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July 30, 2021

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX: 1088
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RE: Docket No. UE 390– In the Matter of PACIFICORP, dba PACIFIC POWER, 2022 Transition Adjustment Mechanism.

Attached are documents for Staff Rebuttal Testimony

CONF Exhibit 1000 Enright
CONF Exhibit 1100 Zarate
CONF Exhibit 1200-1201 Dlouhy
CONF Exhibit 1300 Gibbens
CONF Exhibit 1400-1401 Anderson, page 10 is Highly-Confidential
Exhibit 1500 Fox
CONF Exhibit 1600-1601 Hanhan
Exhibit 1601 (filed in electronic format)

/s/ Kay Barnes
Kay Barnes
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CERTIFICATE OF SERVICE

UE 390

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 30th day of July, 2021 at Salem, Oregon

/s/ Kay Barnes

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UE 390
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CASE: UE 390
WITNESSES: MOYA ENRIGHT

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1000
REDACTED

Rebuttal and
Cross-Answering Testimony

July 30, 2021

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

A. My name is Moya Enright. 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. Have you previously provided testimony in this case?

A. Yes. In my opening testimony (Staff/100-104), I addressed PacifiCorp's compliance with the TAM guidelines and previous TAM order, and the Company's EIM benefits forecast.

Q. What is the purpose of your rebuttal and cross-answering testimony?

A. The purpose of my testimony is provide a summary of the issues covered by Staff in rebuttal and cross-answering testimony, respond to testimony from PacifiCorp on issues related to EIM benefits, and respond to opening testimony filed by parties, including AWEC's adjustments relating to Other Revenues and BCC material costs, and CUB's proposal for an earlier 2023 TAM filing.

Q. Please summarize the issues covered by Staff in this rebuttal and cross-answering testimony.

A. Staff's rebuttal and cross answering testimony is structured as follows:

Staff/1000, Issue 1 responds to testimony from PacifiCorp relating to Staff's proposed adjustments to forecasted EIM benefits. This section also rebuts PacifiCorp's proposed change to the EIM benefits allocation factor, which was introduced by the Company in its reply filing on July 9, 2021.

Staff/1000, Issue 2 responds to opening testimony from AWEC regarding PacifiCorp's failure to update Other Revenues in its initial filing, and AWEC's recommendation that increased revenue from Fly Ash sales be reflected in the TAM. This section also rebuts PacifiCorp's reply testimony on these issues.

Staff/1000, Issue 3 responds to opening testimony from AWEC regarding a trend of over-forecasting of materials and supplies expenses for Bridger Coal Company (BCC), and its recommended adjustment to correct for the over-forecasting. This section also rebuts PacifiCorp's reply testimony on this issue.

Staff/1000, Issue 4 responds to opening testimony from CUB recommending that PacifiCorp file the 2023 TAM early to allow time for parties and Staff to fully review the TAM considering the imminent move to using AURORA for PacifiCorp's power cost forecasting. This section also rebuts PacifiCorp's reply testimony on this issue.

In Staff/1100, Issue 1, Staff witness Kathy Zarate rebuts PacifiCorp's reply testimony regarding Staff's recommended adjustment to forecasted QF costs.

In Staff/1200, Issue 1, Staff witness Dr. Dlouhy addresses opening testimony from CUB and AWEC regarding the Company's proposed change to the calculation of Market Caps, and rebuts PacifiCorp's reply testimony on this issue.

In Staff/1300, Issue 1, Mr. Gibbens addresses the benefits of the Nodal Pricing Model (NPM), rebutting PacifiCorp's reply testimony on this issue.

In Staff/1300, Issue 2 Mr. Gibbens responds to Calpine's testimony regarding the calculation of the Direct Access Consumer Opt-Out Charge. This section also rebuts PacifiCorp's reply testimony on this issue.

In Staff/1300, Issue 3 Staff witness Scott Gibbens responds to Calpine's testimony regarding the transference of Production Tax Credits. This section also addresses PacifiCorp's reply testimony on the issue.

In Staff/1400, Issue 1, Staff witness Rose Anderson addresses coal contract negotiations, and responds to Sierra Club's opening testimony and PacifiCorp's reply testimony on this issue.

In Staff/1400, Issue 2, Ms. Anderson addresses the new coal contracts for Dave Johnson, Hunter, and Craig, responding to PacifiCorp's reply testimony on this issue.

In Staff/1400, Issue 3, Ms. Anderson deals with the Huntington Coal contract, and responds to PacifiCorp's reply testimony on the issue.

In Staff/1400, Issue 4, Ms. Anderson addresses economic cycling and cost over forecasting at Jim Bridger, responding to CUB's opening testimony and PacifiCorp's reply testimony on this issue.

In Staff/1500, Issue 1, Staff witness John Fox rebuts PacifiCorp's reply testimony relating to PacifiCorp's coal related Informational Run.

In Staff/1500, Issue 2, Mr. Fox rebuts PacifiCorp's reply testimony regarding the burn rate and minimum take at the Naughton and Wyodak plants.

In Staff/1600, Issue 1, Staff witness Nadine Hanhan rebuts the Company's reply testimony addressing Staff's proposed change to forecasted wheeling costs.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, EIM BENEFITS

Q. Please summarize your testimony regarding PacifiCorp's forecasted EIM benefits.

A. In Staff/100, Issue 2, I dealt with Staff's three concerns regarding the Company's forecasted GHG benefits, including an incorrectly applied growth factor, a limited period of historic data, and CCA price growth. In this section, I recommended adjustments which would increase EIM benefits to Oregon customers by approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

In Staff/800, Issue 1, witness Dr. Dlouhy addressed PacifiCorp's EIM Energy Transfer benefits Regression model, offering two adjustments to improve the accuracy of the model. This resulted in a decrease in EIM benefits to Oregon customers of approximately $452,000.

Q. Did PacifiCorp respond to Staff's concerns regarding EIM benefits in its reply testimony?

A. Yes. PacifiCorp accepted both sets of Staff recommendations in its reply testimony, including a caveat that Staff's recommendation on CCA growth would be accepted on a "non-precedential" basis only.[1]

PacifiCorp also complains that it has been unable to replicate Staff's calculations.[2] In response, Staff invites the Company to refer to the workpapers provided by Staff concurrently with opening testimony, to

[1] PAC/400, Staples/83, lines 17 - 18.
[2] PAC/400, Staples/83, lines 6 - 11.

request a workshop to discuss, or to issue discovery requests as appropriate.

Q. Did PacifiCorp's reply testimony make any additional proposals regarding EIM benefits forecast in the 2022 TAM?

A. Yes. In its reply testimony, PacifiCorp proposed a change to the allocation factor for EIM benefits, changing from System Generation (SG) to System Energy (SE). The result is an approximate **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** increase to Oregon net power costs.

Q. Does Staff have concerns with PacifiCorp's proposal in this case?

A. Yes. Staff has a number of concerns with PacifiCorp's proposal in this case. Procedurally, this is a new issue the company is presenting late in the proceeding, which is improper. This issue was raised initially in PacifiCorp's Wyoming General Rate Case (GRC), in which the Company opposed a change in the allocation factor for EIM benefits from SG to SE. Only after losing that issue in Wyoming did PacifiCorp attempt to argue that a corresponding change was appropriate in Oregon. To request such a change now is opportunistic, unsupported by the record in this case and contrary to the Company's substantive position in Wyoming.

PacifiCorp argues that a change in this case is warranted because "EIM benefits are a component of the TAM, and PacifiCorp and the parties in the TAM have always addressed the inclusion of these benefits for Oregon customers in this proceeding."[3] PacifiCorp's logic is flawed

[3] PAC/400, Staples/10.

because *all* allocations issues flow through corresponding state ratemaking proceedings—simply because there is a ratemaking implication to an allocations issue does not mean that ratemaking proceedings are substitutes for issues that should be addressed through the MSP process.

PacifiCorp also fails to adequately support its recommendation in this case. As PacifiCorp acknowledged in its Wyoming GRC proceeding, "EIM settlements have been treated as firm power in the Company's accounting classification (booked to FERC account 555, which is allocated based on the SG factor) since the Company joined the EIM in October 2014."[4] In this case, the Company's support is simply a reference to "oral deliberations from PacifiCorp's Wyoming general rate case."[5] The Company fails to provide substantive analysis that moving from an SG to an SE is a more appropriate method for allocating EIM benefits among the states.

Importantly, PacifiCorp's analysis in its Wyoming GRC is contrary to its position in this case.[6] In that case, the Company argued that EIM benefits are characteristically "closer to firm power from the perspective of risk to NPC, because the power is backed by the available capacity of the Company's own resources"[7] and firm power is allocated as SG.

[4] Wyoming Public Service Commission Docket No. 20000-578-ER-20, Rebuttal Testimony of David G. Webb at 16, lines 7-9 (September 2020). Accessible at https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-regulation/wyoming/filings/docket-20000-___-er-20/9-11-rebuttal/RMP_Rebuttal_Testimony.pdf.
[5] PAC/400, Staples/9, lines 6-7.
[6] *See* 2021 WL 3056175 (Wyo.P.S.C.), paragraphs 95-97.
[7] Wyoming Public Service Commission Docket No. 20000-578-ER-20, Sur-Reply Testimony of David G. Webb at 12, lines 4-6 (December 2020). Accessible at https://www.rockymountainpower.net/content/dam/pcorp/documents/en/rockymountainpower/rates-

Finally, PacifiCorp's proposal should be rejected because it is contrary to the 2020 Multi-State Protocol (MSP). In the MSP process, the parties reached a settlement agreement regarding allocation factors that would be used during the Interim Period, during which time the Company has been utilizing an SG factor to allocate EIM benefits.[8] Even if EIM settlements are not directly addressed by the 2020 Protocol, changing the way certain costs and benefits have been allocated under the 2020 Protocol (and therefore the assumption of how such costs would continue to be allocated) is violative of the spirit of the agreement and undermines the overall value proposition of settlement. PacifiCorp assumes the risk of disparate ratemaking treatment among its jurisdictions. It is not appropriate to shift this risk to Oregon ratepayers simply because of a decision in Wyoming—particularly one that the Company opposed in that forum.

For the reasons set forth above, the Company's proposal should be rejected.

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regulation/wyoming/filings/docket-20000-___-er-20/12-11-20-sur-reply-testimony/Sur-Reply_Testimony_REDACTED.pdf.

[8] Wyoming Public Service Commission Docket No. 20000-578-ER-20, Rebuttal Testimony of David G. Webb at 18, lines 1-7 (September 2020).

ISSUE 2, OTHER REVENUES

Q. Please summarize AWEC and Staff's testimony regarding PacifiCorp's forecasted Other Revenues.

A. In Staff/500, Issue 2, witness Ms. Zarate recommended no adjustment to PacifiCorp's forecast of Other Revenues.[9] This contrasts with opening testimony provided by AWEC, in which witness Mr. Mullins argued that PacifiCorp had "omitted the calculation of Other Revenues … and refused to provide the analysis in discovery," recommending that Other Revenues be forecasted, and increased Fly Ash sales also be reflected in the TAM.[10]

Q. Did PacifiCorp respond to AWEC's concerns in its reply testimony?

A. Yes. PacifiCorp indicates that it will update Other Revenues to reflect an expiring contract, resulting in an increase of approximately $3 million in the TAM.[11]

PacifiCorp rejected AWEC's proposal to include increased fly ash sales in the TAM, arguing that revenues from fly ash have traditionally been included in base rates and updated in general rate cases.[12]

Q. What is Staff's position on the Other Revenues issue?

A. Staff is concerned that it appears PacifiCorp has taken a selective approach in updating its Other Revenues, after refusing to do so in its

[9] Staff/500, Zarate/5, lines 1-5.
[10] AWEC/100, Mullins/18, lines 3-9.
[11] PAC/400, Staples/92.
[12] PAC/400, Staples/93, lines 12-13.

initial filing. Updating discrete elements, without a full update to Other Revenues consistent with the 2011 TAM Order,[13] is inappropriate.

