figure 1, PacifiCorp, on a JIT basis for Oregon RPS compliance only, first needs a physical renewable generation resource in 2030. Alternatively, the Company, in response to Staff Data Request 51 in Docket No. LC 67, stated that "[t]he new wind and transmission project will also allow PacifiCorp to deliver Oregon renewable portfolio standards (RPS) compliance benefits, extending *the period in which PacifiCorp has an incremental compliance need from 2028* out to 2034…"[40]

Q. Regarding Staff's Public Meeting Memorandum (above), what did PacifiCorp include in its response regarding renewable investments?

[39] Pages 201 – 202 of PacifiCorp's 2017 IRP. Figure 1 here replicates Figure 2.28 in the 2017 IRP.

[40] Staff/102, Gibbens/5 (PacifiCorp's response to Staff Data Request 51 part b). Emphasis added.

A. The Company's November 28, 2017 filing—its response to Staff's Public Meeting Memorandum for the December 5, 2017 Public Meeting—included the following:

> "The Energy Vision 2020 projects meet both a near-term need within the two- to four-year period that otherwise would be filled by uncommitted FOTs, and a long-term energy and capacity need, at a heavily discounted cost and with reduced exposure to volatile wholesale markets that are driven by volatile fossil fuel prices and increasing carbon price risk. This is not the first time that renewables have provided an economic opportunity to displace FOTs at a lower cost and risk; in fact *all 1,698 MW of PacifiCorp's existing contracted and owned renewable resources included in rates today, not including qualifying facilities, were acquired and approved by the Commission because they were demonstrated to be least-cost, least-risk, displaced FOTs, and were acquired well before any thermal capacity or renewable portfolio standard (RPS) need."*[41]

Q. Do PacifiCorp's EV 2020 projects serve to meet its Oregon RPS requirements?

A. Staff stated its conclusion above—that PacifiCorp is making these EV 2020 investments at this time due to the benefits stated by the Company in its

[41] Page 3 of PacifiCorp's November 28, 2017 filing in Docket No. LC 67, pertaining to the Company's 2017 IRP. Emphasis added.

direct testimony, including the availability of the PTC—and not for RPS compliance purposes.

Q. How do capacity factors and project need intersect?

A. When customers require additional investment in order to meet their power supply needs, they must assume some risk associated providing the power they need. No forecast is perfect, and so long as the Company makes the best decision with the information possible at the time, the ultimate cost of the energy being provided is most likely justified. This is the crux of least cost/least risk planning. However, in this case, customers do not need additional investment made on their behalf in order to have the power they need. More so, the Company is taking a calculated risk, in order to take advantage of an economic opportunity. If the Company is allowed to use historic actuals to forecast wind capacity factors, then an under-performing wind plant results in higher power costs for customers. Any forecasted wind capacity factor that is below that provided in the cost/benefit analysis in the 2017 IRP will reduce the amount of wind generated in the TAM. Any reduction in wind generation must be made up for by running other generators or making market purchases, which will ultimately result in higher power costs.

Q. Please describe why Staff believes the Commissions has directed parties to treat EV 2020 differently than normal wind resources.

A. As noted previously the 2017 IRP Order, the Commission provided a conditional acknowledgement of the EV 2020 action plan. This was in part due to the Commission’s inability to determine a need for the projects. The Commissioner’s Order states:

> Limiting our acknowledgment to PacifiCorp’s planning assumptions is an unusual step that responds to the unusual difficulties of this planning cycle. Although we do not definitively resolve questions surrounding need, it should be apparent that when a utility does not need to take action within the action plan window to address regulatory compliance or reliability needs in the near-term, we will pay significantly more attention to near-term cost impacts and longer-term cost risks.[42]

In least cost/least risk planning, need is usually the first step in determining what potential solutions to pursue. Staff assumes that if the Commission declined to make a determination on need, it at the very minimum has concerns over the actual need of the project. This question of need and its implications discussed above, however, are only part of the Commission’s decision to condition the acknowledgement. The Commission also noted that the process was unusual and not ideal, noting:

> [W]e share Staffs and the intervenors' struggles with the abrupt presentation of PacifiCorp's plan and rigidity of its procurement proposal. PacifiCorp's procurement plans presented in pre-IRP planning meetings changed dramatically to what the company proposed in its filed IRP and supplemental analysis. This left many stakeholders unable to support the 2017 IRP, as they had little chance for input and for comparing the proposal with alternatives.[43]

Following the IRP, PacifiCorp then continued with its RFP process, which at the Company’s request was proceeding simultaneously to the IRP. In Commission Order No. 18-178, in which the Commission chose not to

[42] Order No. 18-138 at 9-10.
[43] Order No. 18-138 at 9.

acknowledge the Final Shortlist, the Commission reaffirmed its concern for customer protections noting:

> Our conditioned acknowledgement was intended to protect customers by holding PacifiCorp to the benefits forecast in its IRP projections. We stated that PacifiCorp's recovery may be conditioned or limited to ensure project benefits are no less than the assumptions presented in the IRP, listing pre-commercial operational date (COD) risks such as construction cost overruns, delays that impact PTC value, and project costs, and **post-COD risks such as project performance**, tax changes, and resource value relative to market.[44]

The non-acknowledgement of the RFP was the result of a planning process which the Commission could not guarantee was the least cost/least risk plan. In the same order, the Commission states:

> We simply cannot conclude at this time that the narrow shortlist from PacifiCorp's RFP—a packaged bundle of mostly company-owned Wyoming wind resources connected to a single transmission line—clearly represents the renewable resource portfolio offering the best combination of cost and risk for PacifiCorp customers.[45]

Maintaining the use of the P50 forecasts holds PacifiCorp to the NPC benefits forecast in the IRP. Because Staff, parties, and the Commission all have concerns over the prudence of the investment decision, it is not fair, just or reasonable to make customers bear performance risk associated with the EV 2020 plants. Staff notes that should the capacity factors exceed the P50 forecasts, which by definition should occur 50% of the time,[46] Staff's proposal will result in a higher power cost forecast than otherwise would have occurred.

[44] Order No. 18-178 at 2 (emphasis added).
[45] *Ibid.* at 10.
[46] P50 signifies the statistical confidence level for an estimate in probabilistic Monte Carlo simulations. i.e. 50% of simulated results exceed the P50 estimate.

This means that barring a PCAM adjustment, the Company has the opportunity to financially benefit from Staff's proposal.

Q. Does Staff have any alternate recommendation?

A. Should the Commission decide against Staff's recommendation above, Staff suggests that the Commission make one change to the Company's proposal. The Company should not utilize pre-repowered actuals to forecast the capacity factor for post re-powered plants. In the 2019 TAM, the use of actuals provided the benefit of increased accuracy in capacity factor forecasts at the expense of shifting the risk of wind generation to customers. The 50/50 split was meant to incorporate newer data while splitting the risk of wind plant performance between customers and stakeholders. In the 2020 TAM, however, almost all of the wind farms will have been repowered by December 31, 2020. 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.[47] In this TAM, the use of historic actuals does not provide a benefit of incorporating newer data. In fact, the use of actuals will reduce the accuracy of the wind plants as the actuals are based on data collected from no longer utilized components. In response to Staff DR 16, the Company noted it "solicited wind modeling P50 studies as well as studies to evaluate the sub-hourly generation output increases expected from the repowered facilities."[48]

[47] See LC 67 Informational Update filed July 28, 2017.
[48] Staff/102, Gibbens/3.

This means that the most accurate estimate for the newly re-powered plants is the P50 estimate.

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

A. Staff's primary recommendation is that the Commission require the Company to utilize P50 estimates for all EV 2020 projects. Customers should not bear performance risk of wind projects when need is unclear and the investment decision was not clearly the least cost/least risk plan. Staff's alternative recommendation is that the Commission direct the Company to continue to use the 50/50 split, but to treat any re-powered plant as a new plant, where the P50 forecast is the only component utilized in the calculation until new actuals are collected post repowering.

ISSUE 3. EV 2020 AND PTC CUSTOMER PROTECTIONS

Q. Please describe the issue.

A. In Commission Order No. 18-138, the Commission discussed potential customer protections for EV 2020 project shortfalls and overruns. Staff's first two issues discuss way in which Staff envisions ways to protect customers from certain variable cost risk. The inclusion of EV 2020 benefits in the TAM protects customers against short-term benefit loss. The wind capacity factor proposal protects customers from NPC risks. However, one variable cost risk is unaccounted for, PTC forecasts. The majority of the benefit of the EV 2020 projects in the first 10 years lies in the PTC forecast. Without a mechanism by which to hold the Company accountable to the forecast in the 2017 IRP, customers bear the risk. Staff will not restate its arguments for customer protections regarding EV 2020, but notes that the concern over need and optimal planning apply to PTC forecasts.

Q. Please explain the risks ratepayers face in regards to PTC forecast.

A. The main risk is lower realized PTC dollar value than expected. This can occur in two ways. One is associated with lower than expected generation. The other is in the PTC value forecast being higher than realized PTC per KWh.

Q. How does Staff propose to mitigate PTC forecast risk for customers?

A. Staff recommends the Commission limit the dollar benefits of the EV 2020 projects in this proceeding in such a way that PTC benefits, net of any applicable Wyoming wind tax (net PTC benefits), included in a TAM filing be no less than the net PTC benefits included in the Company's economic analyses supporting these EV 2020 projects. In other words, Staff recommends the Commission—in order to protect ratepayers and in the context of the annual TAM filings—impute values of net PTC benefits that are no less than the Company included in its February 2018 analyses. Given the variation in actual net PTC benefits likely to be realized year-to-year, Staff recommends this be evaluated annually in the TAM proceeding and on a cumulative basis. Staff recommends this mechanism be implemented beginning with (forecasted) net PTC benefits for 2020 (in the 2020 TAM filing) and continuing through the 2030 TAM filing, or through the last year for which PacifiCorp will realize PTC as a result of the Company's EV 2020 projects in this proceeding, whichever year is later.

For purposes of ratemaking in PacifiCorp's annual power cost adjustment mechanism (PCAM) proceedings, the benefits of the EV 2020 projects in this proceeding will not be subject to any deadband, sharing, or earnings test restrictions.

ISSUE 4. OFFICIAL FORWARD PRICE CURVE SCALARS

Q. What is the Official Forward Price Curve?

A. In regards to the TAM, the OFPC is the market price fed into GRID on an hourly basis by which GRID optimizes the generation portfolio and makes necessary market purchases and economic market sales. The OFPC starts as an average monthly price, which gets shaped by the hour on a generally speaking weekly basis. So apart from holidays, every week within each month will look identical. The scalars shape the monthly price by applying a different factor to each hour in a month for a given day type. A factor of 1.1 would mean that prices are 10% higher than average for that particular hour in the week (average price X hourly factor). The monthly average price in GRID remains the same as the OFPC monthly price but each hour in a day type will be higher or lower to reflect normal prices.

Q. How is the Company proposing to change the scalar methodology?

A. Before the current TAM, the Company scaled the OFPC by applying factors based on the average value for five years of historical hourly prices from PowerDex.[49] Each day type factor was the result of the average of that day type's hourly price over the five years divided by the monthly average price.

The Company is proposing to use a single year of day-ahead hourly market prices at the California-Oregon Border (COB) and Palo Verde (PV) markets provided by CAISO.[50] The process is similar, but instead of five

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[49] PAC/100, Wilding/19.
[50] *Ibid*.

consecutive years, the Company proposes to use two concurrent years to derive the factors.

Q. What does Staff like about the proposed methodology?

A. As the Company states, the CAISO data is publicly available, which increases transparency.[51] Further the day-ahead prices are a better proxy for the prices the Company normally sees in actual operations, as real time hourly prices account for only about six percent of the actual transactions made by PacifiCorp in the wholesale market.[52]

Q. Does Staff have concerns related to PacifiCorp's scalar proposal?

A. Yes. Staff has two concerns. First, Staff is concerned with the use of only a single year (2017) by which to achieve normalized prices. Second, Staff is concerned that the proxy built into GRID, using day-ahead prices at COB and PV is not reflective of the prices the Company sees at the markets which it does a large portion of its transactions.

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

A. In using only a single year of data, the Company leaves the scalars open to being dramatically influenced by any single year price anomalies. PV and COB both reside on the California border. As main hubs for energy in and out of California, they will tend to move in unison based on demand and supply factors within the state. Anomalous weather or supply events in 2017 will have a direct impact on the prices faced by GRID in 2020. This will result in changes

[51] PAC/100, Wilding/21.
[52] *Ibid.*

to NPC for customers from events that may be unrealistic to occur again in 2020. This is still an issue in the Company's previous methodology, but the effect was muted somewhat by the use of multiple years of data. Unfortunately, the averaging of prices over multiple years, which smooths out the anomalous prices, is what causes the lack of realistic pricing patterns the Company points out in Figure 2 of Wilding's Testimony.

Q. How did the Company account for possible extreme events?

A. The Company attempted to reduce the single event outliers by putting price caps on the data of -$50/MW and $250/MWEIM market in 2020.[53] This results in less volatile prices for some extreme events; however, an unseasonal heatwave or a large equipment outage will still elevate prices up to the cap in a non-normalized manner.

