PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah Street, Suite 2000
Portland, Oregon 97232

August 30, 2023

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97301-3398

Re: UE 420—PacifiCorp's Surrebuttal Testimony and Exhibits

PacifiCorp d/b/a Pacific Power encloses for filing in the above-referenced docket the Surrebuttal Testimony and Exhibits of Ramon R. Mitchell, James Owen, Matthew D. McVee, Ryan Fuller, and Michael G. Wilding.

Included with this filing are electronic workpapers, which have been uploaded to Huddle. Confidential and highly confidential material in support of the filing has been provided to parties under Order No. 16-128 and Order No. 23-211.

If you have any questions about this filing, please contact Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Matthew McVee
Vice President, Regulatory Policy and Operations

Enclosures

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of PacifiCorp's **Reply Testimony and Exhibits** on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

Service List
UE 420

AWEC	
TYLER C PEPPLE **(C) (HC)** DAVISON VAN CLEVE, PC 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 tcp@dvclaw.com	BRENT COLEMAN **(C) (HC)** DAVISON VAN CLEVE, PC 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 blc@dvclaw.com
JESSE O GORSUCH **(C) (HC)** DAVISON VAN CLEVE 1750 SW HARBOR WAY STE 450 PORTLAND OR 97201 jog@dvclaw.com	
CALPINE SOLUTIONS	
GREGORY M. ADAMS **(C) (HC)** RICHARDSON ADAMS, PLLC 515 N 27th ST BOISE ID 83702 greg@richardsonadams.com	GREG BASS CALPINE ENERGY SOLUTIONS, LLC 401 WEST A ST, STE 500 SAN DIEGO CA 92101 greg.bass@calpinesolutions.com
KEVIN HIGGINS **(C)** ENERGY STRATEGIES LLC 215 STATE ST - STE 200 SALT LAKE CITY UT 84111-2322 khiggins@energystrat.com	
OREGON CITIZENS UTILITY BOARD	
OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 dockets@oregoncub.org	MICHAEL GOETZ **(C) (HC)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY STE 400 PORTLAND, OR 97205 mike@oregoncub.org
ROBERT JENKS **(C) (HC)** OREGON CITIZENS' UTILITY BOARD 610 SW BROADWAY, STE 400 PORTLAND, OR 97205 bob@oregoncub.org	

KWUA	
KWUA KLAMATH WATER USER ASSOCIATION KLAMATH BASIN WATER USER PROTECTIVE ASSOCIATION 2312 SOUTH SIXTH ST, STE A KLAMATH FALLS, OR 97601 assist@kwua.org	PAUL S SIMMONS **(C)** **(HC)** SOMACH SIMMONS & DUNN 500 CAPITOL MALL STE 1000 SACRAMENTO CA 95814 psimmons@somachlaw.com
PACIFICORP	
PACIFICORP, DBA PACIFIC POWER 825 NE MULTNOMAH ST, STE 2000 PORTLAND, OR 97232 oregondockets@pacificorp.com	AJAY KUMAR **(C)** **(HC)** PACIFICORP 825 NE MULTNOMAH ST STE 2000 PORTLAND, OR 97232 ajay.kumar@pacificorp.com
SIERRA CLUB	
LEAH BAHRAMIPOUR **(C)** **(HC)** SIERRA CLUB 2101 WEBSTER STREET SUITE 1300 OAKLAND CA 94612 Leah.bahramipour@sierraclub.org	ROSE MONAHAN **(C)** **(HC)** SIERRA LCU 2101 WEBSTER ST STE 1300 OAKLAND CA 94612 rose.monahan@sierraclub.org
STAFF	
STEPHANIE S ANDRUS **(C)** **(HC)** PUC STAFF - DEPARTMENT OF JUSTICE 1162 COURT ST NE SALEM, OR 97301 stephanie.andrus@doj.state.or.us	
VITESSE LLC	
DENNIS BARTLETT **(C)** META PLATFORMS INC 1 HACKER WAY MENLO PARK CA 94025 dbart@meta.com	JONI L SLIGER **(C)** **(HC)** SANGER LAW PC META PLATFORMS INC 1 HACKER WAY MENLO PARK CA 94025 eferrell@meta.com
IRION SANGER **(C)** **(HC)** SANGER LAW PC 4031 SE HAWTHORNE BLVD PORTLAND OR 97214 irion@sanger-law.com	

Dated this 30th day of August, 2023.

Santiago Gutierrez
Coordinator, Regulatory Operations

REDACTED
Docket No. UE 420
Exhibit PAC/800
Witness: Ramon J. Mitchell

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Surrebuttal Testimony of Ramon J. Mitchell

August 2023

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I. INTRODUCTION

Q. Are you the same Ramon J. Mitchell who previously submitted direct and reply testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony in this proceeding?

A. I respond to the rebuttal testimony of Anna Kim, Julie Jent, Curtis Dlouhy, Rose Anderson, Madison Bolton, and Itayi Chipanera, filed on behalf of Staff, Bradley G. Mullins, on behalf of the Alliance of Western Energy Consumers (AWEC), Ed Burgess and Maria Roumpani, filed on behalf of the Sierra Club, Steve Johnson, filed on behalf of Vitesse, LLC (Vitesse), and Kevin C. Higgins, on behalf of Calpine Energy Solutions, LLC (Calpine).

Q. Please summarize your testimony.

A. I demonstrate the reasonableness of PacifiCorp's net power costs (NPC) in the 2024 Transition Adjustment Mechanism (TAM) and respond to the testimony from the parties through the following points:

- Aggregate market prices over summer and winter peak periods in 2024 have increased from 2022, and in 2024 there is substantially limited generation availability due to new operating and policy conditions which—all else equal—result in a higher cost of market purchases and increased market purchases to provide replacement energy respectively. This is discussed in Section III.

- The Day-Ahead and Real-Time (DA/RT) price component and the DA/RT volume component are both separately necessary to account for real-world-trading price inefficiencies and volume inefficiencies respectively. Each component serves a separate function. Furthermore, the DA/RT volume component was clearly producing erroneous results in the Initial Filing and the Company's elimination of the error is therefore a correction. This is discussed in Section IV.
- Staff concedes that the use of the third quartile of averages method is inaccurate because it over-forecasts sales volumes and according to Staff's prior testimony on this issue, "the best solution is to make the model more realistic instead of imposing increasingly fallacious assumptions to counter other model shortcomings."[1] Furthermore, AWEC's analyses on market capacity limits is erroneous and when corrected, support the Company's position that the average of averages method is appropriate. This is discussed in Section V.
- The Ozone Transport Rule (OTR) will be removed from the NPC forecast in the November indicative and final filings due to a recent litigation outcome but, the possibility of the rule applying still exists and the Company would reserve the right to file a deferral in that event. The NPC impact of this change is a decrease of $19 million total-company, $5.5 million, Oregon-allocated, relative to the Reply Update. Furthermore, AWEC demonstrates a lack of understanding on the functions within the Aurora software. This is discussed in Section VI.
- The Company's modeling of the impact of coal supply limitations in Aurora is

[1] *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Staff/800, Dlouhy/30 (Jun. 9, 2021).

accurate. Furthermore, the associated NPC impact presented in the Reply Update is accurate and AWEC demonstrates a lack of understanding on how to model with the Aurora software. This is discussed in Section VII.

- There is no issue with Federal Energy Regulatory Commission (FERC) accounting regarding Chehalis. Changes to the relevant FERC accounting practices have been adopted by FERC for implementation on January 1, 2025, and are therefore outside the test period of this docket. Vitesse's proposal to model Chehalis with a static emissions rate (a single pound per metric million British thermal units value) is elegant but, is neither more nor less accurate than the Company's proposal which decreases NPC relative to Vitesse's proposal. This is discussed in Section VIII.
- Staff's proposal to modify the input wind generation profiles and associated capacity factors is counter to Staff's position in their opening testimony and counter to the 2020 TAM settlement. This is discussed in Section IX.
- AWEC demonstrates an apparent inability to properly use the Aurora software and their claim that their computer produces more accurate results lacks evidence generally and lacks evidence in light of this deficiency. This is discussed in Section X.
- The Company's operational decision to not [redacted] is founded on quantified analysis provided to Vitesse—contrary to Vitesse's claim—and regardless, this operational decision is an issue for the power cost adjustment mechanism and not the TAM. This is discussed in Section XII.

- The Company is already investigating the impacts to power costs resulting from the Extended Day Ahead Market (EDAM) and Sierra Club is incorrect in its claim that the EDAM will go-live in 2024. This is discussed in Section XIII.
- The Company complies with the TAM guidelines, contrary to AWEC's unfounded claim, and to develop a step log that will "not provide an accurate estimate of the cost impact of any one change" [2]—as proposed by Staff—is counter to the purpose of the step log. This is discussed in Section XIV.
- The Company's calculation of the transition adjustments in Schedules 294, 295, and 296 and the calculation of the Consumer Opt-Out Charge is appropriate, unbiased, and is consistent with the language in the docket UE 199 stipulation. This is discussed in Section XV.

Additionally, If the Company's NPC forecast were to exclude the OTR, adopt Vitesse's arbitrage revenue proposal by retaining the DA/RT volume component correction, and adopt Vitesse's proposal to use a volume weighted average to calculate the DA/RT price component then the Reply Update's NPC proposal would decrease by $15.6 million total-company, $4.5 million on an Oregon-allocated basis.

III. PERSISTENT NPC UNDER-FORECAST

Q. AWEC claims that the Company's "poor performance relative to past TAM forecasts" is no basis to "simply use the method that produces the highest level of NPC."[3] Does this argument actually respond to the Company's testimony?

A. No. The Company did not suggest that the NPC forecast should be increased simply to make up for the fact that prior NPC forecasts have been persistently understated.

[2] Staff/1000, Anderson/15.
[3] AWEC/200, Mullins/4.

Rather, the undisputed fact of persistent and significant under-forecasting demonstrates: (1) the forecast is inherently biased toward under-forecasting, consistent with the Company's testimony in multiple prior dockets;[4] and (2) that the under-forecast results, in part, from the fact that costs are incurred in actual operations that are not fully and accurately reflected in the modeling. AWEC's testimony on this point is particularly unpersuasive given that AWEC has previously identified individual NPC line items that have been historically *over-forecast* and sought to drive down NPC to make up for the historical over-forecasting, which is the position AWEC apparently now opposes.[5]

Q. AWEC claims that historical under-forecasting in the TAM is the result of "extraordinary" market conditions in 2022 and 2023.[6] Do you agree?

A. No. As discussed in more detail below, the market conditions in 2022 and 2023 are not extraordinary when compared to 2024. Moreover, the facts show that the Company has under-forecast NPC going back at least to 2017, so the market conditions in 2022 and 2023 are irrelevant to the entire scope of the historical under-forecast.

[4] *In the Matter of PacifiCorp, dba Pacific Power, Transition Adjustment Mechanism*, Docket No. UE 400, PAC/600, Mitchell/69 (Jun. 22, 2022); *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 374, PAC/600, Graves/4 (Feb. 14, 2020).
[5] *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Order No. 21-379 at 35 (Nov. 1, 2021).
[6] AWEC/200, Mullins/5.

Q. AWEC argues that the extraordinary market events that have occurred in 2022 and 2023 "are not intended to be captured in a normalized power cost forecast and are precisely why the Commission implemented a PCAM for PacifiCorp[.]"[7] Do you agree?

A. No. Market prices are not normalized in the TAM, so AWEC's argument is entirely misplaced.

Q. AWEC claims forward market prices for 2024 are expected to be lower than market prices in 2022 and therefore "market prices do not justify an increase to the forecast NPC relative to the actual NPC incurred in 2022."[8] How do you respond?

A. AWEC's testimony on this point is misleading for several reasons. First, AWEC presents Figure 2 on page 6 showing Mid-Columbia (Mid-C) and Desert Southwest power prices and Sumas and Opal gas prices and then points to a single price—Sumas gas—that it is 20 percent lower than 2022 levels. However, evaluating AWEC's Figure 2 in its entirety shows that on average: (1) summer power prices are on average **higher** in 2024 relative to 2022; (2) winter power and natural gas prices are on average **higher** in 2024 relative to 2022, with the exception of December 2022; (3) spring power prices are on average **lower** in 2024 relative to 2022; and (4) fall power prices are on average **lower** in 2024 relative to 2022.

[7] AWEC/200, Mullins/5–6.
[8] AWEC/200, Mullins/6.

Q. Why are higher summer and winter prices particularly critical when comparing prices from 2024 to 2022?

A. Summer and winter peak periods are periods of high customer demand and stressed system conditions and higher power prices in those periods will produce NPC that is substantially higher relative to the slight decrease in NPC resulting from low prices in spring and fall months, which have light load and relatively mild system conditions.

Q. Are there any other ways that AWEC's testimony misleadingly compares 2022 and 2024 data to suggest NPC should be lower?

A. Yes. AWEC ignores coal. This omission is particularly egregious because only [redacted] of the 2024 NPC forecast customer load is served by energy from gas resources. Energy from coal resources serves another [redacted] of customer load in the 2024 NPC forecast and coal prices have [redacted] from 2022 to 2024. Company witness James Owen expands on the Company's coal situation in more detail. The below Confidential Figure NPC-1 shows the Company's 2024 resource mix on a megawatt-hour (MWh) basis as of the July Update, allowing the reader to visualize how customer load is served.

[redacted]

Q. Did AWEC's comparison of 2022 to 2024 ignore any other important system changes?

A. Yes. AWEC fails to consider the NPC impact resulting from limited generation availability due to new operating and policy conditions such as coal supply limitations, the OTR,[9] the Jim Bridger gas conversion and associated outage, the removal of the Klamath dams, and the Washington Cap and Invest Program,[10] all of which—all else equal—increase the 2024 NPC forecast.

Taken together, AWEC's misleading description of the data it provided, coupled with the data AWEC ignored, makes its comparison of 2022 to 2024 NPC incomplete and not credible.

[9] The OTR is proposed to be removed from the November filings but, mentioned in testimony here and below since it was included in the Reply Update and parties' rebuttal testimonies include analyses based on that inclusion.
[10] PAC/400, Mitchell/56.

Q. When examining the relevant data, what conclusions can the Commission draw from the price differences between 2022 and 2024?

A. Based on the June 30 official forward price curve (OFPC) used by the Reply Update, from 2022 to 2024:

(1) Pacific Northwest summer and winter peak power prices **increased** by an annual average of 36 percent and Desert Southwest summer and winter peak power prices **increased** by an annual average of 22 percent;

(2) Company coal prices [redacted] by an annual average of [redacted];

(3) Coal supply constraints **increased** NPC, primarily through a [redacted] in coal generation;

(4) Pacific Northwest winter natural gas prices **increased** by 90 percent and Rocky Mountain region winter natural gas prices **increased** by 38 percent (both calculations excluding the anomalous December 2022 price excursion[11]); and

(5) The summer natural gas prices **decreased** by 53 percent in the Pacific Northwest and 57 percent in the Rocky Mountain region.

When the data is examined in its totality and in the context of the broader resource mix and operating changes discussed above ([redacted]), and the Company's exposure to power market prices, it is evident that the unfavorable changes in summer and winter power price conditions, the unfavorable changes in winter natural gas conditions, and the

[11] The Company excluded the outlier data from December 2022 price because inclusion of that anomalous price spike skews the comparison of 2022 to 2024 data. However, in the interest of complete analysis for the record, from 2022 to 2024, December natural gas prices in the Pacific Northwest and in the Rocky Mountain region decreased by 74 percent and 79 percent respectively.

unfavorable changes in [redacted] far outweigh the favorable changes in summer and December natural gas conditions.

Q. Instead of changes in market prices, AWEC claims that the 2024 forecast of "net short-term purchases" is higher than 2022 because of increased costs of short-term purchases and this "result is likely being caused in part by some of the modeling techniques . . . such as the DA/RT [adjustment] and market cap modeling methods."[12] Do you agree?

A. No. As discussed above, increased market prices over peak periods and new operating and policy conditions are the significant contributor to increased NPC, contrary to AWEC's testimony. Furthermore, as I discuss below in Section IV(C), AWEC's usage of "net" short-term purchases provides a misleading picture of the underlying purchases separate from the underlying sales before "netting".

Q. AWEC questions the increase in "net short-term purchases" in the 2024 NPC forecast given the increase in gas generation, in part from the conversion of Jim Bridger Units 1 and 2, and claims there are counterintuitive results.[13] How do you respond?

A. AWEC claims that increased gas production should have decreased net short-term purchase expense and that because the opposite is occurring, the Aurora model is producing counterintuitive results.[14] I rebut AWEC's misguided claims by discussing in Section IV(C) how AWEC's usage of "net" short-term purchases provides a

[12] AWEC/200, Mullins/7.
[13] AWEC/200, Mullins/8.
[14] AWEC/200, Mullins/8.

misleading picture of the underlying purchases separate from the underlying sales before "netting". I also discuss how the changes in purchases across years are supported by the historical data and supported by new operating and policy conditions that the Company has not previously faced in 2022, or years prior.

Q. AWEC concludes its analysis by testifying that "PacifiCorp's modeling in AURORA is producing an excessive level of NPC."[15] Do you agree?

A. No. AWEC's testimony is internally contradictory—several pages earlier, AWEC witness Mullins testifies that "at this point, little is known about how accurate PacifiCorp's AURORA forecasts will be."[16]

Q. AWEC presents a sequential step log in their Table 1. Do the NPC impacts on that step log show the true cost impact of any one step?

A. No. I explained in my reply testimony that by using a sequential step log "the NPC impact of each step is dependent on the position of the step in the log."[17] In docket UE 416, AWEC also acknowledged this fact that a sequential step log skews the NPC impacts based solely on the order in which the calculations were performed.[18]

In clear contradiction of AWEC's own position in docket UE 416, here in docket UE 420, AWEC presents a sequential step log in their Table 1 that, in their own words, results in the NPC "impacts skewed by the order in which the adjustment calculations were performed."[19] Staff also acknowledges "that this type of [sequential] Step Log will not provide an accurate estimate of the cost impact of any

[15] AWEC/200, Mullins/8.
[16] AWEC/200, Mullins/5.
[17] PAC/400, Mitchell/119.
[18] *In the Matter of Portland General Electric Company, Request for a General Rate Revision; and 2024 Annual Power Cost Update*, Docket No. UE 416, AWEC/100, Mullins/36 (May 24, 2023).
[19] *In the Matter of Portland General Electric Company, Request for a General Rate Revision; and 2024 Annual Power Cost Update*, Docket No. UE 416, AWEC/100, Mullins/36 (May 24, 2023).

one change."[20] Yet this is precisely the type of step log that AWEC presents in their testimony, and it is misleading.

In Figure NPC-2 below I re-present a portion of AWEC's Table 1 and in Figure NPC-3 below, I used AWEC's workpapers and AWEC's Aurora project to recreate the version of AWEC's step log which shows the true cost impact of any one change, by modeling each change as a one-off sensitivity. Note the large discrepancy in the DA/RT line item between how AWEC portrays its NPC impact in their testimony as compared to the true cost impact of that one change.

Figure NPC-2 – AWEC's Tabulated NPC Impacts

		Total Company	Approx. Oregon Allocated
1	**RMP July Update NPC Forecast**	**2,527,830,432**	**725,522,878**
2	**Modeling Differences:**		
3	Market Caps - 95th Percentile	5,310,124	1,524,080
4	DA/RT- Method Simplification	(24,536,188)	(7,042,231)
5	Ozone Transport Rule Wyoming	(27,457,586)	(7,880,713)
6	Washington CCA	(72,706,490)	(20,867,785)

Figure NPC-3 – Updated - True Cost Impact of Any One Change

		Total Company	Approx. Oregon Allocated
1	**PP July Update NPC Forecast[1]**	**2,527,830,432**	**725,522,878**
2	**Modeling Differences:**		
3	Market Caps - 75th Percentile[2]	(29,837,509)	(8,563,785)
4	DA/RT- Method Simplification	(80,656,919)	(23,149,670)
5	Ozone Transport Rule Wyoming	(13,806,925)	(3,962,782)
6	Washington CCA	(70,118,877)	(20,125,104)

[1]In AWEC's original table this line item was apparently mislabled as Rocky Mountain Power "RMP"
[2]In AWEC's original table this line item was apparently mislabled as "95th Percentile"

[20] Staff/1000, Anderson/15.

IV. DA/RT ADJUSTMENT

A. Reply to Staff

Q. Staff continues to recommend that the Commission reject the Company's refinement to the DA/RT adjustment's price component because there was not enough time for Staff to review the change.[21] Is this a reasonable basis to reject the Company's refined modeling?

A. No. As noted in reply testimony, the Commission approved the entirety of the DA/RT adjustment in the 2016 TAM over a similar objection from Staff. The Company disagrees that Staff or the parties have had insufficient time to review the relatively modest refinement to the DA/RT price component proposed in this case, particularly because parties reviewed the exact same refinement in last year's TAM.

Moreover, Staff and other parties have been making this same general argument since the 2016 TAM. For example, in the 2017 TAM, Staff argued that the Commission should reject the DA/RT adjustment while parties develop an alternative.[22] In that same case, the Industrial Customers of Northwest Utilities (the predecessor to AWEC) "agree[d] with Staff that the Commission should reject the DART adjustment in this docket while the parties work together to develop an improved methodology that better addresses the issues the Company is attempting to resolve."[23] It is now eight years later and Staff and some parties are still asking the Commission for more time to explore alternatives to the DA/RT adjustment.

[21] Staff/800, Jent/5.
[22] *In the Matter of PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Staff Response Brief at 27 (Sept. 26, 2016).
[23] *In the Matter of PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307 Cross Answering Brief of the Industrial Customer of Northwest Utilities at 2 (Oct. 5, 2016).

Q. Does Staff support any other proposals to modify the DA/RT adjustment?

A. No.

Q. Staff continues to recommend that the Commission examine the DA/RT adjustment together with market caps.[24] Does Staff acknowledge that the Commission previously rejected calls to eliminate market caps if the DA/RT adjustment was approved?

A. It appears so. Staff testifies that the Commission "weigh[ed] in on the DA/RT issue in 2017, the Commission can always reconsider its merits."[25] The Company does not disagree that the Commission can reconsider previously approved modeling adjustments. However, it is incumbent on parties recommending reconsideration to present evidence, such as changed factual circumstances, that warrant reconsideration by the Commission. In this case, Staff has presented no evidence of changed circumstances that would support a change to the TAM modeling. Staff simply observes that the DA/RT adjustment and market caps both involve market transactions and then concludes that observation is sufficient to warrant reconsideration without providing any facts supporting changed circumstances or any underlying facts.

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[24] Staff/800, Jent/5.
[25] Staff/800, Jent/5.

Q. Does Staff continue to assert that the DA/RT adjustment produces "artificial losses?"

A. It appears so. Staff testifies that "the artificial losses that Staff describes would not automatically lead to free profit arbitrage opportunities until market prices reached equilibrium and the purchase price was greater than or equal to the sales price."[26]

Q. Did Staff produce any evidence supporting this conclusion?

A. No. The Company's reply testimony explained that if the inputs to Aurora for a single market showed a purchase price that was less than the sales price, then Aurora would buy and sell arbitrarily (arbitrage) large volumes of power under this situation.[27] Staff appears to disagree with this testimony, but provided no evidence that the Aurora model would not behave exactly as the Company described.

The Company also explained that in the real world, if a purchase price were less than a sales price all rational market participants would take advantage of this free profit arbitrage opportunity until market prices reached equilibrium and the purchase price was greater than or equal to the sales price. Again, Staff's testimony provided no explanation for its apparent belief that actual markets would not behave as the Company described.

Taken together, Staff's rebuttal to the Company's position is a single conclusory sentence and no supporting evidence.

[26] Staff/800, Jent/7.
[27] PAC/400, Mitchell/33.

Q. Staff also states they are "concerned that the Company claims the volume component adds a measure of historical arbitrage revenue to offset the impact of the price component yet also claims to correct this error in their Reply Testimony without much discussion."[28] How do you respond to this testimony?

A. First, it is well established that the volume component includes historical arbitrage revenues, consistent with the Commission's conclusions in the 2017 TAM.

Second, the Company disagrees with Staff's characterization of the correction included in the reply testimony. The Company's reply testimony included four pages of testimony discussing the error correction to the DA/RT volume component. In that testimony, the Company stated that the historical arbitrage revenue of $7.4 million was **explicitly retained** in the DA/RT volume component after the correction.[29] The Company also provided detailed workpapers and responded to discovery requests related to the correction. Staff neither acknowledged nor disputed the Company's evidence.