Staff would support the $3 million reduction in Other Revenues due to the expiring contract, on the condition that PacifiCorp fully review its forecasted Other Revenues, and ensure that any new contracts which may increase revenues in 2022 are included in its indicative November filing.

Staff also supports AWEC's recommendation that increased Fly Ash sales be included in the TAM. Staff reasoning is twofold: this approach ensures benefits are captured fully, without risking their not being accounted for when rates are set in the next General Rate Case; and PacifiCorp's Fly Ash revenues have increased by over 60 percent in the past year alone, which coupled with strong demand for Fly Ash in the US construction sector, indicates that this shift is likely to endure through 2022.[14] Staff supports AWEC's forecasting methodology for Fly Ash revenues, in which is proposes to use calendar year 2020 fly ash revenues as a basis for the 2022 forecast, adjusted to reflect the retirement of Cholla.[15]

[13] Order No. 10-363, page 3.
[14] https://www.carboncure.com/concrete-corner/5-trends-concrete-producers-should-watch-in-2021/
[15] AWEC/100, Mullins/21, lines 15 - 18.

ISSUE 3, BCC COSTS

Q. Please summarize AWEC's testimony regarding PacifiCorp's BCC Materials & Supplies costs.

A. AWEC witness Mr. Mullins testified that that PacifiCorp's forecasts for materials and supplies expenses at BCC have been grossly overstated in recent years, using data drawn from the 2018, 2019 and 2020 final TAM update filings to support this assertion. AWEC recommends reducing Oregon-allocated NVPC by $785,644 to correct for this difference.[16]

Q. Did PacifiCorp respond to AWEC's concerns in its reply testimony?

A. Partially. PacifiCorp conceded that it has over-forecast BCC costs in the past, but rejected AWEC's adjustment on the basis that it under-recovered NVPC overall. PacifiCorp argues that "AWEC should not be able to cherry pick a single line item and single it out for scrutiny when the Company continues to under-recover its NPC year after year."[17]

Q. What is Staff's position on the BCC costs issue?

A. Staff supports AWEC's adjustment on this issue. While overall NVPC must be just and reasonable, this does not negate PacifiCorp's obligation to demonstrate that discrete cost elements are fair, just and reasonable. Staff firmly rejects PacifiCorp's assertion that an overall under-recovery of NVPC justifies the over-forecasting BCC costs, or any other line item in the TAM filing.

[16] AWEC/100, Mullins/22 - 23.
[17] PAC/400, Staples/94, lines 5 - 10.

ISSUE 4, EARLY 2023 TAM FILING

Q. Please summarize CUB's testimony regarding the filing date for PacifiCorp's 2023 TAM, and PacifiCorp's response.

A. CUB witness Mr. Jenks proposed that the deadline for filing the TAM be moved forward to January 15, 2022, as a one-off for the 2023 TAM to facilitate the transition to using AURORA to model NVPC.[18]

PacifiCorp rejected CUB's proposal, arguing that an early filing would lead to a less precise forecast, and that workshops in advance of filing would be sufficient to resolve parties' questions.[19]

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

A. Staff supports CUB's proposal that the Company file prior to its normal filing date for a stand-alone TAM proceeding. PacifiCorp's transition to using AURORA is no small event after over 20 years of using GRID to forecast its NVPC. Staff believes that it is in the best interests of Staff, parties, the Commission, and customers to increase the window for review of the Company's initial 2023 TAM filing.

While Staff is unclear whether it is practicable for the Company to file by January 15, 2022, Staff notes that in a year when the TAM is coupled with a general rate case proceeding, a much earlier filing date is achieved. For example, the 2020 TAM was filed on February 14, 2020. As such, it

[18] CUB/100, Jenks/18.
[19] PAC/400, Staples/95.

seems that PacifiCorp is capable of filing a TAM proceeding by mid-February, at least.

Q. What is Staff's recommendation?

A. Staff supports CUB's recommendation that the Company be required to file its 2023 TAM early, however Staff recommends the Company be ordered to file by February 14, 2022, which is consistent with the timing of a TAM proceeding when coupled with a general rate case proceeding, and which has been demonstrated by PacifiCorp to be achievable in the past.

Further, to address PacifiCorp's concerns related to the availability of forecasted data,[20] Staff recommends that PacifiCorp be permitted to file an update filing on April 1, 2022, including its updated inputs.

[20] PAC/400, Staples/95, lines 3 - 10.

CASE: UE 390
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1100

Rebuttal and Cross-Answering Testimony

July 30, 2021

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. Have you previously provided testimony in this case?

A. Yes. In my opening testimony (Staff/500-503), I addressed standard inputs, other revenues, the Consumer Opt-Out Charge and Qualifying Facilities.

Q. What is the purpose of your testimony?

A. The purpose of my reply testimony is to respond to the testimony of PacifiCorp witness Mr. Douglas R. Staples regarding Qualifying Facilities (QF) costs. Staff witnesses Ms. Moya Enright and Mr. Scott Gibbens address other revenues and the Consumer Opt-Out Charge, respectively.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, QUALIFYING FACILITIES (QF) CONTRACTS

Q. Please summarize Staff's concern with the Company's forecast of Qualifying Facilities (QF) costs.

A. As set forth in my opening testimony, I am concerned that PacifiCorp historically over-estimates the amount of MWh produced from PURPA QF projects, which leads to an overstatement of net power costs (NPC).

Q. Did PacifiCorp respond to Staff's concern in its reply testimony?

A. Not directly. PacifiCorp argues that it disagrees with Staff's adjustment, but does not substantively address Staff's concerns. Rather, the Company summarily concludes that "once the Company implemented CDR, its QF power forecasts increased substantially in accuracy. Based on post-CDR data only, the Company's over-estimation of QF power costs drops from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** to **[BEGIN CONFIDENTIAL**[redacted]."[1] **[END CONFIDENTIAL]** PacifiCorp's argument seems to suggest that because its forecast has become more accurate over time, an additional adjustment is not necessary.

Q. Do you agree with the Company's conclusion that its forecast of QF costs has improved since implementation of the CDR?

A. Yes. PacifiCorp's analysis that that the level of overstatement for forecast QF costs has fallen following implementation of the CDR. However, a **[BEGIN CONFIDENTIAL**[redacted] **[END CONFIDENTIAL]** overstatement of costs is still significant for purposes of setting TAM rates.

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[1] PAC/400, Staples/75.

Q. Does PacifiCorp witness Mr. Staples support your adjustment given that PacifiCorp admits it overstates QF power purchase costs?

A. No. On PAC/400, Staples/75, lines 16 to 19, it appears that PacifiCorp does not support any adjustment because "…PacifiCorp is relying on the best individual information that is available from each QF project."

Q. Do you agree that PacifiCorp is using the best information available?

A. No, PacifiCorp is ignoring information regarding how well its forecast compares to actual costs. Staff has reviewed PacifiCorp's QF forecast and it consistently overstates its QF cost, as described in my opening testimony. PacifiCorp agrees this is the case but nevertheless chooses to ignore it.

Q. Do you have any modifications to your recommendation to reduce NPC by $1.53 million?

A. No. My adjustment is sound and reasonable. The Company agrees that it overstates QF purchase power costs. The fact that the overstatement is reduced following application of the CDR does not change my view as to the appropriate adjustment for the test year period. I continue to recommend that NPC be reduced by $1.53 million (Oregon-allocated).

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 390
WITNESSES: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1200
Market Caps
REDACTED

Rebuttal and
Cross-Answering Testimony

July 30, 2021

Q. Please each state your name and occupation.

A. My name is Curtis Dlouhy. I am a Senior Economist within the Energy Rates, Finance and Audit (ERFA) Division of the Public Utility Commission of Oregon (Commission or OPUC).

Q. What is the purpose of this testimony?

A. The purpose of this testimony is to respond to the reply testimony filed by PacifiCorp (Company) on the issue of market caps.

Q. Please summarize how your position has changed in reply testimony.

A. My position has not changed, and as advocated results in a decrease in NPC by $5.1 million on an Oregon-allocated basis. I maintain that the most-preferred recommendation is to reject the Company's proposed changes to its market cap methodology on the grounds that its change is poorly supported by evidence, is poorly timed given that it will implement AURORA in the next TAM, reinstates a method previously rejected by the Commission in a fully-litigated case, and is based on a misinterpretation of Order No. 20-473 as a directive to change its market caps right now rather than an invitation to explore *many* ways to address its off-system sales forecasting problem.

Q. Do you have an alternative recommendation should the Commission find that a change to market caps is warranted in the 2022 TAM?

A. As a second-best recommendation, I propose an alternate, non-precedential method to calculate market caps that I call the "third quartile of averages" approach for the 2022 TAM. My method maintains the "maximum of averages" approach's desirable ability to portray true market depth while addressing the Company's concerns that GRID incorrectly handles the "maximum of averages" approach when forecasting off-system sales. I requested the Company to perform a GRID run with the market caps I calculated in my "third quartile of averages" approach in Staff Data Request 180 and found that my recommended approach leads to a reduction of $3,358,757 on an Oregon-allocated basis over the Company's filed NPC.[1]

Q. Can you summarize the market cap issue and your opening testimony position on the issue of market caps?

A. Yes. The issue presented by the Company in opening testimony is that it was severely over-forecasting off-system sales due to an unreasonably high market cap in its GRID model.[2] The Company's claims were acknowledged in Commission Order 20-473, and that "PacifiCorp may be able to make targeted forecast adjustments to remedy specific issues with its under-recovery."[3] The Company's current method to calculate market caps is to calculate the market cap by calculating "the highest of four most recently available relevant averages for each trading hub, each month, and differentiated by on- and off-peak hours."[4]

[1] Staff/1201, Dlouhy/2.
[2] PAC/100, Webb/9.
[3] Order 20-473 at 130.
[4] PAC/100, Webb/10.

Q. How does the Company propose to deal with the over-forecasting of off-system sales using market caps?

A. The Company proposes instead to replace this method with the average value of each of the four most recently available months.[5] I refer to this as the "average of averages" approach.

Q. What was your original position on market caps in your opening testimony?

A. In my opening testimony, I advocated rejecting the Company's adjustment to market caps on the basis that the Company's claims of over-forecasting off-system sales are exaggerated and that the "average of averages" approach was previously rejected by the Commission on the grounds that it was too restrictive.[6] I support this by comparing projected and actual off-system sales since 2013 using data provided to me by the Company in Staff Data Request 15.[7]

Q. Are there any reasons why the market cap methodology should be unchanged at this time?

A. Yes. The timing of a change to market caps is improper given that the Company is switching to a new modeling software that is capable of more nuanced modeling of off-system sales than GRID.

[5] PAC/100, Webb/11.
[6] Staff/800, Dlouhy/2.
[7] Staff/800, Dlouhy/36.