Q. Does Staff believe that the Company's removal of outliers will solve the issue?

A. No. Although it may help alleviate the issue, the overall result is still a non-normalizing methodology. The Company argues that increasing solar penetration is resulting in more price volatility in the markets.[54] This may well be the case; however the desire to provide GRID with a realistic market price must be balanced with the need to provide GRID with normalized prices. A single year from two markets does not provide GRID with price scalars that are

[53] PAC/100, Wilding/22.
[54] PAC/100, Wilding/21.

absent anomalous events. Figures 1-3 below shows the scalars using PAC's methodology for the month of January in 2016 and 2017.[55]

Figure 1

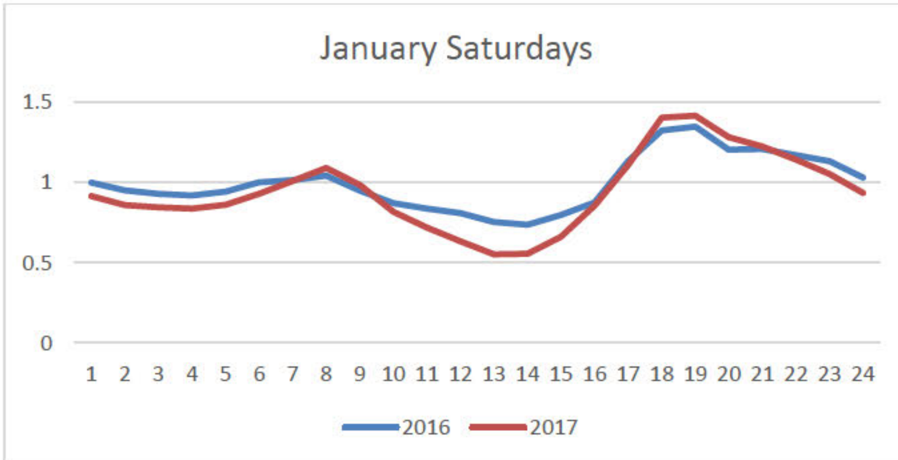
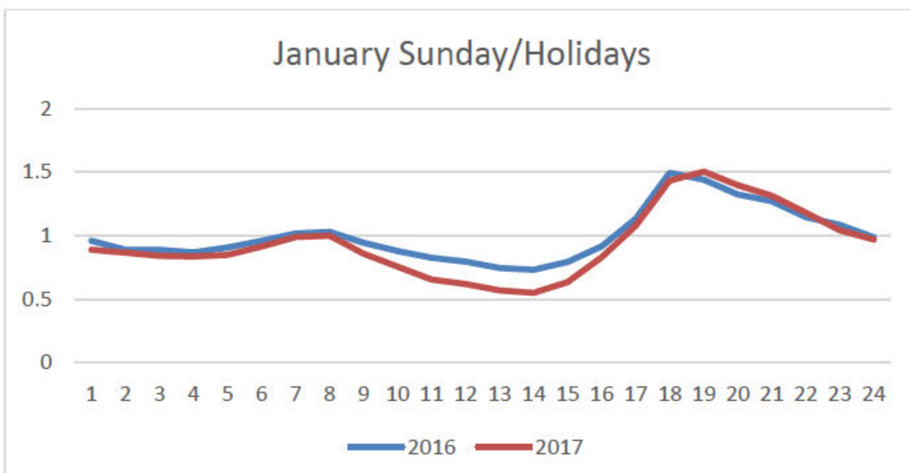
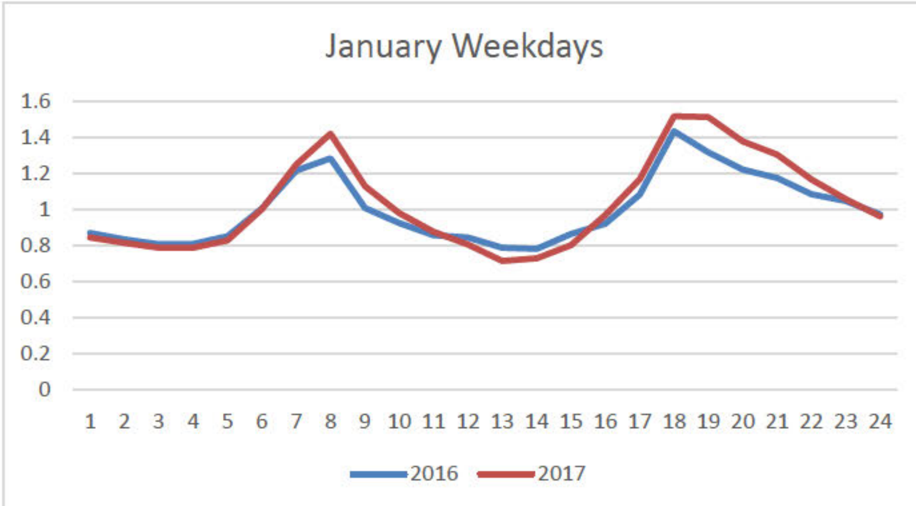


Figure 2



55 Staff/103, Gibbens/1 (PacifiCorp's Response to Staff DR No. 14).

Figure 3



It is clear that 2017 will produce more volatile pricing in this methodology, but that could be the result of increased renewables, although a winter month should provide a smaller impact of solar generation. It could also be that 2016 was a much warmer January than normal in California.[56] Or the difference could be due to the fact that in 2017, "A series of Pacific storms slammed into the West Coast during January. While the storms provided much needed drought relief for California and Nevada, the heavy precipitation caused widespread flooding and mudslides. The huge amounts of snow also increased the avalanche threat. A single storm early in the month dropped over 10 feet of snow on the California mountains."[57] The point being not that 2016 or 2017 would be more indicative of normal, but that PacifiCorp's methodology does not sufficiently account for non-normal events on prices.

[56] https://www.ncdc.noaa.gov/sotc/national/201601
[57] https://www.ncdc.noaa.gov/sotc/national/201701

Q. Please describe Staff's concern regarding the use of Palo Verde and COB.

A. The figure below shows the percentage of actual transactions at each market hub made by the Company in 2017.

[BEGIN CONFIDENTIAL]

Figure 4

[redacted][58]

[END CONFIDENTIAL]

From this Graph, it is clear that the Company completes **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of transactions at Palo Verde, but **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of transactions at COB. In an ideal world, if the Company were to only pick two markets which it used as proxies for the price which it would be facing in the 2020 TAM, it would be PV and Mid-C. The Company made **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of

[58] Confidential Exhibit Staff/104, Gibbens/2 (Confidential response to Staff DR No. 10).

its total purchases from 2015 through 2018 at Mid C. This methodology effectively uses COB as a stand-in for the ideal solution of Mid-C. As Staff has noted in other filings, the prices at Mid-C and COB are not always in lockstep.[59] In fact, following Staff's testimony on the matter, PGE now accounts for this price discrepancy in an out-of-model adjustment because of the Company's ability to arbitrage between COB and Mid-C.[60]

Q. Why does the Company not just use Mid-C instead of COB?

A. There are two issues. The first, CAISO does not provide data for prices at Mid-C. Second, Mid-C is a bilateral market, there is no day-ahead hourly prices to speak of. The purchases are generally done in blocks, over multiple hours or days. This begs the question then, whether an hourly price scalar which reflects increased volatility of California solar, is that important for a Company which makes most of its purchases at a market which is not directly apart of California and does not even have hourly prices. The Company's actual purchases at Mid-C are averages of the 'hourly price' over a longer timeframe. Meaning the prices faced by the Company in actual operations are less volatile than the prices being fed to GRID in the updated methodology.

Q. What is Staff's recommendation for the OFPC scalars?

A. Staff continues to examine the issue, to look for a more optimal solution. Ideally, as Staff notes, Mid-C price shapes should be incorporated in the scalar methodology to some extent. The shape should reflect the markets at which

[59] UE 294 - ICNU/100, Mullins/3.
[60] Order No. 15-536 at 9.

the Company transacts the most. However, Staff has been unable to find a similar data set that can be incorporated with CAISO data in order to achieve reasonable scalars to this point. Staff encourages PacifiCorp to offer potential solutions in its next round of testimony.

For the normalization issue, Staff recommends that the Company utilize at least two years of CAISO data. A single year is insufficient for normalization.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 356
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

June 10, 2019

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 356
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

June 10, 2019

UE 356 / PacifiCorp
May 28, 2019
OPUC Data Request 1

OPUC Data Request 1

PTC's and Wind Projects - Regarding PAC/100, Wilding/8, line 14, please provide the estimated PTC and power cost benefit foregone by not including Dunlap repowering project in the 2020 TAM.

Response to OPUC Data Request 1

In the 2020 Transition Adjustment Mechanism (2020), on an Oregon allocated basis, the Dunlap repowering project produces net power costs (NPC) benefit of $159,857, and production tax credit (PTC) benefit as of $1,308,212. The benefits are calculated using the most recent online date for Dunlap, September 20, 2020, which is updated from the online date that was expected at the time of 2020 TAM initial filing.

UE 356 / PacifiCorp
May 28, 2019
OPUC Data Request 2

OPUC Data Reqnest 2

PTC's and Wind Projects - Regarding PAC/100, Wilding/9, line 1, please provide the estimated PTC and power cost benefit foregone by not including the EV 2020 projects in the 2020 TAM. Please provide the PTC and power cost benefit by each project listed on lines 4 and 5 of the referenced Q & A.

Response to OPUC Data Request 2

In the 2020 Transition Adjustment Mechanism (TAM), the net power costs (NPC) benefit of the Energy Vision 2020 (EV 2020) projects is approximately $4.1 million, on an Oregon allocated basis. Each EV 2020 project's NPC benefit is calculated by pro-rating the total system NPC benefit based on the energy provided by each EV 2020 project in 2020 TAM.

The estimated production tax credit (PTC) NPC benefit for the EV 2020 projects is approximately $6.6 million, on an Oregon allocated basis.

Please refer to Confidential Attachment OPUC 2 for detailed calculations for each of the EV 2020 projects.

Note: the Uinta wind plant is no longer part of the EV 2020 project.

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

UE 356 / PacifiCorp
May 28, 2019
OPUC Data Request 16

OPUC Data Request 16

Wind Capacity Factors - Did the Company solicit or perform new P50 studies for any repowered wind plants?

Response to OPUC Data Request 16

The company solicited wind modeling P50 studies as well as studies to evaluate the sub-hourly generation output increases expected from the repowered facilities. These studies are used to estimate wind plant capacity factors following repowering projects.

The repowered wind plants capacity factors have been adjusted to the expected new capacity factors based on the repowering in the Generation and Regulation Initiative Decision Tool (GRID).

LC 67 / PacifiCorp
June 16, 2017
OPUC Data Request 51

OPUC Data Request 51

Regarding the new Wyoming wind and transmission project:

(a) Did the Company compare this project to one in which one or more coal plants are retired early to free-up transmission for the new wind, reducing or eliminating need for new transmission? If so, what were the results? If not, why not?

(b) Please confirm that the expected cost of environmental compliance in Oregon is less with the proposed wind and transmission project than the Company's previous plan of market REC purchases.

Response to OPUC Data Request 51

(a) PacifiCorp modeled and evaluated a number of regional haze case scenarios that assumed a range of coal unit retirement assumptions. Early in the 2017 Integrated Resource Plan (IRP) portfolio development process, PacifiCorp identified least-cost, least-risk regional haze case adopted for further portfolio analysis. The 1,100 megawatts (MW) of new Wyoming wind and Aelous to Bridger / Anticline transmission line (Energy Gateway sub-segment D2) included in the 2017 IRP preferred portfolio was selected as part of the least-cost, least-risk preferred portfolio reflecting the least-cost, least-risk regional haze compliance alternatives and associated early coal unit retirement assumptions. PacifiCorp did not evaluate alternative coal unit retirement assumptions beyond those evaluated as part of its regional haze analysis.

The 762 MW Dave Johnston plant in eastern Wyoming is the only coal-fueled generating asset on PacifiCorp's system that, if retired by the end of 2020, could relieve transmission congestion and enable incremental wind that is comparable to what can be achieved with the 750 MW of incremental transfer capability associated with the Aeolus to Bridger / Anticline transmission project. The Dave Johnston plant is one of the lowest variable operating cost assets on PacifiCorp's system, and operationally, provides flexibility that facilitates PacifiCorp's ability to import low-cost renewable energy from California through the California Independent System Operator (CAISO) energy imbalance market (EIM). Moreover, this asset provides significant system capacity needed to satisfy PacifiCorp's 13 percent target planning reserve margin (PRM). If this unit were retired at the end of 2020 (approximately three years out), there would be limited time to procure potential replacement resource alternatives capable of delivering energy and capacity benefits comparable to those provided by the Dave Johnston plant.

(b) Confirmed. The proposed 1,100 MW of new wind and Aeolus to Bridger / Anticline transmission line (Energy Gateway sub-segment D2) included in the 2017 IRP preferred portfolio by the end of 2020 is beneficial to customers based on all-in economics of the projects. The new wind and transmission project will also allow PacifiCorp to deliver Oregon renewable portfolio standards (RPS) compliance benefits, extending the period in which PacifiCorp has an incremental compliance need from 2028 out to 2034, while lowering customer costs.

CASE: UE 356
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

Exhibits in Support
Of Opening Testimony

June 10, 2019

UE 356 / PacifiCorp
May 28, 2019
OPUC Data Request 14

OPUC Data Request 14

OFPC Scalars - Is the CAISO data utilized by the Company to shape prices available for multiple years? If so, why did the Company choose not to use multiple years? Please provide either a link to or excel file of the CAISO data for years 2016 and 2017.

Response to OPUC Data Request 14

Yes. Please refer to the company's response OPUC Data Request 13.

Please refer to Attachment OPUC 14 which provides California Independent System Operator (CAISO) hourly day-ahead market prices for 2016 and 2017.

CASE: UE 356
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 104

Exhibits in Support
Of Opening Testimony

June 10, 2019

OPUC Data Request 10

OFPC Scalars - Please provide the amount of energy (MWh) transacted at each market hub by the Company from 2015 to current by month in an excel file. Please include purchases and sales separately.

Response to OPUC Data Request 10

Please refer to Confidential Attachment OPUC 10.

Confidential Attachment OPUC 10 is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

STAFF EXHIBIT 104

IS CONFIDENTIAL AND SUBJECT

TO PROTECTIVE ORDER: 16-128

AND

PROVIDED IN ELECTRONIC FORMAT ONLY

CASE: UE 356
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 200

Opening Testimony

June 10, 2019

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

A. My name is Sabrinna Soldavini. I am a Utility 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/201.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the issues of Other Revenues, Load Forecast, Solar Hourly Shaping, Model Validation, Coal Contracts, and the Company Supply Service Access Charge.