Q. Staff claims that the Company's correction to the DA/RT adjustment made in reply testimony is actually a modeling change and Staff also claims to have issues with the correction.[30] What are Staff's issues?

A. Staff does not articulate any specific issue or concern with the correction. Instead, Staff "assumes that the Company was not in agreement with what historical values were showing so the Company's 'correction' takes out that portion of the adjustment."[31] As explained in reply testimony and in more detail below in Section

[28] Staff/800, Jent/7.
[29] PAC/400, Mitchell/49.
[30] Staff/800, Jent/8.
[31] Staff/800, Jent/8.

IV(C), the volume component of the DA/RT adjustment was erroneously showing net revenues, which is conceptually inconsistent with the fact that the volume component of the DA/RT adjustment is designed to reflect *inefficiencies* and associated *costs* in how the Company balances its system.

Q. Staff has updated its recommendation to remove both the refinement to the price component and the correction to the volume component.[32] Do you have any concerns with Staff's quantification of its adjustment?

A. Yes. Staff claims that adopting their proposal, which includes removing the correction to the DA/RT volume component, results in a decrease to NPC of $66.21 million, Oregon-allocated.[33] That number, however, appears to be a sum of an Oregon-allocated amount and a total-Company amount.

Staff "recommends that the dollar value adjustment be updated from ($5.21) million"—which is an Oregon-allocated amount[34]—"to ($66.21) . . .to reflect the change that PacifiCorp made in their Reply Testimony to the volume component of the DA/RT adjustment."[35] However, to update from $5.21 million to $66.21 million is a change of $61 million. $61 million Oregon-allocated at the total-company level is $213 million. As shown in the Reply Update, the impact of the DA/RT volume component correction is $61 million **total-company**.[36] Not $61 million Oregon-allocated.

[32] Staff/800, Jent/9–10.
[33] Staff/700, Kim/3.
[34] Staff/100, Kim/6.
[35] Staff/800, Jent/10.
[36] PAC/401, Mitchell/1.

Q. Staff also recommends that the Company hold workshops to discuss changes to Aurora.[37] How do you respond?

A. It is unclear exactly what Staff has requested, but the Company is not opposed to a reasonable number of workshops to provide parties a better understanding of NPC modeling.

B. Reply to Vitesse

Q. Please describe Vitesse's recommended adjustment to the price component of the DA/RT adjustment.

A. Vitesse recognizes that during times when the sales price exceeds the purchase price, Aurora will model unrealistic arbitrage transactions that do not reflect actual market operations. The Company resolves these situations by flattening the purchase and sales price used in Aurora so that they are the same and the model will more accurately reflect actual operations. Vitesse recommends retaining the flattened prices in Aurora but then making an out-of-model adjustment to multiply the purchase and sale prices by the adjusted forward prices rather than the flattened price used in Aurora.[38]

Q. Does Vitesse continue to recommend this adjustment to the price component of the DA/RT adjustment?

A. Yes. Vitesse continues to recommend its adjustment be approved on a non-precedential basis.[39] Although in response to the Company's reply testimony, Vitesse appears to agree that adopting its recommendation on its own would be

[37] Staff/800, Jent/9.
[38] Vitesse/100, Johnson/15.
[39] Vitesse/200, Johnson/3–4.

double counting arbitrage revenue.[40] So coupled with Vitesse's recommended price adjustment is a corresponding change to how the Company has historically calculated the volume component to include *real* historical arbitrage revenue.

Q. How do you respond to Vitesse's updated recommendation?

A. The Company agrees with Vitesse that modifying the price component as recommended is double counting arbitrage revenue absent removal of normalized arbitrage revenue from the volume component. Conceptually, Vitesse's recommended out-of-model adjustment more appropriately reflects the expected 2024 arbitrage revenue as compared to the use of historical normalized data. However, implementing Vitesse's recommendation in this case requires also implementing the Company's correction to the DA/RT volume component. The Company's correction is unrelated to Vitesse's recommendation to use test period data instead of historical data to forecast arbitrage revenue for 2024. But without the correction, implementing Vitesse's recommendation exacerbates (increases) the overestimation of arbitrage revenue resulting from the error in the volume component and results in forecast arbitrage revenue that far exceeds achievable levels for 2024. Therefore, without the Company's corrections, Vitesse's recommendation is unreasonable and introduces additional error into the NPC forecast. That additional error would be on top of the substantial $60 million worth of artificial arbitrage revenue error in the Reply Update and would factually not reflect the expected 2024 real arbitrage revenue, but instead introduce more error into the NPC forecast. The Company does not propose that the Commission adopt Vitesse's recommendation under this scenario. The impact of

[40] Vitesse/200, Johnson/10.

adopting Vitesse's adjustment is an increase to NPC of $3.3 million total-company, $0.95 million Oregon-allocated, after the removal of the OTR as discussed in Section VI.

Q. Vitesse also notes that the Company agreed to adopt its volume weighted averaging adjustment.[41] Have you quantified the impact of Vitesse's two proposals?

A. Yes. Adopting Vitesse's volume weighted average methodology in conjunction with Vitesse's test period arbitrage revenue methodology, which presupposes the DA/RT volume component correction, increases NPC by approximately $3.6 million total-company, $1.0 million on an Oregon-allocated basis; this is after the removal of the OTR as discussed in Section VI. None of these adjustments were quantified in the Reply Update NPC forecast because the Company had misunderstood Vitesse as not recommending adoption of these adjustments in this year's TAM.[42]

Q. Vitesse remains concerned that some of the underlying data used to calculate the DA/RT adjustment is based on monthly transactional data at hubs that have very few transactions.[43] How do you respond to this concern?

A. As noted in reply testimony, Vitesse produced no evidence that hubs with relatively small trading volumes produce any inappropriate variance between: (1) the DA/RT price component's adders; and (2) the Company's actual buy and sell prices as compared to the unadjusted OFPC prices (which are derived from broker quotes and not calculated by the Company); and (3) because this variance is still present in actual

[41] Vitesse/200, Johnson/12.
[42] PAC/400, Mitchell/37.
[43] Vitesse/200, Johnson/13.

operations there is still a need for the DA/RT price component to correct for this $/MWh (price) inefficiency observed in actual operations. While it is true that some hubs will have greater historical volume from which to calculate the variance, there is no evidence showing that adders resulting from trading hubs with less volumes than other trading hubs are inaccurate. To the extent that Vitesse is proposing to exclude certain hubs from the DA/RT adjustment, it is incumbent on Vitesse to (1) identify the hubs it defines as "small," something Vitesse has not done; and (2) provide evidence that excluding those "small" hubs produce a more accurate NPC forecast. Vitesse has provided no evidence supporting either point and speculation is insufficient to support an adjustment.

Q. Vitesse is also concerned "that the adoption of the DA/RT percent price adder without the Company demonstrating its load forecasting [in actual operations] is reasonable skips over one of the very reasons the Company is seeking the adjustment: the contribution to increased NPC that is caused by forecast error."[44] How do you respond?

A. Vitesse's concern is not specific to the DA/RT price component. Rather, Vitesse's concern relates to nearly every single element of the NPC forecast because the Company's activities in actual operations that impact system balancing transactions involve: (1) forecasts of load; (2) forecasts of generation from wind, solar, hydro, geothermal resources; (3) expectations of coal fuel availability, gas fuel availability, transmission capacity availability, and generation plant availability; (4) hedging policies and counterparty credit worthiness; (5) compliance with reliability standards;

[44] Vitesse/200, Johnson/15.

(6) compliance with federal and state environmental requirements; and (7) a myriad of other factors that all contribute to the volume of balancing transactions *in actual operations* needed to serve real customer load. Given that the Company's actual operations involve a myriad of forecasts created on a daily basis that relate to nearly every single element of the NPC forecast, it is not appropriate to isolate a single line item like the Company's *actual operational* load forecast and its associated impact on an isolated component of the NPC forecast like the price component of the DA/RT adjustment.

C. Reply to AWEC

Q. AWEC argues that the correction to the DA/RT adjustment included in your reply testimony constituted an improper modeling change that is not allowed by the TAM Guidelines.[45] How do you respond?

A. As an initial matter, the Company disagrees with AWEC's claim that "PacifiCorp made a wholesale change to the DA/RT method, which it labels as a correction but which is actually a modeling change."[46] The DA/RT volume component was producing an erroneous result—in the Initial Filing there was a $97 million *credit* (revenue that lowers NPC) to customers in the DA/RT volume component. However, the DA/RT volume component adjusts system balancing transaction volumes to reflect the *inefficiencies* and associated *costs* incurred in actual operations. A calculation that is designed to simulate *costs* associated with real-world trading *inefficiencies* but produces substantial ($97 million) and unrealistic *revenue* is clearly

[45] AWEC/200, Mullins/10.
[46] AWEC/200, Mullins/10.

producing an erroneous result. A correction is a change made to fix an error and the Company's correction to the DA/RT volume component is therefore appropriate.

Q. Was the Company's correction consistent with the TAM Guidelines?

A. Yes. As AWEC's own testimony explains, the TAM Guidelines state: "The Company may make corrections to, or address omissions in, the components included in the Company's Initial Filing."[47] In this case, the Company made a correction to the DA/RT volume component of the Initial Filing so that the adjustment produces non-erroneous results. The fact that AWEC claims the correction involved a change to the model is inapposite because the entirety of the Company's NPC forecast is a model so almost any correction can be considered a change to the model relative to the Initial Filing.

Q. Is AWEC's opposition to the DA/RT adjustment consistent with its position regarding other changes included in the Reply Update?

A. No. The Company's Reply Update included a real modeling change to more accurately reflect "thermal generation marginal costs".[48] Notably, the thermal generation marginal cost modeling change **decreased** NPC by $75 million total-company, which exceeds the $60 million total-company NPC increase resulting from the correction to the DA/RT adjustment. If the DA/RT adjustment is prohibited by the TAM Guidelines, then so is the "thermal generation marginal cost" change and when both are removed the net impact is an increase in total-company NPC of $22 million, $6.2 million Oregon-allocated.

[47] *In the Matter of PacifiCorp, dba Pacific Power, 2009 Transition Adjustment Mechanism Schedule 200, Cost-Based Supply Service*, Docket No. UE 199, Order No. 09-274 at 4 (Jul. 16, 2009).
[48] PAC/400, Mitchell/12.

In addition to AWEC accepting modeling changes that decrease NPC, while opposing corrections that increase NPC, AWEC also recommended for the first time in its rebuttal testimony a modeling change to remove market caps from the Four Corners market.[49] AWEC's own modeling change decreases NPC and AWEC makes no mention of whether its change is permissible under the TAM Guidelines.

Q. AWEC claims that PacifiCorp updated the volume component as an "ad hoc modeling change" because the Company "did not like that the [volume component] was now reducing NPC[.]"[50] Is this a fair characterization of the correction?

A. No. As discussed above, the purpose of the volume component is to reflect inefficiencies that exist in actual operations but are not captured by Aurora. Inefficient operations cannot be expected to reduce *actual* NPC and the associated modeling of inefficient operations cannot be expected to reduce *forecast* NPC, which is why the correction was required as explained in detail in my reply testimony.

Q. AWEC claims that the Company's testimony describing the correction to the volume component of the DA/RT adjustment was "vague and unsupported."[51] Is that a fair characterization of your testimony?

A. No. As an initial matter, AWEC's reference to "vague and unsupported" testimony points to a short summary description of the correction found in the Reply Update section of my testimony. Elsewhere in my reply testimony, I provided a detailed explanation of why the correction was required, how it was performed,[52] and the

[49] AWEC/200, Mullins/20.
[50] AWEC/200, Mullins/28.
[51] AWEC/200, Mullins/11.
[52] PAC/400, Mitchell/47–50.

analytics were included in the workpapers provided to the parties with the reply testimony.

Q. AWEC questions whether the Company "fully understands the mechanics of the DA/RT adjustment, since the [volume component] was in no way related to arbitrage revenues."[53] Elsewhere in testimony AWEC reiterates its claim that "[t]here has never been any a discussion of arbitrage revenues included in the historical adjustment in the DA/RT adjustment."[54] Do you agree?

A. No and AWEC's testimony on this point is perplexing given the clear historical record of Commission orders in prior TAMs explaining that arbitrage revenues have always been included in the volume component of the DA/RT adjustment. Indeed, my reply testimony discussed the 2017 TAM, where Staff specifically criticized the DA/RT adjustment for purportedly excluding arbitrage transactions.[55] The Company's testimony in that case explained:

> **Q. Does the system balancing transaction adjustment include arbitrage transactions?**
>
> A. Yes. The Company purposefully included arbitrage transactions entered at the same time for the same volume and delivery point so that the benefits were included in the historical results. This reduces the cost of system balancing transactions and is realistic because it reflects the historical availability of such opportunities.[56]

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[53] AWEC/200, Mullins/11.
[54] AWEC/200, Mullins/29.
[55] PAC/400, Mitchell/32–33.
[56] *In the Matter of PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, PAC/400, Dickman/32 (Aug. 1, 2016).

In the Commission's order affirming the DA/RT adjustment, the Commission specifically rejected Staff's argument that the DA/RT adjustment improperly excluded arbitrage revenues.[57]

Then, in the 2018 TAM, Staff again claimed that the DA/RT adjustment improperly excluded arbitrage revenues[58] and the Commission once again affirmed the adjustment.

Q. How does the DA/RT adjustment account for arbitrage revenues?

A. Arbitrage revenue in the context of my testimonies is synonymous with the historical gain present in the four-year historical market transaction data that is a part of the volume component of the DA/RT adjustment. This historical gain is the combination of individual arbitrage transactions that create revenue (therefore appropriately called arbitrage revenue) and the historical revenue calculated when the Company buys below the OFPC and sells above the OFPC.

Q. AWEC claims that "arbitrage revenues have been removed from NPC for over ten years beginning in the 2013 TAM."[59] Is that accurate?

A. No. AWEC refers to a Commission order that removed a different arbitrage and trading revenue credit from the NPC forecast, which occurred three years before the Commission approved the DA/RT adjustment. The Company's NPC forecast does not include the arbitrage and trading revenue credit that was addressed in the 2013 TAM, but that does not mean that arbitrage revenues are not reflected in the

[57] *In the Matter of PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 13 (Dec. 20, 2016).
[58] *In the Matter of PacifiCorp, dba Pacific Power, 2018 Transition Adjustment Mechanism*, Docket No. UE 323, Staff/200, Kaufman/12 (Jun. 9, 2017).
[59] AWEC/200, Mullins/11.

DA/RT adjustment, which was approved in the 2016 TAM and has been used in every TAM since that time.

Q. AWEC continues to recommend "simplifying the DA/RT method" by using only the volume component, which AWEC claims will "still captur[e] 100% of the DA/RT adjustment."[60] Do you agree with AWEC's recommendation that the volume component alone "captures 100 percent of the DA/RT adjustment?"

A. No. By eliminating the price component, AWEC's recommendation fails to capture the modeling impact of the fact that the Company has historically sold at lower prices than the monthly average price and purchased at higher prices than the monthly average price. AWEC would retain the component of the DA/RT designed to address trading volume inefficiency but eliminate the component designed to address market price inefficiency. The DA/RT adjustment has always contained two critical components—which have been repeatedly affirmed by the Commission—and AWEC has presented no evidence in this case that eliminating either component will produce a more accurate forecast.

Moreover, AWEC claims that the volume component of the DA/RT adjustment cannot capture arbitrage revenue because it results in "offsetting volumes and their associated revenues are equal and offsetting."[61] But if this is true, then the volume component would have no impact on NPC because the volumes are equal and offsetting, and the costs and revenues are equal and offsetting. In reality, however, the historical costs of purchases exceed the historical revenue from sales, which is why the volume component increases NPC (unless it is erroneous, as it was before the

[60] AWEC/200, Mullins/25.
[61] AWEC/200, Mullins/29.

correction), and this increase to NPC is subject to an offset embedded in the historical data reflecting historical arbitrage revenues.

Q. AWEC claims that the price component skews the dispatch results in Aurora, which is producing levels of short-term purchase transactions that are inconsistent with historical levels.[62] Is that correct?

A. No. As an initial matter, AWEC's testimony fails to acknowledge the paradigm shift in 2024 that is limiting generation and that—all else equal—results in either increased purchased power or reduced wholesale sales.

Q. In its Confidential Figure 5, AWEC purports to show a comparison of Aurora model results and historical net short-term purchases to show the dramatic increase in 2024.[63] Do you agree with how AWEC presented its data?

A. No. AWEC presented **net** short-term purchases, which means that the underlying patterns in short-term purchases separate from the underlying patterns in short-term sales is not visible to the reader. Additionally, the historical data includes energy imbalance market (EIM) purchase and sales volumes even though Aurora's forecast does not include that data. This means that AWEC compared the NPC *forecast* volumes—**with no** EIM volumes—to historical NPC *actual* volumes—**with** EIM volumes.

The following Confidential Figure DART-1 and Confidential Figure DART-2 below: (1) separates purchases from sales to show patterns otherwise lost by offsetting (netting) the data before presenting it; (2) removes the EIM volumes from the historical data to allow an accurate and appropriate comparison to the NPC

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[62] AWEC/200, Mullins/30.
[63] AWEC/200, Mullins/30.

forecast (which has no EIM volumes); and (3) takes the first seven months of 2023 actual data and ratios it out to proxy for 2023.

[redacted]

[redacted]

In 2024, the NPC forecast in the Reply Update includes the impact of the OTR, the Jim Bridger gas conversion and associated outage, and the removal of the Klamath dams—all of which will increase the short-term purchases relative to the historical data up to the end of 2023, as shown in Confidential Figure DART-1.

Q. AWEC claims that the excessive levels of short-term purchases show that Aurora is "not optimizing short-term sales and purchase transactions at the same level as GRID and in a manner that is less efficient than experienced historically."[64] AWEC continues that this "is an indication that the DA/RT method, as PacifiCorp has implemented it, is not necessary for the AURORA model."[65] How do you respond?

A. Based on the breakdown and re-compilation of AWEC's incomplete analysis and the demonstration above of an accurate portrayal of realistic levels of short-term firm purchases in the NPC forecast, I do not find AWEC's argument on the reasonability of removing the DA/RT price component complete or valid. Furthermore, AWEC does not demonstrate an understanding of Aurora modeling. (I discuss this below starting in Section VI).

Q. AWEC compares historical market transaction dollars to the Aurora modeled market transaction dollars in this year's TAM (combined with the NPC impact of the DA/RT volume component correction) and concludes that the impact is significantly higher with Aurora.[66] Do you agree?

A. No. As an initial matter, AWEC is not comparing comparable data. I elaborate on this further below. However, in order to respond to AWEC's analysis, it is important to establish some simplified terminology for three different categories of costs related to the DA/RT volume component:

- *"Real World Transaction Loss"* refers to the total amount of **actual** historical

[64] AWEC/200, Mullins/30.
[65] AWEC/200, Mullins/30–31.
[66] AWEC/200, Mullins/31.

net cost incurred when day-ahead or real-time market transactions are executed at prices unfavorable to the OFPC[67]; or, the total amount of that net cost expected to be **actually** incurred in the test period. These costs include real-world inefficiencies associated with multi-hour block products, trading in 25 MW increments, and a lack of certainty regarding the future.

- *"Perfect Foresight Transaction Loss"* refers to the total amount of net cost incurred from **forecast** hourly **in-model** (Aurora) transactions that are executed at prices unfavorable to the OFPC.[68] These costs reflect no further price or volume inefficiencies, result from transactions executed to within a fraction of a MW, and result from Aurora's ability to know the future with certainty; and
- *"Adjustment to Get to Real-World Transaction Loss"* refers to the test period dollars that the DA/RT volume component adds to the *"Perfect Foresight Transaction Loss"*[69] to get to the expected *"Real-World Transaction Loss"* in order to account for real-world trading *inefficiencies* and real-world *lack* of perfect foresight[70] (example, trading in 25 MW increments, or trading in 16-hour block products and rebalancing in real-time, or not knowing the future).

Confidential Figure DART-3 below illustrates what the "***Adjustment** to Get to Real-World Transaction Loss*" would have been if the *"Real World Transaction Loss"* were known with certainty during the preparation of the TAM NPC forecast. Please note that for calendar years 2023 and 2024 I have proxied for the *"Real World*

[67] Transactions that are favorable to the OFPC are present as well but, the net is unfavorable.
[68] This is the use of the DA/RT price component which is only ever applied to the perfect in-model transactions.
[69] As discussed above and in reply testimony, the *"Adjustment to Get to Real-World Transaction Loss"* are expected and designed to be costs because they reflect the inefficiencies associated with actual operations, and the only component of revenue embedded into them are arbitrage revenues, which were $9.3 million in 2022.
[70] These dollars are not captured by the DA/RT price component which only impacts the perfect foresight / perfectly efficient hourly transactions that come out of Aurora's modeling.

Transaction Loss" based on extrapolation of historical transactions. Confidential Figure DART-3 below has two columns stacked on top of each other, *"Perfect Foresight Transaction Loss"* and *"**Adjustment** to Get to Real-World Transaction Loss."* The sum of these two stacked columns is the *"Real World Transaction Loss."*

That is to say, Confidential Figure DART-3 shows: (1) what the costs of the real-world trading inefficiencies (DA/RT volume component) **should have been** for the 2016 TAM to the 2022 TAM; and (2) what the costs might be for the 2023 TAM and 2024 TAM, based on extrapolation. These costs—as mentioned above—are labeled *"Adjustment to Get to Real-World Transaction Loss."*

[redacted]

[redacted]

However, because the to-be-incurred *"Real World Transaction Loss"* is not known beforehand (*e.g.*, not known for 2024 during the filing of this TAM) Confidential Figure DART-4 below illustrates what the *"**Adjustment** to Get to Real-World Transaction Loss"* was forecast to be for each TAM since 2016, inclusive of this docket which corrected an error. Note that for 2023 and 2024 I have defined

"Adjustment to Get to Real-World Transaction Loss" as *"Artificial Arbitrage Revenue"* so as to draw attention to them in a different color and to define the term for later use.

That is to say, Confidential Figure DART-4 shows what the costs of the real-world trading inefficiencies (DA/RT volume component) were **forecast to be** for the 2016 TAM to the 2024 TAM. These costs—as mentioned above—are labeled either *"Adjustment to Get to Real-World Transaction Loss"* or *"Artificial Arbitrage Revenue"*.

Please note that the *"Adjustment to Get to Real-World Transaction Loss"* value in the "Corrected 2024" column in Confidential Figure DART-4 is enlarged so that it is visible to the reader. The actual value is $333,350.

[redacted]

[redacted]

As explained above and in my reply testimony, the DA/RT volume component dollars (*"Adjustment to Get to Real-World Transaction Loss"*) are designed to capture *inefficiencies* and attendant *costs* in actual operations that are not captured in Aurora, and real-world *inefficiencies* in trading cannot produce such substantial *revenue* (*"Artificial Arbitrage Revenue")* when compared to Aurora's perfect foresight / perfectly efficient optimized system dispatch.[71] The illustrations above demonstrate: (1) what the DA/RT volume component is designed to do; (2) what the DA/RT volume component actually did; and (3) the clearly erroneous result (*"Artificial Arbitrage Revenue"*) in the Initial Filing of the 2024 TAM.

Effectively, by decreasing NPC through the DA/RT volume component's dollars, "*Artificial Arbitrage Revenue"* is suggesting that Aurora is not optimal enough in its execution of market sales and purchases and so the costs that come out of the model should be reduced or the revenues should be increased. Aurora, however, is a state-of-the-art optimization software used across the industry and the 2023 TAM NPC forecast is already over-optimized and under-forecast relative to the actuals as I demonstrated in my reply testimony. To accept the DA/RT volume component without application of the Company's correction is to suggest that the NPC forecast should be over-over-optimized. This is why there was a clear error in the DA/RT volume component that has been corrected.

Q. Turning to AWEC's Confidential Figure 6,[72] please explain why AWEC's analysis misses the mark.

A. AWEC's Confidential Figure 6 displays *"Real World Transaction Loss"* from 2017

[71] See PAC/400, Mitchell/47.
[72] AWEC/200, Mullins/31.

to 2022. Then, in 2024, AWEC displays the **sum** of *"Perfect Foresight Transaction Loss"* and the NPC impact from the Reply Update that represents the *"Artificial Arbitrage Revenue."* In this way, AWEC's figure displays three separate pieces of data that are not the same things.