Q. Please summarize the Company's response to your testimony.

A. The Company reasserted that it continues to over-forecast off-system sales in GRID and that the "average of averages" approach is the proper way to address the over-forecasting of off-system sales. The Company then states that my comparison of forecasted and actual off-system sales is flawed because it relies on incorrect data and instead provides data that it characterizes as correct. The Company then presents alternate data demonstrating that it has indeed over-forecasted off-system sales since 2013.[8]

Q. Do you find the Company's response persuasive?

A. No. I find that the Company's reply testimony lacks the quantitative analysis necessary to justify reverting back to the "average of averages" approach and mischaracterizes the work done by the Commission and Staff. In particular:

1. The Company made no effort to explore alternate ways to address the over-forecasting of off-system sales and instead proposed a method that has been previously rejected by the Commission.
2. The Company did not provide any analysis to show that the "average of averages" approach more correctly forecasts off-system sales than the "maximum of averages" approach.
3. The Company incorrectly interpreted Order No. 20-473 as a mandate to change its market cap methodology rather than an invitation to explore many alternate modeling techniques.

[8] PAC/400, Staples/23.

4. The Company hindered my analysis by responding to my data requests with insufficient data, then undermined my results by incorrectly claiming that I asked for the incorrect data.

Q. Concerning your first point, why is it problematic that the Company proposed a method previously rejected by the Commission?

A. The Company previously proposed the "average of averages" approach during the 2013 TAM proceedings. During the proceedings, Staff and intervenors found that the "average of "averages" approach was overly restrictive and could under-forecast sales in periods of high demand.[9] Eventually, the "maximum of averages" approach was adopted after the issue was fully litigated.[10]

In its reply testimony, the Company says that it proposes new "straightforward inputs or limits" in this TAM proceeding when calculating market caps.[11] In reality, the Company just recycled an old method that was shown to be just as problematic.

[9] UE 245, Staff/100, Schue/12.
[10] *In re PacifiCorp*, OPUC Docket No. UE 245, Order 12-409 at 7-8 (Oct. 29, 2020).
[11] PAC/400, Staples/17.

Q. The Company claims that its generation resources and the Commission's policy have substantially changed since 2013, making its proposal appropriate under these changed conditions.[12] Do you agree?

A. Yes. PacifiCorp's generation resources have changed since this issue was last brought up in UE 245; however, this does not change the fact that PacifiCorp is again proposing a market cap methodology that was known to be problematic without demonstrating that the problems are no longer relevant. Absent this demonstration, I have no choice to conclude that the problems with the "average of averages" method will still remain. The Company has not demonstrated, with supporting evidence, that a change in its resource mix is better addressed by its proposed methodology for market caps.

Q. Regarding your second point, what analysis would be needed to show that the "average of averages" approach would be preferable to the "maximum of averages" approach?

A. In order to show that the "average of averages" approach would do a better job of forecasting off-system sales than the "maximum of averages" approach under GRID, I would expect to see something similar to the following:

- A time series of actual off-system sales from 2013 to 2020. Two different estimates of this exist in this proceeding, both under the

[12] PAC/400, Staples/20.

Company's response to Staff Data Request 15 and in Figure 4 of the Company's Reply Testimony.[13]

- A time series of projected off-system sales from 2013 to 2020 using the "maximum of averages" approach. This was provided in response to Staff Data Request 15.
- A time series of projected off-system sales from 2013 to 2020 instead using the "average of averages" approach. This would only require a GRID run for each past year using the proposed other market caps but was not provided at any point during the Company's opening or reply testimony.
- A comparison of the "maximum of averages" approach and the "average of averages" approach in AURORA if the Company intended the change to be precedential.

With the first two items, the Company can show how the "maximum of averages" approach compares to actual off-system sales. Without the third item, the Company fails to demonstrate that the "average of averages" approach is truly an improvement under GRID. Without the fourth item, the Company provides no evidence that the "average of averages" would provide proper cost recovery in AURORA.

[13] PAC/400, Staples/23.

Q. Have these analytical shortcomings been brought up before?

A. Yes. In its opening testimony, AWEC also points out that the Company's proposal to switch to the "average of averages" approach is poorly substantiated.[14]

Q. Concerning your third point, why do you believe that the Company incorrectly characterized Order No. 20-473?

A. The Company's testimony portrays Order No. 20-473 as directing the Company to address its over-forecasting of off-system sales in the 2020 TAM and that the preferred way to do it is through market caps. In reality, neither of those are a fair interpretation of Order No. 20-473. That Order states:

> Between now and 2024, PacifiCorp may be able to make targeted forecast adjustments to remedy specific issues with its under-recovery. The TAM is an annual filing and PacifiCorp has an annual opportunity to improve its forecast, just as it did in the 2016 TAM when it introduced the DA/RT mechanism to increase the volume and modeled cost of balancing transactions to increase GRID's balancing costs. PacifiCorp does not necessarily need to develop a complex new adjustment, but may be able to improve its forecast accuracy with straightforward inputs or limits. For example, Staff shows that PacifiCorp's sales to market (also referred to as off-system sales) are being over-forecast, finding a "gross over-estimation of the sales

[14] AWEC/100, Mullins/11.

benefit." PacifiCorp did not address the feasibility of reducing this component of its forecast and it is something that may be considered in the TAM. With PacifiCorp's upcoming transition to a new power forecast model (AURORA) there may be other options for improving PacifiCorp's forecast that will emerge once the parties begin training with the model.[15]

Q. What parts about the quote from the order have you identified that run counter to the Company's narrative that market caps need to be changed during this TAM?

A. I identify three ways that the Company incorrectly uses Order No. 20-473 to justify changing its market caps in the 2022 TAM:

1. The Commission notes that PacifiCorp can propose changes to its methodology to forecast off-system sales between now and 2024. There are still two more TAM proceedings that the Company can use to address the over-forecasting issue with a modeling change, and PacifiCorp has not demonstrated that such a modeling change is necessary once AURORA is utilized to forecast power costs.
2. The Commission notes that the PacifiCorp may be able to address the over-forecasting problem using a simple method. This is not to say that the Company needs to restrict itself to simple methods if they are otherwise inappropriate, as the Company's proposal in this case is.

[15] *In re PacifiCorp*, OPUC Docket No. UE 374, Order 20-473 at 130 (Dec. 18, 2020).

3. The Commission does not use the term “market cap” in this paragraph nor anywhere else in the resolution of this issue. In fact, the Commission notes in this same paragraph that AURORA may provide other options to improve this forecast.

Q. Concerning your fourth point, has the Company’s responses to discovery helped support your position?

A. No. In Staff Data Request 15, I asked the Company to provide a comparison of historic actual off-system sales and GRID-forecasted off-system sales.[16] The Company provided me the GRID-forecasted sales and directed me to other workpapers provided in the TAM. In the body of the Company’s response, the Company noted that these two data sets do not form a perfect comparison but failed to provide me with a pair of data sets that are comparable. I perform my analysis using the data provided to me by the Company while noting its shortcomings.[17]

In the Company’s reply testimony, the Company states that my analysis is invalid because I rely on wholesale data provided in response to Data Requests 2 and 4.[18] However, at no point did I ask for wholesale data. Instead, the Company directed me to Data Requests 2 and 4 while noting its shortcomings without making it apparent where I could find more applicable data.

[16] Staff/802, Dlouhy/2.
[17] Staff/800, Dlouhy/34-36.
[18] PAC/400, Staples/25.

Q. Does the Company use the same wholesale data when conducting their own analysis?

A. No. In its reply testimony, the Company compares GRID-forecasted and short-term sales using a table generated from the PCAM.[19] If it is indeed more relevant to my comparison of actual and projected sales than the wholesale data provided by the Company, this would have been useful in my analysis but was not the data that was provided to me in response to Staff Data Request 15.

Q. Despite the issues with discovery you have outlined above, has your position on market caps evolved since the Company filed its reply testimony?

A. Yes, in light of seeing the Company's reply testimony, and Figure 4 in particular, I do think it is possible that the current "maximum of averages" approach is not the optimal method for forecasting off-system sales for purposes of setting net power costs. However, I still do not support changing the market cap methodology in the manner that the Company suggests.

Q. Please explain.

A. Here are my main points:

- My analysis done using the data provided me by the Company in Staff Data Request 15 points to a completely different result than the analysis done by the Company in its reply testimony.

[19] PAC/400, Staples/23.

- The Company has provided no evidence that implementing the "average of averages" approach now will avoid the problems pointed out in my opening testimony and shared by Staff in UE 245.
- I still believe that it is improper to make a precedential change to market caps this year given that the Commission gave PacifiCorp until 2024 to address its off-system sales issue and specifically names AURORA as a tool to do so.

Q. Given this, what is your recommendation regarding market caps?

A. At this point, I think it is improper to make a precedential change to market caps until the Company can show how the current "maximum of averages" method interacts with AURORA. However, if the Commission is inclined to make a one-time change to the methodology for the 2022 TAM, given that this is the last year utilizing GRID to forecast power costs, one option would be a method that I will call the "third quartile of averages" approach. This approach preserves some of the "maximum of averages" approach's ability to properly model market depth while addressing the Company's concerns of GRID's over forecasting off-system sales when using a more representative market depth.

Q. What is a quartile?

A. A quartile is a set of three values that divide a dataset into four equal groups. Generally speaking, statisticians use quartiles to inspect the distribution of a dataset and identify outliers.

As an example, suppose a data set has 40 points that ranges 1, 2, 3,… 40. The first quartile would contain 1-10, the second quartile would contain 11-20, and the third quartile would be 21-30, and the fourth quartile would contain 31-40. By convention, the number that represents each quartile is a value between the largest number in the previous quartile and the smallest number in the actual quartile. In the above example, the first, second and third quartiles would be represented by 10.5, 20.5, and 30.5, respectively. The fourth quartile is represented by the maximum of the data range, which is 40 in this case.

Q. Please describe the “third quartile of averages” approach.

A. In this approach, I support using the third quartile of the four most recently available relevant averages for each trading hub, each month, and differentiated by on- and off-peak hours. This is the same range of data used in the “maximum of averages” approach and the Company’s proposed “average of averages” approach. For each separate hub-month-on/off peak set of averages, this leaves four data points. So essentially, I find it supportable to average the highest and second-highest observed averages rather than the maximum of averages.

Q. How does this address the Company's concerns of over-forecasting off-system sales with the "maximum of averages" approach and past Staff's concerns of under-forecasting with the "average of averages" approach?

A. The "third quartile of averages" approach should be thought of as a method to split the difference between the "maximum of averages" approach and the "average of averages" approach while keeping the desirable properties of each. Under the "third quartile of averages" approach, the average of the two highest observed averages for each group will be used as a market cap, which will necessarily lead to a market cap that is less than or equal to the "maximum of averages" approach. Likewise, the "third quartile of averages" approach will lead to a market cap that is greater than or equal to the "average of averages" approach.

Q. Why is it preferential to calculate a market cap that is between the "maximum of averages" approach and the "average of averages" approach?

A. First, I would like to reiterate that I believe that the "maximum of averages" approach is the most appropriate for purposes of setting 2022 TAM rates for all reasons previously stated. Staff still questions the validity or scale of the off-system sales problem given that the data used by PacifiCorp do not align with the data provided to Staff.

However, if the Company's claim that the "maximum of averages" approach over-forecasts off-system sales in GRID are determined credible, and if the past Staff's analysis that the "average of averages" approach under-forecasts off-system sales in GRID are still relevant, then a principled approach that determines a value between the two would be the best available option. As discussed earlier, my proposed "third quartile of averages" approach accomplishes that. It finds a value that captures a more realistic market depth than the "average of averages" approach proposed by the Company, but avoids market depths as extreme as the "maximum of averages" approach that the Company claims cause problems in GRID.