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

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1, Other Revenues 2
Issue 2, Load Forecast 4
Issue 3, Solar Hourly Shape 6
Issue 4, Model Validation 10
Issue 5, Coal Contracts 13
Issue 6, Bridger Coal Company Depreciation 15
Issue 7, Company Supply Service Access Charge 18

ISSUE 1, OTHER REVENUES

Q. Please describe what is considered as Other Revenues in the context of this filing?

A. In Docket No. UE 216, PacifiCorp's 2011 Transition Adjustment Mechanism (TAM), Staff raised the issue of a mismatching between updating costs and revenues, if a Company is allowed to include or update the costs associated with new resources, contracts and existing facilities for services it provides to third parties and are accounted for as "other revenue" in standalone power cost filings.[1] As such, Order No. 10-363 in Docket No. UE 216, stipulated that in future standalone TAM filings, the Company would include an update to Other Revenues related to net power costs (NPC). The Company reports the updated to Other Revenues as the difference from the baseline levels specified in UE 217. Other Revenues include those from storage and exchange agreements with Seattle City Light – Stateline Wind Farm, Non-Company owned Foote Creek projects, revenues from BPA associated with the South Idaho Exchange, steam revenues for Little Mountain Steam Revenues, and royalty offset revenues for the James River contract.

Q. How does PacifiCorp's 2020 TAM Other Revenues level differ from the baseline levels set in UE 217?

A. The 2020 TAM projects a decrease in Other Revenues of approximately $26,000 reduction from the baseline set in UE 217. Once adjusted for changes

[1] *See* UE 216, Staff/100, Brown/14.

to load, the projected decrease in the Other Revenues is approximately $68,000.[2]

Q. Does this reduction in Other Revenues lead to an adjustment to tariff Schedule 205, Adjustments for Other Revenue?

A. As stated in the Mr. Wilding's Opening Testimony, this reduction is too small to result in an adjustment to Schedule 205.[3] However, later in the Company's initial filing, in Ms. Ridenour's testimony, the Company included an upwards adjustment to Schedule 205, to account for the approximately $68,000 reduction in Other Revenues.[4]

Q. How does Staff propose to address this inconsistency with Schedule 205 in the Company's Opening Testimony?

A. Staff proposes an adjustment of $(67,946), removing the adjustment for Other Revenues from Schedule 205, and remaining consistent with Mr. Wilding's testimony.

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[2] See PAC/103, Wilding/1.
[3] *See* PAC/100, Wilding/4, lines 1-2.
[4] *See* PAC/300, Ridenour/3, lines 11-13.

ISSUE 2, LOAD FORECAST

Q. How does PacifiCorp's Load Forecast in the 2020 TAM compare to last year's 2019 TAM Load Forecast?

A. Oregon's load is estimated to increase by 1.2 percent, or 183 GWh, from 2019 to 2020. Oregon load is forecasted to be 15,216 GWh in 2020. Due to forecasted load growth, PacifiCorp anticipates $4.9 million more than expected will be collected in NPC based on rates approved in the 2019 TAM, and has included this amount in the overall rate change for the 2020 TAM, as a reduction to NPC.

Q. How does Oregon's load forecast differ from other jurisdictions in the Company's service territory?

A. The difference in Oregon's forecasted load between 2019 and 2020 of 1.2 percent places Oregon in the middle of PacifiCorp's service territory. Utah and Washington are projected to have an increased load of 2.2 and 2.3 percent, respectively. While Wyoming's load is projected to decrease by 0.7 percent, and total company load is projected to increase by 1.4 percent between 2019 and 2020.[5] The change in Oregon load relative to other jurisdictions results in a change to Oregon's allocation of load. Oregon's system energy allocation factor changes from 25.322 to 25.314 percent and the system generation allocation factor changes from 26.725 to 26.456 percent. Staff has reviewed the Company's updated allocation factors and finds them to be reasonable and consistent.

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[5] *See* Exhibit Staff/202, Soldavini/1 (PacifiCorp's Response to Staff DR 42).

Q. What are the primary drivers of the increase in Oregon load in the 2020 TAM?

A. The forecasted increase in Oregon load is due to higher projected demand from data centers, an increase in the number of Oregon residential customers, and a decrease in the Wyoming forecast where the Company notes that "extractive industries continue to adversely affect Company projections."[6]

Q. How did Staff analyze this issue?

A. Staff reviewed the Company's workpapers related to load forecast to ensure proper calculation of the impact. Staff focused on the load forecasts that exhibited the largest changes. Staff traditionally does not produce a full model replication of the Company's load forecast in every power cost filing, but Staff finds the forecasts reasonable on a short-term basis. Additionally, Staff notes that the Company is currently undergoing its 2019 IPR proceeding, and as part of both the TAM and the IRP Staff will continue to monitor and evaluate Oregon's load forecast.

Q. Does Staff propose an adjustment to Load Forecasting?

A. No, at this time Staff has no proposed adjustments for this issue.

[6] *See* Exhibit Staff/202, Soldavini/2 (PacifiCorp's response to Staff DR 43).

ISSUE 3, SOLAR HOURLY SHAPE

Q. Please provide background on the issue of updating solar hourly shape.

A. In this filing, PacifiCorp is proposing to update the way that it models its solar hourly profiles in GRID. As described in Mr. Wilding's testimony, GRID incorporates solar generation based on a "P50 forecast," which "projects generation at a level that is expected to have an equal probability of being higher or lower than forecast."[7] The Company is proposing to continue to incorporate solar generation based on a P50 forecast, but to change the way it shapes hourly solar generation.

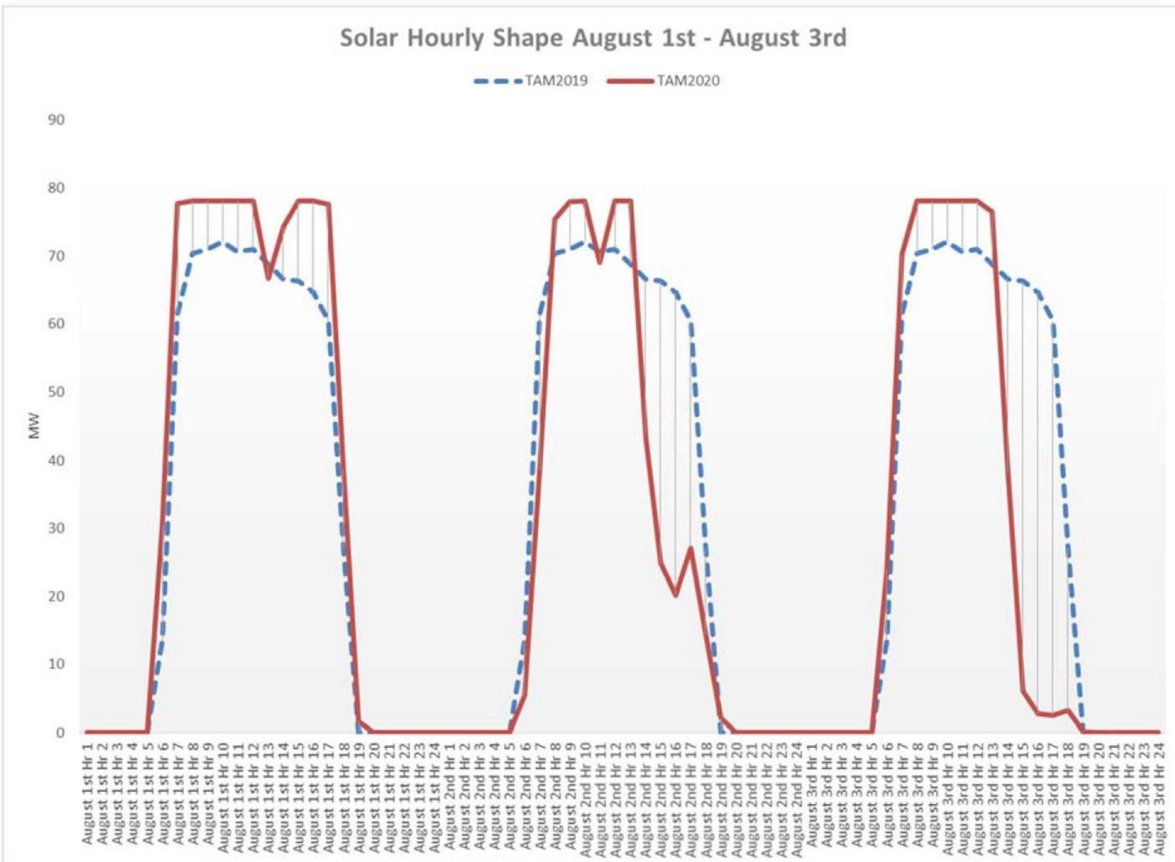
Q. Please describe the change to solar hourly shape the Company has proposed in its filing.

A. The Company has included the P50 forecast to determine total solar generation, but uses actual 2017 energy output from purchased solar facilities to shape hourly solar generation profiles. While the average monthly output remains consistent with the P50 forecast, actual hourly generation is scaled up or down to take into account historic solar generation, using 2017 historic actuals. A visual representation of the hourly shaping update's effects can be seen in the graphic below, which was included in the Company's opening testimony.[8] The red line indicates the updated shaping in the 2020 TAM with

[7] PAC/100, Wilding/23, lines 8-15.
[8] PAC/100, Wilding/24.

hourly variation, and the blue line indicates the modeling in the 2019 TAM, where each day within a month has the same shape.

Figure 1



Q. How does the proposed change in solar shaping affect NPC?

A. The updates to solar hourly shaping increase NPC in Oregon by approximately $237,000.

Q. Please summarize Staff's analysis of the Solar Hourly Shaping.

A. Staff reviewed the Company's proposed methodology for the changes to solar generation shaping, and issued data requests to the Company, requesting the Company model the differences in the 2019 TAM methodology with the proposed updated 2020 methodology for three additional date ranges, and to defend its choice to use just one year's worth of data, rather than an average of multiple years.[9]

Q. Does Staff have a recommendation for this issue?

A. Yes. Staff agrees with the Company that incorporating hourly variations in solar generation is likely to improve forecast accuracy. Though Staff understands the Company's preference towards using the most recent year's solar generation data, if it believes the market is expanding, Staff believes that performing the analysis with a single year's worth of data is insufficient to capture any irregularities that occurred within that year. For example, the solar generation in March of one year could vary greatly with that of March of the next year for reasons other than an increase in solar penetration. It might be the case that the first year was so unseasonably sunny that the average generation was higher in the first year despite a modest increase in solar generation in the second. This could result in a non-normal shape for the month of March due to unseasonable weather.

In a recent workshop, the Company indicated that solar output data should in fact be available for the year 2018. Staff recommends the Company update the model to include the average of 2017 and 2018 data for solar hourly shaping, rather than just 2017 data, in attempt to dampen the effect of any anomalies in 2017 or 2018. To that end, Staff would recommend that moving forward, and beginning with the 2021 TAM, once three years of

[9] *See* Exhibit Staff/203, Soldavini/1 (PacifiCorp's response to Staff DR 19).

historic generation data is available, that the three year average of historic generation be used as opposed to a single year.

ISSUE 4, MODEL VALIDATION

Q. What is Model Validation?

A. One common definition for validity is the ability of a tool to measure what it claims to measure. In the case of GRID, the model claims to measure future NPC based on a variety of inputs. The process of Model Validation is the process of determining how well GRID predicts these future costs. By feeding actual, historic data into GRID, and then comparing how well GRID would have predicted NPC based on historical data with actual costs, one can get a reasonable estimate of the models validity and determine if sources of error in the model are due to inaccurate (forecasted) data or issues with the model itself. The closer to actual NPC costs that GRID predicts with historical data, the more one could reasonably say the model is able to correctly measure what it claims to.

Q. Please describe the background on Model Validation.

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

The parties began a collaborative process that included meetings and workshops to outline the Model Validation process, and the Company included the results of the first Model Validation analysis in its 2019 TAM proceeding, Docket No. UE 339. The results of the initial Model Validation analysis showed that when fed historic data from 2016, GRID estimated 2016 NPC with a variance of $437,913 or .03 percent.[10] In UE 339, Staff noted in that it was too early to come to any conclusions, recommending that additional years be included in the Model Validation process, and that the issue be evaluated after the 2020 TAM proceeding.

Q. What were the results of the Model Validation analysis included in the 2020 TAM proceeding?

A. Included in the Company's 2020 TAM proceeding is a Model Validation analysis for 2017. Performing a backcast for the year 2017 (feeding historical 2017 data into GRID), the GRID model estimates total NPC at $1,525,294,643. Compared with 2017 actual NPC of $1,529,959,607, this is a variance of approximately $4.7 million or 0.3 percent.[11]

Q. What conclusion does Staff draw from the results of the 2017 Model Validation?

A. While the results of the Model Validation are encouraging, and show that the model captures much of the inefficiencies of actual operations, Staff continues to recommend that Commission not use the results to draw conclusions until such a time all parties are able to convene to discuss and analyze the results. Staff also continues to recommend that the Company perform several years worth of Model Validation to provide a more robust sample of data for the parties to analyze and interpret the results and effectiveness of the Model

[10] *See* Docket No. UE 339, PAC/100, Wilding/19.
[11] PAC/100, Wilding/32.

Validation process. The results of the 2017 Model Validation included in this docket demonstrate the benefit that performing additional years of analysis would provide. The results included in the 2019 TAM indicated a variance of just .03 percent, while the variance in the Model Validation performed in this docket, the variance between forecast and actual costs is approximately 0.3 percent or ten times larger than the variance reported in the initial Model Validation process. Clearly, the inclusion of additional years would provide the parties with a larger data set to evaluate, and could help in the determination of which of the model's parameters are most in need of scrutinizing. For example, with the inclusion of five years of analysis, if one parameter showed consistency for four of the five years, but showed a larger variance between actual and predicted costs in the fifth year, it would be easier to determine that the variance may be due to an anomaly rather than an incorrectly specified model.

To this end, Staff proposes that a workshop be convened with all parties to discuss next steps, future scope, and end goals of the Model Validation process prior to the filing of the 2021 TAM.

ISSUE 5, COAL CONTRACTS

Q. Please describe the change in the overall third-party coal supply costs in the 2020 TAM as compared with those in the 2019 TAM.

A. In the Company's initial 2020 TAM filing, it expects a net increase in third-party coal supply costs of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. What are the primary drivers for the change in overall third-party coal supply costs?

A. Mr. Ralston's testimony provides a thorough update on the primary drivers of the overall increase in third-party coal supply costs, but I will touch on a few of the largest drivers here. Primary drivers include an increase in total delivered costs at Naughton, which increased **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** overall, and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per ton from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per ton in the 2019 TAM to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per ton in the 2020 TAM. Dave Johnston saw a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, or **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** increase in delivered coal costs over the prior year. Additionally, the delivered coal costs at the Huntington plant increased by **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** driven by transportation and scheduled cost escalations to the Wolverine and Castle Valley Coal contracts.