That is to say, AWEC's Confidential Figure 6 displays **total actual** historical net cost incurred when day-ahead or real-time market transactions are executed at prices unfavorable to the OFPC—along with all the real-world attendant inefficiencies, and then compares that to the sum of two things: (1) the total net cost incurred from forecast hourly **in-model** transactions that are executed at prices unfavorable to the OFPC but, result from perfect foresight and otherwise perfect efficiency; and (2) artificial arbitrage revenue which is a negative value but, AWEC opportunistically shows it as a positive value.

Q. Have you corrected AWEC's Confidential Figure 6 to display appropriately matched data?

A. Yes. As mentioned above, AWEC's Confidential Figure 6 is misleading in comparing: (1) the sum of *"Perfect Foresight Transaction Loss"* and the inverse of *"Artificial Arbitrage Revenue"*; with (2) *"Real World Transaction Loss."* That comparison is inapt, however, so Confidential Figure DART-5 below displays *"Real World Transaction Loss"* from 2017 to 2022 and then proxies 2023 to 2024 based on extrapolation.

[redacted]

Confidential Figure DART-6 below displays *"Perfect Foresight Transaction Loss"* and is the item that AWEC labels as "Impact of the Price Adjustment in Aurora" in their Confidential Figure 6.

[redacted]

Lastly, the *"Artificial Arbitrage Revenue"* is the thing that was corrected in the DA/RT volume component and doesn't appropriately belong in AWEC's Confidential Figure 6 at all. However, for the sake of consistency I replicate it in its appropriately isolated context below in Confidential Figure DART-7. Now the data is in the appropriate figures and given the appropriate signage.

[redacted]

[redacted]

These three figures above appropriately provide definition, context and correction of AWEC's Confidential Figure 6 and it is disingenuous and confuses the reader to combine all three charts into one. With the above as context, AWEC's corresponding analysis that the "DA/RT method modeling change presented in the July Update, [] increases the cost to $182,693,332" is first, false; second, mischaracterizing the correction as a modeling change; and third opportunistic and one-sided in seeking benefits without recognizing costs by outright ignoring the Company's change to the modeling of thermal generation marginal costs which decrease NPC by $75 million and **is** a modeling change. AWEC's remaining analysis on the DA/RT and arguments as to why the DA/RT price component is unnecessary is invalidated by their false analysis, repeated from their prior testimony and rebutted further above.

V. MARKET CAPACITY LIMITS

A. Reply to Staff

Q. Does Staff continue to recommend use of the third quartile of averages method for calculating market caps?

A. Yes. However, Staff acknowledges that the third quartile of averages methodology will over-forecast off-system sales and thereby create a less accurate NPC forecast.[73]

Q. Why does Staff support a methodology it concedes creates a less accurate forecast?

A. Staff claims that the inaccuracy in the third quartile of averages methodology captures "benefits" that are not captured by the DA/RT adjustment and the determination of EIM benefits.[74]

Q. Is Staff's position here consistent with its prior testimony?

A. No. When testifying on market caps in the 2021 TAM, docket UE 390, Staff witness Dlouhy argued that "Even if the Company's model is not properly forecasting its off-system sales, I believe that the best solution is to make the model more realistic instead of imposing increasingly fallacious assumptions to counter other model shortcomings."[75] Here, he acknowledges that Aurora is over-forecasting off-system sales but then recommends an "increasingly fallacious assumption," i.e., the third quartile of averages methodology, specifically to counter what he believes are "other

[73] Staff/900, Dlouhy/4.
[74] Staff/900, Dlouhy/5.
[75] *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism,* Docket No. UE 390, Staff/800, Dlouhy/30 (Jun. 9, 2021).

model shortcomings." As Staff argued in the 2022 TAM, this "type of results-oriented approach to TAM-modeling should be rejected."[76]

Q. Is there any validity to Staff's recommendation that the Commission should approve an intentionally inaccurate market cap methodology to offset the so-called "artificial losses" Staff claims are embedded in the DA/RT adjustment?

A. No. Staff did not provide any evidence responding to the Company's explanation that the so-called artificial losses in the DA/RT adjustment's price component are accounted for by the arbitrage revenues included in the DA/RT adjustment's volume component. So, there are no DA/RT costs that can be offset by Staff's intentionally inaccurate market caps. As noted in reply testimony, the Commission already addressed Staff's artificial loss issue and rejected Staff's position; Staff has presented no evidence in this case that justifies a different outcome.

Q. Is there any validity to Staff's claim that the forecast EIM benefits are understated and should therefore be offset by intentionally inaccurate market caps?

A. No. Staff compared the Company's EIM benefits forecast to that prepared by the California Independent System Operator (CAISO) and concluded that because the CAISO's benefit calculation was higher than the Company's, there are EIM benefits that could be imputed into the TAM forecast via the use of inaccurate market caps.[77] As an initial matter, even if the EIM benefits are understated, Staff provided zero analysis showing that the over-forecast of NPC created by inaccurate market caps is

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[76] *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism,* Docket No. UE 390, Staff Reply Brief at 7 (Sept. 28, 2021).
[77] Staff/900, Dlouhy/6.

equal to their purported under-forecast of EIM benefits. More importantly, however, Staff's comparison to the CAISO benefits calculation is misplaced because the CAISO uses a different and non-comparable methodology to calculate EIM benefits.

Q. Has the Commission previously addressed the imputation of CAISO's EIM benefits into the TAM?

A. Yes. In the 2017 TAM, Staff and the Oregon Citizens' Utility Board recommended that the TAM include CAISO's benefits calculation rather than the Company's. The Commission rejected that recommendation after concluding that the CAISO calculation was improper to include in the TAM because CAISO included EIM benefits that were already embedded in the Company's NPC forecast.[78] In other words, Staff's conclusion that CAISO calculates higher benefits is not surprising and consistent with the Commission's prior finding. But that conclusion does not mean that the Company's forecast EIM benefits are too low and need to be offset by intentionally inaccurate market caps.

Q. How has the Company's forecast EIM benefits compared to actual EIM benefits?

A. The Company's forecast of 2022 actual EIM benefits was [redacted], and Staff used the Company's model to backcast [redacted] of EIM benefits—meaning that the backcast was within one percent of the actuals.[79]

Furthermore, Staff's comparison of pre-2022 EIM benefit forecasts is inapt because the methodology used to forecast current EIM benefits incorporates recent

[78] *In the Matter of PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. 307, Order No. 16-482 at 16-17 (Dec. 20, 2016).
[79] Staff/900, Dlouhy/7.

shifts in power and gas markets observed in 2022 such that Staff's comparison of pre-2022 EIM benefits suffers from look-ahead bias. Look-ahead bias occurs by using information not available or known in the backcast period and can lead to inaccurate results. Since Staff used the Company's current EIM benefits model which includes those step changes in power and gas market prices in 2022 and: (1) thereby used 2022 information which was not known prior to 2022; (2) to backcast years prior to 2022; then (3) the backcast results for years prior to 2022 are not well comparable to the pre-2022 actuals (which did not—by definition—incorporate events known in 2022).

In this context, the results of the 2022 forecast noted above demonstrate that the current version of the EIM benefits forecast model is doing well to forecast recent events, and without Staff removing look-ahead bias from its backcast, there are no legitimate grounds to claim either an under or over forecast. Again, this means that Staff's proposal to use inaccurate market caps to offset some undefined and unsupported EIM benefits variance has no support in the record.

Additionally, preliminary calculations show that for the first eight months of 2023 (January – August) the actual EIM benefits are approximately [redacted] while the forecast EIM benefits from the 2023 TAM, for the same period, are approximately [redacted]. Again, this means that Staff's proposal to use inaccurate market caps to offset some undefined and unsupported EIM benefits variance—which shows an *opposite* direction of magnitude to Staff's observation using recent 2023 history—has no support in the record.

Q. Staff argues that the EIM "eat[s] away at the sales that would have otherwise happened in a bilateral market" and therefore "it should be expected that off-system sales are lower in practice than what the model forecasts."[80] Does this testimony support the use of the average of averages methodology?

A. Yes. Staff agrees that Aurora does not model EIM sales volumes and therefore either the bilateral market sales volumes must be reduced via lower market caps or the EIM benefits need to be reduced to lower the implied EIM sales volumes if the model is allowed to continue to over-forecast bilateral market sales volumes.

Q. Staff disputes the Company's testimony that the average of averages methodology is reasonable given the [redacted][81] How do you respond?

A. Staff does not dispute the Company's evidence that trading volumes at Mid-C have been declining for the past five years. But Staff argues that its third quartile of averages methodology reflects this decline.[82] On the contrary, if trading volumes are declining year-over-year, even using a historical average of averages methodology will overstate future volumes because those future volumes will be lower than the historical average. Indeed, this is likely why Staff concedes that its third quartile of averages recommendation over-forecasts off-system sales.

[80] Staff/900, Dlouhy/9.
[81] Staff/900, Dlouhy/3–4.
[82] Staff/900, Dlouhy/4.

Q. Staff points to the data contained on Confidential Table 5[83] of your reply testimony to show that the third quartile of averages methodology forecasts a [redacted].[84] How do you respond?

A. Staff's observation misses the mark because the relevant comparator is forecast market sales to actual market sales, not forecast market sales to forecast market sales. The forecast market sales forecast for 2024 shown in Confidential Table 5 are lower because of limited generation availability due to new operating and policy conditions such as coal supply limitations, the OTR, the Jim Bridger gas conversion, the removal of the Klamath dams, and the Washington Cap and Invest Program. As I demonstrate below in Section V(B), when using a "business-as-usual" case to unwind the impacts of these new operating and policy conditions the third quartile of averages methodology is not such a "sharp decline" anymore.

B. Reply to AWEC

Q. AWEC disputes the Company's statement that without market caps Aurora could make "unlimited off-system sales at every market at any time of the day or night—an assumption that is very different from PacifiCorp's actual, historical experience."[85] AWEC then argues that this is incorrect and therefore the Company's views on market caps should be given little weight.[86] Do you agree?

A. AWEC is arguing over semantics and should be ignored. It is an indisputable fact that there is no such thing as unlimited energy in this industry, whether in the form of electricity or computational power. Therefore, there is no possibility for "unlimited"

[83] PAC/400, Mitchell/55.
[84] Staff/900, Dlouhy/4.
[85] PAC/400, Mitchell/50.
[86] AWEC/200, Mullins/16–17.

sales, whether in modeling or in actual operations. AWEC's argument fundamentally boils down to two points. The first point is that the Company claims unlimited energy exists. The second point is that since there is no such thing as unlimited energy, the Company's views on market caps should be given little weight.

Either the reader assumes that the Company believes unlimited energy exists or the reader appropriately interprets the Company's use of the word "unlimited" to mean "unrealistic".

Q. AWEC claims that the Company did not address its recommendation that market caps not apply to the Mid-C and Palo Verde markets because those are liquid hubs.[87] Is that true?

A. No. The Company's reply testimony specifically responded to AWEC's testimony and explained that market caps are necessary at all market hubs because the hubs like Mid-C and Palo Verde that were previously described as liquid hubs are no longer so.[88]

Q. Did AWEC respond to your testimony showing that neither Mid-C nor Palo Verde are liquid hubs because of the decreasing volume of transactions at those hubs and the corresponding increase in energy shortfalls across the region?[89]

A. No. AWEC points to the Company's prior statements that historically Mid-C and Palo Verde were liquid hubs and then concludes that those hubs remain liquid notwithstanding the unrebutted Company testimony showing changed market conditions at those hubs.

[87] AWEC/200, Mullins/17.
[88] PAC/400, Mitchell/74.
[89] PAC/400, Mitchell/74.

Q. Is this the first TAM where the Company modeled market caps at Mid-C and Palo Verde?

A. No. In the 2022 TAM, when the Commission approved the use of the third quartile of averages methodology, the Company's November indicative filing included market caps at Mid-C and Palo Verde. Exhibit B to the Company's November 8, 2021, filing in that case explained the update:

> This update applies the Commission-approved market cap methodology to all market hubs at which PacifiCorp transacts, including Mid-Columbia and Palo Verde. Recent market volatility and current market prices indicate limited market depth at these markets. Energy market prices have more than doubled since the July update, reflecting industry-wide supply constraints. Consistent with PacifiCorp's original application of market caps to all six market hubs based on liquidity issues, market caps are again required system-wide to avoid unreasonable sales volumes and coal generation. This update increases NPC by approximately $8.6 million on a total company basis.[90]

The Commission approved the Company's forecast NPC including the use of market caps at all market hubs. Thereafter, the Company applied market caps to all hubs in the 2023 TAM and carried forward that modeling here.

Notably, the 2022 TAM—which included market caps at Mid-C and Palo Verde—still included a significant over-forecast of market sales volumes and corresponding under-forecast of NPC. Had the Company excluded market caps at those hubs, the under-forecast of 2022 NPC, which is currently an issue in the 2022 power cost adjustment mechanism (PCAM) would have been worse.

[90] *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism,* Docket No. UE 390, Net Power Cost Indicative Update for 2022, Ex. B (Nov. 8, 2021).

Q. AWEC now recommends removing market caps from the Four Corners market because AWEC claims it is now a liquid market.[91] Do you agree?

A. No. AWEC claims that Four Corners is a liquid hub that does not require market caps based solely on the fact that the Company made [redacted].[92] This analysis is overly simplistic and does not demonstrate that Four Corners no longer requires market caps.

Q. AWEC relies on data presented in its Confidential Table 2 to claim that market caps result in "only a fraction of the sales relative to the 2022 levels are being made."[93] Is this true?

A. No. AWEC's Confidential Table 2 ignores the transaction volumes in the DA/RT volume component, which are a proxy for the additional volumes in the NPC forecast that would result if Aurora did not optimize using a single step, or, put another way, the DA/RT volume component reflects the reality that the Company balances its system over multiple time horizons and purchases and sells using multi-hour block products of energy in 25 megawatt (MW) increments. The additional sales volumes calculated by the DA/RT adjustment in conjunction with the Aurora modeled sales volumes combine to produce an outcome that together represents a more reasonable expectation of volumes to be incurred in the test period. These are the volumes that are reflected in Confidential Table 5 of my reply testimony[94] and reflect the same data the Commission relied on in the 2022 TAM.[95]

[91] AWEC/200, Mullins/18.
[92] AWEC/200, Mullins/19.
[93] AWEC/200, Mullins/20.
[94] PAC/400, Mitchell/55.
[95] *See In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism,* Docket No. UE 390, Order No. 21-379 at 28 (Nov. 1, 2021).

In AWEC's Confidential Table 2, AWEC removed the DA/RT volumes in the row titled "AURORA – July Update % of 2022." Therefore, AWEC inappropriately compares actual historical sales from 2022—which include system balancing sales resulting from the purchase and sale of multi-hour block transactions—to Aurora in-model volumes for 2024—which do not include system balancing sales resulting from the purchase and sale of multi-hour block transactions. AWEC's table therefore says nothing about the need for market caps at any particular hub. Rather, AWEC's table demonstrates why the DA/RT adjustment is necessary to ensure that the NPC forecast includes the costs of system balancing transactions that are not captured by the single step optimization used by Aurora.

Q. When the evidence AWEC presented in its Confidential Table 2 is corrected and updated, does it demonstrate the changing market conditions that justified the application of market caps to all hubs in the 2021 TAM?

A. Yes. Confidential Table CAPS-1 below updates the information in AWEC's Confidential Table 2 to include DA/RT volumes and includes 2021 data which were the conditions present at the time of the Company's prior statements that Mid-C and Palo Verde *were* liquid hubs.

[redacted]

[redacted]

The top section of the table shows actual market sales for the 12 months ending June 2021. This is the data that the Company knew in the 2022 TAM when it applied market caps to all hubs. The bottom section of the table shows the more recent actual market sales for the 12 months ending June 2023.

The change in sales volumes illustrated in the table demonstrates why it is still necessary to apply market caps to all hubs. From 12 months ending June 2021 to 12 months ending June 2023 total market sales decreased by 62 percent. Removing market caps implies that there is unlimited[96] market depth, which the historical evidence does not show. (1) Indeed, AWEC acknowledges the Company no longer has firm transmission access to the Palo Verde market; and (2) furthermore, the NPC forecast shows sales at Four Corners and Mid-C that are at or in excess of the recent history. There is no support for AWEC's argument that the Company should allow the NPC forecast to execute more sales at these trading hubs in light of the overwhelming evidence of declining trading volumes presented in my reply testimony and tabulated here, and in light of the lost, long-term firm transmission access to the Palo Verde market.

Q. AWEC claims that using the average of averages methodology to set market caps results in Aurora modeling sales that are far below 2022 actuals.[97] Is this claim correct?

A. No. AWEC's conclusion is based on the flawed data presented in its Confidential Table 2. When that data is corrected, as set forth above, the results show that Aurora forecasts 143 percent of the actual sales in the 12 months ending June 2023.

[96] Please reference my comments above regarding the usage of the world "unlimited."
[97] AWEC/200, Mullins/21.

Q. AWEC also criticizes the average of averages methodology because it only uses four data points to calculate the caps.[98] Is this a valid criticism?

A. No. AWEC's testimony is misleading—each of the "four data points" referenced by AWEC is calculated using 12 months of historical transactional data. In other words, there are up to 8,760 hours of actual energy interchange underlying the data used to calculate the average of averages market caps.

Q. AWEC's recommendation to increase market caps also produced an increase in the NPC forecast, which AWEC claims is a "further indication that the Aurora model optimization is producing unintended results."[99] Is AWEC correct?

A. No. I have examined AWEC's Aurora project and re-ran the model using the higher market caps based on the third quartile of averages methodology. My results show that increasing the market caps using the third quartile of averages method results in a decrease to NPC, contrary to AWEC's assertion.[100] It is unclear how AWEC is performing its Aurora modeling but there seems to be rather serious issues given the multiple inconsistencies with AWEC's Aurora modeling, usage and understanding which I elaborate on in multiple sections below.

Q. AWEC produced evidence in its Confidential Figure 4 purporting to show that the third quartile of averages methodology produces a more accurate level of off-system sales in Aurora when compared to historical sales levels.[101] Is AWEC's analysis valid?

A. No. AWEC presents data in Confidential Figure 4 that it claims demonstrates that

[98] AWEC/200, Mullins/21.
[99] AWEC/200, Mullins/21–22.
[100] AWEC/200, Mullins/21.
[101] AWEC/200, Mullins/22.

using the third quartile of averages methodology produces forecast sales volumes in Aurora that are closer to the historical level of sales made over the five-year period of 2018 through 2022. AWEC's analysis, however, relies on mismatched data that produces inapt comparisons.

Q. What is the first flaw in AWEC's analysis?

A. Like the data presented in its Confidential Table 2, discussed above, the left-hand figure in Confidential Figure 4 *purports* to exclude DA/RT volumes from the forecast results and then compares the *purported* Aurora volumes without DA/RT volumes to the actual historical volumes with DA/RT volumes. For the reasons discussed above, this comparison is invalid.

Q. Does AWEC attempt to justify its exclusion of DA/RT volumes?

A. Yes. AWEC implies in its testimony that the DA/RT volumes are all bookouts.[102] AWEC reasons that because the actual historical sales volumes do not include bookouts then it is appropriate to exclude the DA/RT volumes from the forecast that AWEC then compares to historical actual volumes. In other words, AWEC's entire analysis hinges on its claim that the DA/RT volumes are all bookouts.

Q. Has the Commission addressed bookouts and the DA/RT volumes?

A. Yes. In the 2022 TAM when parties litigated market caps, the Company presented evidence identical to the evidence presented in Confidential Figure 5 of my reply testimony, *i.e.*, the data that compared forecast sales (including DA/RT volumes) to actual sales (excluding bookouts). Like here, in the 2022 TAM, AWEC witness

[102] A "bookout" here refers to the closing of an open position prior to maturity. Bookouts are available when the Company holds offsetting positions (purchase and sale) for the same delivery point, in the same hour, with the same counterparty.

Mullins presented data that included bookouts in the actual data and DA/RT volumes in the forecast data.[103] In response, the Company provided the same explanation as here that it is inapt to essentially equate all DA/RT volumes with bookouts. In Order No. 21-379, the Commission noted AWEC's argument around bookouts, and then relied on the Company's data when it concluded that the "data alone also supports PacifiCorp argument that from a rate-setting perspective, the average of averages is reasonable as it most closely approximates the historical average over the last four years."[104]

Q. Why is it incorrect to claim that the DA/RT volumes are all bookouts, as AWEC claims here?

A. System balancing transaction volumes must reflect the inefficiencies and associated costs of the operational practice of transacting on a monthly basis using, as an example, standard 25 MW increment, 16-hour block products, rebalancing on a daily basis using standard 25 MW increment eight-hour block products, and finally closing the remaining position on an hourly basis in real-time markets. The DA/RT adjustment of system balancing transaction volumes imputes what the volumes in the NPC forecast would be if the forecast was not perfectly optimized in a single step and instead optimized over multiple time horizons using the purchase and sale of multi-hour block products of energy in increments of 25 MW. Bookouts, on the other hand, are available when the Company holds offsetting positions (purchase and sale) for the same delivery point, in the same hour, with the same counterparty. (1) Aurora

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[103] *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism,* Docket No. UE 390, AWEC/100, Mullins/12–13 (Jun. 9, 2021).
[104] *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism,* Docket No. UE 390, Order No. 21-379 at 27–28 (Nov. 1, 2021).

does not model bookouts within the model and so there are no bookouts in the Aurora results; (2) the DA/RT volumes (MWh) are extrapolated solely from those Aurora results and does not contemplate counterparties; and (3) the Company's actual PCAM data, which formed the basis of my Confidential Table 5 and was relied on by the Commission in Order No. 21-379, also excludes bookouts.

Moreover, AWEC's own Confidential Figure 4 displays two figures, and the figure on the right clearly shows that bookouts are only a fraction of the total historical sales volumes and the figure shows that bookouts are decreasing over time, similar to overall off-system sales volumes and the resulting market caps. This result is not surprising—with less market sales volumes there are less sales to bookout.

Q. If the Company were to account for bookouts, as the righthand figure in AWEC's Confidential Figure 4 purports to do, what does the data show?

A. Using AWEC's workpapers, I created a business-as-usual NPC scenario to appropriately compare 2024 sales volume to historical sales volumes, extrapolated the yearly ratio of "sales volumes with bookouts" to "sales volumes without bookouts" and then applied that ratio to the DA/RT volumes derived from using the third quartile of averages methodology. The results show that after adjusting for bookouts, the NPC forecast produced [redacted] of sales volume, which is above the 2018, 2019, 2021 and 2022 sales volumes[105] and well above the [redacted] evidenced in my reply testimony. I have ignored AWEC's concept of "liquid" market hubs in my analysis because the Company has determined that its

[105] See PAC/400, Mitchell/55, Confidential Table 5.

market hubs are no longer liquid. These findings again show that the third quartile of averages produces an overestimation of market sales.

Q. Are there any other problems with the data presented in AWEC's Confidential Figure 4?

A. Yes. First, all the columns in the righthand figure purport to have either bookouts or the DA/RT volumes included—except for the AWEC column, which has neither. AWEC's analysis therefore does not provide a meaningful comparison.

Second, both figures show that the "PAC" column of sales is [redacted], while the "AWEC" column is [redacted] consistent with the narrative description in AWEC's testimony.[106] However, upon examination of AWEC's workpapers, it appears that those two values ([redacted] and [redacted]) are not the result of AWEC removing the DA/RT volumes and simply reporting the sales volumes modeled in Aurora. Rather, those two values are the DA/RT sales volume themselves,[107] which AWEC claims to have removed from its study.[108] This means that the sales levels displayed in both figures in Confidential Figure 4 have the same error, and in their context have no meaning.

Third, in the righthand figure AWEC calculates *historical* sales volumes as the sum of short-term sales and long-term sales. However, for the "PAC" column, AWEC calculates the *forecast* sales volume as **only** the short-term sales, excluding long term sales of [redacted].

[106] AWEC/200, Mullins/23.
[107] "(C) Mullins Actual NPC Figures CONF.xlsx", tab "Conf Figure BGM-7", cell "P33" which links to "(C) 04_OR UE-420 ORTAM24_MktCap 75P.xlsm"
[108] AWEC/200, Mullins/24.