Q. Is implementing the "third quartile of averages" approach a simple solution to implement?

A. Yes. The "maximum of averages" approach selects the highest value out of the four calculated market depths for each month-hub-on/off peak group. The "average of averages" approach takes the average of all four values within that group. My proposed "third quartile of averages" approach selects the two highest values in each group and averages them, which is an easily replicated process in Excel.[20]

Q. How does this change the calculated market caps?

A. In Table 1, I reproduce Table 2 from my opening testimony in Staff/800 and add a column denoting the average market cap at each hub for both on- and

[20] It is worth pointing out that Excel has two pre-built commands to calculate quartiles: QUARTILE.INC and QUARTILE.EXC. These commands both are meant to deal with larger data sets and choose the quartile by interpolating between the edges of extrema contained in adjacent quartiles. Using them leads to odd results with only four points, so I made the choice to manually code Excel to calculate each quartile by averaging the highest and second-highest value in each group. In practice, my manual code outputs a value between QUARTILE.INC and QUARTILE.EXC.

off-peak times.[21] It can be clearly seen that the third quartile forms a suitable middle ground between the Company's and Staff's proposed market caps in their respective opening testimonies.

Table 1: Average Market Cap by Hub & On/Off Peak (MW)[22]

[BEGIN CONFIDENTIAL]

Hub	Company	Staff Opening	Staff Rebuttal
COB HLH	[redacted]	[redacted]	[redacted]
Four Corners HLH	[redacted]	[redacted]	[redacted]
Mid-Columbia HLH	[redacted]	[redacted]	[redacted]
Mona HLH	[redacted]	[redacted]	[redacted]
Palo Verde HLH	[redacted]	[redacted]	[redacted]
Mead HLH	[redacted]	[redacted]	[redacted]
COB LLH	[redacted]	[redacted]	[redacted]
Four Corners LLH	[redacted]	[redacted]	[redacted]
Mid-Columbia LLH	[redacted]	[redacted]	[redacted]
Mona LLH	[redacted]	[redacted]	[redacted]
Palo Verde LLH	[redacted]	[redacted]	[redacted]
Mead LLH	[redacted]	[redacted]	[redacted]

[END CONFIDENTIAL]

Q. Did you make any other changes when calculating market caps using the "third quartile of averages" approach?

A. Yes. The values calculated above reflect the period July 2016 to June 2020. As was pointed out in PacifiCorp's reply testimony, the Company's original filing erroneously calculated its market caps using data from January, 2016 to December, 2019.[23] In opening testimony, I wrote that I was concerned with using the first six months of 2020 due to potential abnormal market responses

[21] Table 2 can be found at Staff/800, Dlouhy/37.
[22] Table compiled from Staff adjustments to "ORTAM22 Dir_Market Capacity DEC20 CONF" workpaper.
[23] PAC/400, Staples/28.

to the COVID-19 pandemic. Under the Company's "average of averages" technique, I wrote that this could artificially deflate market caps due to low energy demand.[24] My concerns are largely mitigated using the "third quartile of averages" technique as this method selects only the two largest caps out of the four.

Q. What is the total dollar value of Staff's adjustment when using the "third-quartile of averages" technique?

A. The Company performed a GRID run using the market caps from the "third quartile of averages" approach in response to Staff Data Request 180.[25] Based on the GRID run contained in the Company's response, I recommend adjusting the NPC in the 2022 TAM down by $3,358,757 on an Oregon-allocated basis.

Q. Are there any other issues in the Company's reply testimony you want to respond to?

A. Yes. I would like to respond to the following in PacifiCorp's reply testimony:

1. The note on page 22 that the Company uses the "average of averages" approach in all other jurisdictions.[26]
2. The assertion and mathematical example on page 22 that the "maximum of averages" approach forces the Company to pick the most extreme outlier.[27]

[24] Staff/800, Dlouhy/38-39.
[25] Staff/1201, Dlouhy/2.
[26] PAC/400, Staples/22.
[27] *Id.*

3. The assertion on page 23 that the magnitude of the difference between projected and actual off-system purchases and sales is significantly different.[28]
4. The assertion on page 26 that AWEC's analysis using actual volumes with DA/RT and booked-out transactions removed is based on flawed assumptions.[29]

Q. Regarding your first issue, is there any reason that the Commission should consider how the Company treats market caps in other Commissions?

A. No. To the extent that this is the methodology used in other jurisdictions, each Commission is nevertheless required to conduct its own independent analysis on issues. Therefore, ratemaking outcomes in other jurisdictions should not be considered precedential in Oregon. Notably, the mechanisms for net power cost recovery is structured differently in other jurisdictions as well.

Q. Regarding your second issue, does the Company correctly characterize the outlier problem with market caps with its discussion and associated mathematical example?

A. No, there are two key points that the Company misses when discussing the merits of the "maximum of averages" approach. The first point is that the market cap is supposed to model what can *possibly* be sold at a market hub,

[28] PAC/400, Staples/23.
[29] PAC/400, Staples/26.

so the “most extreme outlier,” as the Company puts it, does a better job of capturing that value than a mere average of what has been sold at the hub over the last four years. In a sense, the whole design of the “maximum of averages” approach is to account for the most extreme outlier.

Second, the Company grossly misrepresents the difference between the mean market cap and the maximum market cap in its mathematical example. In the example provided, the Company represents the “most extreme outlier” as one that is ten times larger than the next-largest value. Using a four-year horizon in the Company’s demonstrative example, the “maximum of averages” approach would yield a market cap of 1,000 as opposed to 325 using the “average of average approach, a ratio of 308 percent. In the actual data, the percent increase from the “average of averages” approach to the “maximum of averages” approach is nearly half that, with an average ratio of 162 percent.

Q. Regarding your third issue, how do you respond to the difference in magnitude between the forecasted off-system sales and purchases in Figure 4 of the Company’s testimony?

A. As stated previously, I question the Company’s choice of data given that in Staff Data Request 15, I was provided different data than PacifiCorp chose to use in its reply testimony. The data that the Company provided to me shows an over-recovery of off-system sales. Additionally, if the difference in magnitude is indeed an issue, then the Company should explore ways to mitigate this problem in AURORA rather than making a precedential change in its GRID system that it will retiring immediately after this proceeding.

Q. Regarding your fourth issue, how do you respond to the assertion that AWEC's analysis of market caps, DA/RT, and booked-out transactions is based on flawed assumptions?

A. PacifiCorp's criticism of AWEC's analysis on market caps contradicts PacifiCorp's criticism of my own analysis. As stated earlier, PacifiCorp claimed that my analysis was inherently flawed because it relies on wholesale transaction data and does not account for booked-out transactions. At the same time, PacifiCorp is critical of AWEC for removing booked-out transactions and DA/RT transactions that offset in a similar manner. Conducting our own independent analyses relying on different assumptions, AWEC and I both found that the Company's concerns of over-forecasted off-system sales are overstated.

Q. What is your overall recommendation regarding market caps?

A. I want to again present my recommendation as a preferred and second-best options. My most-preferred option is to leave market caps unchanged because the Company did not provide adequate evidence that its "average of averages" approach solves the problem of over-forecasting off-system sales, the Commission gave adequate time to propose other changes in the two ensuring TAM proceedings, and the Company will implement AURORA prior to the 2023 TAM filing. This recommendation results in a decrease to NPC of $5.1 million on an Oregon-allocated basis.

My second-best option is to implement my “third quartile of averages” approach for the 2022 TAM on a non-precedential basis. This method results in a reduction of NPC by $3,358,757 on an Oregon-allocated basis.

I accept that there is some uncertainty around whether AURORA will be able to fully mitigate the Company’s improperly forecasted off-system sales, which should be revisited in a future TAM proceeding, regardless of the Commission’s decision in this case. In a future case, the Company would need to thoroughly demonstrate that the current “maximum of averages” approach still creates a problem that AURORA cannot otherwise solve should it advocate for an alternate market cap methodology.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 390
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1201

Data Requests in Support
Of Rebuttal and Cross-Answering Testimony

July 30, 2021

UE 390 / PacifiCorp
July 28, 2021
OPUC Data Request 180

OPUC Data Request 180

Market Caps - Please run provide a GRID run using all the parameters contained in the Company's original filing except for the market caps contained in attachment titled "dr_180_attachment_conf". Please report the following information from the GRID run:

(a) The total calculated net power cost.

(b) The change in net power cost relative to the "maximum of averages" method to calculate net power costs in all TAM proceedings since 2013 on a system-wide basis.

(c) The change in net power cost relative to the "maximum of averages" method to calculate net power costs in all TAM proceedings since 2013 on an Oregon-allocated basis.

Note that the values included in "dr_180_attachment_conf" are intended to replace cells U68:AF79 in sheets "48 Month Pivot" in the "ORTAM22 Dir_Market Capacity DEC20 CONF" work paper provided by the Company and anywhere else the referenced cells in that work paper may appear in the GRID model.

Response to OPUC Data Request 180

Referencing the Stipulation that was adopted in the 2021 transition adjustment mechanism (TAM), docket UE 375, specifically paragraph 15 (Transition to AURORA for Modeling Net Power Costs (NPC)), page 6, subpart b., lines 3 through 6 which states "PacifiCorp would additionally agree to conduct one AURORA model run per intervenor, so long as the request is reasonable and PacifiCorp has a reasonable time to complete the request during future NPC forecast mechanism proceedings." Although the 2022 TAM utilizes the Generation and Regulation Initiative Decision Tool (GRID), not AURORA, the Company is honoring the intent of the stipulated paragraph referenced above and provides the following response regarding the "one AURORA [GRID] model run per intervenor." Based on the foregoing clarification, the Company responds as follows:

Please refer to Confidential Attachment OPUC 180.

(a) Total Company NPC, as reflected in Confidential Attachment OPUC 180, is $1,432,411,150.

(b) The change in Total Company NPC is ($13,043,391) when compared to the NPC forecast that accompanied PacifiCorp's initial filing / direct testimony in this

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proceeding (initial filing / direct testimony NPC was $1,445,454,540)

(c) PacifiCorp objects to this request as overly burdensome and that the capability to calculate this information is not uniquely possessed by PacifiCorp. Without waiving the foregoing objection, PacifiCorp responds as follows:

The Company has not completed this analysis because the process of allocating the revised NPC is onerous and would not have been available in the timeframe necessary. However, the average allocation factor was 25.751 percent in the Company's initial filing / direct testimony, which would make an Oregon-allocated impact of ($3,358,757) a reasonable approximation. (25.751 percent multiplied by $13,043,391).

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

CASE: UE 390
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1300

Rebuttal and
Cross-Answering Testimony

Redacted

July 30, 2021

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

A. My name is Scott Gibbens. I am the Policy and Economic Analysis Manager employed in the Strategy and Integration Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in this case?

A. Yes. I sponsored Staff/900.

Q. What is the purpose of your testimony?

A. I provide Staff's response to testimony provided by the Company and Intervenors in the case on the nodal pricing model (NPM), consumer opt-out charge, and REC transfer issues.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1: NODAL PRICING MODEL

Q. Please provide a brief summary of your concerns regarding costs and benefits for the Nodal Pricing Model (NPM) and PacifiCorp's response.

A. In my opening testimony, I noted that the Company recently implemented the NPM on January 15, 2021.[1] The NPM provides the Company with a more granular dispatch logic than the previous dispatch model. Through the efficiencies gained by NPM, the Company is expecting to realize power cost savings.[2] I noted that customers pay $8.4 million a year for the NPM, but receive no additional incremental benefits commensurate to the power cost savings the Company is now expected to gain.[3] No other parties filed testimony related to the issue.