Q. Is the Company currently involved in any coal supply negotiations?

A. Yes, the Company's current contract with Western Energy, the previous owner of the Rosebud mine, which supplies coal for the Colstrip plant expires at the end of 2019. The Company notes in its testimony that negotiations with the mine's new owners were expected to begin as early as April 2019. A new coal supply agreement is still in the negotiation phase, and the prices for coal at the Colstrip mine are subject to change based upon these ongoing negotiations in future 2020 TAM updates. Until a new contract is in place, the Company is basing Colstrip costs on the 2019 Annual Operating plan from Western Energy Company.

Q. Does Staff have an adjustment or recommendation regarding third-party coal supply costs?

A. No, Staff has no adjustment at this time, and is actively monitoring the Company's ongoing negotiations, and awaiting updates on the issue before making a recommendation. The negotiations are highly confidential, but Staff and the Company have been working closely together to stay appraised of any new developments. Staff notes that it retains the ability to review the final contract for prudence, including in next year's TAM proceeding if the contract is finalized after the close of the record in this case.

ISSUE 6, BRIDGER COAL COMPANY DEPRECIATION

Q. Please explain Bridger Coal Company's (BCC) relationship to PacifiCorp.

A. BCC is a joint venture of Idaho Power and PacifiCorp, which is owned by Idaho Energy Resources Co. (IERCO), a wholly owned subsidiary of Idaho Power, and Pacific Minerals, Inc. a wholly owned subsidiary of PacifiCorp. BCC charges PacifiCorp for coal at cost, which includes a component of BCC depreciation expense.

Q. Please summarize Staff's analysis of BCC Depreciation.

A. In the 2019 TAM, Staff raised the issue of the Company's recovery of depreciation expense from ratepayers related to plant that has been added since the Company's last general rate case and thus has yet to be reviewed for prudence.[12] In the stipulation approved in Order No. 18-421, the stipulating parties agreed that in subsequent power cost cases, PacifiCorp would provide additional information detailing the justification of the depreciable lives of BCC assets as well as any variations to BCC depreciation levels from the levels established in the Company's previous TAM, for each year since the Company's previous rate case.

Q. How has BCC depreciation expense varied since the Company's most recent rate case?

A. The Company's last rate case, UE 263, was filed in 2013. PacifiCorp calculates total BCC depreciation expense for the period ranging from January 2018 –

[12] *See* UE 339 Staff/200, Kaufman/13 through Kaufman/16.

December 2018 at approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. This represents an approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** over the prior year, which the Company notes is largely due to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].**[13] Since the Company's last general rate case in 2013, BCC depreciation expense has ranged from approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[14] The Company also provides estimates for BCC depreciation in 2019 and 2020, with estimated depreciation levels of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, respectively.[15]

Q. Has Staff confirmed PacifiCorp provided the necessary workpapers, as outlined in Order No. 18-421?

A. Yes. PacifiCorp has submitted workpapers as part of this year's TAM outlining the depreciable lives of BCC assets. The associated workpapers also include a description of how and why BCC depreciation expense has varied from the level set in its most recent general rate case.

[13] Exhibit PAC/202, Ralston/1.
[14] *Ibid.*
[15] *Ibid.*

Q. Does Staff have a recommendation for how BCC Depreciation costs should be treated?

A. Staff does not have a recommended adjustment at this time, but given the joint-ownership between Idaho Power and PacifiCorp on this plant, recommends that PacifiCorp, Idaho Power, Staff and interested intervenors convene a workshop to work through the BCC depreciation issues in a consistent manner. Staff recommends that an initial workshop be convened prior to December 31, 2019.

ISSUE 7, COMPANY SUPPLY SERVICE ACCESS CHARGE

Q. What is the Company Supply Service Access Charge?

A. Per OAR 860-038-0720, an electric utility's New Large Load Direct Access (NLDA) program must include a forward-looking rate adder, which customers who elect to return to standard offer or cost-of-service from an NLDA program will be subject to if their return results in a significant increase to existing cost of service rates. The Company Supply Service Access Charge, is the name PacifiCorp has chosen for its forward-looking rate adder that customers who elect to be served under the Company's new large load direct access program will be subject to, for four years, if they subsequently decide to return to cost of service and that return results in an increase to existing cost of service customer of more than 0.5 percent.

Q. How is the Company Supply Service Access Charge calculated?

A. Per the Company's NLDA tariff, the Company Supply Service Access Charge is calculated as the incremental difference between the four-year levelized cost of capacity that is calculated for avoided cost and the fixed generation costs, Schedule 200. The levelized cost of capacity for the upcoming four years is currently less than the fixed generation costs contained in Schedule 200, and therefore the Company Supply Service Access Charge is $0/MWh.

Q. Does Staff propose any changes to the Company Supply Service Access Charge?

A. In a recent Staff memo recommending that PacifiCorp's NLDA tariff be allowed to go into effect, Staff indicated it would review the forward looking rate adder methodology in future TAM filings, as the value of the charge is calculated for customers.[16] Because the charge is set at zero, and there are currently no customers in the position to be subject to the Company Supply Service Access Charge, Staff proposes no changes to the calculation, or level of, the charge at this time. Staff will continue to monitor the status of the Company's NLDA program and evaluate the methodology of the Company Supply Service Access Charge in future proceedings as customers elect to participate in the Company's NLDA program.

Q. Does this conclude your testimony?

A. Yes.

[16] *See* Docket No. ADV 900, Staff Report for Public Meeting.

CASE: UE 356
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

June 10, 2019

WITNESS QUALIFICATION STATEMENT

NAME: Sabrinna Soldavini

EMPLOYER: Public Utility Commission of Oregon

TITLE: Utility Economist
Energy Rates, Finance and Audit Division

ADDRESS: 201 High St. SE Ste. 100
Salem, OR 97301-3612

EDUCATION: Masters of Science, Agricultural Economics
Purdue University, West Lafayette, Indiana

Bachelor of Science, Economics
University of Oregon, Eugene, Oregon

EXPERIENCE: I have been employed by the Oregon Public Utility Commission (Commission) since August 2018 in the Energy, Rates and Finance Division. My responsibilities include providing research, analysis, and recommendations on a range of regulatory issues for filings made by utilities.

Prior to working for the Commission I was a consulting analyst for MGT Consulting, primarily to help large public school districts prepare for bond proposals through budget analysis and statistical modelling/projections of student and demographic data. Prior to this work, I was a Research Assistant at Purdue University where I conducted research on the economic feasibility of biofuel feedstocks. Additionally, I have experience working in Data Analysis, and Program Coordination within the technology sector.

CASE: UE 356
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

June 10, 2019

UE 356 / PacifiCorp
May 30, 2019
OPUC Data Request 42

OPUC Data Request 42

Please refer to, UE 339, PAC/100, Wilding/4. Please recreate Table 1, for the years 2019 and 2020, using the table below for reference.

Total Company Sales at System Input by Jurisdiction (GWh)				
	2019 Previous TAM Forecast	2020 Current TAM Forecast	GWh Change	Percentage Change
Oregon				
Washington				
California				
Utah				
Idaho				
Wyoming				
FERC*				
Total				

*Includes sales for resale

Response to OPUC Data Request 42

Please refer to the table provided below:

Table 1 Total Company Sales at System Input by Jurisdiction (GWh)				
	2019 Previous TAM Forecast	2020 Current TAM Forecast	GWh Change	Percentage Change
Oregon	14,943	15,126	183	1.2%
Washington	4,471	4,576	105	2.3%
California	879	880	1	0.1%
Utah	24,725	25,258	532	2.2%
Idaho	3,857	3,934	77	2.0%
Wyoming	9,847	9,780	-67	-0.7%
FERC*	322	319	-3	-1.0%
Total	59,045	59,873	828	1.40%
*Includes sales for resale				

OPUC Data Request 43

Please explain, in narrative form, the major drivers for the changes between the load forecasts in the 2019 TAM and the 2020 TAM. If the Company feels there is quantitative evidence to support this narrative, please provide in electronic spreadsheet format.

Response to OPUC Data Request 43

The primary drivers for changes between the load forecast in the 2019 transition adjustment mechanism (TAM), docket UE 339 and the 2020 TAM, docket UE 356 are a higher projected demand from data centers driving up the commercial forecast, a higher forecast for the number of residential customers driving a higher residential forecast and a declining forecast for Wyoming where extractive industries continue to adversely impact company projections.

CASE: UE 356
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits in Support
Of Opening Testimony

June 10, 2019

STAFF EXHIBIT 203

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 16-128

AND IS

PROVIDED IN ELECTRONIC FORMAT ONLY

CASE: UE 356
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony

June 10, 2019

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

A. My name is Moya Enright. I am a Senior Utility and Energy Analyst 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/301.

Q. What is the purpose of your testimony?

A. I discuss the 2020 TAM filing and Staff's analysis of the issues. Specifically, I will discuss Staff's review of and recommended Commission action regarding: the Western Energy Imbalance Market (EIM) benefit forecast, Wholesale Transactions and Hedging, Economic Cycling, and Day Ahead/Real Time (DA-RT) Adjustment.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following Staff Exhibits:

- Staff/301: Witness Qualification Statement
- Staff/302: PacifiCorp's responses to Staff DR Nos. 36, 37, 39, 63, 58, and 62.
- Staff/303: PacifiCorp's confidential responses to Staff DR Nos. 36, 37, 24, and 53.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1, Western Energy Imbalance Market Benefit Forecast 4
Issue 2, Wholesale Transactions and Hedging 14
Issue 3, Economic Cycling 17
Issue 4, Day Ahead/Real Time (DA-RT) Adjustment 25

Q. Please summarize your recommendations and adjustments.

A. Staff makes the following recommendations and adjustments:

1. EIM benefit forecast
   a. Staff recommends an inter-regional transfer benefits forecast of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on a total company basis.
   b. Staff recommends including excess GHG revenue for the benefit of customers, equaling an adjustment of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** on a total company basis.
2. Wholesale transactions and hedging
   a. No adjustment recommended.
3. Economic Cycling
   a. Staff recommends removing the four-month economic cycling period restriction.
   b. Staff recommends allowing GRID to economically cycle non-majority-owned units as a case study, and based on those results, PacifiCorp discuss economic cycling opportunities with co-owners.
   c. Staff recommends PacifiCorp conduct a cost benefit analysis of allowing EIM participating units to economically cycle in GRID.

4. DA-RT adjustment
   a. Staff recommends an adjustment to the DA-RT price adder calculation to use historic daily prices rather than historic average monthly prices.

ISSUE 1, WESTERN ENERGY IMBALANCE MARKET BENEFIT FORECAST

Q. What is the Energy Imbalance Market?

A. The Energy Imbalance Market (EIM) is a real-time wholesale power market. Its automated dispatch system provides economic benefits to participants by efficiently balancing load and generation resources. It also provides reliability and renewable integration benefits to the grid. PacifiCorp joined the EIM in 2014.

Q. How does participating in the EIM benefit PacifiCorp?

A. PacifiCorp benefits from its participation in EIM in a number of ways:

- *Excess Greenhouse Gas (GHG) Revenue*. GHG revenue is awarded when CAISO determines generation within an EIM entity served CAISO load.[1] Excess GHG revenue results when a GHG emitting resource and non-GHG emitting resource are generating at a node, power is being exported from the node to California, and more power is generated than is exported to California.
- *Flexibility Reserve Savings*. These savings occur because the diversified footprint of EIM allows PAC to hold lower reserves than would otherwise be necessary.
- *Intra-Regional Transfer Benefits*. These benefits accrue through EIM optimizing the automated dispatch of PacifiCorp's EIM participating units.

[1] Energy generated in California or imported into the state to serve California load is subject to California's GHG obligation. GHG revenue in EIM is intended to compensate entities importing power into California for their compliance costs.

- *Inter-Regional Transfer Benefits*. These benefits arise due to EIM facilitating transactions between PacifiCorp, CAISO, and other EIM participants on a five- and 15-minute basis.

Q. Are each of the four benefits forecasted in the 2020 TAM?

A. No, only two of the four benefits are currently forecasted in the TAM. Flexibility reserve savings and inter-regional transfer benefits are currently forecasted; however, excess GHG revenue and intra-regional benefits are not.

Q. Please explain how flexibility reserve savings and inter-regional transfer benefits are forecasted in the 2020 TAM.

A. PacifiCorp proposes to use different forecasting approaches for each benefit:

- *Flexibility Reserve Savings*. These savings occur because the diversified footprint of EIM allows PAC to hold lower reserves than would otherwise be necessary. PacifiCorp has asserted that due to its participation in EIM, it will be required to hold approximately 130 MW less reserves in 2020 than if it did not participate. This benefit is modelled by simply reducing the reserve requirement in GRID by 130 MW. Flexibility Reserve Savings in the 2020 TAM amount to a benefit of $1.6 million.[2]
- *Inter-regional transfer benefits*. These benefits occur when PAC earns money by exporting to EIM or saves money by importing from EIM. PacifiCorp has forecasted this benefit using a linear regression.

[2] PAC/100, Wilding/28, line 12.

Q. Has PAC changed its approach in forecasting EIM benefits in this year's TAM filing?

A. Yes. PacifiCorp has proposed a new approach for forecasting inter-regional transfer benefits. In the 2019 TAM, inter-regional transfer benefits were forecasted using a linear regression with one independent variable: time. PacifiCorp now proposes to use four independent variables: electricity market prices, gas market prices, EIM transfer capability, and spring oversupply conditions.

Q. Does Staff have any concerns with the new model proposed by PacifiCorp?

A. Yes, Staff is concerned to see a proposed **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** reduction in EIM benefits in the 2020 TAM compared with the 2019 TAM. There has been no convincing evidence presented to suggest that EIM benefits should decline in 2020. In fact, the latest data made available by PacifiCorp shows that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[3] These trends can be observed in Figure 1.

[BEGIN CONFIDENTIAL]

[3] PacifiCorp confidential workpaper "ORTAM20w_EIM Benefits CONF".

Figure 1

[redacted]

[END CONFIDENTIAL]

The model proposed by PacifiCorp adds weight to springtime results in recent years, however the Company has not presented any empirical evidence to demonstrate that spring oversupply conditions affect EIM results, nor has it provided convincing arguments to support its approach.