Given that AWEC's Confidential Figure 4 contains both conceptual errors and mathematical errors, it provides no support for AWEC's recommended market caps.

Q. Can you correct the errors in AWEC's Confidential Figure 4 to allow for a meaningful comparison of historical and forecast off-system sales?

A. Yes. First, I corrected AWEC's erroneous reporting which showed forecast sales without the DA/RT volumes being equal to the DA/RT volumes themselves.

Second, I have corrected AWEC's error on the exclusion of long-term sales volumes.

Third, I reflected a declining trend in bookouts, consistent with the general declining trend in market volumes.

Fourth, I removed the "AWEC" column given that its results were flawed, for the reasons discussed above.

Fifth, I excluded the year 2018 from the analysis because the market caps rely on four years of historical data, not five.

Sixth, my analysis was based on a business-as-usual scenario which excludes the myriad of operational changes included in the 2024 NPC forecast that are not present in the historical data, such as coal supply limitations, the OTR, the Jim Bridger gas conversion and associated outage, the removal of the Klamath dams, and the Washington Cap and Invest Program.

Seventh, for illustrative purposes, I visualized a proxy of 2023 sales volumes by using the first seven months of actual 2023 sales volumes and ratioing them out to twelve months. This proxy is not a business-as-usual case and I use it below only to support the use of the average of averages method.

Eight, I have now corrected and re-visualized AWEC's proposed third quartile of averages approach to again demonstrate its unreasonableness. The visualization below in Confidential Figure CAPS-2 is that corrected and updated version of AWEC's erroneous analysis. The righthand chart is still in error regarding bookouts.

[redacted]

[redacted]

Q. Why are the 2023 volumes so low compared to prior years?

A. Of the myriad of restrictions on generation availability in the 2024 TAM NPC forecast, coal supply limitations, and the Washington Cap and Invest Program are present for the entirety of 2023 as well. The Company's coal supply limitations in particular have cut down on coal generation and by consequence diminished the Company's ability to make off-system sales after serving native load. This emphasizes the crucial need for a market caps methodology, which will produce reasonable results in 2024, and not exacerbate the inaccuracy in the NPC forecast.

Q. How is it that the left-hand chart which AWEC views to be more accurate, in Confidential Figure CAPS-2, shows sales volumes in 2024 that exceed all the years that are used to set the market caps?

A. The market capacity limits are calculated **before excluding bookouts** from the sales volumes and therefore the total sales volume in each year used to calculate the market caps is higher than the actual total sales volume in each year. This is why using the average of averages method to set a maximum level of sales will **not** by definition "result in a level of sales that is less than the historical average".[109]

Q. Have you also prepared a correction of AWEC's analysis that includes the impact of the operational changes present in 2024?

A. Yes. For comparison purposes, I have corrected AWEC's Confidential Figure 4, updated it with an extrapolation of a declining trend of bookouts, updated it with the proxy of 2023 data and present it below. This Confidential Table CAPS-3 below includes the operational changes that will impact 2024 in the "PAC" column and is therefore simply a correction and update to AWEC's Confidential Figure 4 (again removing the 2018 column, which is not used to calculate market caps) and the chart on the left (which uses the method that AWEC prefers) still shows that the 2024 sales volume is above the 2021 sales volume, above the 2022 sales volume, above the 2023 extrapolated sales volumes, and well above the [redacted]. The righthand chart is still in error regarding bookouts.

[109] AWEC/200, Mullins/21.

[redacted]

Q. AWEC also questions the treatment of bookouts and the DA/RT volume component when comparing forecast to historical off-system sales.[110] In particular, AWEC claims that the Company's comparisons exclude bookouts, but include the DA/RT volumes in the Aurora forecast that the Company then compared to historical actual sales.[111] How do you respond to this issue?

A. PacifiCorp's position here is consistent with its prior positions—the TAM modeling does not account for bookouts as all the DA/RT volumes like AWEC implies and therefore comparing the total level of sales in the TAM forecast to actual results including bookouts is a mismatch. Consistent with the data in the PCAM and relied on by the Commission in the 2022 TAM, the Company removed bookouts from the historical data that is compared to the TAM forecast. Similarly, consistent with the 2022 TAM, the Company included the DA/RT adjustment volumes in the NPC forecast because the historical data includes the additional volumes resulting from the

[110] AWEC/200, Mullins/23–24.
[111] AWEC/200, Mullins/24.

use of block products and different time horizons and therefore the NPC forecast compared to that historical data should include the same volumes.

VI. OTR

Q. Has the Company's recommendation for the OTR changed as a result of a recent court order?

A. Yes. It is my understanding that on July 27, 2023, the Tenth Circuit Court of Appeals issued an order that stays the enforcement of the OTR in Utah pending the outcome of the ongoing litigation. Based on that order and the continuing uncertainty around Wyoming, the Company will remove the OTR from the NPC forecast for both Utah and Wyoming in the November indicative and final filings. In the event that the OTR becomes enforceable in either Utah or Wyoming in 2024, the Company intends to file a separate deferral, consistent with the approach taken in the settlement of the 2023 TAM. The NPC impact of removing the OTR is a reduction of $19 million total-company, $5.5 million, Oregon-allocated.

Q. Notwithstanding the Company's decision to not include the OTR in the indicative NPC updates, do you have any response to AWEC's OTR testimony?

A. Yes. AWEC continues to claim that the Company modeled the impact of the OTR annually even though it applies to only May through September.[112] This is untrue and is but one example of the rather serious issues surrounding the multiple inconsistencies with AWEC's Aurora modeling, usage and understanding that I referenced in Section V(B) above.

[112] AWEC/200, Mullins/33.

Q. Please explain.

A. The below Figure OTR-1 is taken from the Company's Aurora project.

Figure OTR-1

Set ID	Constraint Type	Item ID	Limit	Limit Units	Emission Pricing	Limit Type	Limit Definition
PacifiCorp _Emit_100	Emission	NOX	yr_PacifiCorp _Limit_100	Ton	sc_PacifiCorp _Emit_	Year	mn_OTR
Utah _Emit_100	Emission	NOX	yr_Utah _Limit_100	Ton	sc_Utah _Emit_100_	Year	mn_OTR
Utah _Emit_121	Emission	NOX	yr_Utah _Limit_121	Ton	sc_Utah _Emit_121_	Year	mn_OTR
Wyoming _Emit_121	Emission	NOX	yr_Wyoming _Limit_121	Ton	sc_Wyoming _Emit_	Year	mn_OTR

This section of the project is that part which governs the imposition of the OTR on the NPC forecast. AWEC is confused on the entry in the column titled "Limit Type" which reads "Year" and perhaps confused on the entry in the column titled "Limit" which contains entries that begin with "yr". However, refer to the highlighted column titled "Limit Definition". It specifies a set of time intervals smaller than the period declared in the "Limit Type" column. For example, this column can constrain resource dispatch for only a subset of the months of each year when the "Limit Type"=Year. This restriction is controlled by entering a reference to a monthly time series ("mn_") with values of 1 for the effective months and 0 (zero) for other months. Accordingly, the entry in the "Limit Definition" table instructs Aurora as to which months of the year the OTR should be applicable to. The below Figure OTR-2 is the definition provided to Aurora for that "mn_OTR" entry in the "Limit Definition" table.

Figure OTR-2

OTR

	ID	Use	1	2	3	4	5	6	7	8	9	10	11	12
1	OTR	OTR Seasons	0	0	0	0	1	1	1	1	1	0	0	0

In the column header of the above figure, the numbers 1 through 12 correspond to the 12 months in a year. It is evident that the OTR season is activated by an entry of "1" during the months of May to September and deactivated with an entry of "0" during the other months of the year. Furthermore, the Aurora software contains a "Help" file, and this information is available to AWEC and anyone that opens the help file. The help file clearly identifies how the columns function and the Company's usage of Aurora's features to restrict the Ozone Season to May through September is clearly explained. I provide the appropriate extract from the help file below in Figure OTR-3.

Figure OTR-3

Limit Definition Column

Column Type = Text

The Limit Definition column specifies a set of time intervals smaller than the period declared in the Limit Type column. For example, use this column to constrain resource dispatch for only a subset of the months of each year when the Limit Type = Year. This restriction is controlled by entering a reference to a monthly time series (mn_) with values of **1** for the effective months and **0** (zero) for other months. An annual times series (yr_) may also be used in this column as long monthly time series are nested inside it.

NOTE: Inputs can only be specified by a monthly or annual time series. For information on how to specify a time series for a variable, see Entering a Time Series.

- Input Tables
  - Constraint Table
    - Limit Definition Column

VII. COAL UNIT MODELING

A. Reply to Staff

Q. Staff recommends that the Company revise its modeling of minimum take coal volumes to use the contractual price for the volumes in the minimum take tier.[113] How do you respond?

A. Contrary to Staff's testimony, there is no benefit from implementing this recommendation and it will not improve the accuracy of the modeling in Aurora. As an initial matter, Staff's recommendation fails to recognize the reality of minimum take volumes—they are fixed amounts of coal that the Company must pay for regardless of whether the volume is used. In this way, a minimum take volume is comparable to any other fixed cost that cannot be avoided. Modeling a minimum take volume as if it were a variable and avoidable cost would introduce an inaccuracy into Aurora because the model would no longer reflect actual operations. The Company's approach is fully consistent with Commission precedent on this point.

Moreover, in Aurora there are certain contractual annual minimum volume constraints on coal that must be enforced in the modeling. That minimum volume constraint has no flexibility (i.e., it is a fixed constraint and there is no ability to go above or below the minimum). Other coal tiers are modeled as separate streams of fuel and each have their applicable contract price when there is flexibility within that tier. The minimum take volumes in Aurora are fixed, have no flexibility, are not allowed to increase above minimum, and are not allowed to decrease below minimum. That single tier, the fixed tier, is a certain volume of coal that must be

[113] Staff/1000, Anderson/3.

burned regardless of system conditions within the model and Aurora does not take an explicit price for it.

Q. Staff testifies that, "Using the actual cost of coal under minimum take volumes will result in the Aurora model's shadow prices for its minimum take constraints accurately reflecting the value of increasing the minimum take quantity."[114] How do you respond?

A. Staff's testimony is not entirely clear and susceptible to two interpretations. However, as discussed below neither interpretation is correct.

First, Staff appears to suggest that the volume of coal subject to a minimum take constraint can increase in Aurora. This is incorrect. The Company models each coal tier independently and the minimum coal tier is modeled as a fixed volume with no ability to increase, i.e., Aurora cannot keep burning "no price" coal simply because it is "no price". Additional volumes in coal contracts are modeled as separate tiers and the ability to burn more coal is provided in the incremental tiers (separate fuel streams) that are separately modeled in Aurora.

Second, if Staff's position is that using a zero price means that Aurora is burning coal that may not be economic, then that position is not supported in the record in this case. Whether that explicit price on the minimum take is deleted, set to zero, or set to the actual dollar per metric million British thermal unit ($/MMBtu) price of the minimum take, there will be negligible change (noise)[115] to the NPC forecast. However, Aurora will still burn more than the minimum volume when there are other incremental tiers (other fuel streams) provided to those coal plants that have

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[114] Staff/1000, Anderson/3.
[115] PAC/400, Mitchell/115.

incremental tiers and when it is economic to do so. This is clearly exemplified in the Company's NPC reports where it is evident that those coal plants that have incremental flexibility are burning into that incremental flexibility.

To the extent Staff is essentially recommending that the Company no longer model minimum take volumes, that approach is contrary to well established Commission precedent and inconsistent with actual operations.

Q. Please describe Staff's concerns regarding Hunter and Huntington.

A. In opening testimony, Staff agreed that Aurora would have [redacted].[116] In rebuttal testimony, Staff has changed its position and now testifies that "[redacted]"[117]

Q. Did Staff explain why its testimony changed?

A. No. Staff provided no analysis for its new "finding."

Q. Is there any merit to Staff's "finding"?

A. No. In the Reply Update, Aurora modeled consumption of all the coal available at Hunter and Huntington. This result would not have changed if the Company used a non-zero price for the minimum take volumes. To prove this fact, the Company entered the contractual price for the minimum take provision at Hunter and Huntington [redacted]) and both plants burned exactly the same amount of coal. Furthermore, the Company conducted a

[116] Staff/1000, Anderson/12.
[117] Staff/1000, Anderson/12.

counterfactual analysis wherein Aurora was provided the opportunity to burn twice the amount of coal[118] at both Hunter and Huntington and Aurora burned more coal at both those plants. This result is intuitive because on a $/MWh basis, coal is on average substantially cheaper than market purchases.

Q. Do you agree that the analysis Staff requested is relevant to evaluating the merits of the coal supply agreements for Hunter and Huntington?

A. No. As discussed by Company witness Owen, the contractual minimum take levels in the relevant coal supply agreements resulted from comprehensive economic analysis conducted contemporaneously with contract negotiations. It is inappropriate for Staff to after-the-fact second guess that analysis using market conditions that were not known at the time of contracting. So even though the analysis above demonstrates that Staff's new "finding" is factually incorrect, it is also irrelevant for purposes of evaluating the prudence of the coal supply agreements.

B. Reply to AWEC

Q. Please describe AWEC's adjustment related to the Reply Update coal costs.

A. AWEC recommends that the Commission reject the updated coal costs because AWEC claims that the Company did not accurately portray the impacts of the coal supply update.[119] In particular, AWEC testifies, "PacifiCorp represented that the impact of its coal supply update was a $1,281,503 reduction to PacifiCorp's forecast NPC on a total-Company basis."[120] However, "Based on [AWEC's] AURORA model runs, the coal supply update increased PacifiCorp's forecast NPC by

[118] This coal is fictional, and this modeling is solely to rebut Staff's contention and not representative of any real coal supply assumptions.
[119] AWEC/200, Mullins/12.
[120] AWEC/200, Mullins/11.

$110,944,033."[121] In other words, AWEC claims that its analysis shows the coal supply update increased the NPC forecast by $111 million whereas the Company showed it as a decrease to NPC of $1.3 million. AWEC therefore recommends a $111 million total-company decrease to NPC[122] and recommends that the Company's "coal supply costs be calculated consistent with PacifiCorp's initial filing."[123]

Q. Is there any merit to AWEC's coal update adjustment?

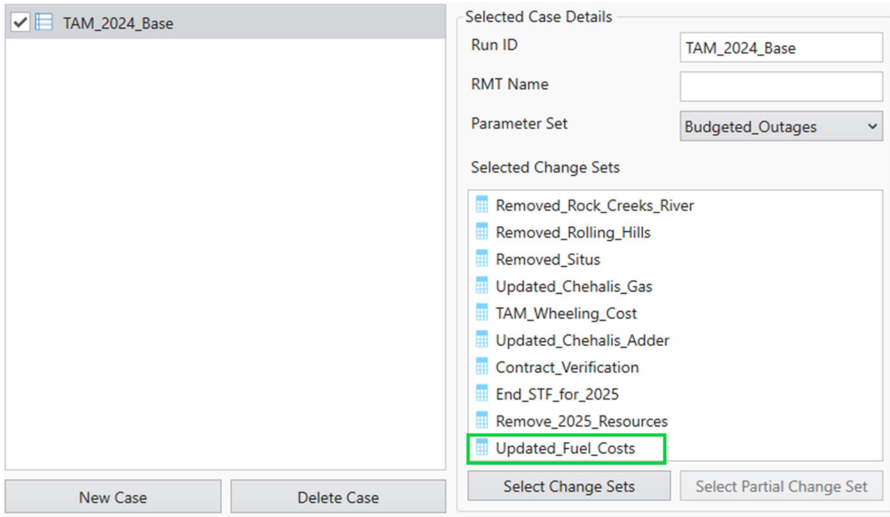
A. No. Based on AWEC's workpapers, its analysis is incorrect and relies on incorrect Aurora modeling that invalidates the entirety of AWEC's coal update adjustment. This is another example of the rather serious issues surrounding the multiple inconsistencies with AWEC's Aurora modeling, usage and understanding that I referenced in Section V(B) above.

Q. Please explain how AWEC arrived at its incorrect comparison of coal costs from the Initial Filing to the Reply Update.

A. In the Company's Initial Filing, the Aurora project had what Aurora calls a "Study Case" entitled "TAM_2024_Base" and what Aurora calls a "Change Set" in that Study Case titled "Updated_Fuel_Costs." The Initial Filing's Study Case, which utilized all the Change Sets inside of it, formed the base NPC of the Initial Filing. Figure COAL-1 below shows a screen shot of the Aurora model for the Initial Filing.

[121] AWEC/200, Mullins/12.
[122] AWEC/200, Mullins/2.
[123] AWEC/200, Mullins/12.

Figure COAL-1



Q. What are Change Sets in Aurora?

A. In Aurora, Change Sets are workpapers that modify the underlying database that holds the model inputs. To create the Initial Filing's NPC forecast, the Company applied the "Updated_Fuel_Costs" Change Set because that Change Set held the cost costs used in the Initial Filing.

Q. Can you illustrate the difference between the Initial Filing Aurora run with and without the "Updated_Fuel_Costs" Change Set?

A. Yes. Confidential Figure COAL-2 below shows the coal prices and volumes from the Initial Filing's underlying database without application of the "Updated_Fuel_Costs" Change Set.

[redacted]

To be clear, the values in Confidential Figure COAL-2 are **not** the coal prices and volumes used in the Initial Filing. The values in Confidential Figure COAL-2 are outdated coal prices and volumes from before coal supply restrictions were incorporated into the NPC forecast. The values are therefore unrelated to the 2024 TAM Reply Update and have never been used in any of the modeling to create the 2024 TAM NPC proposal.

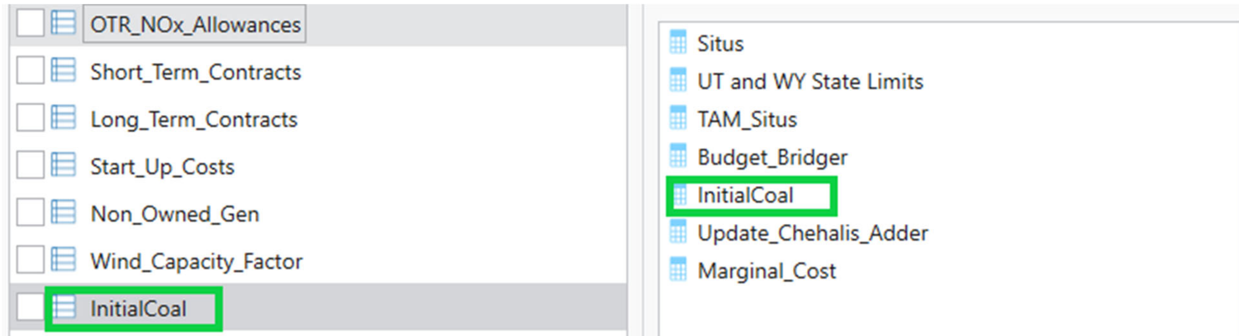
Confidential Figure COAL-3 below shows the coal prices and volumes in the Initial Filing's underlying database with application of the "Updated_Fuel_Costs" Change Set. A simple comparison of Confidential Figure COAL-3 and Confidential Figure COAL-2 shows a significant difference between the coal prices and volumes used in the Initial Filing as compared to the coal prices without the "Updated_Fuel_Costs" Change Set.

[redacted]

Q. What is the relevance of Confidential Figure COAL-2 and Confidential Figure COAL-3 to AWEC's testimony?

A. When AWEC attempted to independently introduce the coal costs from the Initial Filing into the Aurora project from the Reply Update, AWEC erred and did not apply the "Updated_Fuel_Costs" Change Set before migrating the data. This is evident from an examination of AWEC's Aurora project wherein AWEC created a study case called "InitialCoal" with a Change Set called "InitialCoal" to attempt to replicate the Company's coal prices and volumes from the Initial Filing. AWEC's study case and the associated changeset is illustrated below in Figure COAL-4.

Figure COAL-4



When examining AWEC's underlying database with application of the "InitialCoal" Change Set one will observe coal prices and volumes as illustrated in the below Confidential Figure COAL-5, which are **identical** to Confidential Figure COAL-2 above. As explained above, the data in Confidential Figure COAL-2 is **not** the data used in the Initial Filing. The correct data is reflected in Confidential Figure COAL-3, but that is **not** the data AWEC used for its comparison of the Initial Filing and the Reply Update.

[redacted]

Q. Please summarize what this means for AWEC's claim that the Company's did not accurately reflect the impact of the coal supply update.

A. AWEC claims that "PacifiCorp did not report the true impact of the [coal supply] update"[124] and then derives an adjustment that AWEC claims will reduce NPC by $111 million total-company.[125] This testimony and adjustment, however, is fictional and based on AWEC's erroneous Aurora modeling—AWEC compared the Company's Reply Update Aurora run to an erroneous AWEC-created Aurora run that had no relationship to the Company's Initial Filing's NPC proposal. Based on that comparison, AWEC erroneously concluded that the updated coal prices and volumes increased total-company NPC by $111 million. Had AWEC accurately compared the

[124] AWEC/200, Mullins/12.
[125] AWEC/200, Mullins/2.

actual Aurora run from the Initial Filing to the Aurora run from the Reply Update, AWEC would have realized that total NPC did, in fact, decrease based on the isolated impact of updating from the initial filing's coal supply assumptions to the Reply Update's coal supply assumptions; which is as the Company portrayed in its reply testimony. [126]

Q. AWEC recommends "that the coal supply costs be calculated consistent with PacifiCorp's initial filing".[127] After correcting AWEC's analysis, what is the impact of AWEC's recommendation?

A. Adopting AWEC's recommendation after correction for AWEC's erroneous analysis would inappropriately **increase** NPC by $1.3 million total-company, $0.37 million Oregon-allocated.

VIII. WASHINGTON CAP AND INVEST PROGRAM

A. Reply to AWEC

Q. AWEC claims that PacifiCorp is including the costs of the Washington Cap and Invest Program emissions allowances in the wrong FERC account.[128] Is that true?

A. No. AWEC claims that PacifiCorp has improperly included the cost of emission allowances "as a cost of fuel for Chehalis in FERC Account 447- Fuel"[129] instead of expensing the allowances to FERC Account 509 - Allowances. However, this is incorrect. Based on my conversations with the Company's FERC accounting experts, on June 29, 2023, FERC approved a new rule with an effective date of January 1,

[126] PAC/401, Mitchell/1.
[127] AWEC/200, Mullins/12.
[128] AWEC/200, Mullins/35–36.
[129] AWEC/200, Mullins/36.

2025, that may require the Company to expense the Climate Commitment Act allowances to FERC Account 509.[130] Because that new rule is not effective until 2025, however, it does not impact this 2024 TAM or the future 2024 PCAM.

Moreover, the specific FERC accounting applicable to the GHG allowances should not dictate whether the allowance costs are accounted for in the modeling of the TAM NPC forecast. There is no doubt that actual dispatch decisions related to Chehalis will take into account the added costs of GHG allowances and therefore an accurate TAM NPC forecast requires the modeling to take into account the same GHG allowance, regardless of their accounting treatment.

Q. AWEC argues that modeling the impact of GHG allowances produces uneconomic dispatch at Chehalis.[131] How do you respond?

A. AWEC's claim of uneconomic dispatch does not hold up under scrutiny. AWEC claims the "cost of uneconomic dispatch" to be: (1) the increase in total-company NPC resulting from applying a GHG allowance price to Chehalis; less (2) the cost of the GHG allowances themselves. In a hypothetical scenario where the GHG allowance price were $1,000/MWh and the Chehalis plant never generated at all (0 MWh) because of this high cost, then the cost of the GHG allowances would be $0; (0 MWh * $1,000/MWh). Per AWEC's logic then, the "cost of uneconomic dispatch" in this scenario would be: (1) the increase in NPC resulting from applying a GHG allowance price to Chehalis (which would be entirely the cost of replacement energy); less (2) the cost of the GHG allowances themselves (which would be $0

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[130] *Accounting and Reporting Treatment of Certain Renewable Energy Assets*, 183 FERC ¶ 61,205, Order No. 898 (2023).
[131] AWEC/200, Mullins/35.

since Chehalis never generated). In this scenario, this "cost of uneconomic dispatch" would then be entirely the cost of replacement energy, per AWEC's logic. Defining replacement energy as uneconomic dispatch is inaccurate and AWEC's statement that the "cost of uneconomic dispatch" contributed to $7,428,063 (a total-company number) is therefore an inaccurate statement.