In its reply testimony, the Company noted that GRID has perfect foresight, knowing load and dispatch costs for every hour that the model optimizes.[4] In actual operations however, load and marginal costs are only close estimates. The Company analogizes the NPM to intra-regional EIM benefits, which the Commission declined to adjust as part of the 2017 TAM.[5] Summarily, PacifiCorp argues that both provide real benefits in actual operations, but are already captured by the perfect foresight of GRID.[6]

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[1] Staff/900, Gibbens/9, line 14.
[2] *Id.* page 8-9, line 18.
[3] *Id.* page 10, line 13.
[4] PAC/400, Staples/78, line 11.
[5] *Id.* page 79, line 6.
[6] *Id.* page 80, line 10.

Q. Does Staff agree with the Company's position?

A. No. The advantages of the NPM are largely distinct from the perfect foresight of GRID. As shown below in Confidential Figure 1, GRID is a zonal model, meaning that PacifiCorp's service territory is divided into twelve load centers and twelve resources bubbles connected via transmission bubbles. This means that GRID does not have the granularity to identify the impact of a single unit on the entire transmission system. GRID only optimizes each bubble subject to the constraints; therefore, the impact of any resource within a bubble to the transmission system is unknown in GRID. GRID simply is not complex enough to fully take into account the limits of the transmission network. If GRID had more granular capabilities, the Company would not have a need to switch to a nodal power cost forecasting model next year.

Confidential Figure 1

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

In a nodal model, each load center and generating unit has a unique locational marginal price (LMP). The model optimizes resources and transmission together, which results in a unique cost for each nodal point. GRID selects the cheapest cost resource to serve load, while a nodal model would instead select the cheapest means to serve.

Q. Does the Company refute Staff's assertion that a nodal model is more granular than GRID?

A. No. Staff raised this same argument in opening testimony, noting that GRID is a zonal model that lacks the granularity of a nodal model. PacifiCorp did not dispute this fact, and instead argued that GRID has perfect foresight. PacifiCorp did refer to Staff's proposal as including "alleged benefits", however Staff's proposed adjustment is based on benefits stated by the Company in PacifiCorp's Nodal Pricing Model Memorandum of Understanding.[7] The Company has provided no evidence that the switch in dispatch logic provides the Company with more accurate load data. Thus, the fact that GRID has static load that it can optimize to is not pertinent to the issue. The Company will never have perfect foresight in actual operations and has implemented the DA/RT adjustment and proposed a change to market cap methodology to address the implications of this, to attempt to achieve more accurate forecasts. However, the NPM has nothing to do with load forecasting or subsequent market transactions directly related to perfect planning. The NPM provides the Company with an optimization tool that GRID does not possess. Because of this, an adjustment to power costs needs to be made so that customers receive the benefit of the investment they made.

Q. Does Staff recommend a reoccurring adjustment or change in modeling methodology?

A. No. Once PacifiCorp changes its power cost forecasting model from GRID to a nodal model, AURORA, the adjustment will no longer be needed. AURORA will have the same granularity that PacifiCorp now realizes through its new operational dispatch model. The savings realized by the new dispatch model will be captured by AURORA and customers will realize those benefits through

[7] PAC/400, Staples/78, line 1.

a standard model run. Staff's proposed adjustment is a one-time adjustment, which does not ask that customers receive a net benefit from the NPM, but instead recommends that customers do not pay for a something and receive nothing in return. Staff invites the Company to perform a power cost model run with AURORA, which has already been used by the Company to forecast power costs in other states this year. The difference in NPC forecasts between the zonal model GRID and the nodal model AURORA if any, would provide an estimate of the benefit of a more granular dispatch logic. Since both models have perfect foresight, PacifiCorp's argument would fail to explain any difference in forecasts.[8]

Q. What is Staff's recommendation?

A. Staff recommends that the Company reduce its NPC forecast by $8.4 million as a proxy for the benefits realized in actual operations from the NPM. As explained in my opening testimony, setting costs equal to benefits was the same method used when determining EIM benefits prior to actual operations.[9] As such, Staff's proposal is consistent with past Commission precedent when net benefits are difficult to quantify but are anticipated and used to justify utility investment.

In the alternative, Staff recommends that the Commission direct the Company to perform a TAM model run with the same inputs as GRID, using the AURORA model. The difference would provide parties with information

[8] UE 374, PAC/2000, Wilding/67, line 8.
[9] In re PacifiCorp, OPUC Docket No. UE 287, Order No. 14-331 at Appendix A, page 4, lines 16-21 (October 1, 2014).

necessary to address the issue in the 2022 PCAM filed in spring of 2023. Staff notes that the Commission could choose to utilize the AURORA model as the basis for an adjustment in this year's TAM, but Staff does not recommend taking that approach due to the lack of history and familiarity of utilizing AURORA to forecast PacifiCorp's NPC. Waiting until the PCAM will allow Staff and stakeholders to utilize AURORA in next year's TAM prior to proposing adjustments or other recommendations regarding NPM benefits in the PCAM the following year.

ISSUE 2: CONSUMER OPT-OUT CHARGE

Q. Please summarize Calpine Solutions' concern with PacifiCorp's calculation of the Consumer Opt-out Charge and the Company's response.

A. PacifiCorp's Schedule 296 has two components: (1) the five-year transition adjustment (i.e. Schedule 200 generation charges for years one through five), and (2) the Consumer Opt-out charge (COOC), which recovers the projected difference between the fixed generation costs normally recovered in Schedule 200, for the five years following the five-year opt-out process (years six through ten) and the market value of the energy to serve the departed load. In opening testimony, Calpine Solutions (Calpine) noted that PacifiCorp held the Consumer Opt-out charge at zero, artificially suppressing the result of the calculation which would have gone negative (i.e. a credit rather than a charge).[10] In the sample calculation, the forward market prices were high enough to more than offset the costs of the generation present in Schedule 200. Calpine argues that preventing the COOC from going negative (i.e. a credit to participating Direct Access (DA) customers) is inconsistent with the purpose of transition charges and credits, is inconsistent with applicable direct access law, does not result in unwarranted cost-shifting, and is supported by sound policy.[11] For these reasons, Calpine urges the Commission to order

[10] Calpine Solutions/100, Higgins/4, line 8.
[11] See Calpine Solutions/100.

PacifiCorp to remove any constraint on the calculation of the COOC that prevents it from resulting in a negative value.

In response, PacifiCorp argues that the COOC was never meant to go below zero, as it was designed to recover the costs of the fixed generation which would otherwise be borne unfairly by COS customers.[12] PacifiCorp also argues that if the COOC were allowed to go negative, unwarranted cost-shifting would occur, where the COS customers would be subsidizing DA customers who choose to leave the utility's system.[13] Calpine has argued that transition adjustments in general are meant to eliminate to the extent practicable cost-shifting in either direction, so that neither COS or DA customers are harmed by the choice of a customer to purchase power from a third-party source.[14]

Q. Does Staff find that the 2022 TAM is the optimal forum for resolution of this issue on an on-going basis?

A. No. This issue is best dealt with in an on-going manner through the open investigation into long-term direct access issues, Docket UM 2024. The docket is meant to allow parties to look at all inter-related DA issues, with a holistic approach to arrive at a fair and reasonable outcome on several policy issues, including transition charges and credits. Should forward market prices shift, the issue of whether or not the COOC should be allowed to go below zero may not be required to set rates in this docket. Staff recommends that the Commission make a recommendation on how to proceed with the issue in this docket, but

[12] PAC/900, Meredith/4, line 19.
[13] PAC/900, Meredith/4, line 21.
[14] Calpine Solutions/100, Higgins/8, line 11.

note that it will consider the issue again, in the context of all other issues and potential changes to Direct Access in UM 2024.

Q. Upon review of PacifiCorp's reply testimony on this issue, does Staff find evidence supporting PacifiCorp's claim that cost-shifting concerns weigh in favor of holding the COOC at or above zero?

A. No. Staff does not find that the Company has shown that unwarranted cost-shifting would occur if the COOC were allowed to go negative. From a theoretical perspective, the COOC is meant to account for the costs that otherwise would be placed on COS customers from a DA customer's decision to leave in years six through ten following the opt-out decision. The basis being that utility investment to serve the departed load would not be fully recovered in the first five years, and that the fixed costs present in Schedule 200, need to be considered as a part of the cost to leave the system during this time. In the event that the value of the energy being produced by the generation paid for through the COOC is greater than the cost of the generation itself, then COS customers would only be indifferent to a DA customer's choice, if the COOC was allowed to go negative. It would only make sense to subtract the value of the freed up energy from the fixed costs if the freed up energy was meant to be a benefit of these customers leaving the system. If the methodology didn't account for the full benefit of leaving the system, then it result in cost-shifting, because the full benefit and full cost would no longer be counted. With the charge held at zero, COS customers are receiving a credit equal to the difference between the market value of the energy and the zeroed out COOC, thus cost-shifting would exist, but in the opposite direction as the Company claims. Staff notes that uncertainty around future costs and market prices produces potential risks to COS customers which may change the actual level of cost-shifting to the benefit or detriment of customers. However, this risk is borne by all DA participants and COS customers regardless of the COOC's ability to go below zero. Holding the COOC at or above zero only means that these risks will no longer be symmetrical, creating a bias towards subsidization for COS customers. Staff also notes that it did not consider the merits of the COOC, as those will be discussed in UM 2024. Instead Staff considered the theoretical basis for the methodology itself. Both Calpine's and PacifiCorp's arguments also implicate interpretation of Oregon's Direct Access laws, which Staff will address in briefing.

Q. What is Staff's recommendation for purposes of this proceeding?

A. Staff recommends that the Commission order the Company to utilize its approved methodology to calculate the COOC as a freely floating mechanism that can go below zero. For future TAM proceedings, Staff recommends that parties and the Commission consider this issue in the context of all other DA issues in docket UM 2024.

ISSUE 3: REC TRANSFERS

Q. Please provide a brief summary of REC transfers to Electric Service Suppliers (ESSes).

A. In docket UE 339, parties agreed to a resolution to the problem of how to appropriately credit DA customers for the value of REC's produced by generation paid for through the transition adjustments. Parties generally agreed that because the RECs were effectively paid for by the DA customers through the transition adjustment, but that valuation of the RECs proved difficult, transferring the RECs was a simple and reasonable approach to ensure there was no cost-shifting.[15] In Commission Order No. 21-203, the Commission determined that a transferred REC, which did not accompany the underlying energy as well, did not meet the statutory definition of a bundled REC. ESSes are required to utilize 80% bundled RECs to meet their RPS obligation going forward, however if the RECs being transferred are no longer considered bundled, the value of the REC to the ESS and thus to the DA customer would arguably not be commensurate with the cost paid for by the DA customers for the RECs through the transition charge.

The recently signed House Bill 2021 however provides a clarification of the issue and explicitly states that a bundled REC can be acquired, "By an electricity service supplier by retirement by an electric company where the renewable energy certificate satisfied paragraph (a) or (b) of this subsection prior to such retirement and was retired on behalf of the electricity service

[15] Commission Order No. 18-421, Appendix A, page 8, line 7.

supplier on behalf of a retail electricity consumer that pays transition adjustments to the electric company."[16]

Q. What are parties' positions on this issue?

A. Calpine raised this issue prior to the decision made by the Commission in Order No. 21-203 or the passing of HB 2021. It notes that it was an open issue and recommended that in the event the RECs could no longer be considered bundled, then ESSs should be credited with the full market value of the REC. In its reply testimony, PacifiCorp noted that HB 2021 modified the definition of a bundled REC to allow an ESS to use transferred RECs to meet RPS obligations.