Modeling inter-regional benefits with an added emphasis on spring months reduces the impact of higher prices and higher loads at other times of the year. Higher prices and higher loads are the same market conditions which PacifiCorp identified as drivers of higher EIM benefits in testimony.[4] It is not logical that this approach would be taken considering the Company's expectation of higher prices in 2020 power markets.[5]

[4] PAC/100, Wilding/30 & 31.
[5] PAC/100, Wilding/13.

Q. Have PacifiCorp's models for forecasting inter-regional dispatch benefits been accurate to date?

A. No. Figure 2 below summarizes how inter-regional dispatch benefits were forecasted in previous TAM filings. Staff measures accuracy as the percentage of actual benefits accounted for in the forecast.

As demonstrated in Figure 2, inter-regional dispatch benefits have been consistently under forecasted in the TAM. In the three year period of 2016 to 2018, the cumulative difference between the forecast and actuals is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. This represents a **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** reduction to NPC that customers did not benefit from.

[BEGIN CONFIDENTIAL]

Figure 2

[redacted]

[END CONFIDENTIAL] [6]

[6] UE 339 - PAC/100, Wilding/41, table 5, and PacifiCorp confidential workpaper "ORTAM20w_EIM Benefits CONF".

Q. What action does Staff recommend?

A. Staff recommends reverting to the model used to forecast inter-regional benefits in the 2019 TAM, which was agreed on by PacifiCorp and parties. Although previous models to date have under-forecast benefits, the 2019 TAM model is yet to show inaccuracies in its forecast ability. It was the first model in which all parties agreed to a methodology. It is simpler and more transparent than the Company's updated model. It further provides a more common sense forecast result as it maintains the trend of increasing benefits over time evidenced in Figure 1 above. This model forecasts inter-regional transfer benefits totaling **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for 2020[7].

Q. Please explain why excess GHG revenue and intra-regional transfer benefits are not forecasted in the 2020 TAM?

A. *Intra-Regional Transfer Benefits.* Discussion with PacifiCorp has led Staff to understand that intra-regional benefits arising from optimized dispatch are comparable to the optimization carried out in GRID. This indicates that although not explicitly forecasted in the TAM, intra-regional benefits are reflected in NPC.

Excess GHG Revenue. PacifiCorp was unable to provide a reasonable response as to why GHG revenue was not included. PacifiCorp has stated that it does not currently have a model to forecast excess GHG revenue. However, the Company did include a GHG adjustment to its forecast in

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[7] PacifiCorp confidential workpaper "ORTAM20w_EIM Benefits CONF".

UE 323 (2018 TAM) and excess GHG revenue is included in the currently proposed EIM benefits model for Portland General Electric (UE 359).

Q. Would ratepayers benefit from Excess GHG revenue being included in the TAM?

A. Yes, ratepayers would benefit from including excess GHG revenue in the TAM through a reduction to net power costs.

PacifiCorp's responses to Staff discovery requests show that PacifiCorp has received GHG revenue totalling **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** since joining EIM.[8] The utility maintains that due to its record keeping processes it is unable to provide data on what proportion of the GHG revenue is excess to its EIM GHG obligation.[9]

Excess GHG revenue is calculated as the difference between GHG revenue earned in EIM, and GHG expenses to meet obligations arising from EIM sales associated with the cost of compliance with California Air Resource Board Cap-and-Trade program. PacifiCorp currently records GHG expenses for both non-EIM bilateral sales into California and EIM trades in the same account. Staff discovery has shown that the Company's total GHG expense for EIM and bilateral sales since joining EIM was **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[10]

[8] Staff/302, Enright/1 (PacifiCorp's response to Staff DR 36); Staff/303, Enright/1 (confidential attachment to PacifiCorp's response to Staff DR 36).
[9] Staff/302, Enright/2 (PacifiCorp's response to Staff DR 37); Staff/302, Enright/3 (PacifiCorp's response to Staff DR 39).
[10] Staff/302, Enright/2 (PacifiCorp's response to Staff DR 37); Staff/303, Enright/2 (confidential attachment to PacifiCorp's response to Staff DR 37).

[BEGIN CONFIDENTIAL]

Figure 3

[redacted]

[END CONFIDENTIAL][11]

Staff estimates that PacifiCorp has received a minimum of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in excess GHG revenue since joining EIM. It is important to note that actual excess GHG revenue is higher than this estimate. The correct value of excess GHG revenue cannot be calculated by Staff using the data provided by PacifiCorp.[12] This is due to EIM GHG expenses and non-EIM GHG expenses being tracked together. In Staff's calculation the excess GHG revenue is reduced due to the GHG expenses from PacifiCorp's non-EIM trades into California being included in the overall GHG expense figure.

Q. What action does Staff recommend?

A. Staff recommends that excess GHG revenue be included in EIM benefits for the 2020 TAM. As PacifiCorp has not been forthcoming with the details of its

[11] Staff/303, Enright/1 (confidential attachment to PacifiCorp's response to Staff DR 36); Staff/303, Enright/2 (confidential attachment to PacifiCorp's response to Staff DR 37).

[12] Staff/302, Enright/2 (PacifiCorp's response to Staff DR 37); Staff/302, Enright/3 (PacifiCorp's response to Staff DR 39).

EIM-related GHG expenses, Staff recommends that GHG revenues in their entirety are allocated as an EIM benefit.

Staff recommends a forecast of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in GHG revenue for the 2020 TAM. This amounts to the average GHG revenue received in the four full calendar years that PacifiCorp has participated in EIM.

Staff also recommends that PacifiCorp begin tracking GHG expenses from EIM sales in an individual account, so that in future TAM filings more accurate data is available to estimate excess GHG revenue.

Q. Are fixed EIM costs being recovered?

A. Yes. In UE 339, the Commission ordered that fixed EIM costs continue to be recoverable under the TAM on an interim basis until the Company's next general rate case.

Q. What are Staff's recommendations?

A. Staff has recommendations relating to GHG revenue and inter-regional transfer benefits.

- *Inter-regional transfer benefits.* Staff recommends rejecting the model for inter-regional transfer benefits inter-regional transfer benefits proposed by PacifiCorp, and that the model approved in the 2019 TAM is used in its place. Staff recommends a forecast of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** for inter-regional transfer benefits.
- *Excess GHG revenues.* Staff recommends that an adjustment of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to the 2020 TAM to

account for excess GHG revenue. This is the average GHG revenue received in the four full years that PacifiCorp has been operating in EIM. Staff also recommends that PacifiCorp begin to track GHG expenses from EIM sales in an individual account, so that in future TAM filings, more accurate data is available to estimate excess GHG revenue.

- *Total EIM benefits*. Staff recommends a total EIM benefit of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL].** See Figure 4 for a breakdown of this amount.

[BEGIN CONFIDENTIAL]

Figure 4

[redacted]

[END CONFIDENTIAL]

ISSUE 2, WHOLESALE TRANSACTIONS AND HEDGING

Q. Please provide an overview of wholesale purchase costs and sales revenue in the 2020 TAM, compared with the 2019 TAM.

A. The 2020 TAM forecasts increasing Oregon load and lower overall power prices. This follows the 2019 TAM, which also forecasted higher load in Oregon and lower power prices.

Revenue from market sales has decreased in the 2020 TAM compared with the 2019 TAM filing. This is driven by lower sales volumes, which are 4,709 GWh lower than in 2019, and an average sales price of $30.89/megawatt-hour (MWh), which is 1 percent lower than in the 2019 TAM.

The cost of market purchases has also decreased due to lower purchased volumes and purchase prices. The 2020 TAM forecasts 2,071 GWh less purchased energy compared with the 2019 TAM, with an average price of $25.31/MWh, which is 1 percent lower than last year's TAM.

QF expenses have increased due to increased volumes of energy being purchased from solar facilities in Oregon and Utah. The effect of this is a $13.22 million increase in QF costs compared with the 2019 TAM. This issue is discussed further in Staff/400.

Q. Please describe Staff's analysis of wholesale purchase costs and sales revenues.

A. PacifiCorp models NPC using GRID, a production cost model that simulates the dispatch of the Company's power system on an hourly basis. 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. This issue is discussed further in Staff/200 and testimony from PacifiCorp.[13]

Q. Does PacifiCorp hedge its future energy requirements?

A. Yes. PacifiCorp hedges its future energy needs in accordance with its risk management policy. PacifiCorp's risk management policy is reviewed at least once a year, and is adjusted if changes in markets, laws, regulations, or the Company's internal organizational structure give rise to change. PacifiCorp's risk management function actively monitors changes in energy markets, reviewing risk management reports and metrics with front office on a daily basis.[14]

Q. How has PacifiCorp's risk management policy performed in light of significant volatility in Northwestern energy markets over the past twelve months, with spiking electricity prices, the Enbridge gas pipeline forced outage, and the declaration of bankruptcy by PG&E in January 2019?

A. One function of the Company's risk management policy is to monitor the credit profile of PacifiCorp's trading counterparties. Staff has learned through DRs that PacifiCorp's credit risk management group discontinued all trading with PG&E in June 2018 as a result of the Company's deteriorating credit

[13] PAC/100, Wilding/32.
[14] Staff/302, Enright/4 (PacifiCorp's response to Staff DR 63).

rating. As a result of this, PacifiCorp had no wholesale purchase or sales transactions with exposure to PG&E when it filed for bankruptcy in January 2019.[15]

PacifiCorp uses hedging to reduce its exposure to market volatility and events such as the Enbridge pipeline outage. PacifiCorp uses To-Expiry Value-at-Risk (TEVaR) limits to guide its energy hedging. TEVaR is calculated on the Company's combined electricity and natural gas exposure for three consecutive 12-month rolling periods, and illustrates with a 95 percent confidence level the Company's potential exposure to adverse market events.[16] Maximum and minimum TEVaR limits allow PacifiCorp to limit the negative effect of volatility in power and natural gas markets on its net power costs, and also benefit from positive market conditions.

Q. Does Staff have a recommended adjustment?

A. No. Staff has no recommended adjustment.

[15] Staff/302, Enright/5 (PacifiCorp's response to Staff DR 58).
[16] Staff/302, Enright/6 (attachment to PacifiCorp's response to Staff DR 62).

ISSUE 3, ECONOMIC CYCLING

Q. Please provide a background for this issue.

A. Changing market conditions have resulted in some PacifiCorp coal units being un-economic to operate during certain periods. This occurs when the forecasted market price is lower than the marginal cost of operating a coal unit for an extended period. In this scenario it is economic to cycle the coal plant (i.e., temporarily stop generating).

When coal plants are economically cycled, it results in lower net power costs. PacifiCorp first modelled the economic cycling of three plants in the 2019 TAM with a forecasted 7,636 hours of economic cycling.[17] When the 2019 TAM was filed, PacifiCorp had cycled units for an average of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.[18]

The 2020 TAM does not propose to change to the methodology used in the 2019 TAM to model economic cycling.

Q. What benefits are forecasted from economic cycling in the 2020 TAM?

A. The 2020 TAM forecasts a reduction in NPC of $1.5 million from economic cycling compared with the 2019 TAM.

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[17] UE 339 - PAC/100, Wilding/36.

[18] UE 339 - PAC/100, Wilding/36, Confidential Table 4.

Q. Does Staff have any concerns about PacifiCorp's modeling of Economic Cycling?

A. Yes. Although Staff recognizes that significant savings have been modelled in the 2020 TAM from economic cycling, Staff finds that additional potential savings are being limited by unwarranted restrictions on PacifiCorp's modeling of economic cycling. Staff would like to see these restrictions removed or relaxed so that the full benefits of economic cycling can be achieved.

Q. Please list and explain the restrictions that are placed on Economic Cycling units in the GRID model.

A. PacifiCorp places the following restrictions on Economic Cycling in GRID:

- *Economic Cycling Period*: The economic cycling period is a four month period each year in which GRID is permitted to model economic cycling. The period runs from February 1 to May 31.[19]
- *Majority owned units*: Only majority owned units are made available for economic cycling.[20]
- *Non-EIM participating units*: Only non-EIM participating units are made available for economic cycling.[21]

[19] PAC/100, Wilding/17.
[20] UE 339 - Exhibit PAC/201, Ralston/29.
[21] UE 339 - Exhibit PAC/201, Ralston/29.

Q. Please explain the concerns that Staff has with the economic cycling period.

A. The modelled economic cycling period runs for a four-month period from February 1 to May 31, a period which was identified by PacifiCorp as appropriate for economic cycling due to a number of spring market conditions.[22] Despite this, Staff discovery has shown that economic cycling has occurred on **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[23]

Staff has found through discovery that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of cycling hours since 2014 occurred in months that are not included in the cycling period.[24] This is illustrated in Figure 5 below.

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[22] These factors are mild weather, lower load, spring runoff, lower market prices and solar generation ramping up. See UE 339, Exhibit/PAC, Ralston/201.

[23] Staff/303, Enright/3 (confidential attachment to PacifiCorp's response to Staff DR 24); Staff/303, Enright/4 (confidential attachment to PacifiCorp's response to Staff DR 53).

[24] Staff/303, Enright/3 (confidential attachment to PacifiCorp's response to Staff DR 24); Staff/303, Enright/4 (confidential attachment to PacifiCorp's response to Staff DR 53).

[BEGIN CONFIDENTIAL]

Figure 5

[redacted]

[END CONFIDENTIAL]

Q. How does Staff recommend its concerns about the economic cycling period be addressed?

A. Staff recommends that PacifiCorp allow the model to cycle units when it is economic to do so during all 12 months of the year.

Q. Please explain the concerns that Staff has with cycling exclusively non-EIM participating units?

A. EIM has a track record of presenting great economic benefits in the TAM. Nevertheless, market conditions that incentivize economic cycling in spring, such as low market prices and low load, are the same conditions that PacifiCorp has identified as drivers of lower EIM benefits.[25] Staff expects that

[25] PAC/100, Wilding/31.

there may be benefits to economically cycling units instead of offering the units into EIM.

Staff is unaware of any physical or market reason why EIM participating units cannot be considered for economic cycling. As EIM participation can be opted into or out of on a daily basis, EIM participation should not preclude economic cycling. In fact, Staff's analysis of historic instances of economic cycling at PacifiCorp has revealed that in 2018 alone, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** EIM participating units were economically cycled.