Q. If the Company removed Chehalis from the NPC forecast, would NPC increase?

A. Yes. The Company performed an Aurora run without Chehalis and NPC increased $131 million total-Company, $37 million Oregon-allocated, relative to the Reply Update. This result is not surprising because any time that Chehalis dispatched in Aurora, it did so with the added GHG compliance costs resulting from Washington law. If Chehalis did not dispatch in those hours, the Company would have to rely on other generation, which by definition will be higher cost, otherwise Chehalis would not have dispatched in the first place. Therefore, Oregon customers are receiving benefits from Chehalis even with GHG compliance.

B. Reply to Vitesse

Q. Vitesse continues to recommend that the Company model Chehalis emission allowance costs on a variable basis.[132] Have you reconsidered your initial opposition to this recommendation?

A. Upon further analysis, Vitesse's proposal on the modeling of emissions at Chehalis has merit based on the following. First, the inefficiencies and associated cost that would occur due to the EIM using one flat $/MWh for GHG bids occur at the transition between the hour-ahead (HA) timeframe and the intra-hour (EIM)

[132] Vitesse/200, Johnson/28.

timeframe. Because Aurora does not model the EIM and because Vitesse, as clarified in its rebuttal testimony, is not referring to the generation profile used for EIM GHG revenue and costs (I elaborate more on this nuance below), then using an emissions rate in the Aurora model will appropriately stop optimization at the HA timeframe without reaching into EIM. This modeling is consistent with energy only optimization after excluding EIM GHG revenue and costs.

Second, [redacted]

Q. What is the NPC impact of adopting Vitesse's recommendation?

A. Vitesse's recommendation increases total-Company NPC by $5.0 million, or $1.42 million Oregon-allocated. However, although Vitesse's recommendation is a more elegant way to model the cost of emissions, it requires as input a static pound per MMBtu (lb/MMBtu) emissions rate (as opposed to a static $/MWh). To calculate either the static lb/MMBtu value or the static $/MWh value one needs to take an aggregate amount of pounds of emissions emitted over a large time period (example, one year) and divide by the aggregate amount of MMBtu consumed over that large time period. This embeds historical fuel usage into the forecast of future fuel usage and although Vitesse's approach is more *elegant* in the usage of that historical data, I do not believe that it is more *accurate*.

Q. Vitesse testifies that the "Company [is incorrect] in argu[ing] that because the EIM only takes bids on a $/MWh basis it cannot consider the variable cost of allowance in Chehalis's participation in the EIM."[133] How do you respond?

A. In the EIM there are two types of bids, energy bids and GHG bids. [redacted], which incorporates GHG bids into the energy bids for that deemed delivery. In rebuttal testimony, the Company referred to "GHG costs" and spoke to the GHG bids in the EIM, which take **one** flat $/MWh entry. Vitesse's rebuttal refers to the energy bids only[134] in the EIM, which take **multiple** flat $/MWh price / quantity pairs for energy (non-GHG) related bids. Both energy bids and GHG bids are submitted to the EIM in units of $/MWh. My statement on GHG bids is correct and Vitesse's statement on energy bids is correct.

In reply testimony, the Company understood Vitesse to be referring to the generation profile of the Chehalis plant for **all** dispatch, which includes both energy dispatch and GHG dispatch. I now understand from Vitesse's surrebuttal that they are referring only to the **energy** dispatch since they explicitly mention the price / quantity pairs of the energy bids that take multiple flat $/MWh values. Because Aurora does not model the EIM, I did not reference Aurora in my rebuttal testimony response to Vitesse, which explains Vitesse's statement that the "Company provides no explanation for why it could not use the Aurora feature."[135] However, now that it

[133] Vitesse/200, Johnson/29.
[134] Vitesse/200, Johnson/29, footnote 32 (describes bids on segments of a plant which can only be the energy bid, because the GHG bid is one flat vale).
[135] Vitesse/200, Johnson/29.

is clear Vitesse is referring to energy only dispatch[136] in the non-CAISO EIM footprint (of which PacifiCorp's service territory is a part) then I was able to reconcile my reply testimony statements with Vitesse's opening testimony statements and this is what produces that "further analysis" I referenced above and the associated NPC impact (increase to NPC) that I do not advocate for on the basis of accuracy.

IX. WIND GENERATION

Q. Has Staff changed its recommendation for forecasting wind generation?

A. Yes.[137] In its opening testimony, Staff proposed using "a four-year average of actual results for each power generating facility" as the wind generation forecasting method.[138] Staff indicated that its method only used a three-year average, because Staff excluded all data from calendar year 2019. Although Staff used a three-year average forecast, Staff testified that it proposed using "the Company's forecast unadjusted" for facilities with less than four years of full operating history.[139]

Q. How did the Company respond to Staff's recommendation?

A. The Company pointed out that Staff's recommendation did not account for the changes resulting from wind repowering, which rendered pre-repowered generation data obsolete.

Q. Did Staff address the issue you raised?

A. No. Staff did not rebut the Company's evidence that because of repowering, no wind facility subject to Staff's proposed methodology has four years of historical data.

[136] Which excludes Chehalis GHG revenue per Vitesse's rebuttal clarification.
[137] Staff/1200, Chipanera/1–4.
[138] Staff/600, Chipanera/3–4.
[139] Staff/600, Chipanera/4.

Because Staff did not rebut the Company's evidence, there is no basis to adopt Staff's adjustment.

Q. Do you agree with how Staff accounted for the 2021 substation fire?

A. No. Staff identified three facilities it believes were impacted by the substation fire and for each facility, Staff replaced the actual October 2021 generation with the actual October 2022 generation.[140] But Staff provided no analysis demonstrating that the 2022 data was appropriate as a replacement.

Q. Are there any other issues with Staff's methodology?

A. Yes. Staff failed to account for the settlement in the 2020 TAM. In that case, the agreed upon input capacity factors for all of the wind facilities subject to Staff's adjustment were not to be changed until "2024, in the 2025 TAM."[141] Staff's proposal here does not use those same capacity factors.

X. AURORA MODEL

Q. AWEC recommends that the Commission set NPC based on the Aurora run performed on their computer, rather than the Aurora runs performed by the Company.[142] Did AWEC provide any evidence that its computer is more accurate?

A. No, and given the fact that there are multiple examples of rather serious issues surrounding the multiple inconsistencies with AWEC's Aurora modeling, usage and understanding which I elaborate on in multiple sections above, there is no basis to conclude that AWEC's modeling is accurate or reliable.

[140] Staff/1200, Chipanera/3.
[141] *In the Matter of PacifiCorp, dba Pacific Power, 2020 Transition Adjustment Mechanism*, Docket No. UE 356, Order No. 19-351 at 6, Appx. A at 8–9 (Oct. 30, 2019).
[142] AWEC/200, Mullins/39.

XI. ARIZONA PUBLIC SERVICE (APS) SHORT TERM TRANSMISSION

Q. How do you respond to the fact that AWEC no longer proposes an adjustment to remove the costs and benefits of the APS short-term transmission to Palo Verde?[143]

A. The Company agrees with AWEC's decision to withdraw this adjustment.[144] While the Company disagrees with much of AWEC's testimony, the Company will not respond given that AWEC has withdrawn its adjustment.

XII. EIM MODELING

Q. Vitesse criticizes the Company's decision "[redacted]" and argues that the "the Company made this change in its reply testimony and it should have been identified in its direct testimony."[145] Is this a fair criticism?

A. No. As an initial matter, to be clear, the decision referenced by Vitesse was an operational decision, not a modeling decision used in the TAM to forecast NPC for 2024. More importantly, Vitesse's criticism misses the mark because the operational decision was made after the filing of the Company's direct testimony and therefore could not have been discussed in direct testimony. The Company's operational decision is discussed in more detail in the surrebuttal testimony of Company witness Michael Wilding. Lastly, the NPC forecast in this TAM is a forecast of the actual NPC expected to be incurred in calendar year 2024 and accordingly, the NPC forecast should reflect actual operations, not the other way around. The prudency of the

143 AWEC/200, Mullins/39.
144 However, the Company disagrees with many of AWEC's claims in this "e. APS Short-Term Firm Transmission" section of their testimony.
145 Vitesse/200, Johnson/18.

Company's immediate actual operations (which, in the context of the NPC forecast, will occur in 2024) is a discussion for the PCAM.

Q. Vitesse also claims the "Company does not present its methodology" for determining the cost "[redacted] which Vitesse testifies is presumably [redacted]"[146] Do you agree?

A. No. In a discovery response to Vitesse, the Company provided a confidential attachment and stated: "Please refer to Confidential Attachment Vitesse 25, tab "HR", cell "B20" which provides the calculation of the value that is [redacted] That Confidential Attachment Vitesse 25, tab "HR", cell "B20", along with the entirety of the workbook which the cell is located in, presented the methodology.

XIII. EDAM

A. Reply to Staff

Q. Please outline Staff's recommendations regarding the Company's participation in the EDAM.

A. Staff recommends that the Company investigate alternatives to how it forecasts EIM benefits and alternatives to the third quartile of averages methodology given its upcoming participation in the EDAM.[147] Staff also recommends that the Company provide an estimate of EDAM benefits, presumably in the 2025 TAM.[148]

[146] Vitesse/200, Johnson/21.
[147] Staff/900, Dlouhy/10.
[148] Staff/900, Dlouhy/10.

Q. How do you respond to Staff's recommendations?

A. As an initial matter the Company is forecasting with the average of averages method in the Reply Update, not the third quartile of averages, and Staff agrees that the Company's average of averages method is more accurate. Regardless, the Company is already investigating the impacts to power costs resulting from EDAM participation.

B. Reply to Sierra Club

Q. Sierra Club testifies that "PacifiCorp has publicly announced its intention to begin EDAM participation in 2024, not 2025" and therefore the EDAM is relevant to the 2024 TAM.[149] Is that true?

A. No. As of August 2023, the Company and the CAISO have jointly revised the start date of the EDAM to 2026.

XIV. COMPLIANCE WITH TAM GUIDELINES

A. Reply to Staff

Q. Please describe Staff's recommended change to how the step log is presented in future TAMs.

A. Staff recommends that, "In the future, the Company should include a Step Log that lists the changes from the previous TAM and their cost impacts sequentially."[150] Staff acknowledges that this recommendation will "not provide an accurate estimate of the cost impact of any one change."[151]

[149] Sierra Club/200, Burgess/9.
[150] Staff/1000, Anderson/14–15.
[151] Staff/1000, Anderson/15.

Q. How do you respond to Staff's recommendation?

A. First, the Company is surprised that Staff would recommend that the step log be made less accurate. The Company's understanding of the step log is that it is designed to show the impact of each individual change made from the modeling used in the prior TAM. Staff's recommendation would no longer achieve this goal.

Second, the Company cannot accommodate Staff's recommendation for the November indicative or final TAM updates because there is insufficient time (approximately seven days) to use a sequential step log. For example, if the Company completes the indicative pricing TAM model runs on November 6 (each November filing requires approximately **60** Aurora model runs for a total of approximately **120** Aurora model runs across approximately two weeks inclusive of weekends—and this **assumes no errors are found in the quality control process**) and discovers an error in the first step of the step log, then the Company would have to rerun every model related to the TAM NPC proposal from the first step to the last step because each step depends on the results of the prior step. Not only is this administratively burdensome, more importantly it is infeasible because there is insufficient time between the issuance of the Commission's final order and the November 8 due date for the indicative runs. Under the current methodology, an error in one step only necessitates the rerunning of that one step (and possibly the cumulative step), which is manageable on the tight timeframes required after the Commission's final order.

Third, the administrative burden of a sequential step log also applies to the Initial Filing and Reply Filing. Given that Staff agrees its request "will not provide an accurate estimate of the cost impact of any one change" relative to prior TAMs, there is no basis to require a change to how the step log is performed.

B. Reply to AWEC

Q. Please explain AWEC's adjustment related to the base period used for the Reply Update.[152]

A. AWEC claims that PacifiCorp "updated the historical base period data to be based on calendar year 2022, rather than based [*sic*] the year ending June 2022, a change which is [] not allowed"[153] because according to AWEC "wholesale updates to the historical, base period data used to forecast NPC are [] not allowed" by the TAM Guidelines.[154]

Q. What NPC inputs did the Company update in the Reply Update?

A. The TAM Guidelines specify that the Company will update NPC in the Reply Update using the most recent OFPC and new power, fuel and transportation/transmission contracts, both physical and financial, and updates to existing contracts.[155] Accordingly, the Company updated its modeling inputs with the new power and fuel contracts (along with the other required items) available as of the Reply Update.

Q. What modeling inputs are calculated solely using a combination of the updated OFPC, power contracts (transactions) and gas contracts (transactions)?

A. The following inputs are non-exclusive examples of items that are updated in the Reply Update by virtue of updating forward prices and known transactions: (1)

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152 AWEC/200, Mullins/13.
153 AWEC/200, Mullins/10.
154 AWEC/200, Mullins/9.
155 AWEC/200, Mullins/9 (quoting *In the Matter of PacifiCorp, dba Pacific Power, 2009 Transition Adjustment Mechanism Schedule 200, Cost-Based Supply Service*, Docket No. UE 199 Order No. 09-274 at 4 (Jul. 16, 2009)).

physical gas transactions; (2) financial gas transactions; (3) physical power transactions; (4) financial power transactions; (5) day-ahead / real-time physical power transactions; (7) market sales transactions; and (8) EIM transactions.

Q. Although AWEC claims that the Company made "wholesale" updates to the base period data, did AWEC identify any specific updates that it objects to?

A. Yes. The only items AWEC could specifically identify are market caps and the DA/RT adjustments.[156] However, both those NPC inputs will change as a result of the required update to the OFPC and known market transactions. In particular, market caps are calculated solely on market (physical power) sales transactions, which the Company is required to update as part of the Reply Update. And the DA/RT adjustments are calculated solely based only on day-ahead / real-time physical power (purchases and sales) transactions, the OFPC, and Aurora's output, all of which are also updated/forecast in the Reply Update.

Q. AWEC claims that the Company has not updated the market caps and DA/RT adjustment in prior TAMs.[157] Is that true?

A. No. The same updates that AWEC criticizes here have been updated in past TAMs. For example, the Company updated market caps with physical power sales transactions in prior TAM Reply Updates. The Company updates all power, fuel and transportation/transmission contracts whenever possible in all TAM filings.

As we move forward in time and the Company leverages better software and more improved processes and systems, the Company is able to more quickly process its contractual data and more quickly disseminate that data internally. To the extent

[156] AWEC/200, Mullins/13.
[157] AWEC/200, Mullins/13.

that the Company receives these contracts and has the tools, capability, and time to incorporate these contracts into the NPC forecast, the Company will always follow the TAM Guidelines, as it has done here and in prior TAMs.

Q. Did AWEC identify any other data from the "historical base period" that was updated in the Reply Update?

A. No. And AWEC's reference to "base periods" is misleading in the context of the Reply Update and of no relevance to the required updating of the OFPC, power, fuel or transportation/transmission contracts. AWEC's reference to "base periods" is something AWEC raised in the last general rate case (GRC) wherein AWEC requested the initial filing of the TAM to base all of its modeling inputs on a period ("base period") that is no earlier than December 31 of the year prior to the filing. The Company responded that doing so would delay the filing of the initial TAM because the processing of data received after December 31 takes many months. AWEC's argument in that GRC was completely unrelated to the Company's reply filing required updates. Consequently, the "Third Partial Stipulation"[158] that AWEC references is an agreement to **not** adopt AWEC's proposal regarding the vintage of the modeling inputs used in the **initial** filing and unrelated to the Reply Update.

XV. TRANSITION ADJUSTMENT CALCULATION

Q. Please describe Calpine's concerns that appear in its rebuttal testimony.

A. In its opening testimony, Calpine took issue with the incorporation of the DA/RT adjustment to the in-spreadsheet, market price component of the transition adjustment calculation in Schedules 294, 295, and 296 and the Consumer Opt-Out Charge

[158] AWEC/200, Mullins/14.

(collectively, the transition adjustments).[159] In its rebuttal testimony, Calpine continues to disagree with the application of the DA/RT price component to the in-spreadsheet, market price component of the transition adjustments calculation, arguing that the Company's application of the DA/RT price component is biased.

Q. Did any other party address this issue?

A. Yes. Staff agreed with the Company's position and disagreed with Calpine.[160]

Q. As an initial matter, Calpine claims that the Company admitted that it "selectively limited the DA/RT adjustments solely to the net discounted prices associated with market sales and ignored the premium prices associated with market purchases."[161] Is that true?

A. No, and Calpine's own testimony makes that fact clear. As Calpine testifies, they do not object to the fact that the "DA/RT discounts and premiums are currently included in the transition adjustment calculation as applied to avoided market purchases and increased market sales attributed to direct access[.]"[162] Calpine therefore concedes that both the "discounted prices associated with market sales" and the "premium prices associated with market purchases" are applied when the Company calculates the NPC impact of departing direct access load (Steps 1 and 2 in the calculation described in my reply testimony).[163]

[159] Calpine Solutions/100, Higgins/4.
[160] Staff/1100, Bolton/3–4.
[161] Calpine Solutions/200, Higgins/3.
[162] Calpine Solutions/200, Higgins/7.
[163] PAC/400, Mitchell/121–122.

Q. What is the basis for Calpine's claim that the Company should use unadjusted forward prices for valuing the energy freed-up by departing direct access load?

A. Calpine argues that the Company's approach to the market price component is flawed because the stipulation entered in docket UE 199 requires the Company to use "the market price" for both the California-Oregon Border (COB) and Mid-C markets.[164] Calpine argues that the Company's use of the sales price discount in the transition adjustment calculation violates the stipulation and so it must use "the market price" "with no attempt to apply a sales discount or purchase premium to that price."[165] Calpine argues that the Company's inclusion of the DA/RT adjustment in the spreadsheet market price component is a "reinterpretation of a well-established compromise."[166]

Q. Do you agree that the stipulation approved in docket UE 199 prohibits the Company from using more accurate forward prices to value freed-up energy?

A. No. Calpine claims that the docket UE 199 stipulation requires the Company to use a "unitary market price" for the transition adjustment calculations,[167] but that language is nowhere in the stipulation itself. The stipulation says that the calculation must use the "simple monthly average of the COB price, the Mid-Columbia price, and the avoided cost of thermal generation" and that "the monthly COB and Mid-Columbia prices will be applied to the heavy load hours or light load hours separately".[168] The DA/RT price component's price adders are a monthly average adjustment. The

[164] Calpine Solutions/200, Higgins/5.
[165] Calpine Solutions/200, Higgins/5.
[166] Calpine Solutions/200, Higgins/6.
[167] Calpine Solutions/200, Higgins/5.
[168] *In the Matter of PacifiCorp, dba Pacific Power, 2009 Transition Adjustment Mechanism Schedule 200, Cost-Based Supply Service*, Docket No. UE 199, Order 08-543 at 15 (Nov. 12, 2008).

DA/RT price component takes the monthly OFPC, averages and creates a sell price at COB and a sell price at Mid-C (separated into heavy load hours and light load hours) and thermal generation can only be priced at a sell price. In other words, the application of the refined forward prices resulting from the DA/RT adjustment is consistent with the language in the docket UE 199 stipulation.

Q. Does the stipulation in docket UE 199 dictate how the Company must calculate the market prices used in the transition adjustment calculation?

A. No. And there is nothing in the stipulation that prevents the use of a more accurate forward price resulting from the use of the DA/RT price component.

Q. Does the docket UE 199 stipulation support the Company's use of the sell price for COB and Mid-C when valuing the freed-up energy (Step 3)? [169]

A. Yes. As Calpine's testimony explains, the relevant language in the docket UE 199 stipulation states that "any remaining monthly thermal generation **that is backed down** for assumed retail access load will be priced at the simple monthly average of the COB price, the Mid-Columbia price and the avoided cost of thermal generation."[170] The fact that the calculation is pricing avoided generation, means that the only appropriate price is the price that would be realized if the Company were selling that generation into the market. Calpine's position is that the market prices should not reflect any discount or any premium, but the text of the stipulation Calpine relies on contradicts this position. Because thermal generation can only sell energy and cannot purchase it, the application of the adjusted sell price is consistent with the stipulation.

[169] PAC/400, Mitchell/122.
[170] Calpine Solutions/200, Higgins/4.

Q. Calpine also claims that the market price component, as captured in the UE 199 stipulation, "has a dual role: it represents value to the Company of energy that is freed-up by direct access *and* it is indicative of what direct access customers are reasonably expected to pay to procure their power supply."[171] Do you agree?

A. No. That may have been Calpine's opinion, but that is not the Company's. Calpine's position also seems at odds with the underlying purpose of the transition adjustments, which is to protect customers from unwarranted cost shifting. Calpine's testimony also appears to contradict Calpine witness Higgins' testimony in docket UE 199, where he agreed that the transition adjustment calculation "is not intended to promote direct access service."[172]

Q. Does this conclude your surrebuttal testimony?

A. Yes.

[171] Calpine Solutions/200, Higgins/6 (emphasis original).
[172] *In the Matter of PacifiCorp, dba Pacific Power, 2009 Transition Adjustment Mechanism, Schedule 200 Cost-Based Supply Service*, Docket No. UE 199, SES/100, Higgins/8 (Jun. 23, 2008) (*citing In the Matter of Pacific Power & Light (dba PacifiCorp), Request for a General Rate Increase in the Company's Oregon Annual Revenues*, UE 170, Order No. 05-1050 at 21 (Sept. 28, 2005)).

REDACTED
Docket No. UE 420
Exhibit PAC/900
Witness: James Owen

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Surrebuttal Testimony of James Owen

August 2023

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I. INTRODUCTION

Q. Are you the same James Owen who previously submitted direct and reply testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony?

A. I respond to the rebuttal testimony of Rose Anderson and Anna Kim, filed on behalf of the Public Utility Commission of Oregon (Commission) Staff, and Ed Burgess, filed on behalf of Sierra Club. I also address the status of the Ozone Transport Rule (OTR), an issue raised in the rebuttal testimony of Bob Jenks, on behalf of the Oregon Citizens' Utility Board, and Steve Johnson, on behalf of Vitesse, LLC.

Q. Please summarize your surrebuttal testimony.

A. In my testimony, I address the following issues:

- I rebut Staff's new adjustments and recommendations related to the Huntington/Wolverine coal supply agreement (CSA) and the Hunter/Gentry CSA, demonstrating that these adjustments are unreasonable and speculative, especially considering the challenging conditions in the Utah coal market.
- I respond to Staff's recommendations that the Company hold a workshop before each TAM filing to address the current state of the coal markets, and file a coal-fired generation report.
- I address Staff's and Sierra Club's comments on the current Long-Term Fuel Supply Plan for the Bridger plant (2023 Fuel Plan).

- I explain why the Company has now removed all costs associated with the OTR from the 2024 Transition Adjustment Mechanism (TAM) and why a deferral should be allowed if the OTR goes into effect in 2024.

III. HUNTINGTON AND HUNTER CSAs

Q. Did Staff propose CSA-related adjustments for the first time in its rebuttal testimony?

A. Yes. Staff proposes two new adjustments. The first is a partial disallowance of $400,000 for the Huntington/Wolverine CSA, asserting that PacifiCorp should have used Wolverine's force majeure claim for the Lila Canyon mine fire to expand the CSA's environmental regulation clause.[1] The second is a disallowance of 10 percent of the Hunter/Gentry CSA costs, or $[redacted], on the basis that the request for proposal (RFP) should have "[redacted]."[2]

Q. Do you have a general response to these adjustments?

A. Yes. Neither disallowance should be accepted. In both my initial and reply testimony, I explained the extraordinary conditions prevailing in the Utah coal market, including increased demand and significant shortages in supply exacerbated by the Lila Canyon mine fire. These conditions have created a sellers' market, resulting in the inability of buyers to acquire new coal supplies, much higher prices, and less favorable contract terms. To mitigate net power cost (NPC) increases and potential reliability issues associated with coal supply shortfalls, PacifiCorp has worked diligently to find additional, cost-effective fuel supplies for the Hunter plant, secure the most favorable CSA terms possible, and manage its existing supplies for

[1] Staff/1000, Anderson/9.
[2] Staff/1000, Anderson/11.

the Huntington plant. Staff does not contest PacifiCorp's testimony on the supply and demand imbalances in the Utah coal market and the increased bargaining power of coal suppliers in this market to set price and contract terms. Staff nevertheless contends that PacifiCorp could have obtained better terms on its existing and new CSAs. Staff fails to provide any evidentiary support for this contention or to reconcile it with the uncontested evidence that in the current Utah coal market, sellers have increased ability to demand higher prices, set CSA terms, and shift contract risks to buyers—not the other way around as Staff posits.