Q. Does Staff agree with the Company's assertion?

A. For the most part yes. Staff notes that the language in HB 2021 refers to retirement on behalf of the ESS, which is slightly different than transferring a bundled REC.[17] However, Staff believes it is a reasonable approach to have the Company retire 80% of the total RECs paid for the DA customers using bundled RECs in accordance with the new statute, and to maintain the current methodology to transfer the other 20% of unbundled RECs to the ESS.

Q. Does this conclude your testimony?

A. Yes.

[16] https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled. Page 15.
[17] *Ibid.*

CASE: UE 390
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1400

Rebuttal and
Cross-Answering Testimony

July 30, 2021

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

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

Q. Have you previously provided testimony in this case?

A. Yes. I provided testimony in Exhibit 700 regarding PacifiCorp's new coal contracts, the Huntington coal contract, and the modeling that informs the Company's coal contract negotiations

Q. What is the purpose of your testimony?

A. My testimony responds to PacifiCorp's Reply Testimony on the topics from Staff Exhibit 700 and also to other parties' recommendations on related topics.

Q. Have you prepared any Exhibits for your testimony?

A. Yes. I have prepared Exhibit 1401 containing PacifiCorp's response to a Staff Data Request.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, COAL CONTRACT NEGOTIATIONS

Q. Please summarize your main arguments from Opening Testimony regarding the business plan fueling budget forecast that informs PacifiCorp's coal contract negotiations.

A. My Opening Testimony recommends three improvements to the methodology of the forecast used to inform PacifiCorp's coal contract negotiations, based on workpapers provided to Staff in discovery responses. First, the forecast should cover at least the entire duration of the coal contract. Second, the forecast should include the best forecast of PacifiCorp's long-term resource buildout from its most recent IRP. Third, the forecast should consider opportunities to create savings for customers by cycling coal units off during the off-peak season.[1]

Q. Has Staff reviewed additional information from PacifiCorp on this topic since Staff's Opening Testimony?

A. Yes. PacifiCorp witness Ralston has explained that the forecasts used to inform coal contract negotiations already cover the entire duration of the coal contracts.[2] In addition, PacifiCorp has provided corrected workpapers that show that at least four years of data is used to inform coal contract negotiations. Finally, a response to a Staff data request states that, "For the 10-year business plan, the IRP group provides the most likely resource

[1] Staff/700, Anderson/12.
[2] PAC/600, Ralston/22.

buildout expectations at the point the 10-year business plan needs to be locked down."[3]

Q. Is the additional information that has been provided sufficient to allay Staff's concerns?

A. Not completely. Staff appreciates the additional information provided by the Company. The workpapers, discovery, and testimony provided by PacifiCorp show that the forecast covers the contract duration and includes the impacts of expected resource buildout over that timeline. Staff is satisfied with these elements of the forecast. However, there is still room for improvement in the consideration of economic cycling and in the transparency of how economic cycling is considered when negotiating coal contracts. Staff remains concerned that the Commission and stakeholders have little insight into how (or whether) the Company considers economic cycling for its thermal resources when negotiating coal contracts. In addition, there is little transparency into how the Company uses its fueling budget forecast to inform contract negotiations. Without transparency into PacifiCorp's decision making on this topic, Staff cannot determine whether the Company is taking all opportunities to reduce costs for ratepayers.

[3] Staff/1401. PacifiCorp's response to Staff Data Request 155, part b.

Q. Have parties provided arguments and expressed concerns that indicate PacifiCorp should reduce minimum take volumes and facilitate economic cycling to the extent possible?

A. Yes. PacifiCorp has received many arguments from parties that it should be considering the impacts of potential future unfavorable market and/or regulatory conditions in general and in its coal contract negotiations and in operational decisions.[4,5,6,7] PacifiCorp's coal contracts should not be deemed prudent unless, prior to contract execution, economic cycling is considered and the minimum take commitment level is kept as low as reasonably possible. This allows the Company to seize any opportunities for economic cycling or general reduction of coal volume commitment.

For units that show potential to benefit ratepayers through economic cycling, future coal supply agreement negotiations should seek to obtain a minimum take level that would facilitate economic cycling, while also seeking the option to purchase more coal if needed to support reliability.

Q. Is it important for PacifiCorp to provide transparency into its coal contract negotiations and demonstrate that it has taken adequate measures to reduce risk to customers?

A. Yes. As shown in response to Sierra Club Data Request 1.12, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of the Company's **[BEGIN**

[4] Docket No. UE 323. Staff/500, Kaufman/35-37.
[5] Docket No. UE 323. Sierra Club/100, Vitolo/8.
[6] Docket No. UM 1712. Sierra Club's Initial Brief. Page 1.
[7] Staff's final comments to PacifiCorp's 2019 Integrated Resource Plan. Page 12,

CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]** coal contracts will expire at the end of **[BEGIN CONFIDENTIAL]** [redacted].[8] **[END CONFIDENTIAL]** As PacifiCorp considers replacing these expiring contracts, it will be important for the Company to provide transparency and allow the Commission, Staff, and stakeholders to determine whether the Company has performed reasonable analysis to support the minimum take levels and contract length in any new coal contracts. In review of these contracts, Staff anticipates that a key element of its prudence review will include analysis of this issue.

Q. What does Staff recommend PacifiCorp do to provide transparency into certain aspects of its coal contract negotiations?

A. Staff recommends that for each future TAM filing, the Company provide the following:

1. For every new coal supply agreement subject to prudence review, PacifiCorp should provide an in-depth explanation of how the Company considered the potential for economic cycling when deciding on minimum take levels in that contract.
    - EIM participation should not be assumed to preclude the possibility of economic cycling. The Company must show whether EIM participation is better for customers than economic cycling.

[8] Staff/703. PacifiCorp's reply to Sierra Club's Data Request 1.12.

- Joint ownership should not be assumed to preclude the possibility of economic cycling. The Company must show whether cycling would be economic at co-owned units. For any units that could cycle economically, PAC must demonstrate that it reached out to co-owners to request they consider cycling as well.

2. A chart should be provided comparing the MMBtus from the generation forecast used to inform contract negotiations to the number of MMBtus that PacifiCorp will be contractually obligated to pay for at each plant, by year.
3. PacifiCorp should provide workpapers for the generation forecasts used to inform negotiations on each new coal contract introduced in that TAM filing.

Q. Does Staff have additional recommendations around PacifiCorp's coal contracting process based on the testimony of other parties?

A. Yes. Sierra Club has recommended that PacifiCorp provide copies of its coal supply agreements and affiliate mine plans in each TAM filing.[9] Staff concurs that this is a reasonable measure to provide Staff and parties the information needed to assess the economics of PacifiCorp's coal contracts.

Given that these contracts represent a substantial portion of the cost included in rates in the TAM, these contracts should be provided in order to ensure that parties have ample ability and time to review. Although PacifiCorp has routinely made coal contracts and affiliate mine plans available to view in person or over

[9] Sierra Club/100, Burgess/3-4.

a web platform, this does not allow parties an ability to revisit contract provisions easily at a later date, and to spend ample time reviewing and analyzing contract provisions and how they relate to one another outside of the purview of the Company.

The asymmetry with access to contracts is clearly demonstrated in PacifiCorp's reply testimony, in which the Company chose to quote specific highly confidential contract provisions—something that Staff and other parties do not have equal ability to do. The disparity of access to information and the incongruent standards for reproducing this information should not continue. Parties should be provided these documents, subject to the appropriate protective order agreements, as a matter of course in the proceeding as part of the Company's filing requirements.

Q. Does Staff have any other recommendations around PacifiCorp's coal contracting process based on the testimony of other parties?

A. Yes. Additionally, Sierra Club has recommended that the Commission provide guidance for PacifiCorp regarding future contract negotiations:

> The Commission should establish best practices for future coal supply agreements, including limiting the minimum take quantity, shortening contract terms to the extent practicable, including provisions that allow for avoidance of minimum take requirements, and forecasting anticipated generation using average costs in anticipation of coal contract negotiations.[10]

[10] Sierra Club/100, Burgess/3.

Staff concurs that understanding Commission expectations could be useful to the Company when negotiating contracts, and to parties when reviewing contract prudence. Staff is not endorsing any specific minimum take level or contract term length as a best practice. Staff would add that contract provisions allowing relaxation or cancellation of a minimum take level for certain economic, as well as regulatory causes, could be beneficial to customers.

To be clear, Staff interprets "forecasting anticipated generation using average costs in anticipation of coal contract negotiations" above to mean that, when PacifiCorp is performing its generation forecast for the purposes of informing its coal contract negotiations, the Company will remove the minimum take constraint for any plant in any years that it does not have an active contract. It is Staff's understanding that the Company already does this.

Q. Does Staff continue to recommend that the Company perform a study of economic cycling on its system?

A. Yes. Staff continues to recommend that "PacifiCorp should perform a follow-up economic cycling study that seeks to identify additional opportunities for cost savings through economic coal cycling. Following the conclusion of the 2022 TAM, PacifiCorp should be required to both solicit feedback from Staff and other interested stakeholders and then complete a follow-up study prior to the next TAM."[11]

[11] Staff/700, Anderson/6.

ISSUE 2, DAVE JOHNSTON, HUNTER, AND CRAIG COAL CONTRACTS

Q. In its Opening Testimony, what was Staff's recommendation on the prudence of minimum take levels in PacifiCorp's new coal contracts?

A. In its Opening Testimony, Staff argued that the Dave Johnston and Craig coal contracts should be deemed imprudent, mainly because the forecasts that informed these negotiations did not appear to cover the entire contract duration, and did not adequately consider economic cycling. Staff recommended the Hunter contract be deemed prudent, since the forecast supporting minimum take levels at Hunter appeared to be more robust and consider economic cycling.

Q. Has PacifiCorp provided additional information on this topic since Staff's Opening Testimony?

A. Yes. PacifiCorp has provided corrected workpapers for its response to Staff DR 71 showing that the analysis used to inform the Dave Johnston and Craig coal contract negotiations in fact covered the majority of the duration of the contracts. PacifiCorp has confirmed that it did not consider economic cycling at Dave Johnston or Craig, arguing that Dave Johnston is unlikely to see benefits from economic cycling and that Craig is a jointly owned plant which the Company cannot cycle without agreement from co-owners.[12]

[12] PAC/600, Ralston/15.

Q. Does Staff continue to recommend a prudence disallowance for the Craig and Dave Johnston coal minimum take levels?

A. Yes. PacifiCorp must evaluate economic cycling at its coal plants. Broad statements that the ownership or cost of a plant make economic cycling impractical are not sufficient. A full assessment of economic cycling on PacifiCorp's system as a whole is needed before PacifiCorp signs its coal supply agreements. Without studying the optimal economic cycling outcome for each of its coal plants, PacifiCorp's estimate of the optimal level of generation at any of its dispatchable plants will be inaccurate, and therefore the Company cannot optimally set its minimum take levels in any of its coal contracts.

Regarding the Craig coal plant, PacifiCorp's argument that joint ownership at Craig precludes the ability to cycle the plant for economic reasons is unconvincing. PacifiCorp has not shown that it took any steps to evaluate economic cycling at Craig, or to discuss the possibility with co-owners. Given this lack of analysis, Staff recommends that the Commission find the new Craig coal contract to be imprudent.