[BEGIN CONFIDENTIAL]

Figure 6

[redacted]

[END CONFIDENTIAL]

Q. How does Staff recommend its concerns about cycling exclusively non-EIM participating units be addressed?

A. Staff would like PacifiCorp to conduct a cost benefit analysis of allowing EIM participating units to economically cycle. This could be achieved by first running GRID without restricting EIM participating units from economically cycling, allowing PacifiCorp to identify which units it could be economic to cycle. Further steps would involve comparing the economic benefits of cycling the unit, or allowing the unit to participate in EIM instead of cycling the unit. Consideration should be given to secondary effects of cycling EIM participating units. For example, if restricting an EIM unit from cycling in GRID results in a different unit economically cycling, the cumulative benefits of cycling the non-EIM unit, and benefits of the original unit participating in EIM, should be taken into consideration.

Q. Please explain the concerns that Staff has with excluding non-majority-owned units from economically cycling?

A. As market conditions continuously change, opportunities for savings arise. It was such changes to market conditions that first signaled the potential benefits of economically cycling units in GRID. This process has increased forecast accuracy and reflects actual operations with a $0.7 million savings to PacifiCorp's customers in the 2019 TAM[26] and a proposed $1.5 million savings in the 2020 TAM,[27] with only majority-owned units being economically cycled. In addition to the financial benefits of economic cycling, environmental benefits also accrue when coal generation is replaced by lower emitting alternatives. It is safe to assume that PacifiCorp's co-owners of non-majority-owned plant would share PacifiCorp's drive to identify and dispatch the most cost-effective generation sources, and for this reason Staff is concerned that further opportunity for savings may be missed by excluding these units from consideration for economic cycling.

[26] UE 339 - PAC/108, Wilding/1.
[27] PAC/107, Wilding/1.

Q. How does Staff recommend its concerns about non cycling non-majority owner units be addressed?

A. Staff recommends that PacifiCorp conduct a case study by running GRID without restriction to determine which units can be economically cycled. For any non-majority owned units identified as economic to cycle, Staff would like PacifiCorp to commit to discuss cycling options with their co-owners. Staff notes that this is not an adjustment to GRID or NPC forecast, but a recommendation which utilizes GRID to identify opportunities in a changing market. If the Company is successful in finding non-majority owned plants to cycle and does so in the future, Staff will work with the Company to accurately reflect actual operations in the NPC forecast.

Q. Please summarize Staff's position regarding the modeling of economic cycling in GRID.

A. Staff recognizes that significant changes have been made in the 2019 TAM, and further benefits have been proposed for the 2020 TAM. Staff would like to see a comprehensive review of the restrictions in place on modeling economic cycling to ensure that the best possible result is found for customers. Staff's position on each of the highlighted restrictions is as follows:

- *Economic cycling period*. The four month restriction should be lifted, permitting GRID to economically cycle plant in any month.
- *Majority owned units*. Restrictions should be lifted from units to allow for GRID to run case study. For any units identified as economic to

cycle, Staff would like PacifiCorp to discuss cycling options with their co-owners.

- *EIM participating units*. Staff recommends PacifiCorp conduct a cost benefit analysis of allowing EIM participating units to economically cycle in GRID.

ISSUE 4, DAY AHEAD/REAL TIME (DA-RT) ADJUSTMENT

Q. Please explain the DA-RT adjustment.

A. The DA-RT adjustment comes in two forms:

- *Volume adjustment*. This adjustment is made to reflect the fact that PacifiCorp must transact in the market in set quantities, e.g. a 25 MW block, while GRID does not have this restriction and instead buys and sells MW of any quantity.
- *Price adjustment*. This creates distinct prices in GRID for system balancing sales and purchases. According to the 2019 TAM, its objective is "to better reflect the market prices available to the Company when it transacts in the real-time market."[28]

Q. What has been the position of Staff and Intervenors on the DA-RT adjustment?

A. The DA-RT adjustment was first introduced in the 2016 TAM.[29] The model was opposed by Staff, Oregon Citizens' Utility Board (CUB) and the Industrial Customers of Northwest Utilities (ICNU) (now the Alliance of Western Energy Consumer, (AWEC)). ICNU and CUB argued that the power cost forecast should use an unbiased forward price curve representing a median estimate for future spot prices. CUB also argued that DA-RT would lead one bad hydro year (or other weather event) to over-forecast future system balancing purchases. ICNU argued that PacifiCorp is including a bid-ask spread by modeling a higher price for purchases than for sales in the

[28] UE 339 - PAC/100, Wilding/27.
[29] UE 296 - PAC/100, Dickman/22.

same market at the same time. ICNU proposed an alternative flat spread between purchases and sales of $0.50/MWh.[30]

The DA-RT adjustment was once again opposed by Staff, CUB and ICNU in the 2017 TAM. ICNU argued that because the DA-RT calculation incorporated actual historical purchases and sales, it leads to day-ahead wind and load integration costs being double counted. Staff found the price adder to be unrealistic and arbitrary, and challenged the use of separate prices for purchases and sales. CUB raised issues with the data underlying the model, and proposed that PacifiCorp use data it already has on production capacity and capacity factors model when the market prices are above or below average.

Q. What has been the position the Commission on the DA-RT adjustment?

A. In finalizing the 2017 TAM, the Commission called on PacifiCorp and parties to develop a substitute model that would be more effective than the DA-RT adjustment in its current form.[31]

In 2012, the Commission stated its intention to make adjustments to PacifiCorp's models when there is evidence of a flaw in the model.[32] Staff's analysis will describe the flaw identified in the DA-RT model which is preventing it from reflecting the price differentials it was designed for. Staff

[30] Commission Order 15-394, pages 2 – 4.

[31] UE 307, Order No. 16-482, page 13 (December 20, 2016). ("We decline to adopt Staff and CUB'S recommendation that we eliminate the adjustment now and direct PacifiCorp and parties to work on substitute modeling adjustments to better simulate buy and sell balancing transactions for future TAM proceedings.").

[32] UE 245, Order No. 12-409 page 9 (Oct 29,2012) ("Our goal is to appropriately value Pacific Power's resources and we support adjustments to the valuation model only when there is evidence of a flaw in the model.").

is proposing an alternative model which will more accurately "reflect the market prices available to the company when it transacts in the real-time market,"[33] PacifiCorp set out to do when designing the DA-RT adjustment.

Q. Has Staff identified a flaw in the DA-RT price adjustment model?

A. Yes. The DA-RT price adjustment is intended to compensate PacifiCorp for having to transact in real-time at prices higher or lower than the market average. It was designed by PacifiCorp to "to better reflect the market prices available to the company when it transacts in the real-time market."

Despite this, the adder is constructed in a way that does not reflect the real-time market, specifically, by using monthly average market prices.

Take for example a real time power trader. The trader cannot consistently transact at the monthly average market price because simply put, the price does not yet exist. Real time market prices fluctuate throughout the month, and it is only at the end of the month that all of the month's prices are known and the average monthly price calculated.

Figure 7 shows a real example of sales trades carried out by PacifiCorp in June 2018, comparing five daily market prices with a five-day average price.[34] **[Begin Confidential]** [redacted] **[End Confidential]**.

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[33] UE 339 - PAC/100, Wilding/27.

[34] Constructed using a five-day sample of PacifiCorp's sales in **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** is the most recent data that is included in the DA-RT calculation for 2020 TAM.

The average power price in the period is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per MWh, and is represented by a horizontal red line. Figure 7 illustrates how a high price on one day of the week (Wednesday) inflates the five-day average price. This is due to the equal weight given to that price, and in spite of the utility not carrying out any trade on that day.

The average market price does not reflect real-time operating conditions in which the trader cannot possibly sell at Wednesday's high price, or the five-day average price, to make up for lower prices in the market on Monday, Tuesday, Thursday, and Friday.

Figure 7

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Figure 8 uses the same data to demonstrate the effect of using an average market price on the DA-RT price adder. Despite the three sales being transacted very close to the daily market price, the adder is large. This figure demonstrates once again how volatility in energy markets can inflate the adder, even when the Company does not engage in any transactions on the high price day.

Figure 8

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. The objective of the DA-RT price adder is to better reflect the market prices available to the company when it transacts in the real-time market. Can Staff propose a means to achieve this?

A. Yes. Staff proposes that the DA-RT adder be calculated by using the daily market price, rather than the average market price. Staff believes that this approach provides a better means of achieving PacifiCorp's goal to "reflect the market prices available to the company when it transacts in the real-time market," allowing PacifiCorp to be compensated appropriately.

Staff has calculated the DA-RT price adjustment using daily data, and has identified a significant difference in average adjustment value when Staff's approach is employed. These results are summarized in Figure 9 below.

Figure 9

[Begin Confidential]

[redacted]

[End Confidential]

Staff is unsure of the magnitude or direction of this adjustment on NPC, but believes that the change in methodology will more closely align the model to its stated purpose.

Q. Does this conclude your opening testimony?

A. Yes.

CASE: UE 356
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

June 10, 2019

WITNESS QUALIFICATIONS STATEMENT

NAME:	Moya Enright
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility and Energy Analyst Energy Rates, Finance and Planning Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Energy Risk Professional Certification (part-qualified). Global Association of Risk Professionals. M.Sc. Political Science, 2015. University of Amsterdam. M.Sc. Investment, Treasury and Banking, 2011. Dublin City University. B.A. International Business and Languages, 2008. Dublin City University through a joint curriculum with École Supérieure de Commerce de Montpellier.
EXPERIENCE:	Senior Utility and Energy Analyst at OPUC since January 2019. Energy Trader for Meridian Energy from 2015 to 2019. Meridian Energy is a power generator and retailer operating both in New Zealand and Australia. Trading and Operations Analyst at Tynagh Energy from 2011 to 2013. Tynagh Energy is an independent power producer operating in the Republic of Ireland. Senior Electricity Market Controller at EirGrid from 2008 to 2011. EirGrid is the Irish electricity Transmission System Operator. It operates the Single Electricity Market for the Republic of Ireland and Northern Ireland. Accounts Assistant roles from 2004 to 2008, including Audit Intern at KPMG in Northern Ireland.

CASE: UE 356
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Exhibits in Support
Of Opening Testimony

June 10, 2019

UE 356 / PacifiCorp
May 29, 2019
OPUC Data Request 36

OPUC Data Request 36

EIM Benefits - In Excel format, please show total monthly revenue from the EIM greenhouse gas (GHG) adder since joining EIM.

Response to OPUC Data Request 36

PacifiCorp records greenhouse gas (GHG) revenues received in California Independent System Operator (CAISO) Charge Code 491 in SAP Account 508015. Please refer to Confidential Attachment OPUC 36 for the SAP detail. Note: CAISO resettles months multiple times, therefore, in any given SAP month multiple production months are being recorded. The production period is noted in the "text" column of the SAP detail.

Confidential Attachment OPUC 36 is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

UE 356 / PacifiCorp
May 29, 2019
OPUC Data Request 37

OPUC Data Request 37

> **EIM Benefits -** In Excel format, please show total monthly expenses for GHG compliance with the California Air Resources Board since joining EIM.

Response to OPUC Data Request 37

> PacifiCorp records greenhouse gas (GHG) expenses incurred by selling bilaterally into the California Independent System Operator (CAISO) market or through the energy imbalance market (EIM) in SAP Account 546516. Please refer to Confidential Attachment OPUC 37 which provides the SAP detail. The "Text" field in the SAP detail notes what production period the amounts relate to. PacifiCorp does not differentiate between GHG obligations incurred related to the EIM and wholesale bilateral sales. This expense relates to both EIM and bilateral California sales.
>
> Confidential Attachment OPUC 37 is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

UE 356 / PacifiCorp
May 29, 2019
OPUC Data Request 39

OPUC Data Request 39

EIM Benefits - Please provide the calculation methodology for GHG proceeds, including an explanation of the rationale for using the methodology. If PacifiCorp is not calculating GHG proceeds as GHG adder revenue less GHG compliance expenses for California load, please also calculate the benefits using this methodology.

Response to OPUC Data Request 39

PacifiCorp does not calculate a net proceeds on greenhouse gas (GHG) related to wholesale activities and the energy imbalance market (EIM). PacifiCorp's goal is to procure a sufficient quantity of allowances to cover the GHG obligation incurred by making bilateral wholesale sales into California and the EIM. PacifiCorp can identify the revenues received from the EIM to cover the obligation incurred in the EIM – please refer to the Company's response to OPUC Data Request 36. PacifiCorp records expense related to the bilateral and EIM activity by accruing expense at the average cost of inventory of GHG allowances purchased – please refer to the company's response to OPUC Data Request 37. PacifiCorp, however, does not know the proceeds received to cover the GHG obligation incurred by non-EIM bilateral sales into California. There is no GHG cleared price in the California Independent System Operator (CAISO) day-ahead market. Thus, when PacifiCorp sells into the CAISO day-ahead market and receives a day-ahead locational marginal price (LMP) proceeds, it is not possible to know how much of those proceeds relate specifically to GHG and not energy.

UE 356 / PacifiCorp
May 31, 2019
OPUC Data Request 63

OPUC Data Request 63

Hedging Strategy - If PacifiCorp has carried out analysis of the robustness of its energy risk management policy in light of the recent volatility in Northwest energy markets, please provide a copy of this analysis.

Response to OPUC Data Request 63

PacifiCorp risk management reviews the energy risk management policy at least annually and proposes adjustments to policy language or limits as necessary to respond to changes in markets, internal organizational structure, or applicable laws and regulations. In addition, risk management also reviews reports summarizing key market inputs, electricity and natural gas position reports, and risk management reports on a daily basis with the front office to confirm accuracy and robustness of risk management metrics.

UE 356 / PacifiCorp
May 31, 2019
OPUC Data Request 58

OPUC Data Request 58

Wholesale Purchases and Sales - PG&E filed for Chapter 11 bankruptcy protection in January 2019.

(a) Please detail PacifiCorp's exposure to this event.

(b) If PacifiCorp's power cost filing was affected by the event, please quantify any financial impacts, and provide a narrative explanation of non-financial impacts.

(c) If PacifiCorp has carried out analysis relating to this event, please provide the analysis.