Q. Are either of Staff's new proposed adjustments related to information that PacifiCorp provided for the first time in its reply testimony?

A. No. The information Staff relies upon for these adjustments was provided in my initial testimony. Staff's failure to timely raise its adjustments in its opening testimony has made it difficult for PacifiCorp to conduct discovery on these adjustments and provide a more complete response.

A. Staff's Huntington/Wolverine CSA Adjustment

Q. Please describe the Huntington/Wolverine CSA.

A. PacifiCorp executed the Huntington/Wolverine CSA in 2015 when it closed the Deer Creek mine and needed to replace the fuel supply to Huntington.[3] The Huntington/Wolverine CSA terminates in 2029, several years in advance of the 2032 closure date for Huntington in PacifiCorp's 2023 Integrated Resource Plan (IRP). As I explained in my initial testimony, the Huntington/Wolverine CSA includes an environmental regulation clause allowing the Company to [redacted]

[3] *In the Matter of PacifiCorp, dba Pacific Power, Application for Approval of Deer Creek Mine Transaction*, Docket No. UM 1712, Order No. 15-161 at 2 (May 27, 2015).

[redacted].[4]

Q. Shortly after the execution of the Huntington/Wolverine CSA, did the Commission reject a challenge to its prudence based on its minimum take provision?

A. Yes. In the 2017 TAM, the Commission found that the Huntington/Wolverine CSA's minimum take provision was a required term and the CSA was more advantageous to customers than the alternative of relying on the spot market with attendant supply and price risks.[5]

Q. Since that time, has the Commission explained the circumstances that would cause it to reconsider the prudence of the Huntington/Wolverine CSA?

A. Yes. In 2021, the Commission explained that, if PacifiCorp could no longer economically consume the [redacted] contract minimum under the Huntington/Wolverine CSA, the Commission would be willing to entertain an argument for a disallowance if PacifiCorp did not thoroughly explore the costs and benefits of contract termination or renegotiation.[6]

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[4] PAC/200, Owen/8–9.
[5] *In the Matter of PacifiCorp, dba Pacific Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 9 (Dec. 20, 2016).
[6] *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Order No. 21-379 at 23 (Nov. 1, 2021).

Q. Since 2021, has PacifiCorp economically consumed more coal than the contract minimum under the Huntington/Wolverine CSA?

A. Yes. As noted in my initial testimony, PacifiCorp burned 2.8 million tons of coal in 2021 and 2.5 million tons in 2022 at Huntington.[7] In 2023-2024, PacifiCorp expects to take all the coal it can obtain under the Huntington/Wolverine CSA, while also working on replenishing the now-depleted stockpiles at the Huntington plant and the nearby Rock Garden stockpile that supplies both Huntington and Hunter.

Since 2022, PacifiCorp has had to curtail Huntington's generation because of coal supply shortfalls, which has increased NPC. With higher natural gas and power prices and looming resource adequacy issues, the concern at Huntington in the 2024 TAM is around obtaining sufficient coal supplies, not whether the Huntington/Wolverine CSA's minimum take requirement could result in uneconomic dispatch of the plant.

Q. Please explain the circumstances of Wolverine's force majeure claim under the Huntington/Wolverine CSA.

A. Wolverine has supplied the Huntington/Wolverine CSA in part through the Lila Canyon mine, which produced roughly 25 percent of the coal in Utah over the last several years. After a fire at that mine in September 2022, Wolverine invoked the CSA's force majeure clause for coal sourced from the Lila Canyon mine. As I explained in my reply testimony, [redacted]

[7] PAC/200, Owen/9–10.

[redacted]

Q. What section of the Huntington/Wolverine CSA controls force majeure claims?

A. [redacted]

Q. **Does the Huntington/Wolverine CSA** [redacted]

A. [redacted] I have attached copies of Article IX and XI of the Huntington/Wolverine CSA as Highly Confidential Exhibit PAC/901.

Q. Please explain Staff's proposed adjustment related to the environmental regulation clause in the Huntington/Wolverine CSA.

A. Staff asserts that PacifiCorp should have [redacted]

[8] PAC/500, Owen/15–16.

[redacted]

Q. Does Staff contest your reply testimony making clear that PacifiCorp has no [redacted] in response to Wolverine's force majeure claim?

A. No, Staff does not contest or even address my reply testimony that Wolverine's force majeure claim [redacted]. Staff's adjustment thus fails to acknowledge the contractual obligations or realities of Wolverine's force majeure claim.

Q. Would the amendment Staff proposes effectively eliminate the minimum take agreement in the Huntington/Wolverine CSA?

A. Yes. Allowing PacifiCorp to terminate the Huntington/Wolverine CSA [redacted] largely negates PacifiCorp's minimum take commitment in the CSA. The Commission has recognized that minimum take provisions are industry standard and PacifiCorp cannot obtain a CSA without such a commitment. Staff's position that PacifiCorp could have amended the Huntington/Wolverine CSA to effectively eliminate its minimum take commitment is completely unrealistic, even under normal market conditions.

Q. Under current market conditions in Utah, is PacifiCorp in a position to obtain voluntary contract concessions from Wolverine?

A. No. In 2024, Wolverine is expected to provide approximately [redacted] of

[9] Staff/1000, Anderson/9.

Huntington's coal supply at approximately $[redacted]/ton.[10] This is [redacted] than the monthly average price of $93/ton in the Utah market as of June 2023.[11] Given the value of the Huntington/Wolverine CSA in this market, [redacted]

Q. Staff explains that it calculated its adjustment based on the "possibility" of a carbon price being implemented during the term of the Huntington/Wolverine CSA and the expense the CSA's minimum take requirement could cause in that event.[12] Is this a reasonable adjustment?

A. No. Staff's explanation of its adjustment reveals its impermissibly speculative nature. Staff's adjustment is based on multiple layers of projection and speculation—the unsupported premise that Wolverine would accept the amendment proposed by Staff

[10] PAC/500, Owen/17.
[11] PAC/500, Owen/10.
[12] Staff/1000, Anderson/9; Staff/1001, Anderson/2.

without increasing the price or reducing supply; the imposition of a carbon price within the term of the CSA; a change in market prices that would result in reduced dispatch below the CSA's minimum take levels; [redacted]. Staff's speculative adjustment also disregards uncontested facts about the Huntington/Wolverine CSA in the 2024 TAM, including that: (1) the CSA is supplying the Huntington plant at [redacted] current Utah coal market prices, and (2) generation from the Huntington plant in the 2024 TAM reduces market reliance, mitigates NPC increases, and improves reliability.

Q. Staff also recommends that PacifiCorp seek an [redacted] in all future CSAs [redacted][13] Is this recommendation reasonable?

A. No. [redacted]

[13] Staff/1000, Anderson/6.

[redacted]

B. Staff's Hunter/Gentry CSA Adjustment

Q. Please summarize your previous testimony on the Hunter/Gentry CSA.

A. As outlined in my initial testimony, the Hunter/Gentry CSA was obtained through an RFP PacifiCorp completed on September 28, 2022. The Hunter/Gentry CSA is [redacted], covering [redacted] tons in 2023 and [redacted] tons in 2024 and 2025. The Company's economic analysis of the Hunter/Gentry CSA—which Staff does not contest—demonstrates that it provides $[redacted] in value to customers.

Q. Please describe Staff's proposed adjustment to the Gentry CSA.

A. Staff claims that it is "unclear" whether the Hunter RFP provided information to bidders about the quantity of coal PacifiCorp was seeking and that PacifiCorp might have obtained savings if the RFP better informed bidders about PacifiCorp's needs. On this basis, Staff proposes a [redacted] disallowance of the Hunter/Gentry CSA costs, an adjustment of $[redacted]

Q. Did the Company specify the quantity of coal it was seeking through the Hunter RFP and communicate this to bidders?

A. Yes. The Company reached out to potential coal suppliers and requested bids for up to [redacted] for 2023 and up to [redacted] for 2024 and 2025. The Company also requested bids for options beyond 2025 at [redacted]. The

RFP was similar in design to PacifiCorp's past coal RFPs, which have consistently produced prudent and reasonable CSAs.

Q. Staff claims that PacifiCorp should have conducted a "pre-RFP optimization" study to determine the exact amount of coal it sought to procure, contending that this information would have allowed bidders to customize their bids and lower costs by reducing coal quantities. Please respond.

A. The output of Utah coal mines decreased by 14 percent in 2022. In such a market, PacifiCorp had to move quickly in its procurement process and demonstrate maximum flexibility in accepting any and all appropriate bids. The pre-RFP study for which Staff is now advocating would have slowed the issuance of the RFP and potentially discouraged bidder participation, the opposite of what the circumstances required. Furthermore, such a study was not necessary. As stated above, PacifiCorp has completed numerous RFP processes which have resulted in prudent CSAs.

Q. How much coal was the Company able to secure for Hunter through the RFP and otherwise?

A. Through the RFP, the Company obtained [redacted] for 2023 and [redacted] for 2024 and 2025 from the Hunter/Gentry CSA and [redacted] for 2024 and 2025 from the Hunter/Wolverine CSA.[14] Separate from the RFP, the Company also negotiated with Bronco for [redacted] in 2023, [redacted] in 2024, and [redacted] in 2025.[15] In total, the Company was able to acquire [redacted] for 2023, [redacted] for 2024, and [redacted] for 2025. This is significantly less than what PacifiCorp sought to acquire through the RFP, reflecting

[14] PAC/500, Owen/8.
[15] PAC/200, Owen/17.

the supply constraints in the Utah coal market. Confidential Table 1 shows the Hunter RFP coal volumes and Bronco renegotiated tons of coal:

Confidential Table 1

Hunter RFP and Bronco Renegotiation			
CSAs	**2023**	**2024**	**2025**
Hunter/Gentry CSA	[redacted]	[redacted]	[redacted]
Hunter/Wolverine CSA	[redacted]	[redacted]	[redacted]
Total RFP	[redacted]	[redacted]	[redacted]
Hunter/Bronco CSA	[redacted]	[redacted]	[redacted]
Total Tons Acquired	[redacted]	[redacted]	[redacted]

Q. Is there evidence that the RFP's flexible design allowed PacifiCorp to receive a range of customized bids from different bidders?

A. Yes, this is demonstrated by the significant differences in the two CSAs derived from the RFP. In particular, the Hunter/Gentry CSA demonstrates that this bidder was able to customize its bid and successfully offer coal quantities [redacted] Staff's adjustment is based on the theory that more specific volume requirements in the RFP would have resulted in a lower cost bid from Gentry. There is no evidence to support this theory, especially given the [redacted] Gentry offered in its bid.

Q. How much coal did the Hunter plant consume in 2022?

A. Hunter burned [redacted] of coal in 2022, which included a large portion of the available stockpiled inventory.

Q. Why did the Hunter RFP seek volumes in excess of what Hunter had most recently consumed?

A. For several reasons. First, PacifiCorp curtailed Hunter's generation beginning in

September 2022 to match coal deliveries and assure system reliability; if more coal had been available, the plant would have utilized it. Second, PacifiCorp needed to replenish Hunter's coal inventory stockpile, which PacifiCorp relied upon throughout 2022. Third, given the ability of PacifiCorp to direct coal supplies to the Hunter plant, Huntington plant, or the Rock Garden safety stockpile, any excess coal could be stockpiled at Rock Garden (which is also in need of replenishment).

Q. On your last point, Staff contends that, given the close proximity of the Hunter and Huntington plants and the overlapping suppliers, customers could benefit from CSAs that allow coal from one of these plants to be burned at the other.[16] Please comment.

A. Staff is correct that the Company's ability to interchange coal supplies at Hunter and Huntington plants provides benefits to customers. PacifiCorp captures this benefit primarily through its three Utah coal inventory stockpiles, one each at Hunter and Huntington and a third at Rock Garden. PacifiCorp sets a total inventory level and divides the inventory among the three stockpiles based on physical site limitations. Based on the status of coal supplies to Hunter and Huntington, PacifiCorp can use the stockpiles to supplement existing supplies or store excess coal. In 2022-2023, PacifiCorp has relied upon the Rock Garden stockpile to make up for shortfalls at Huntington, allowing PacifiCorp to direct more coal to the Hunter plant.

[16] Staff/1000, Anderson/9–10.

Q. [redacted] **and asks PacifiCorp to explain whether it considered heat rate curves in its Hunter RFP analysis.[17] Please respond.**

A. The PLEXOS model, which the Company used in the Hunter RFP analysis, takes account of the heat rate curves of all PacifiCorp plants when it optimizes generation resources. The Hunter and Huntington plants are operating at reduced loads because of coal supply shortages in the Utah coal market. Because both coal plants are operating at lower loads, they are less efficient which results in higher heat rates. Heat rates are only one factor impacting the Company's evaluation of the Hunter and Huntington plants operation. The Company also evaluates numerous other factors such as differentials in transportation of coal supply to both plants, stockpile sizes, other joint owners' coal needs at Hunter, etc. The Company is optimizing the use of available coal supply for both plants as stated earlier in my testimony.

Q. Staff recommends that, in future RFPs, PacifiCorp perform a pre-RFP optimization to determine the amount PacifiCorp needs to procure and provide this information in the RFP and any contract negotiations.[18] Does PacifiCorp have concerns about this recommendation?

A. Yes. The optimization analysis Staff recommends would provide highly confidential information to coal suppliers and give them more bargaining power in the already constrained and competitive coal supply market. This would negatively impact

[17] Staff/1000, Anderson/10.
[18] Staff/1000, Anderson/11.

PacifiCorp's customers. Staff's recommendation that the Company provide detailed information to sellers on the Company's precise coal requirements is imprudent and contrary to normal industry practice. The disadvantages of this recommendation are real and tangible, while any advantages appear highly speculative.

Q. In its opening testimony, Sierra Club sought to disallow the Hunter/Gentry CSA for reasons that you rebutted in your reply testimony. Does Sierra Club continue to seek a disallowance of this CSA?

A. It is not clear. While Sierra Club states that it still supports its initial recommendations,[19] it does not contest or otherwise respond to my reply testimony which established that there is no basis for Sierra Club's proposed disallowance of the Hunter/Gentry CSA.

IV. COAL WORKSHOP AND GENERATION REPORT

Q. Staff testifies on the complex nature of the coal markets and the challenges of understanding the TAM's forecast of coal costs. Noting the helpful workshop PacifiCorp recently held on coal issues in docket UE 421 (PacifiCorp's power cost adjustment mechanism (PCAM) filing), Staff recommends that PacifiCorp begin holding such a workshop every year in advance of the TAM filing.[20] Does the Company support this recommendation?

A. Yes, for the most part. PacifiCorp agrees that a deeper understanding of the coal markets is necessary for parties to recognize the challenges PacifiCorp faces in fueling its coal-fired thermal plants and the experience and expertise PacifiCorp brings to meeting these challenges. PacifiCorp would prefer to hold such a workshop

[19] Sierra Club/200, Burgess/1.
[20] Staff/700, Kim/7.

shortly after its initial filing, however, to allow PacifiCorp to explain specific aspects of its filing and to avoid overloading the schedule as PacifiCorp prepares its TAM filing. The Company hopes that, by holding such a workshop early in the TAM docket, parties will cease raising coal adjustments for the first time just weeks in advance of the TAM hearing.

Q. Staff also proposes that PacifiCorp file a Coal-Fired Thermal Generation Report with each TAM filing.[21] A template for the report is contained in Staff/701. Does the Company object to providing the report Staff proposes?

A. Yes. PacifiCorp is already providing significant information on its coal-fired plant generation in each TAM and is open to providing additional information as reasonably necessary. But PacifiCorp objects to providing monthly variance analysis of its forecast and the prior year's actual thermal generation, as proposed in Exhibit Staff/701, because preparation of this report would be extremely time consuming, the information would not be available in time to be included in the TAM Initial Filing, and the comparison of actual and forecast generation is generally conducted in the PCAM, not the TAM. PacifiCorp needs additional time to review Staff's proposed report template, which Staff presented for the first time in its rebuttal testimony. PacifiCorp is willing to meet with Staff and other interested parties at the conclusion of this TAM to discuss changes in providing coal generation report information for future TAM filings.

[21] Staff/700, Kim/7.

V. 2023 FUEL PLAN

Q. Staff recommends that in future long-term fuel supply plans, PacifiCorp allow the model to select coal fuel supplies and mine retirement dates, rather than inputting this information into the model.[22] Is this recommendation practical or necessary?

A. No. As noted in my reply testimony, PacifiCorp has agreed to developing its long-term fuel plan for the Jim Bridger plant in conjunction with PacifiCorp's IRP.[23] PacifiCorp uses the results of the IRP as inputs to the PLEXOS model for purposes of developing the long-term fuel plan. The development of the long-term fuel plan is already a major undertaking. Staff's recommendation effectively proposes turning the already comprehensive long-term fuel plan into a separate and subsidiary IRP process, which is both impractical and unnecessary.

Q. Staff notes the difference in the [redacted] in the 2023 Fuel Plan and the TAM Initial Filing and asks PacifiCorp to clarify whether PacifiCorp aligned the TAM to the 2023 Fuel Plan in the Reply Update.[24] Please respond.

A. PacifiCorp's Initial Filing in the TAM preceded the completion of the 2023 Fuel Plan and does not reflect its findings. As I explained in my reply testimony, the Reply Update now reflects the preferred strategy from the 2023 Fuel Plan.[25] Staff also requested that PacifiCorp provide the annual quantities and total costs used for Jim

[22] Staff/1000, Anderson/4.
[23] PAC/500, Owen/29.
[24] Staff/1000, Anderson/4–5.
[25] PAC/500, Owen/35.

Bridger in the Reply Update.[26] This information can be found in the workpapers submitted with my reply testimony.[27]

Q. In its rebuttal testimony, Sierra Club continues to advocate for selection of Scenario 4 as the Preferred Scenario in the 2023 Fuel Plan, instead of Scenario 5/6. Has Sierra Club raised any new concerns about the 2023 Fuel Plan?

A. No. In its rebuttal testimony, Sierra Club acknowledges that Scenario 4 is higher cost than Scenario 5/6 by approximately $[redacted],[28] and Scenario 4 would produce an NPC increase of $[redacted] in the 2024 TAM.[29] But Sierra Club speculates that there might be errors in PacifiCorp's analysis that could change this outcome.[30] Sierra Club does not provide any specific evidence to support its position, pointing only to the correction PacifiCorp made in my reply testimony which reduced the benefits of Scenario 5/6 from $[redacted] to $[redacted]. Sierra Club simply reiterates its earlier arguments against selection of Scenario 5/6 (arguments which it incorrectly refers to as "uncorrected…errors and inconsistencies"),[31] none of which change the fact that Scenario 5/6 is the least cost, least risk fueling scenario by a significant margin.

Q. Are there errors in the 2023 Fuel Plan that would change the benefits identified for customers?

A. No, there are no errors in the 2023 Fuel Plan that would change the conclusions that were reached in that Fuel Plan. To show that the conclusions remain the same,

[26] Staff/1000, Anderson/5.
[27] See workpapers "FUELLIGHTS-ALL 2024 TAM Reply.xlsx" and "01 OpsCostSchedules"
[28] Sierra Club/200, Burgess/1–2.
[29] Sierra Club/200, Burgess/5.
[30] Sierra Club/200, Burgess/1–2.
[31] Sierra Club/200, Burgess/3.

PacifiCorp is providing a corrected 2023 Fuel Plan as Exhibit PAC/902 to this testimony which revises the error identified above (which was discussed in my reply testimony). Additionally, PacifiCorp has identified an inconsequential error in Appendix 7 that has also been corrected. There were inconsistencies between some of the generation and MMBtu numbers presented in Appendix 7 versus Appendices 8–13. The proper values were used in the calculation of the present value of revenue requirement, so none of these errors change the $[redacted] benefit that was identified in the 2023 Fuel Plan.

Q. Sierra Club continues to argue against including data from 2023 in the analysis, largely repeating its arguments from its opening testimony.[32] How do you respond?

A. As I stated in my reply testimony, it makes little sense to align the 2023 Fuel Plan with the 2023 IRP but then use a different start date for the analysis.[33] In any event, Sierra Club acknowledges that the inclusion of 2023 in the analysis contributes to only $[redacted] of the $[redacted] differential between Scenario 4 and Scenario 5/6,[34] making it immaterial to selection of the preferred scenario.

[32] Sierra Club/200, Burgess/4.
[33] PAC/500, Owen/39.
[34] Sierra Club/200, Burgess/4.

Q. Sierra Club claims that PacifiCorp has not explained why 2023 costs differ between Scenarios 4 and 5,[35] why there remains [redacted] "other generation" in Scenario 5 than Scenario 4,[36] and why there are different values for coal cost inputs in PacifiCorp's various workpapers.[37] Can you address these issues?

A. The differences that Sierra Club has raised are largely a function of the differing assumptions in Scenario 4 and Scenarios 5/6. In Scenario 4, [redacted] In Scenarios 5/6, [redacted]

Q. Sierra Club claims that the 2023 Fuel Plan should not have considered costs beyond 2024 (2025–2029) because these are irrelevant to the 2024 TAM, and costs from these years comprise most of the delta between Scenario 4 and Scenarios 5/6.[38] Is Sierra Club's position consistent with the purpose of the long-term fuel planning process?

A. No. The long-term fuel plan process was designed to allow parties to consider coal

[35] Sierra Club/200, Burgess/4.
[36] Sierra Club/200, Burgess/4–5.
[37] Sierra Club/200, Burgess/5.
[38] Sierra Club/200, Burgess/4.

supply strategies on a multi-year basis.[39] Hence, the use of the phrase "long-term" to describe the plan. While the TAM itself is focused on a one-year horizon, PacifiCorp must look beyond the TAM test year in developing a long-term fuel plan.

Q. Sierra Club also persists in its recommendation that the Company produce an annual long-term fuel plan.[40] Is this similarly inconsistent with the purpose of the long-term fuel plan?

A. Yes. Long-term fuel plans have always been considered a "periodic" filing,[41] not an annual filing. This is because they cover multiple years and represent a major undertaking for the Company.

Q. Sierra Club's preferred Scenario 4 assumes the minimum prudent operating level at BCC. In your reply testimony, you note that BCC operating costs increase when fixed costs are spread over fewer tons, adding to the costs of Scenario 4.[42] Does Sierra Club contest this fact?

A. No. Sierra Club simply claims that PacifiCorp has not identified the costs that it considers fixed, and that PacifiCorp could try to spread recovery of some of these costs over a longer period to decrease their impact.[43] Neither of these arguments refute the basic fact that reducing BCC output as contemplated in Scenario 4 increases overall costs to customers.

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[39] *See* 2023 Fuel Plan at PAC/502, Owen/5 ("As set forth in PacifiCorp's compliance filing in the 2015 TAM, Docket UE 287, the purpose of the long-term fuel supply plans for plants fueled by captive mines is to determine the least-cost, risk-adjusted coal supply *evaluated on a multi-year basis*." (Emphasis added)). *See also In the Matter of PacifiCorp, dba Pacific Power, 2014 Transition Adjustment Mechanism*, Docket UE 264, Order No. 13-387 at 15 (Oct. 28, 2013) (concurring opinion of Commissioner John Savage) ("Bridger coal costs must be assessed over a period of years, and not yearly as proposed by ICNU, because of the nature of mining operations.").
[40] Sierra Club/200, Burgess/8.
[41] Order No. 13-387 at 7 (adopting the proposal for the Company to "prepare a periodic fuel supply plan.")
[42] PAC/500, Owen/37.
[43] Sierra Club/200, Burgess/6–7.

Q. Did the Company incorrectly conflate Scenario 4 (BCC low production) with other scenarios [redacted]?[44]

A. No. My reply testimony addressed [redacted] because Sierra Club complained that some of the scenarios reflected different coal pricing assumptions. I explained that this was due in part to the fact that [redacted].