The minimum take levels set for Craig **[BEGIN HIGHLY CONFIDENTIAL]** [redacted] **[END HIGHLY CONFIDENTIAL]**. However, PacifiCorp has not done a thorough study of economic cycling and the Company should bear any risk that the Craig minimum take levels have been set too high. As the remedy to PacifiCorp's imprudence in executing this contract, Staff recommends that TAM rates reflect modeling Craig without minimum take constraints in the TAM for the duration of this coal supply agreement. This approach insulates ratepayers from risk for PacifiCorp's lack of consideration of economic cycling.

When committing to coal contracts at shared plants, Staff expects that economic cycling will be considered as an option in PacifiCorp's modeling and discussed with co-owners if it shows the potential to reduce power costs for ratepayers while maintaining reliability and maintenance requirements.

Regarding the Dave Johnston plant, Staff accepts that Dave Johnston is unlikely to be selected for economic cycling because of its relatively low cost. However, because the Company did not perform an analysis of economic cycling on its system as a whole or at Dave Johnston, Staff continues to recommend that the new contract at Dave Johnston be deemed imprudent and that as the remedy, Dave Johnston should be modeled without minimum take requirements in the TAM for the duration of the contract.

Q. Does Staff continue to argue that the Commission should find the Hunter contract prudent?

A. No. After further reflection, Staff finds that minimum take levels in PacifiCorp's coal contracts cannot be deemed prudent due to the Company's lack of analysis to assess whether economic cycling at any of its coal plants can reduce costs for ratepayers while maintaining reliability and other system requirements. As the remedy for the Company's imprudent analysis, Staff recommends that Hunter should be modeled without minimum take requirements in the TAM for the duration of the new contract.

ISSUE 3, THE HUNTINGTON COAL CONTRACT

Q. Please summarize Staff's position in its Opening Testimony on the Huntington coal contract.

A. In its Opening Testimony, Staff argues that because the Company's modeling used to inform coal contract negotiations appears to be generally deficient, the minimum take assumption should be removed from the Huntington plant in the TAM until the Company develops an adequate modeling methodology.

Q. Has PacifiCorp provided additional information on this topic since Staff's Opening Testimony?

A. Yes. The testimony of Seth Schwartz in PacifiCorp's Exhibit 500 explains that substantive conversation on the minimum take levels in the Huntington coal contract occurred during the 2017 TAM. In the 2017 TAM Order, the Commission stated that it was not persuaded by CUB's concerns about the minimum take levels in the Huntington coal contract.[13]

Q. Does Staff continue to recommend a prudence disallowance for the Huntington coal contract based on its lack of consideration for economic cycling?

A. No. Staff has reviewed the additional testimony and evidence provided by PacifiCorp, and finds that PacifiCorp did not necessarily have access to information that would have indicated the need to set the Huntington minimum take agreement at a lower level to accommodate economic cycling in 2014.

[13] Order 16-482. Page 9.

Q. Please elaborate on the economics relevant to the Huntington agreement when it was signed.

A. The Huntington coal contract minimum take levels have turned out to be too high for optimal results. However, when considering what the Company knew or should have known at the time it signed the Huntington CSA, Staff looked to the 2013 and 2015 PacifiCorp Integrated Resource Plans and the Northwest Power and Conservation Council's (NWPCC) 2010 Sixth Power Plan. Staff found that neither IRP predicted the rapid growth in renewable development that has occurred in the years since, or the resulting periods of low market prices.

For example, the 2013 IRP market price forecast showed an increase from $30/MWh in 2013 to $40/MWh in 2016.[14] The 2013 preferred portfolio included only 660 MW of new utility-scale renewable resources during the entire 20 year planning timeframe through 2032.[15] The 2015 IRP similarly envisioned steadily increasing market prices, and the 2015 preferred portfolio included even fewer renewables, adding only 7 MW of utility-scale renewable resources during the 20 year planning timeframe.[16,17] The most recent NWPCC power plan at the time was the sixth Power Plan, which had been published in 2010. The Sixth Power Plan forecasted that renewables would be developed to meet existing

[14] PacifiCorp's 2013 Integrated Resource Plan. Page 2.
[15] PacifiCorp's 2013 Integrated Resource Plan. Page 11.
[16] PacifiCorp's 2015 Integrated Resource Plan. Page 196.
[17] PacifiCorp's 2015 Integrated Resource Plan. Pages 159-160.

RPS goals, for a total of 1450 aMW across the region, but did not consider the possibility that renewable development would exceed RPS requirements.[18] While stakeholders raised concerns in Docket No. UM 1712 about the contract, based on the uncertain economic and regulatory environment for coal at the time, the Commission did not choose to deem the contract imprudent in that docket or in response to party's concerns in the 2017 TAM.[19,20,21]

Q. Did any other party make a recommendation related to the Huntington Coal Supply Agreement?

A. Yes. In its Opening Testimony, CUB points out that the Huntington coal contract has a provision allowing PacifiCorp to exercise termination rights if it becomes uneconomic to burn coal at Huntington. CUB recommends, given all of the environmental regulation that has passed since 2015, that the Company conduct an analysis to determine whether the Huntington contract "is leading to uneconomic dispatch of the plant, whether that is related to new environmental laws and regulations and whether it is in customers' interests to invoke the contract termination provisions."[22]

Q. Has PacifiCorp responded to CUB's recommendation?

A. Yes. In its Reply Testimony, PacifiCorp states that an environmental regulation must be directly applicable to the Huntington plant, unlike SB 1547, in order to seek termination of a CSA. PacifiCorp argues that it would not be certain to

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[18] NWPCC. Sixth Power Plan. Page 10-8.
[19] Docket No. UM 1712. Sierra Club's Reply Brief filed April 28, 2015. Page 1.
[20] Docket No. UM 1712. ICNU/100, Mullins/29-30.
[21] Docket No. UM 1712. Staff/600, Crider/4-8.
[22] CUB/100, Jenks/14.

obtain better contract terms for its Huntington coal supply agreement if it invoked a contract termination clause and then immediately had to either find a new coal supplier in the 'illiquid Utah coal market' or renegotiate a new contract with the same coal supplier.[23] PacifiCorp argues that the 2021 IRP is a more appropriate venue for studying the ongoing economics of the Huntington plant.

Q. What is Staff's position on CUB's recommendation that the Company look into the possibility of exercising the termination clause in its Huntington CSA?

A. Staff finds CUB's interpretation and recommendation to be persuasive, and recommends that the Company conduct analysis to determine whether contract provisions in the CSA result in uneconomic dispatch of the plant, and if yes, whether that uneconomic dispatch is related to environmental laws and regulations.[24] Staff is concerned about the Company's more conservative view of the termination provisions in light of the representations made in Docket UM 1712.[25] The study should consider opportunities for gas conversion, economic cycling, and early retirement of Huntington. The study could take place as a part of the 2021 IRP.

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[23] PAC/600, Ralston/29.
[24] CUB/100, Jenks/15.
[25] *See e.g.* UM 1712 – PAC/500, Crane/4-11. Specifically, see PAC/500, Crane/7, lines 13-20:

> **Q. Parties are also concerned that the long-term CSA creates an incentive for the Company to continue to burn coal at Huntington when it would otherwise be uneconomic to do so and therefore limits the Company's future options. Please respond.**
>
> A. Because the Company can exercise its termination rights if it becomes uneconomic to burn coal at Huntington, there is no incentive to continue burning coal when it is uneconomic to do so and the Company's options are not limited. Furthermore, the Company will conduct its future planning based on its understanding of Article 8."

Staff also recommends that, in addition to performing a Huntington study, the Company should seek provisions in future coal contracts that allow for contract termination if a plant becomes substantially uneconomic for reasons unrelated to environmental regulation.

ISSUE 4, ECONOMIC CYCLING AT JIM BRIDGER

Q. What is CUB's recommendation in its Opening Testimony regarding Jim Bridger unit 1?

A. In its Opening Testimony, CUB recommends a study that closes Bridger 1 **[BEGIN CONFIDENTIAL]** [redacted].[26] **[END CONFIDENTIAL]** Additionally, CUB recommends that Bridger 1 be allowed to economically cycle in GRID forecasts and that its operators should increase cycling in operations.

Q. What was PacifiCorp's reply to CUB's recommendation?

A. PacifiCorp replies that many parts of the western United States are under drought conditions, resulting in customer benefits from Jim Bridger's operation during Q2 of 2021. Additionally, PacifiCorp argues that it would be impractical to cycle Jim Bridger off because it would have to agree to a cycling plan with the plant's co-owner, Idaho Power. Finally, PacifiCorp argues that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** and taking a unit offline for economics limits the utility's ability to perform maintenance on other units.

Q. What is Staff's position on a study of economic cycling for Jim Bridger Unit 1?

A. Staff finds that a study looking at the potential to cycle Jim Bridger 1 would be helpful to Staff and stakeholders in determining whether a forecast that includes economic cycling at Jim Bridger unit 1 is a requirement for setting

[26] CUB/100, Jenks/17.

reasonable rates in the TAM. In order to best inform the question, the study should include practical considerations, such as whether the unit can be cycled off while still allowing necessary maintenance to take place on other units.

Alternatively, the study to identify economic cycling opportunities across PacifiCorp's system recommended in my Opening Testimony could satisfy the need to study economic cycling at Jim Bridger unit 1. Cycling of Jim Bridger 1 should then be included in modeling in TAM filings, to the extent that cycling is shown to be beneficial to customers and consistent with reliability and maintenance requirements.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 374
WITNESS: ROSE ANDERSON

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1401

Exhibits in Support Of Rebuttal and Cross-Testimony

July 30, 2021

OPUC Data Request 155

Coal Supply Agreements
In response to OPUC Staff DR 71, PacifiCorp wrote that to inform negotiations around the new coal contracts at Dave Johnston, Hunter, and Craig, "PacifiCorp's finance department calculates net power costs (NPC) over the 10-year business planning horizon based on projected data using the Generation and Regulation Initiative Decision Tool (GRID)".

(a) How many years were studied in GRID? If the GRID forecast ends before the full 10 years of the business planning horizon, how does Pac project generation levels in the later years of the business plan?

(b) Does the forward-looking 10-year analysis include ten years of resource buildout selections from the most recent IRP? If not, what modeling assumptions are used regarding resource buildout over the 10-year timeframe?

Response to OPUC Data Request 155

PacifiCorp objects to this request as overly broad, outside the scope of this proceeding, cumulative, and not reasonably calculated to lead to admissible evidence. Without waiving the foregoing objection, PacifiCorp responds as follows:

(a) The Company's 10-year business plan Generation and Regulation Initiative Decision Tool (GRID) runs were performed for the full 10-years covered by the relevant 10-year business plan.

(b) The net power costs (NPC) section of the 10-year business plan is typically finalized in June of each year. The Integrated Resource Plan (IRP) is typically finalized in April of every other year (with an update filing in the between year). For the 10-year business plan, the IRP group provides the most likely resource buildout expectations at the point the 10-year business plan needs to be locked down.

CASE: UE 390
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1500

Rebuttal and
Cross-Answering Testimony

July 30, 2021

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

A. My name is John L. Fox. I am a Senior Financial 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. Have you previously provided testimony in this case?