Response to OPUC Data Request 58

(a) PacifiCorp had no exposure to Pacific Gas and Electric (PG&E) resulting from wholesale purchases and sales at the time of the bankruptcy filing. PacifiCorp's credit risk management group shut off all wholesale trading with PG&E in June 2018 as a result of a deteriorating credit profile from significant announced wildfire potential liabilities.

(b) As noted in the company's response to subpart (a) above, PacifiCorp had no exposure to PG&E, therefore this net power costs (NPC) transition adjustment mechanism (TAM) filing is unaffected by the event.

(c) As noted in the company's response to subpart (a) above, PacifiCorp had no exposure to PG&E, therefore no analyses were performed as a result of the event.

Hedging Policy Update
January 2019





PACIFICORP
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Planned Changes to To-Expiry Value-at-Risk (TEVaR) Limits

- PacifiCorp plans the following modifications to the To-Expiration Value-at-Risk (TEVaR) limits in the PacifiCorp energy risk management policy as shown below to respond to reduced correlations in power and natural gas markets:

Potential Change in Forecasted Net Power Costs (NPC)

	Existing Policy Limits		Proposed Policy Limits	
TEVaR	**Minimum**	**Maximum**	**Minimum**	**Maximum**
Year 1 (months 1 through 12)	0%	3.0%	0.0%	**4.0%**
Year 2 (months 13 through 24)	1.5%	6.0%	1.5%	**7.0%**
Year 3 (months 25 through 36)	3.0%	12.0%	3.0%	12.0%

- Changes to risk management policy limits require approval by the risk oversight committee and Pacific Power president
- As the original limits were developed through a collaborative hedging process with regulators, the Company is reviewing these changes with regulators before implementation

TEVaR Risk Metric History

- TEVaR is a statistical method to approximate potential losses a portfolio could incur at a given confidence level over a holding period from the current date through maturity of open forward positions
- TEVaR is calculated on the combined power and natural gas fixed-price exposure for three consecutive 12-month rolling periods using a to-expiry holding period, a 95% confidence level, forward prices, forward volatilities, and historical correlations between power and natural gas prices
- This metric was first introduced at PacifiCorp in May 2010 as front office hedge targets, then added to the risk management policy as firm limits in August 2011
- The calculation and limit structure has not changed since inception, except in May 2012 when the position management horizon was shortened from 48 to 36 months and the fourth year limits were removed

TEVaR Risk Metric Limits

- Maximum TEVaR limits are designed to limit the impact of power and natural gas market prices on net power costs, or to control underhedging
- Underlying the maximum TEVaR limit is a specified maximum percentage increase in net power costs due to market price changes for each year. This specified maximum increase is based on an assumed acceptable risk of escalation in net power costs that might occur due to power and/or natural gas unfavorable price changes balanced by a similar potential for reduction in net power costs that might occur due to power and/or natural gas favorable price changes
- Minimum TEVaR limits are designed to control overhedging and allow net power costs to benefit from favorable market price changes. A breach of a minimum TEVaR limit does not force speculative transactions to increase TEVaR

TEVaR Recent Values

- TEVaR values have been climbing in recent years, despite similar net open positions, forward price curves, and volatilities
- On October 31, 2018, the year 1 and 2 TEVaR values exceeded the maximum limits:

YR	TEVaR @ 10/31/2018	Minimum	Maximum	Percentage	Status
YR1	$59.3m	$0.0m	$44.1m	134.3%	exceeds limit
YR2	$92.4m	$22.0m	$87.9m	106.8%	exceeds limit
YR3	$136.4m	$44.7m	$178.7m	68.4%	within limits

- The Pacific Power president approved a temporary exception to policy limits in October 2018 to allow risk management and the front office time to complete a full review of TEVaR inputs, calculations, and limits

Review of TEVaR Inputs

- Risk management evaluated each of the inputs to the TEVaR model:
  - Net open electricity and natural gas positions
  - Forward price curves
  - Volatilities
  - Correlations
- Risk management determined the marked decline in correlations- most notably since 2015- is the primary driver for the uptick in TEVaR and associated limit excursions
- The following slides summarize the changes of each input and its associated impacts on TEVaR

TEVaR Inputs- Net Open Electricity and Natural Gas Positions

- Larger net open positions (requirements net of hedges) generally result in larger TEVaR values as there is more value at risk
- Net open power positions have remained relatively stable as hedge volumes have changed in step with requirements
- Net open natural gas positions have become less short in recent years
- The TEVaR model simulates potential changes in value of power and natural gas portfolios simultaneously
- So long as power to natural gas correlations are relatively strong (i.e., power and natural gas markets are assumed to move similarly in relative direction and magnitude), the combination of the Company's net long power and net short natural gas portfolios provide for relatively stable TEVaR values
- Risk management evaluated changes in requirements, hedges, and resulting net open positions of the power and natural gas portfolios and determined these have not contributed substantially to the recent increase in TEVaR values

TEVaR Inputs-
Forward Price Curves

- TEVaR generally rises as forward prices increase as higher prices create more value at risk from price changes on open positions
- Prices crested in late 2013 and early 2014, falling into early 2016 and then rebounding before trading sideways for the last couple of years before a small recent uptick
- Risk management evaluated changes in forward price curves and determined these have not contributed substantially to the recent increase in TEVaR values

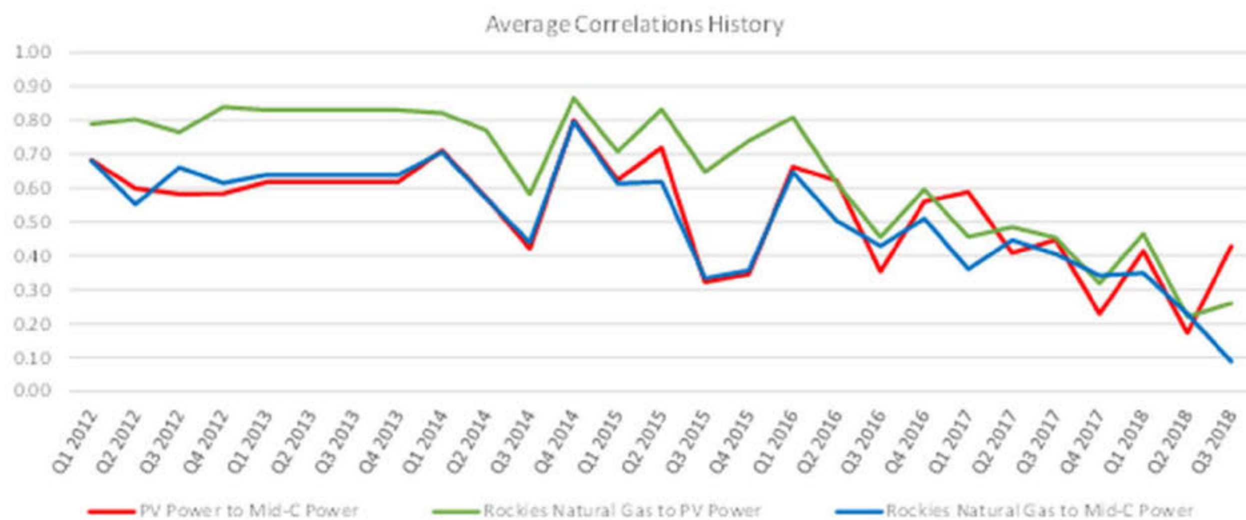
TEVaR Inputs-Volatilities

- TEVaR generally rises as volatilities increase as higher volatilities increase the magnitude of price shocks generated during the simulation
- PacifiCorp obtains its volatilities from independent market sources, based on implied volatilities observed from option markets
- Risk management evaluated changes in volatilities and determined these have not contributed substantially to the recent increase in TEVaR values

TEVaR Inputs- Correlations

- Impacts on TEVaR from changes in correlations vary based on direction and magnitude of all net open positions, but given the Company's net long power and net short natural gas open positions, TEVaR generally rises when correlations fall
- The Company's forward position has traditionally been long power on the east side of the system, partially offset by short power on the west side of the system, for a net long power position overall, with short natural gas offsetting the net power length
- As long as correlations are relatively strong, the combination of the Company's net long power and net short natural gas portfolios provide for relatively stable TEVaR values
- As correlations decline, changes in value from these positions are less likely to offset and the distribution of possible outcomes widens, increasing TEVaR
- Correlations have substantially decreased since 2015
- **Risk management evaluated changes in correlations and determined these have contributed substantially to the recent increase in TEVaR values**

TEVaR Inputs-
Correlations



- Power to natural gas and power to power correlations have fallen significantly since 2015
- Natural gas units are less likely to be on the margin (i.e., set the price of power) given the addition of renewable resources, especially solar generation
- If gas is rarely or never the fuel used by the marginal unit, power to gas correlations decline

Planned Changes to To-Expiry Value-at-Risk (TEVaR) Limits

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Year 3 (months 25 through 36)	3.0%	12.0%	3.0%	12.0%

CASE: UE 356
WITNESS: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
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OREGON

STAFF EXHIBIT 303

Exhibits in Support
Of Opening Testimony

June 10, 2019

STAFF EXHIBIT 303

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO. 16-128

CASE: UE 356
WITNESS: Kathy Zarate

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 400

Opening Testimony

June 10, 2019

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

A. My name is Kathy Zarate. I am a Utility 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/401.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarize analysis and recommendations on certain issue regarding PacifiCorp's 2020 Transition Adjustment Mechanism filing, Docket No. UE 356.

Q. Did you prepare any exhibits for this docket?

A. Yes. I prepared the following exhibits:

- Staff/401: Witness Qualification Statement
- Staff/402: PacifiCorp's Responses to Staff Data Request Nos. 60 and 77.
- Staff/403: PacifiCorp's Confidential Responses to Staff Data Request Nos. 70, 74 75 and 77.

Q. How is your testimony organized?

A. My testimony is organized as follows:

Issue 1. Standard inputs 3
Issue 2. Wheeling Costs 5
Issue 3. Qualifying Facilities Costs 9
Issue 4. DJ Clean Fuels and Hunter Coal Treatment.......... 14

Q. Please summarize your recommendations in this case.

A. Except for two areas, I do not have any proposed adjustments at this time. I may have additional adjustments as PacifiCorp makes standards updates in this proceeding, such as its Official Forward Price curve.

The two adjustments I do recommend are from an Oregon-allocated perspective and are: a **[Begin Confidential]** [redacted] **[End Confidential]** reduction to PacifiCorp's 2020 estimate of total wheeling cost; and a **[Begin Confidential]** [redacted] **[End Confidential]** reduction to Qualifying Facility (QF) purchased power costs. Both of these adjustments reflect that PacifiCorp's methodology in forecasting these costs has consistently led to the over-forecast of these two categories of costs.

ISSUE 1. STANDARD INPUTS

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

A. Standard inputs refer to various cost items associated with the production of power costs in operating power plants and other sources of power. The standard inputs for review are heat rates, forced and scheduled maintenance outages, natural gas price forecast, Official Forward Price Curve (OFPC), fuel price and minimum operating level. In general, except as specified below, Staff has reviewed the inputs and identifies no issues or recommendations for additional analysis or adjustments.

With natural gas prices, the Enbridge Explosion has significantly affected the price of natural gas from certain "hubs."[1] Staff believes as the market recovers and adjusts to normal operations after the Enbridge Explosion, natural gas prices should reflect standard ongoing economic market forces and not reflect a major pipeline outage.

Staff is concerned that PacifiCorp's proposed rates included in the original filling assumed gas prices as reflected at Sumas and based on forward curves dated 12/31/2018. Staff believes those curves may be too heavily biased by the Enbridge event and reflect price futures that may be too high for normalized ratemaking. Staff instead recommends the Company update the natural gas price projection based on current forwards, since these are more reflective of ongoing market pricing. Also, hubs other than Sumas may provide

[1] https://vancouversun.com/news/local-news/enbrige-pipeline-ruptures-sparks-massive-fire-near-prince-george.

a better indicator of future costs, since Sumas was (apparently) more affected by the Enbridge incident than other hubs.

Therefore, Staff recommends that PacifiCorp through its updates will revise its natural gas prices and Official Forward Price Curve. PacifiCorp notes that the 2020 TAM is based on the December 31, 2018, Official Forward current projection of natural gas price and OFPC.

Additionally, in response to Staff Data Request 60, a copy of which is attached as Exhibit Staff/402, PacifiCorp notes that the first 36 months of the OFPC, and perhaps the natural gas prices, are based on broker quotes and settled prices. Given that there are more recent broker quotes and transactions, since December 31, 2018, I recommend that PacifiCorp include in its updates those revised projections and curves using newer broker quotes and contracts. This would appear to be further warranted again by the shock of the Enbridge pipeline explosion.

Q. Please discuss minimum operation levels.

A. I do not have any adjustment for the minimum operating levels of PacifiCorp generation. I do note that in PAC/100, Wilding/16, lines 7-13, the witness states that to limit the number of contested issues, and consistent with prior TAM filings, PacifiCorp has set for its GRID runs the minimum operating levels before any environmental upgrades were installed for Jim Bridger units 3 and 4. I note that given that the Commission has not determined the prudence of the upgrades, PacifiCorp's treatment is consistent with that lack of determination of prudence.

ISSUE 2. WHEELING COSTS

Q. Please discuss wheeling expenses.

A. PacifiCorp incurs significant wheeling expenses in operating its generation supply business and serving its customers. PacifiCorp's response to Staff Data Request No. 75, Attachment 75-1, a copy of which is attached as Exhibit/403, provides the Company's actual wheeling expenses for the period 2015 through the first quarter of 2019. The Table Below provides those wheeling costs.

Table 1.

	2015	2016	2017	2018	2019	2016-2018 Average	TAM proposed 2020
Actual Wheeling Costs	$148,425,345	$130,788,903	$134,473,119	$135,021,597	$143,226,056	$133,427,873	$132,801,884

Q. What does Table 1 illustrate?

A. My review of Table 1 leads a few observations. First, the wheeling expenses for 2015 appear to be an outlier in that it is significantly higher than any of the other years. Second, the wheeling expenses for 2016 through 2018 appear to be reasonably stable. The first quarter of 2019, with a value of $35,806,514,[2] when annualized, is substantially higher than the preceding years, except for 2015, and it is unclear whether that is due to the annualization of the first quarter or an increase in wheeling expenses due to some other factors. For purposes of comparing the PacifiCorp 2020 wheeling expenses, I compare the three-year average of 2016 through 2018 to PacifiCorp's projection. The three-

[2] Staff/403, Zarate/402(PacifiCorp's response to Staff DR 75).

year average is $133,427,873, which is slightly higher than PacifiCorp's TAM value of $132,801,884.[3] As discussed later in this testimony, my analysis also includes looking at PacifiCorp's history of projections to actuals and I use this analysis to finalize my recommendations.