Q. How do you respond to Sierra Club's position that the Company should have modeled other scenarios involving early mine closure?[45]

A. One-half of the scenarios included in the 2023 Fuel Plan involve early mine closure. None of these were as beneficial to customers as were the scenarios that assumed BCC would continue to operate until 2029. There is no evidence that modeling additional iterations of the early mine closure scenarios would change this outcome.

VI. OZONE TRANSPORT RULE

Q. Does the Company plan to remove the impacts of the OTR from the 2024 TAM?

A. Yes. The Company reduced OTR costs in the Reply Update, and now plans to remove them entirely in the TAM Final Update. Please refer to the surrebuttal testimony of Company witness Ramon Mitchell for a more detailed discussion of the NPC decrease resulting from this change.

Q. Why did the Company remove OTR costs from this filing?

A. The Company removed OTR costs from its 2024 TAM forecast because: (1) the Tenth Circuit Court of Appeals granted petitioners', including PacifiCorp, motion to stay the Environmental Protection Agency's (EPA) final disapproval of Utah's state

[44] Sierra Club/200, Burgess/7.
[45] Sierra Club/200, Burgess/7.

implementation plan (SIP) on July 27, 2023; and (2) EPA proposed approval of Wyoming's OTR SIP on August 14, 2023. While timelines cannot be predicted precisely, the OTR stay for the state of Utah is expected to remain in place at least through the 2024 ozone season. For Wyoming, it is unlikely OTR would be implemented in 2024 since the EPA has proposed to approve the state's plan.

Q. Is there a possibility that the OTR could be implemented in 2024?

A. Yes, while unlikely, it is possible that the timelines for implementation could be accelerated.

Q. Does the Company plan to seek a deferral if the OTR is implemented in 2024?

A. Yes. This is consistent with the stipulated treatment of the OTR in the 2023 TAM.[46]

Q. Does this conclude your surrebuttal testimony?

A. Yes.

[46] *See In the Matter of PacifiCorp, dba Pacific Power, 2023 Transition Adjustment Mechanism*, Docket UE 400, Order No. 22-389, App. A at 6, Section 19 (Oct. 25, 2022).

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PACIFICORP

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August 2023

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OF OREGON

PACIFICORP

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Corrected 2023 Jim Bridger Long-Term Fuel Supply Plan

August 2023

PACIFICORP HIGHLY CONFIDENTIAL LONG-TERM FUEL SUPPLY PLAN FOR THE JIM BRIDGER PLANT - (CORRECTED)

May 31, 2023

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

REDACTED
HIGHLY CONFIDENTIAL

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1 INTRODUCTION AND EXECUTIVE SUMMARY

In PacifiCorp's 2014 Transition Adjustment Mechanism (TAM) filing, the Public Utility Commission of Oregon (Oregon Commission) adopted PacifiCorp's proposal to prepare periodic fuel supply plans comparing affiliate mine supply to alternative fuel supply options, including market alternatives for the Jim Bridger Power Plant.[1] As set forth in PacifiCorp's compliance filing in the 2015 TAM, Docket UE 287, the purpose of long-term fuel supply plans for plants fueled from captive mines is to determine the least-cost, risk-adjusted coal supply evaluated on a multi-year basis. The long-term fuel plan is designed to ensure that fuel supplies are fair, just, and reasonable, and that they satisfy the Oregon Commission's prudence and affiliate interest standards.

PacifiCorp has previously filed long-term fuel plans in December 2015, March 2018, and April 2022. After the Company filed the 2018 Fuel Plan, the Oregon Commission directed PacifiCorp to develop an alternative analysis using a shortened plant life of January 1, 2030, instead of December 31, 2037, to comply with Oregon Senate Bill (SB) 1547 signed in 2016. PacifiCorp refreshed the 2018 Fuel Plan in March 2019 to evaluate the reasonableness of the Company's fueling strategy for the Jim Bridger plant using the shortened plant life. The 2023 Fuel Plan is consistent with Oregon SB 1547 as it contemplates consuming coal through 2029, in conformity with PacifiCorp's 2023 Integrated Resource Plan (IRP).

In the October 2021 final order in PacifiCorp's 2022 TAM, the Oregon Commission required PacifiCorp to provide an updated long-term fuel plan in 2022 and submit it with the 2023 TAM. In February of 2022, PacifiCorp sought to delay this filing because several events had created significant uncertainty which prevented the Company from definitively determining the least-cost, risk-adjusted coal supply for the Jim Bridger plant at that time.[2] Specifically, those events included actions by the United States Environmental Protection Agency (EPA) around Jim Bridger's regional haze obligations, revised dates for Idaho Power Company's exit from the Jim Bridger plant, and PacifiCorp's commitment to evaluate carbon capture, utilization and sequestration (CCUS) at the Jim Bridger plant.

Recognizing the uncertainties and difficulties, the Oregon Commission required PacifiCorp to file the 2022 Fuel Plan in April 2022 and clarified that the plan did not need to be a final strategy. While the 2022 Fuel Plan was preliminary, it considered the options available to PacifiCorp based on the best information available at the time. The 2023 Fuel Plan has confirmed the findings of the 2022 Fuel Plan and is likewise based on the best available information. Some uncertainties have been resolved in the last year, however uncertainty still exists surrounding many issues including the EPA's establishment of new nitrogen oxides (NOx) emissions budgets under Ozone National Ambient Air Quality Standards (Ozone Transport Rule) in the state of Wyoming, CCUS requirements, and coordination with Idaho Power Company on exit or gas conversion dates.

In the May 2022 final order in PacifiCorp's 2021 IRP Filing, the Oregon Commission directed PacifiCorp "to file an updated long-term fuel plan for Jim Bridger with its 2023 IRP… PacifiCorp agreed with that

[1] *In the Matter of PacifiCorp d/b/a Pacific Power, 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Net Power Costs Approved Subject to Adjustments, Order No. 13-387 (Oct. 28, 2013).
[2] *In the Matter of PacifiCorp d/b/a Pacific Power, 2022 Transition Adjustment Mechanism*, Docket No. UE 390, Motion to Amend Order No. 21-379 (Feb. 11, 2019).

assessment and consented to provide the updated plan with the 2023 IRP"[3] which was released on March 31, 2023. In April 2023, the Oregon Commission extended the deadline to May 31, 2023.[4]

In the October 2022 final order of PacifiCorp's 2023 TAM, the Oregon Commission approved a stipulation where PacifiCorp agreed that "[m]odeling for the Long-Term Fuel Supply Plan will be conducted in a platform able to accept multiple fuel price tiers such as Aurora or PLEXOS. PacifiCorp will include the following scenarios:

i. Scenario that does not assume a minimum take at either the Black Butte or Bridger Mine; *(Refer to Scenario 6 below)*
ii. Scenario evaluating an alternative to the minimum take requirement in the Black Butte coal supply agreement signed in 2022; *(Refer to Scenario 1 below)*
iii. Scenario evaluating early closure of the Bridger mine (before 2028) and fueling Jim Bridger through end of life with stockpiled coal supplies. *(Refer to Scenario 3 below)*"[5]

To develop the 2023 Fuel Plan, PacifiCorp studied, reviewed, and evaluated different fueling options for the Jim Bridger plant. The evaluation of these fueling options provides valuable insight into [redacted] As part of its 2023 IRP, PacifiCorp assessed various long-term coal supply options as well as alternative options for Jim Bridger Units 3 and 4, including retrofit for CCUS, conversion to natural gas and/or other alternative fuels, and early retirement. The 2023 IRP preferred portfolio selected the conversion of Units 3 and 4 to natural gas in 2030 which requires the ending of coal consumption by December 31, 2029.

Within the 2023 Fuel Plan, the Company has presented several different fueling options. The fueling options consider varying delivery schedules sourced from Bridger Coal Company (Bridger mine), the Black Butte mine, and mines located in Wyoming's Southern Powder River Basin (SPRB). Additionally, the different coal delivery options for the Bridger mine contain various mine plan scenarios outlining specified delivery schedules. Included in these different mine scenarios are estimated shutdown dates for the Bridger mine.

The 2023 Fuel Plan provides third-party coal supply volume and pricing estimates based upon the current contract and ongoing discussions with the Black Butte mine, as well as recent coal pricing forecasts from Energy Ventures Analysis (EVA). The 2023 Fuel Plan provides estimated volumes and rail rates for transportation services based on agreements with the Union Pacific Railroad (UPR) for the transport of coal from third-party coal supply sources. The estimated plant modifications and capital requirements, defined by equipment category, as well as total costs needed to support large volumes of SPRB coal are derived from a detailed third-party study completed in 2017 by the engineering and consulting firm Burns & McDonnell, adjusted for inflation and to account for volumes associated with operating two coal units instead of four coal units.

After considering factors influencing the long-term fueling strategy and information available to PacifiCorp at this time, the Company developed and evaluated six Jim Bridger plant coal fueling options:

[3] *In the Matter of PacifiCorp d/b/a Pacific Power, 2021 Integrated Resource Plan*, Docket No. LC 77, 2021 IRP Acknowledged with Modifications and Exceptions, Order No. 22-178 (May 23, 2022).
[4] *In the Matter of PacifiCorp d/b/a Pacific Power, 2023 Integrated Resource Plan*, Docket No. LC 82, Order No. 23-131 (Apr. 6, 2023).
[5] *In the Matter of PacifiCorp d/b/a Pacific Power, 2023 Transition Adjustment Mechanism*, Docket No. UE 400, Comprehensive Stipulation Adopted: Directives for Future Filings, Order No. 22-389 (Oct. 25, 2022).

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- **Scenario 1** [redacted]
- **Scenario 2** [redacted]
- **Scenario 3** [redacted]
- **Scenario 4** [redacted]
- **Scenario 5** [redacted]
- **Scenario 6** [redacted]

As a preliminary indication of the cost-effectiveness of the proposed scenarios using recent assumptions, the Company completed a Present Value Revenue Requirement (PVRR) calculation, comparing major components of PacifiCorp's system costs resulting from the various fueling options, including a composite ranking considering both financial and risk weighting. These costs include coal purchases, natural gas purchases, and system power purchases offset by wholesale power sales (System Costs). Other components not considered in the analysis include costs associated with qualifying facilities, power purchase agreements, geothermal and wheeling. These items do not vary with system dispatch in the PLEXOS model and would not vary between scenarios. This analysis is based on the Company's forward price curve for power and natural gas, which does not include greenhouse gas costs, but does account for the impacts of certain recently proposed EPA emissions requirements, such as the Ozone Transport Rule. The results of the PVRR analysis and risk evaluation indicate that Scenario 5 and Scenario 6 are the current least-cost, risk-adjusted options. Option 6 was modeled assuming no minimum take-or-pay obligations for the Bridger mine or Black Butte Coal Company. Based on PacifiCorp's evaluation using the PLEXOS model, all of the available incremental coal from the Bridger mine would be cost-effective. As a result, the fueling plans in Scenario 5 and Scenario 6 are essentially the same. Therefore, Scenarios 5 and 6 will be referred to as the "Preferred Scenario" in this report going forward.

The benefits of pursuing the Preferred Scenario as the long-term fueling strategy for the Jim Bridger plant include the following:

- Provides the least-cost, risk-adjusted fuel supply for the Jim Bridger plant,
- [redacted]

Although the Preferred Scenario is the current least-cost, risk-adjusted fueling option for the Jim Bridger plant, PacifiCorp will continue to evaluate the best fueling option for the Jim Bridger plant, taking into consideration both cost and risk, and will update the long-term fuel supply plan after each IRP is released to reflect changing assumptions and expectations.

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2 EVALUATION METHODOLOGY

In the 2023 Fuel Plan, PacifiCorp evaluated several different fueling options for the Jim Bridger plant. The methodology used to evaluate the fueling options is similar to the methodology used in the April 2022 long-term fuel plan. As noted above, the 2023 Fuel Plan considers the variable components of PacifiCorp's System Costs. The same production software used in the 2023 Integrated Resource Plan (IRP), PLEXOS, was used for the 2023 Fuel Plan. Prior plans used PacifiCorp's Generation and Regulation Initiative Decision Tools model (GRID) and costs for the consumed tons required to support the generation forecast under each fueling option were then calculated. The cost of coal for the Jim Bridger plant under each fueling option was then compared to the system benefits of incremental coal-fired generation from the PLEXOS model on a PVRR basis.

3 BACKGROUND

The Jim Bridger plant is a coal-fired plant located in Sweetwater County, Wyoming. The facility is located approximately eight miles north of Point of Rocks, Wyoming, and approximately 24 miles east of Rock Springs, Wyoming.

The Jim Bridger plant is the largest power plant on the PacifiCorp system (2,120 megawatts) and is jointly owned by PacifiCorp (66.7%) and Idaho Power Company (Idaho Power) (33.3%). The Jim Bridger plant consists of four almost identical units, each with a nominal 530 net megawatt capacity. Over the four-year period of 2019-2022, the Jim Bridger plant consumed approximately 24 million tons of coal, an average of six million tons per year. The plant is designed to consume coal sourced from southwest Wyoming with heat content in the range of 9,000 Btu/lb. to 10,000 Btu/lb.

The Bridger mine is located adjacent to the Jim Bridger plant. Having ceased underground mining operations in December 2021, the Bridger mine currently consists solely of surface mining operations. Like the Jim Bridger plant, the Bridger mine is jointly owned by PacifiCorp (66.7%) and Idaho Power (33.3%). The surface mine is a combination dragline and truck/loader operation that produces approximately [redacted] million tons of coal per year.

For regulatory purposes, the Bridger mine is consolidated with PacifiCorp's operations. PacifiCorp's share of the Bridger mine is included in the PacifiCorp rate base and its share of mining costs, including depreciation and depletion, is included in System Costs.

In addition to the Bridger mine deliveries, the Jim Bridger plant has historically received the remaining portion of its coal supply requirements from the nearby Black Butte mine. The UPR provides rail access for all the coal delivered from the Black Butte mine to the plant.

4 ASSUMPTIONS

Currently, the Jim Bridger plant has three potential sources for coal supply:

- The Bridger mine
- The Black Butte mine

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- Wyoming's SPRB mines

As demand for generation from the Jim Bridger plant is expected to decline significantly after Units 1 and 2 convert to natural gas in 2024, the 2023 Fuel Plan examines scenarios ranging from [redacted]

To assist with the characterization of the potential supply changes over time, the fueling options have been separated into "near-term" and "long-term" periods for discussion purposes. For purposes of the 2023 Fuel Plan, the near-term period has been defined as 2023 and corresponds to the time that Units 1 and 2 are consuming coal before the conversion of those units to gas operation. The key assumptions in the 2023 Fuel Plan are explained below:

4.1.1 Generation

As mentioned above, generation forecast assumptions are provided by PacifiCorp's PLEXOS model for each fueling option studied. To ensure compliance with the Regional Haze Consent Decree with the State of Wyoming, the 2023 Fuel Plan assumes Jim Bridger Units 1 and 2 will stop consuming coal December 31, 2023 and convert to natural gas in 2024. Consistent with the outcome of the 2023 IRP, Jim Bridger Units 3 and 4 will continue to consume coal until December 31, 2029, and then also convert to natural gas in 2030.

On a total plant basis (i.e., including Idaho Power's expected consumption), coal consumption is forecast to be in the range of [redacted] million to [redacted] million tons for 2023.

4.1.2 Plant Depreciable Life

The assumed depreciable life in Oregon of PacifiCorp's share of the Jim Bridger plant extends through 2029 for Units 1 and 2 and through 2025 for Units 3 and 4. Other states in PacifiCorp's service territory use differing depreciable lives for different units ranging from 2023 to 2037, based upon PacifiCorp's 2018 depreciation study and other regulatory agreements.

4.1.3 Bridger Mine Plans

In early 2023, the Bridger mine prepared three operating mine plans; [redacted]

[redacted]

4.1.4 Third Party Coal

Due to the geographic location of the Jim Bridger plant, economic fuel supply alternatives other than the Bridger mine are limited to one additional operating mine located in southwest Wyoming and the SPRB mines of Campbell County, Wyoming.

The Black Butte mine, located 20 miles southeast of the Jim Bridger plant, is operated by Lighthouse Resources Inc. (Lighthouse). Lighthouse emerged from bankruptcy in 2020. The mine is a multiple seam, multiple pit operation with the overburden removed by draglines and a truck/loader fleet. In recent years, the mine has produced less than [redacted] tons per year and the Jim Bridger plant has been the mine's primary customer. Between 2019 and 2022 the Jim Bridger plant received approximately [redacted] tons, an average of [redacted] tons per year, from the Black Butte mine. Coal from the Black Butte mine is delivered by rail to the Jim Bridger plant under an agreement with UPR.[6]

The Powder River Basin is the largest coal mining region in the United States. Coal from the SPRB is classified as sub-bituminous coal. SPRB coal contains an average heat content of approximately 8,800 Btu/lb. The coal mined in the SPRB is low sulfur and low ash. Due to its unique quality characteristics, SPRB coal has been consumed by energy markets in multiple states across the country. In 2022, there were seven mining companies operating twelve active mines in Wyoming's Powder River Basin, producing roughly 238 million tons. SPRB mines contain the highest heat content coal in the basin ranging between 8,600 Btu/lb. and 8,950 Btu/lb. These mines are located about 550 miles from the Jim Bridger plant. SPRB mines and the Jim Bridger plant are served by UPR. Consumption of SPRB coal requires UPR delivery.

4.1.5 Black Butte Pricing

As of May 2023, coal from the Black Butte mine is purchased under a Coal Supply Agreement (CSA) signed June 19, 2022 that ends December 31, 2023. [redacted]

[6] Due to limited coal reserves, estimated production costs, transportation difficulties, and the planned closure of the Naughton plant in 2025, Kemmerer Operations, LLC's Kemmerer mine is not considered a viable fuel source for the Bridger plant.

[redacted]

4.1.6 Black Butte Mine Volume

PacifiCorp conducted a high-level review of the Black Butte mine coal resource and reserve estimates in 2015. The study consisted of reviewing available third-party Black Butte reserve and geology documents, along with Black Butte's geology information and permitting status. At the time, based on the information reviewed, the conclusion of the review was that the Black Butte mine had [redacted] tons that could be considered economic coal reserves under the terms and conditions of the then-current contract.

PacifiCorp and Idaho Power purchased 14 million tons between 2016 and 2022. The scenario that consumes the highest volume of Black Butte coal, assumes purchases of [redacted] tons by PacifiCorp and Idaho Power between 2023 and 2029. Therefore, this study assumes that Black Butte has sufficient coal reserves to satisfy the Jim Bridger plant. Note that the reserve estimate includes the expansion of Black Butte mine into the Pit 15 area. As of May 2023, the permitting process for this area is still pending with federal government agencies. If Pit 15 is not permitted, the risk exists that sufficient reserves may not be available from the Black Butte mine under [redacted]

4.1.7 Assumed SPRB Coal Pricing

Coal pricing for 2023 comes from a coal supply agreement with [redacted] Volumes purchased by PacifiCorp range from [redacted]. SPRB coal pricing in the 2023 Fuel Plan beyond 2023 is based on a long-term coal forecast published by EVA in spring 2023.

4.1.8 Powder River Basin Coal in the Near-Term

Powder River Basin coal has a high propensity to spontaneously combust and is the most friable coal type consumed in the power industry. While major plant modifications would be required to receive and consume large volumes of SPRB coal safely and reliably at the Jim Bridger plant, currently the plant is likely capable of consuming SPRB coal on a limited scale without major modification to the plant's coal unloading or coal consuming infrastructure. For example, in a test during 2015, the plant handled and consumed 10 trains totaling 140,540 tons of SPRB coal. Based on knowledge gained from that test and PacifiCorp's professional judgment, PacifiCorp believes that up to a total of 800,000 tons of SPRB coal per year can be safely and reliably consumed without major modifications to the plant infrastructure. This estimate is considered aggressive, as issues with scheduling or handling coal could result in lower maximum annual SPRB volumes using the existing infrastructure. The current 800,000-ton assumption could be adjusted based upon the results of actual coal deliveries in 2023 from the [redacted].

4.1.9 Transportation

Coal from the Bridger mine is delivered to the Jim Bridger plant via conveyor belt, and the cost of conveying the coal is included in the delivered coal cost. The Jim Bridger plant is also connected by a rail spur to the UPR mainline track. UPR has the trackage rights to the mainline and spur to the Jim Bridger plant and, as a result, the Jim Bridger plant is captive to UPR for deliveries by rail. Deliveries from all sources other than the Bridger mine are assumed to be delivered by the UPR. As mentioned above, the transportation rates for delivery of Black Butte and SPRB coal are based upon the current rail transportation agreement with UPR and escalated beyond 2023.

4.2 Jim Bridger Plant Capital

PacifiCorp selected the consulting firm Burns & McDonnell (B&M) to perform an independent capital evaluation of the plant modifications and capital expenditures required at the Jim Bridger plant to consume volumes, up to 100%, of SPRB coal. B&M completed a comprehensive study in June 2017. The study outlined high priority plant modifications and the estimated costs in converting the Jim Bridger plant's main fuel source to SPRB coal. The study focused on required modifications to several systems including coal handling and storage, rail delivery, mechanical process/power island, electrical, substation and overhead distribution and air permitting.

The required coal handling system modifications identified engineering controls that would be needed and relied upon to reduce and mitigate coal dust throughout the coal handling system. The study emphasized the importance of having adequate wash down capability by installing and utilizing fixed pipe wash down systems in existing coal reclaim and conveyor tunnels, crusher houses, tripper bays and in the rail unloading hopper facilities. The study also assumed a loop track and thaw shed would be required. Recommendations were made on how to safely and reliably handle SPRB coal: keep areas clean, eliminate ignition sources and detect spontaneous combustion with accumulated SPRB coal dust. These safety steps are designed to protect people, equipment, and enclosures from explosions due to the dangerous spontaneous combustion tendencies of SPRB coal.

Required modifications to the rail delivery system outlined in the 2017 study indicate that the current unloading configuration is [redacted]

In the 2023 Fuel Plan, the capital modifications for [redacted] The 2023 Fuel Plan assumes that Idaho Power will participate in the capital modifications. PacifiCorp's estimated cost of the capital modifications based on B&M's June 2017 study is approximately [redacted], as provided in Table 1.

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TABLE 1
Jim Bridger Plant Capital Costs

[redacted]

5 FUEL SUPPLY MIX

PacifiCorp evaluated six fueling scenarios for the Jim Bridger plant for the 2023 Fuel Plan. Those scenarios are described below. Please refer to Appendices 1-13 for detailed fueling mix and pricing information for each fueling option considered. Summaries of the fuel supply mix, including average volumes for the near-term and long-term, for each fueling option evaluated are provided below. Note that Scenarios 5 and 6 result in the same solution but were run in PLEXOS with different assumptions as seen below.

5.1 Scenario 1 [redacted]

Scenario 1 considers [redacted]

5.2 Scenario 2 [redacted]

Scenario 2 considers [redacted]

5.3 Scenario 3 [redacted]

Scenario 3 considers [redacted]

5.4 Scenario 4 [redacted]

Scenario 4 considers [redacted]

5.5 Scenario 5 [redacted]

Scenario 5 considers [redacted]

5.6 Scenario 6 [redacted]

Scenario 6 considers [redacted]

6 PVRR ANALYSIS AND RESULTS

6.1 Jim Bridger Coal Fueling Cost Analysis

The PVRR analysis represents a present value revenue requirement using major NPC components for the PacifiCorp system. The fuel costs for all coal and gas plants are included along with power purchase costs offset by power sales revenues. Scenario 2 [redacted] The PVRR results have been discounted using PacifiCorp's weighted average cost of capital. A total PVRR differential has been calculated for each of the six fueling scenarios comparing the total PVRR for each option against the Preferred Scenario, the fueling option with the lowest PVRR dollar amount.

Table 2 below shows the results of the PVRR analysis for each fueling option in the 2023 Fuel Plan supplying the Jim Bridger plant with coal through December 2029. Also included in Table 2 is a financial ranking from 1 to 6 for each of the fueling options. Table 2 also shows the Preferred [redacted] The other fueling options range between these options. Additional discussion on risk assessment for each fueling option is presented in the next section below.

TABLE 2
PVRR Analysis Through December 2029

[redacted]

6.2 RISK ANALYSIS

The following table provides a risk assessment for each scenario and outline the specific categories that have been considered in the risk evaluation analysis. Table 3 illustrates a risk assessment of Scenarios 1 through 6 through December 2029.