A. Yes, I provided opening testimony in Staff/600, with accompanying exhibits Staff/601 and Staff/602.

Q. What is the purpose of your testimony?

A. I respond to the Company's reply testimony regarding the Informational Run for modeling coal costs and partially respond to the Company's reply testimony regarding the Naughton and Wyodak plants.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, INFORMATIONAL RUN

Q. Please summarize the Company's reply testimony regarding the Information Run.

A. The Company confirms Staff's understanding that the Informational Run does not include any minimum take provisions, but "does adjust the average cost to compensate based on take or pay contracts with coal suppliers"[1] and that "the costs of other resources that replace the coal fuel expense are also included in the model."[2] The Company also acknowledges that "Staff believes that these costs obscure the effects of economic cycling for the purposes of the informational run."[3]

In response to Staff's recommendation that the Informational Run should exclude take or pay provisions, the Company states that "such an approach would render the study meaningless"[4] and "assuming away costs that would actually be incurred simply invalidates the study results."[5] In support of its position, the Company also references the Commission's decision that modeling of minimum-take provision in the 2017 TAM was appropriate in determining coal costs.[6]

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[1] PAC/400, Staples/41.
[2] *Id.*
[3] *Id.*
[4] PAC/400, Staples/42.
[5] *Id.*
[6] See *In re PacifiCorp*, OPUC Docket No. UE 307, Order No. 16-482 at 10-11 (Dec. 20, 2016).

Q. Does Staff agree that the approach would render the study meaningless?

A. No. Although the Informational Run may not reflect costs that are actually incurred, it would provide insight into opportunities for cost savings in the future.

Q. Is the Company's reliance on the Commission's 2017 TAM order relevant in this case?

A. No. The issue in the 2017 TAM was related to actual modeling of minimum take provisions in forecasting coal costs, necessitated by limitations in GRID. In this case, the Informational Run is not being used to forecast coal costs for 2022. The Company's reliance on that provision is immaterial to this issue. Rather, the Company agreed to perform an Informational Run (not for ratemaking purposes), as follows:

> PacifiCorp agrees to perform an informational AURORA model run, based on the initial TAM filing, that removes any operational constraints related to the minimum take provisions in the coal supply agreements and uses an average coal price for purposes of dispatching coal plants. PacifiCorp will provide this informational AURORA model run in the initial TAM filing until all coal costs are removed from Oregon rates (through the 2029 forecast).[7]

[7] *In re PacifiCorp*, OPUC Docket No. UE 375, Order No. 20-392 at 4 (Oct. 30, 2020).

Q. Does the Company's reply testimony discuss the difference between liquidated damages and a "take-or-pay" provision?

A. Yes, the Company states that "Liquidated damages are an alternative to a "take-or-pay" provision which requires the customer to purchase the coal or pay for it anyway."[8]

Q. Does the Company discuss how utilities determine the fuel cost for economic dispatch when they have coal supply and transportation contracts with liquidated damages and projected burn falls below the minimum take obligation?

A. Yes, the Company states the following:

> Utilities do not include the fixed cost of liquidated damages in determining the variable cost for the dispatch of their power plants. Customers benefit from least-cost dispatch as utilities only include the variable cost of fuel in the decision whether to operate a power plant (just as utilities would not include the fixed cost of a pipeline contract for transportation of natural gas). If the power plant dispatches at the variable cost (subtracting the liquidated damages from the full contract coal price) but would not have dispatched at the full cost, the most economic decision is to dispatch the power plant even though the fuel cost charged to the customer is greater than the fuel cost used for dispatch purposes. If a power plant still does not dispatch economically after subtracting the cost of liquidated damages, then the least-cost decision is to reduce plant operations and pay the liquidated damages.[9]

Q. What is Staff's position with regard to the minimum take provisions?

A. Staff continues to advocate for excluding all costs associated with minimum take provisions from the Informational Run.

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[8] PAC/500, Schwartz/14.
[9] PAC/500, Schwartz/16.

The Company has stated repeatedly that it wishes to “honor the spirit of the 2021 TAM Stipulation” with regard to the “must run” setting.[10]

In Staff’s view, the Company should provide the Informational Run by not adding back liquidated damages and/or “take-or-pay” provisions or, alternatively, be required in the future to provide the results of the informational run both with, and without, those costs included. The Company should be ordered to provide the analysis (with and without) concurrently in the 15 day work papers.

Staff continues to assert that inclusion of these costs obscures the effects of economic cycling for the purposes of the Informational Run.

[10] PAC/400, Staples/35 and PAC/100, Webb/14.

ISSUE 2, BURN RATE AT NAUGHTON AND MINIMUM TAKE AT WYODAK

NAUGHTON

Q. Please discuss the Company's response to your concern regarding the burn rate variance for the Naughton plant.[11]

A. The Company explains that the burn rate variance cited by Staff is due to scheduled overhauls in 2022, the expected retirement of Unit 1 in 2025, and loss of efficiency due to operating the plant at a lower capacity.[12]

Q. Based on the information provided, are you now proposing an adjustment for the Naughton Plant?

A. No.

WYODAK

Q. Please summarize your concerns with PacifiCorp's forecast of coal costs for the Wyodak plant.

A. In my opening testimony, I noted that there was an increased to Wyodak's burn rate, which led to an increase in power costs in this case. I also noted, based on information provided in the filed case that the Wyodak plant was running below its minimum take requirement.

[11] Staff/600, Fox/5.
[12] Staff/600, Fox/12.

Q. Please discuss the Company's response to your testimony regarding the Wyodak plant.

A. The Company elaborates on the operational circumstances causing the Wyodak plant to run below the minimum take in 2022.[13]

Q. Based on the additional information provided, are you now proposing an adjustment for Wyodak?

A. No.

Q. Does this conclude your testimony?

A. Yes.

[13] PAC/600, Ralston/23-24. See also Staff/600, Fox/31.

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WITNESS: NADINE HANHAN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1600

Rebuttal Testimony

July 30, 2021

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

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

Q. Have you previously provided testimony in this case?

A. Yes. I submitted Opening Testimony (Staff/300) and Exhibits (Staff/301-303).

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the Company's testimony regarding wheeling costs in Exhibit PAC/400.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

- Staff/1601 – PacifiCorp response to Staff Data Request 179 and confidential attachment.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1, WHEELING COSTS

Q. Please summarize your position in Opening Testimony.

A. Staff's primary concern was overestimated wheeling costs included in PacifiCorp's net power cost forecast. Staff had recommended an adjustment of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** wheeling cost input for the year of 2022 based on the fact that the data for this line item showed an ongoing lower cost.[1]

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

A. The Company indicated that the reason for these apparent ongoing lower costs is because **[BEGIN CONFIDENTIAL]** [redacted][2] **[END CONFIDENTIAL]**

[1] Staff/300, Hanhan/5-6.
[2] PAC/400, Staples/88-89.

Q. Do you continue to have concerns with this?

A. Generally, no. the Company has explained the limited-duration nature of a reduction in these costs, and therefore Staff finds that the Company's forecast of the **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** is appropriately forecast in 2022 net power costs. The Company also addressed Staff's questions pertaining to two other wheeling line items, and Staff was also satisfied with those responses.

Q. Did the Company's Reply Testimony include updates to any other wheeling costs?

A. Yes, the Company's testimony states that updates to wheeling costs included an increase of totaled $9.5 million.[3]

Q. Please explain the increase in costs.

A. The Company has updated wheeling costs to include the impacts of the BPA rate case. While the Company explained in testimony that the total effect of the updates in wheeling costs are projected to be $9.5 million, Staff submitted data requests on this number and discovered that **[BEGIN CONFIDENTIAL]** [redacted][4] **[END CONFIDENTIAL]** As a result, roughly $7.2 million of the net increase can be attributed to the BPA rate

[3] PAC/400, Staples/7, lines 5-6.
[4] Confidential Electronic Attachment to Exhibit Staff/1601.

case.[5] Staff believes it is appropriate to include this in the power cost forecast. This is consistent with Staff's position in UE 391.[6]

Q. Are there additional updates that Staff expects to see included in the Company's net power costs?

A. Yes. In preparing a data response to Staff, PacifiCorp stated that it became aware of an error in its updated wheeling cost file, specifically the "WAPA FIRM TRANS" path. PacifiCorp indicated that it should not have included any expenses for the months of May through October. This resulted in an overstatement of wheeling costs by roughly $2.3 million on a total-company basis. The Company indicated that it will correct this in its indicative filing in November 2021.[7] Staff interprets to mean that this will result in an increase of power costs of roughly $7.2 million for 2022 instead of the $9.5 million reflected in the Company's Reply Testimony. Staff supports this removal.

Q. Does this conclude your testimony?

A. Yes.

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[5] Exhibit Staff/1601. PacifiCorp Response to DR 179. $9.5 million - $2.3 million = $7.2 million.
[6] UE 391 / Staff/300, Hanhan/3.
[7] Exhibit Staff/1601.

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STAFF EXHIBIT 1601

Exhibits in Support of
Rebuttal and Cross-Answering Testimony

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OPUC Data Request 179

Transmission, wheeling - Please refer to PAC/400, Staples/8. The Company states, "The Company has updated wheeling expenses to reflect the actual costs from June 2020 through December 2020, and to incorporate the expected impacts of the recently settled BPA rate case. The update increases total company NPC by approximately $9.5 million".

(a) Please provide all work papers showing how the Company calculated these costs.

(b) Regarding subpart a. to this data request, please direct Staff to exact cells, rows and columns of cells showing how the Company calculated these costs.

(c) Please provide a detailed explanation of how the Company arrived at these costs.

(d) Please provide all new Wheeling Costs in an identical manner as presented in the original work paper labeled ORTAM22w Dir_Wheeling.xlsx.

(e) Regarding subpart d. to this data request, please direct Staff to exact cells, rows and columns of cells showing changes to new wheeling costs.

(f) Please provide an itemized breakdown of what these costs are. Please also show how much of this increase in costs is due to the BPA rate case, and how much is due to other factors.

Response to OPUC Data Request 179

(a) Please refer to the confidential 3-day work papers supporting the reply testimony of Company witness, Douglas R. Staples and the July 2021 net power costs (NPC) update, specifically file "Cumulative_ORTAM22w Jul_Wheeling CONF.xlsx."

(b) Referencing the file stated in the Company's response to subpart (b) above, please refer to tab "Wheeling Costs," cell range AT1 through BE156, as well as the cells and ranges referred to in the formulas of those cells.

(c) In the case of costs that have no known or measurable change, the most recent 12 months of costs are used to forecast expenses in the future. For cost items that exhibit known and measurable changes (rate cases, escalating contracts, etc.) those changes are incorporated into the cost forecast.

(d) Please refer to the Company's response to subpart (a) above.

(e) Changes are not calculated within the Company's work papers. Please refer to Confidential Attachment OPUC 179, tab "All Wheeling Cost Changes." Note: in responding to this data request, the Company became aware of an error on one line of the updated wheeling cost file, specifically the "WAPA FIRM TRANS"

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line. That cost item should not have included any expenses for the months of May through October, which has resulted in an overstatement of approximately $2.3 million on a Total Company basis, which will be corrected in the Company's indicative filing in November 2021. Without that error, wheeling costs would only have increased $7.2 million on a Total Company basis, with essentially the entire amount attributable to updates related to the Bonneville Power Administration (BPA) rate case.

(f) Please refer to Confidential Attachment OPUC 179, tab "BPA Cost Changes" for a breakdown of the change related specifically to the BPA rate case. The total impact is approximately $7.3 million on a Total Company basis.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

Confidential Staff Exhibit

Confidential attachment to PacifiCorp's response to Staff DR 179 is filed in electronic format