Q. Did you also request PacifiCorp provide its prior projections of its wheeling costs?

A. Yes. The Company's response to Staff DR No. 74, summarized in Table 2 below and provided in full in Exhibit Staff/403, provides PacifiCorp's projections of its wheeling costs.

Table 2- Confidential

[Begin Confidential]

Years	Dockets	Projected Wheeling Cost ($) - (Total Company)
2015	UE -287	[redacted]
2016	UE -296	[redacted]
2017	UE -307	[redacted]
2018	UE -323	[redacted]
2019	UE -339	[redacted]
2020	UE -356	[redacted]

[End Confidential]

Q. How do the PacifiCorp's projections compare to actual total company wheeling costs?

A. Table 3 below provides such a comparison.

[3] See Exhibit PAC/102, Wilding/5.

Table 3 – Confidential

Begin Confidential

			Year				
	2015	2016	2017	2018	2015-2018 Average	TAM proposed 2020
Actual Wheeling Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
Projected Wheeling Cost	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Actual to projected Ratio	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	

End Confidential

Q. What do you observe from Table 3?

A. PacifiCorp has an extended history of overestimating its total wheeling costs. Over the time period of 2015 through 2018, PacifiCorp overestimates its wheeling costs on an average of **[Begin Confidential]** [redacted] **[End Confidential].**

Q. If that same relationship held for 2020, what would PacifiCorp's total wheeling costs be given PacifiCorp's estimate for 2020 total wheeling Cost?

A. Given that PacifiCorp projects its total wheeling costs for 2020 to equal **[Begin Confidential]** [redacted] **[End Confidential]**, **[Begin Confidential]** [redacted] **[End Confidential]** of that value is **[Begin Confidential]** [redacted] **[End Confidential]**. This value, however, is lower than the total actual wheeling costs incurred in any year.

While an adjustment appears warranted as PacifiCorp has a history of substantially over-estimating its total wheeling costs, I recommend a conservative adjustment by setting the projected 2020 wheeling cost to the least actual annual value of total wheeling cost over the last several years. This value is **[Begin Confidential]** [redacted] **[End Confidential]**. Therefore, my adjustment is the difference between **[Begin Confidential]** [redacted] **[End Confidential]**, and equals **[Begin Confidential]** [redacted] **[End Confidential]** which I round to **[Begin Confidential]** [redacted] **[End Confidential]**. On an Oregon-allocated basis, this equals an adjustment of **[Begin Confidential]** [redacted] **[End Confidential]**.

Q. Do you have any other observations?

A. Yes, as indicated by PacifiCorp in its response to Staff Data Request No. 74, PacifiCorp does not include wheeling revenues in the TAM. In its next round of testimony, Staff requests that PacifiCorp indicate how wheeling revenues are captured for the benefit of customers. If such benefits are not captured, PacifiCorp should explain why that is not the case. Staff will also continue to analyze this further to ensure that wheeling revenues are appropriately captured for the benefit of customers.

ISSUE 3. QUALIFYING FACILITIES COSTS

Q. Please discuss Qualifying Facilities (QF) under the Public Utility Regulatory policies Act of 1978 (PURPA) and the recent policy of handling QFs for power cost purposes.

A. In forecasting power costs for a future test year, part of the power cost forecast is comprised of new QFs. The date at which a new QF is forecast to begin commercial operation during the future test period could have significant impact on the amount of generation forecast from these new QFs. Power costs also include a forecast of power production from existing QFs, but my testimony will focus on the issue of handling new QFs. For example, if PacifiCorp forecasts a Commercial Operation Date (COD) of January 1, 2020 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 while in fact the QF was not in operation for ten months of year. PacifiCorp would have to replace the purchased power assumed to be available from the QF. It would therefore be possible that market purchases or utility operation of its existing resources could be cheaper than the QF power. This creates a discrepancy between what was forecast and actual power costs.

Q. What process does PacifiCorp use in this TAM filing?

A. PacifiCorp used the same methodology as that established in the 2018 TAM (Docket UE 323), where the Commission adopted CUB's proposal for the treatment of QF costs in the TAM. In UE 323, the Commission directed PacifiCorp to calculate and apply a Contract Delay Rate (CDR) based on a three-year history of delays for new QFs. The Commission-adopted methodology also includes weighting the CDR by QF size to more accurately reflect the rate impact of forecast errors.

Q. Did PacifiCorp use that same methodology in this docket, UE 356?

A. Yes. In PAC/100, Wilding/14, lines 12 through 19, PacifiCorp states that it used the same methodology as that approved by the OPUC in the 2018 TAM.

Q. Does CUB's CDR address Staff's concern about the over-forecasting of QF costs?

A. No, this is evident because the CDR adjustment pales in comparison to the average PacifiCorp over projection of QF costs. In UE 323, the adjustment relating to CDR was $353,000, on Oregon-allocated basis. Using an SG factor of 25.741,[4] this translates to a total Company value of $1,371,353. ($1,371,353=$353,000/.25741). This is only a small percentage of the average over-forecast noted by Staff in Table 4, below, of **[Begin Confidential]** [redacted] **[End Confidential]**. The PacifiCorp forecast of 2018 QF purchase power cost on a total company basis was **[Begin Confidential]** [redacted] **[End Confidential]**. This translates into a CDR adjustment of **[Begin Confidential]** [redacted] **[End Confidential]**. My adjustment based on the historic average over forecasting by PacifiCorp of its QF purchased power cost is 6 percent.

Q. How do the 2020 TAM projections by PacifiCorp regarding QF costs compare to the 2019 TAM?

[4] Footnote 9 on page 6 of UE 323 Order No.17-444.

A. The 2020 TAM has QF purchased power cost increase by $13.2 million.[5]

Q. Did Staff ask PacifiCorp how its projections of QF purchased power costs compare to actuals?

A. Yes. Staff Data Request No. 70, asked PacifiCorp to provide both its actual and projected QF purchase power costs for the years 2015 through 2018. Table 4, below, created based on the information provided by PacifiCorp in response to Staff's Data Request No. 70 (Exhibit Staff/403).

Table 4-Confidential

[Begin Confidential]

	2018	2017	2016	2015	Average
New QF $ Forecasted	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
New QF $ Actual	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Difference (actual-Forecast)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Percentage Difference	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[End Confidential]

Q. What do you conclude from Table 4?

A. In the case of Qualifying Facility purchases, PacifiCorp consistently overestimates its QF purchase power cost. Over the 2015 through 2018 time-period, the average level of overestimation is six percent. Given that PacifiCorp has not identified a change in approach or estimating QF purchase power costs, there is no reason to assume that the consistent overestimation.

[5] See, PAC/100, Wilding/14, lines 4-9.

Q. Should your adjustment be adjusted in part because of the CDR adjustment PacifiCorp makes in this TAM filling?

A. Yes, It is very likely that part of PacifiCorp's over-forecasting of QF purchased power cost is corrected by the CDR. Therefore, it is sensible to take into account the CDR in developing my adjustment.

Given that the moving average level of PacifiCorp's over-forecasting of QF purchased power cost is 6 percent, and the CDR adjustment for the 2018 TAM amounted to $353,000, it is appropriate to modify my 6 percent recommendation by reducing it to 5.56 percent. (6% - 0.44%).

Inasmuch as PacifiCorp projects its 2020 QF purchased power cost to equal **[Begin Confidential]** [redacted] **[End Confidential]** the recommended downward total company adjustment is 5.56 percent of that total or **[Begin Confidential]** [redacted] **[End Confidential]**, which I round to **[Begin Confidential]** [redacted] **[End Confidential]** Using PacifiCorp's projected 2020 SG factor of 26.456, from line 1 of Exhibit PAC/101, Wilding/1, I obtain an Oregon allocated adjustment of **[Begin Confidential]** [redacted] **[End Confidential]**.

Q. Did PacifiCorp calculate a CDR adjustment for the 2020 TAM?

A. Yes, Exhibit PAC/107, Wilding/1, step 4 has a CDR adjustment of $216,024 this smaller than CDR adjustment from UE 323, using PacifiCorp's values of $216,024 yields an Oregon-allocated adjustment of **[Begin Confidential]** [redacted] **[End Confidential]**.[6]

[6] PacifiCorp's projected 2020 SG factor of 26.456, from line 1 of Exhibit PAC/101, Wilding/1.

Q. What adjustment do you recommend?

A. I recommend a downward adjustment to PacifiCorp's QF purchased power Oregon allocated amount of **[Begin Confidential]** [redacted] **[End Confidential]**.

ISSUE 4. DJ CLEAN FUELS AND HUNTER COAL TREATMENT

Q. Please provide a background for this issue.

A. PacifiCorp and DJ Clean Fuels, LLC identified an opportunity to install refined coal facilities on the Dave Johnston power plant property in 2018. The refined coal production facility, owned by Dave Johnston, 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. DJ Clean Fuels will install a refined coal treatment facility that would “straddle” approximately 6 feet of the moving incoming coal feedstock conveyor belt at the Dave Johnston 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 DJ Clean Fuels who treats the coal and then sells it back to PacifiCorp for approximately the same price. DJ Clean Fuels makes money off of the tax credit, while PacifiCorp gets a better burning coal product at a lower cost. UP 393 was approved on May 7, 2019, and as part of the approval, the Commission directed the Company to pass the benefits of the better burning coal through to customers in its power cost filings.

The Company has generally identical agreements in place for the Hunter plant, which was also approved by the Commission in OPUC Docket No. UP 369, which also has benefits that are to accrue to customers in power cost filings.

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

A. Staff asks that the Company update the coal cost at Dave Johnston to reflect the approval of UP 393 in the 2020 TAM forecast. Staff further requests that the Company provide evidence of the inclusion of the benefits of UP 369, a similar transaction at the Hunter plant, have been incorporated into the 2020 TAM. If the benefits will not be included, Staff requests a narrative explanation as to why that is the case.

Q. Does this conclude your opening testimony?

A. Yes.

CASE: UG 347
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement

June 10, 2019

WITNESS QUALIFICATION STATEMENT

NAME:	Kathy Zarate
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Economist Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Master of Science, Environmental and Sustainability Oregon State University, Corvallis, Oregon (2019-2022) Bachelor of Arts, Economics Oregon State University, Corvallis, Oregon Bachelor Degree in Law Republic University, Santiago, Chile
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since April 2016, with my current position being a Utility Economist, in the Energy - Rates, Finance and Audit Division. My responsibilities include research, analysis, and recommendations on a range of regulatory issues such as review of affiliated interest filings, property sales applications and rate proposals. Prior to working for the OPUC I have approximately 10 years of professional experience in contracting and audit review work, including six years as contract specialist for 3 Com, Santiago, Chile, with responsibilities including coordinating and preparing contracts with resellers, reviewing company books and records, coordinating logistics in business delivery, and investigating property theft. I, also, have experience working in data analysis and conducting research on the general economic field.

CASE: UE 356
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibits in Support
Of Opening Testimony

June 10, 2019

UE 356 / PacifiCorp
May 31, 2019
OPUC Data Request 60

OPUC Data Request 60

Wholesale Purchases and Sales - Please provide a narrative explanation of how PacifiCorp forecasts power prices, including references to data included in the work papers provided to Staff by PacifiCorp.

Response to OPUC Data Request 60

Note: the official forward price curve (OFPC) utilized in the 2020 transition adjustment mechanism (TAM) is the December 31, 2018 OFPC.

PacifiCorp's natural gas and electricity OFPC were developed from a combination of December 31, 2018 market forwards and a long-term fundamentals-based price forecast. The first 36 months of the curve, beginning with prompt month (February 2019), reflect broker quotes and/or settled prices in the forwards market. Month 37 (February 2022) through month 48 (January 2023) are a forwards-fundamentals blend that segues into a fundamentals-only forecast starting in month 49 (February 2023).

The averaged broker quotes or settled prices, which comprise the first three years of the OFPC, are compiled by PacifiCorp's front office and validated by risk management via an independent survey of broker quotes and settled prices. Transitional month 37 through month 48 are an average of market month 25 (February 2021) through month 36 (January 2022) with fundamental month 49 (February 2023) through month 60 (January 2024), respectively.

Starting month 49, the OFPC is no longer rooted in market expectations, as with market forwards, but instead in supply and demand balances as forecast by AuroraXmp® (AURORA), a Western Electricity Coordinating Council (WECC) wide production cost simulation model. AURORA solves to optimize total cost subject to operating and transmission constraints. AURORA's output is generated at the monthly level for heavy-load and light-load periods; hourly prices are then generated by the application of hourly scalars to AURORA's monthly output. This process generates the hourly prices used in Generation and Regulation Initiative Decision tool (GRID).

Please refer to the confidential 5-day transition adjustment mechanism (TAM) work papers, file "ORTAM20w_Market Price Index (1812) CONF.xlsx" which includes PacifiCorp's forecasted power prices in this 2020 TAM.

UE 356 / PacifiCorp
May 31, 2019
OPUC Data Request 77

OPUC Data Request 77

Wheeling - What percentage of 2020 projected wheeling cost is comprised of charges by BPA for using its transmission system?

Response to OPUC Data Request 77

The wheeling costs charged by the Bonneville Power Administration (BPA) are approximately 69 percent of total projected wheeling costs in 2020 and included in the 2020 transition adjustment mechanism (TAM).

CASE: UE 356
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 403

Exhibits in Support
Of Opening Testimony

June 10, 2019

STAFF EXHIBIT 403

IS CONFIDENTIAL AND SUBJECT

TO PROTECTIVE ORDER: 16-128

AND

PROVIDED IN ELECTRONIC FORMAT ONLY

CERTIFICATE OF SERVICE

UE 356

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 10th day of June, 2019 at Salem, Oregon

Kay Barnes

Kay Barnes
Public Utility Commission
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UE 356 - SERVICE LIST

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