TABLE 3
Risk Evaluation Through 2029

[redacted]

The defined risk profile categories include (1) Incremental Capital – the risks associated with the total costs of incremental capital expenditures related to each fueling scenario, (2) Coal Market – risks associated with adequate coal supplies, as well as coal and transportation price, (3) Power and Natural Gas Market Volatility – risks associated with power market price volatility driven by changing natural gas prices, availability of hydro generation, impacts of renewable energy sources, load demand, and (4) Jim Bridger Plant Environmental Compliance – risks associated with new environmental regulations that could change generation at the Jim Bridger plant.

For each fueling scenario under each risk category, a number ranging between 1 and 4 has been assigned. Number 1 is designated as “favorable and low risk.” Number 2 is “favorable and moderate risk,” and number 3 is “less favorable and high risk.” Number 4 is designated as “least favorable and highest risk.” The sum of the risk numbers for each category for each scenario, results in an overall “composite project risk” score.

[redacted]

7 REMAINING UNCERTAINTIES

Recent and ongoing events have increased uncertainty around the future of Jim Bridger plant’s fuel plans in a way that make definitive Jim Bridger long-term coal supply decisions or commitments high risk at this time. The following is a short summary of some of the major uncertainties that impact the 2023 Fuel Plan and an explanation of how the plan may change depending on the resolution of the uncertainties.

7.1 JIM BRIDGER GAS CONVERSIONS

Jim Bridger Units 1 and 2 are scheduled to be converted to natural gas in 2024 as required by a Regional Haze Consent Decree with the State of Wyoming. Based on the Company's 2023 IRP, Units 3 and 4 are scheduled to be converted to natural gas in 2030. The 2023 IRP analyzed a scenario where Jim Bridger Units 3 and 4 were not converted to natural gas, which resulted in significantly higher costs to PacifiCorp customers.[7] The natural gas conversion of Jim Bridger Units 1 and 2 is an enforceable environmental compliance requirement (Regional Haze requirements under the Clean Air Act (CAA)) under a consent decree entered into by the state of Wyoming and the Company[8] and an administrative consent order with EPA. The state of Wyoming issued an air permit for the natural gas conversion of Jim Bridger Units 1 and 2 in December 2022, as well as submitted a state-approved revised regional haze state implementation plan to EPA requiring the natural gas conversion. EPA is reviewing the submission and is expected to conduct a separate federal public comment process on the plan in summer of 2023. PacifiCorp submitted a notice of compliance and request for termination of the EPA order in March of 2023, which is currently under EPA review. While some of these processes have not yet been finalized, and uncertainty remains, the gas conversion process is underway and any alternative compliance scenarios will be based on Units 1 and 2 converting to gas. The conversion of Units 3 and 4 is further out in time and thus subject to more uncertainty. Due to these uncertainties, [redacted]

7.2 PACIFICORP'S COMMITMENT AND REQUIREMENT TO EVALUATE CCUS AT JIM BRIDGER

Pursuant to Wyoming Statute §§ 37-18-101 and -102 and the Wyoming Public Service Commission Administrative Rules, PacifiCorp is required to analyze the suitability of CCUS at coal fired electric generation facilities, owned in whole or in part with another utility or utilities subject to the provisions of Wyo. Stat. § 37-18-102(a). The Company has determined that Jim Bridger Units 3 and 4 are potentially suitable candidates for CCUS. Additionally, the consent decree entered into by the state of Wyoming and the Company required the Company to issue request(s) for proposals (RFP) for the installation of CCUS at Jim Bridger Units 3 and 4 no later than January 1, 2023. PacifiCorp released the CCUS RFP to qualified bidders in November of 2022 for the Jim Bridger facility. [redacted]

CCUS installation at Jim Bridger Units 3 and/or 4 has the potential to significantly impact coal burn and dispatch. The generation forecast and coal requirement at the Jim Bridger plant will likely increase if PacifiCorp elects to, or is required to, install CCUS at Bridger Units 3 and/or 4. Proceeding with the Preferred Scenario in the near-term would not preclude the future installation of CCUS at the Jim Bridger plant while PacifiCorp continues to evaluate options and work to comply with Wyoming's CCUS regulations. Fueling strategies for CCUS scenarios would focus on availability and reliability of coal supply.

[7] PacifiCorp's 2023 IRP, Chapter 9 – Modeling and Portfolio Selection Results, pages 266-267.
[8] Wyoming Consent Decree, Docket No. 2022-CV-200-333 (February 14, 2022).

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7.3 PROPOSED EPA RULES

Ozone Transport Rule

The EPA proposed a federal implementation plan for 26 states, including Wyoming, in April of 2022, to eliminate significant contributions to nonattainment of the 2015 ozone National Ambient Air Quality Standard (NAAQS) in neighboring states, known as the Ozone Transport Rule, "good neighbor rule," or "interstate transport" provision of the CAA.[9] However, on January 31, 2023, EPA delayed final action on Wyoming's ozone interstate transport state implementation plan to December of 2023. Wyoming cannot be included in the federal plan until EPA disapproves the state plan. EPA finalized its federal ozone plan on March 15, 2023, but deferred action on Wyoming, meaning the state is currently not subject to the federal plan but could be once EPA finalizes its determination on the state plan. EPA's deferral of Wyoming is currently under litigation. EPA's federal plan is focused on reducing NOx, a precursor to ozone formation, and requires fossil-fuel-fired power plants to participate in an allowance-based ozone season trading program beginning in 2023. The federal rule includes SCR-like NOx budgets for each generating unit and will impact the Company and its operations. The final rule has been released by EPA but has not yet been published in the Federal Register, meaning compliance timelines are not yet established.

Jim Bridger Units 3 and 4 are currently equipped with SCR. Given the impacts of the federal plan on PacifiCorp's Utah coal plants, and depending on EPA's determination on Wyoming's state plan, these units may take on a more critical role in the compliance and reliability strategy for PacifiCorp's fleet and may operate at higher levels than previously forecasted during the ozone season (May – September). Proceeding with the Preferred Scenario, as explained above when discussing the possibility of CCUS at the Jim Bridger plant, keeps all the fueling alternatives on the table as PacifiCorp determines the most effective course of action for compliance with the rule and preserving reliability. Litigation of Utah and other state plan disapprovals is currently underway, and the final rule is also expected to be heavily litigated.

EPA's deferred action on Wyoming's state plan creates a great deal of uncertainty about how the Ozone Transport Rule will impact PacifiCorp's coal fleet. While this is pending, the Preferred Scenario is the most economical in the interim and will provide PacifiCorp time to better understand this potential regulation and its impacts on the generation fleet.

Greenhouse Gas Rule

EPA issued proposed regulations under section 111 of the CAA on May 23, 2023, to address greenhouse gas emissions from fossil-fuel fired electric generating units (the "Greenhouse Gas Rule"). The standards proposed in the rule would regulate new gas-fired combustion turbines and set standards for states to regulate existing coal plants, converted natural gas plants and certain large and frequently used existing gas turbine plants. The standards vary significantly based on facility-specific factors – including whether the unit is new or existing, whether it is fueled by coal or natural gas, how frequently it operates, and whether it is scheduled to retire in the coming years. Coal units operating beyond 2032 face increasingly stringent emission limits, and those operating beyond 2040 must comply with emission limits consistent with carbon capture and sequestration starting in 2030. PacifiCorp is evaluating the specific impacts of the proposal and how they impact the Bridger Units and the fueling plan. The impacts from the Greenhouse Gas Rule create some uncertainty due to changing future requirements for coal and gas units and because these requirements could be adjusted when the rule is finalized. The Preferred Scenario allows PacifiCorp

[9] *See* 42 U.S.C. 7410(a)(2)(D)(i)(I); 87 Fed. Reg. 20036 (April 6, 2022).

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to maintain options to address the impacts and system-wide adjustments that may result from the proposed rule.

7.4 Idaho Power Company's Planned Exit Dates

PacifiCorp's 2023 IRP Preferred Portfolio plans for Jim Bridger plant Units 1 and 2 to cease consuming coal on December 31, 2023 and convert to natural gas consumption. PacifiCorp's IRP also anticipates that Units 3 and 4 will cease consuming coal on December 31, 2029 and convert to natural gas. The IRP also provides December 31, 2037, as the closure date for all units. PacifiCorp and Idaho Power Company (Idaho Power) are aligned in the decision to consume coal in Units 1 and 2 through 2023, since Idaho Power's 2021 IRP calls for the conversion of two units to natural gas consumption in 2024. However, PacifiCorp and Idaho Power currently differ on the operation of Jim Bridger plant Units 3 and 4. Idaho Power's 2021 IRP provides December 31, 2025, as the closure date for a third Jim Bridger plant unit and December 31, 2028, as the closure date for a fourth Jim Bridger plant unit. Currently, these differences make modeling the Jim Bridger plant's future fueling needs difficult. Idaho Power is preparing an updated IRP which is scheduled to be released later in 2023. For purposes of the 2023 Fuel Plan, PacifiCorp has assumed the information in Idaho Power's 2021 IRP will remain the same. Ultimately, as co-owners of Jim Bridger plant and Bridger mine, PacifiCorp and Idaho Power will need to align their plans to best accommodate the unique needs of their respective customers. The solutions will impact each owner's access to and usage of the Jim Bridger plant and Bridger mine in the future.

REDACTED

HIGHLY CONFIDENTIAL

8 CONCLUSION

In this 2023 Fuel Plan, PacifiCorp has identified a long-term fueling plan for the Jim Bridger plant that aligns with the Company's 2023 IRP, responds to changing fuel requirements, and allows flexibility to deal with uncertainty. This plan is PacifiCorp management's current strategy and lays out the various considerations and options available to PacifiCorp based on the best information available at this time. Alternative mine plans have been developed, evaluated, and reviewed for the Bridger mine which provided information and direction in determining the optimal volume at the Bridger mine.

After considering factors influencing this long-term fueling strategy and information available to the Company at this time, six different fueling options have been developed and evaluated. Based upon the results of the detailed PVRR analysis, which was further enhanced by utilizing a risk profile, the Preferred Scenario (Scenarios 5 and 6) provides the least-cost, risk-adjusted option and informs PacifiCorp's 2023 Jim Bridger plant fueling strategy. The Preferred Scenario assumes BCC operates two draglines. This plan would allow PacifiCorp [redacted]

Although the Preferred Scenario is the current least-cost, risk-adjusted fueling option for the Jim Bridger plant, energy market volatility and changing environmental legislation continues to create uncertainty around the future of Jim Bridger. PacifiCorp will continue to evaluate the best fueling options for the Jim Bridger plant as conditions change and as decision points for various supply options approach. PacifiCorp will update the long-term fuel supply plan after the 2025 IRP is finalized.

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APPENDIX 1 – SCENARIO 1 – [redacted]

[redacted]

APPENDIX 2 – SCENARIO 2 – [redacted]

[redacted]

REDACTED
HIGHLY CONFIDENTIAL

APPENDIX 3 – SCENARIO 3 – [redacted]

[redacted]

REDACTED
HIGHLY CONFIDENTIAL

APPENDIX 4 – SCENARIO 4 – [redacted]

[redacted]

REDACTED

HIGHLY CONFIDENTIAL

APPENDIX 5 – SCENARIO 5 – [redacted]

[redacted]

REDACTED
HIGHLY CONFIDENTIAL

APPENDIX 6 – SCENARIO 6 – [redacted]

[redacted]

REDACTED
HIGHLY CONFIDENTIAL

APPENDIX 7 – JIM BRIDGER PLANT CONSUMED FUEL SUMMARY

[redacted]

REDACTED
HIGHLY CONFIDENTIAL

APPENDIX 7 – JIM BRIDGER PLANT CONSUMED FUEL SUMMARY (CONT'D.)

[redacted]

REDACTED
HIGHLY CONFIDENTIAL

APPENDIX 8 – SCENARIO 1 – JIM BRIDGER PLANT

[redacted]

REDACTED
HIGHLY CONFIDENTIAL

APPENDIX 8 – SCENARIO 1 – JIM BRIDGER PLANT (CONT'D.)

[redacted]

REDACTED

HIGHLY CONFIDENTIAL

APPENDIX 9 – SCENARIO 2 – JIM BRIDGER PLANT

[redacted]

REDACTED

HIGHLY CONFIDENTIAL

APPENDIX 9 – SCENARIO 2 – JIM BRIDGER PLANT (CONT'D.)

[redacted]

REDACTED

HIGHLY CONFIDENTIAL

APPENDIX 10 – SCENARIO 3 – JIM BRIDGER PLANT

[redacted]

REDACTED

HIGHLY CONFIDENTIAL

APPENDIX 10 – SCENARIO 3 – JIM BRIDGER PLANT (CONT'D)

[redacted]

REDACTED

HIGHLY CONFIDENTIAL

APPENDIX 11 – SCENARIO 4 – JIM BRIDGER PLANT

[redacted]

REDACTED

HIGHLY CONFIDENTIAL

APPENDIX 11 – SCENARIO 4 – JIM BRIDGER PLANT (CONT'D.)

[redacted]

REDACTED

HIGHLY CONFIDENTIAL

APPENDIX 12 – SCENARIO 5 – JIM BRIDGER PLANT

[redacted]

REDACTED
HIGHLY CONFIDENTIAL

APPENDIX 12 – SCENARIO 5 – JIM BRIDGER PLANT (CONT'D.)

[redacted]

REDACTED

HIGHLY CONFIDENTIAL

APPENDIX 13 – SCENARIO 6 – JIM BRIDGER PLANT

[redacted]

REDACTED

HIGHLY CONFIDENTIAL

APPENDIX 13 – SCENARIO 6 – JIM BRIDGER PLANT (CONT'D.)

[redacted]

Docket No. UE 420
Exhibit PAC/1000
Witness: Matthew D. McVee

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Surrebuttal Testimony of Matthew D. McVee

August 2023

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I. INTRODUCTION

Q. Are you the same Matthew D. McVee who previously submitted reply testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company)?

A. Yes.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony in this proceeding?

A. I respond to the rebuttal testimony of Rose Anderson, filed on behalf of Staff, Bradley G. Mullins, filed on behalf of the Alliance of Western Energy Consumers (AWEC), and Bob Jenks, filed on behalf of the Oregon Citizens' Utility Board (CUB).

Q. Please summarize your testimony.

A. First, the Public Utility Commission of Oregon (Commission) should reject recommendations to penalize the Company for complying with Washington's Cap and Invest Program. Staff and AWEC both recommend that Oregon customers not pay some or all of the costs to purchase greenhouse gas (GHG) emission allowances required by Washington law. If Oregon customers are going to receive the benefits of the Chehalis plant—in the form of lower net power costs (NPC)—then Oregon customers should pay the costs to generate at Chehalis, including the costs to comply with Washington law. Both Staff's and AWEC's recommendations are contrary to sound public policy and contrary to the 2020 PacifiCorp Inter-Jurisdictional Allocation Protocol (2020 Protocol).

Second, the Commission should reject CUB's recommendation that the

Company prepare an October NPC update and that the Commission order the Company delay recovery of non-Transition Adjustment Mechanism (TAM) costs in order to mitigate customer rate impacts. CUB has not justified its request for an overly burdensome additional NPC update, which would precede the November NPC update by a matter of weeks. And, although the Company is always concerned about customer rate impacts, CUB's proposal to delay recovery of non-TAM costs is outside the scope of the TAM and better addressed in other proceedings such as the Power Cost Adjustment Mechanism (PCAM).

III. WASHINGTON CAP AND INVEST PROGRAM

A. Reply to Staff

Q. Has Staff's position changed with respect to the treatment of the Washington Cap and Invest Program's no-cost allowances?

A. No. Staff does not dispute that a Washington state agency has directed PacifiCorp to allocate the no-cost allowances provided by Washington state to Washington customers.[1] However, Staff's position is that PacifiCorp's compliance with Washington law is unfair, which "leads to the question of whether ratepayers or the Company should pay for the costs of this unfair treatment."[2] Staff's conclusion is that customers should either be relieved of this cost or only pay 50 percent of the cost of the no-cost allowances Oregon customers would otherwise be allocated.[3] Either way, Staff's position is that Oregon customers should not pay their full share of compliance costs for generating at the Chehalis plant.

[1] Staff/1000, Anderson/16.
[2] Staff/1000, Anderson/16.
[3] Staff/1000, Anderson/16–17.

Q. How do you respond to Staff's recommendation?

A. Staff's recommendation penalizes the Company for complying with Washington law. Staff does not dispute that the Company is required to obtain emission allowances for Chehalis generation and that the state of Washington has provided no-cost allowances for Washington customers. Staff, however, would shift costs of complying with these legal requirements to the Company, essentially creating a disallowance for compliance with state law. If Oregon customers are going to receive the benefits of Chehalis, then Oregon customers need to pay the costs to generate those benefits. And if Oregon customers do not want to pay compliance costs for Chehalis, then it is reasonable for Oregon customers to not receive the benefits of Chehalis' generation.

Q. How would NPC change if Chehalis were excluded?

A. Oregon rates would increase if Chehalis were removed from the NPC forecast, as explained by Company witness Ramon Mitchell. Staff's recommendation, therefore, amounts to insisting that the Company subsidize Oregon customers so that Oregon customers receive the NPC benefits of Chehalis, while the Company pays for the compliance costs to achieve those benefits.

Q. Is Staff's recommendation that Oregon customers should not pay full compliance costs consistent with your understanding of how other environmental compliance costs are allocated to Oregon customers?

A. No. All the Company's generation resources incur various types of environmental compliance costs and generation taxes, many of which are imposed by the state where the resource is located. These include costs like the Wyoming wind tax, Portland Harbor remediation costs, upgrades at generation facilities that are necessary to comply with environmental requirements like fish passage at hydroelectric plants or avian curtailments at wind facilities. These direct impacts to generation are consistently system allocated. Oregon customers pay these environmental compliance and generation tax costs incurred by resources that are used to serve Oregon customers. Adopting Staff's position here sets a poor precedent for other existing and future environmental compliance costs imposed by other states on generating resources located in those states. If Oregon policy becomes one where Oregon customers pay only for costs imposed by the state of Oregon, then it will become very difficult for the Company to serve Oregon customers with resources located in other states, like Wyoming wind facilities or Utah solar facilities. Additionally, it could lead to the situs assignment of Oregon's environmental policies that impact a system resource located in Oregon like the Hermiston generating facility.

Q. Staff also "finds this issue to be a state energy policy and as such should be entirely borne by Washington per MSP guidelines."[4] Do you agree?

A. No. Although unclear, Staff appears to be referencing Section 3.1.2.1 of the 2020 Protocol, which states:

> <u>State-Specific Initiatives</u>: Costs and benefits associated with Interim Period Resources acquired in accordance with a State-specific initiative will be allocated and assigned on a situs basis to the State adopting the initiative. State-specific initiatives include, but are not limited to, the costs and benefits of incentive programs, net-metering tariffs, feed-in tariffs, capacity standard programs, solar subscription programs, electric vehicle programs, and the acquisition of renewable energy certificates.

[4] Staff/1000, Anderson/17.

In addition to Section 3.1.2.1, Section 3.1.7 of the 2020 Protocol states that both "[g]eneration-related dispatch costs and associated plant" and "[g]eneration and fuel-related taxes" will be allocated using the System Generation (SG) Factor. As noted above, the compliance costs associated with the Washington Cap and Invest Program are appropriately characterized as a generation-related dispatch tax—there is no compliance obligation if there is no generation and the amount of the compliance obligation is determined by the amount of generation. Indeed, AWEC specifically, and correctly, describes the compliance obligation as a "generation tax," leaving little room to argue for any treatment other than allocation using the SG Factor.[5]

Taken together, Sections 3.1.2.1 and 3.1.7, make clear that a generation tax, like the GHG dispatch cost imposed by Washington state are not situs assigned to the state imposing the tax, which is consistent with how the Wyoming wind tax is allocated under the 2020 Protocol.

Q. If the overall compliance costs of the Washington Cap and Invest Program should be allocated to Oregon under the 2020 Protocol, which is Staff's recommendation, why are you recommending different treatment for the no-cost allowances?

A. The no-cost allowances Washington has decided to provide to its own customers is tied directly to Washington's retail load and the attributes associated with PacifiCorp serving that load. The provision of no-cost allowances is distinct from the generally applicable generation tax imposed by the Washington Cap and Invest Program. As was noted in PacifiCorp witness Zepure Shahumyan's testimony, the provision of

[5] AWEC/100, Mullins/12.

no-cost allowances was determined by the Washington Department of Ecology to be limited to Washington's retail load.[6] Therefore, these no-cost allowances are assigned consistent as a state specific initiative under 3.1.2.1 under the 2020 Protocol.

Q. Is Staff's treatment of the Washington Cap and Invest Program different from the California cap and trade program?

A. Yes. Staff has described the California program as follows:

> Energy exported to California to meet load in that state is subject to California's GHG obligation. The EIM provides GHG revenue to compensate generators both inside and outside of California for their compliance costs. Oregon's IOUs benefit when their GHG revenue in EIM is excess to their GHG compliance costs.
>
> * * *
>
> IOUs outside California may include a "GHG bid adder" when submitting bids to EIM for thermal units. The GHG bid adder is calculated based on the price of a California Carbon Allowance (CCA) and reflects the IOU's potential GHG compliance cost for power exported to California. The GHG bid adder allows CAISO's market optimization to identify the least cost dispatch to serve California load (considering GHG compliance costs), and the least cost dispatch to serve load within the rest of the EIM (absent GHG compliance costs).[7]

The California program is functionally equivalent to the Washington program, except that Staff has taken the position that it is unfair for Oregon customers to pay for the full cost of emission allowances in Washington.

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[6] PAC/600, Shahumyan/5.

[7] *In the Matter of PacifiCorp, dba Pacific Power, Transition Adjustment Mechanism*, Docket No. UE 400, Staff/100, Enright/27 (May 25, 2022).

B. Reply to AWEC

Q. Has AWEC's position changed regarding the treatment of the Washington Cap and Invest Program?

A. No. AWEC still takes the extreme position that Oregon customers should pay nothing for the GHG allowances the Company is required to obtain in order to generate at Chehalis. In other words, AWEC wants Oregon to take the full benefits of Chehalis, in the form of lower NPC, without paying the full costs.

Q. Has AWEC proposed similar treatment for other generation taxes, like the Wyoming wind tax?

A. No.

Q. Did AWEC propose similar treatment for the GHG allowances in the California cap and trade program?

A. No. AWEC has singled out the Washington program for unique treatment and exclusion of costs from the TAM.

Q. AWEC claims that the Company is using the wrong accounting for the GHG allowances, which should not be included as a cost of fuel for Chehalis under the Federal Energy Regulatory Commission's (FERC) uniform system of accounts.[8] How do you respond?

A. This issue is a red herring; to the extent that the compliance costs are incurred when Chehalis generates electricity to serve Oregon customers, it is appropriate for Oregon customers to pay those amounts through the TAM, regardless of the specific account into which the costs are expensed. Company witness Ramon Mitchell provides

[8] AWEC/200, Mullins/36.

additional discussion of this issue and explains why AWEC's testimony is also contrary to guidance from FERC.

IV. RATE SHOCK

Q. CUB takes issue with the Commission orders cited in your reply testimony addressing rate shock and suggests that the principles described in those orders no longer apply.[9] How do you respond?

A. CUB does not appear to substantively disagree with the Commission precedent I discussed. To reiterate, I cited three Commission orders—two from 2001 and one from 2006 (which relied on the orders from 2001)—for the proposition that the Commission previously found that it cannot use rate shock as a basis to set a utility's revenue requirement.[10] CUB's testimony does not directly refute this point. In fact, CUB points out that they are not recommending that the Commission use rate shock to set the revenue requirement in the TAM,[11] which is a helpful clarification.

Q. CUB references legislative testimony from former Commission Chair Lee Beyer to argue that the Commission has authority to delay or defer a rate increase because of rate shock.[12] Do you agree with CUB's characterization?

A. No. CUB's interpretation of the legislative testimony is inconsistent with Commission cases decided both before and after the testimony was provided to the

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[9] CUB/200, Jenks/3–4.
[10] *In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149*, Docket No. UE 115, Order No. 01-988 (Nov. 20, 2001); *In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149*, Docket No. UE 115, Order No. 01-842; *In the Matter of Pacific Power & Light (dba PacifiCorp), Request for a General Rate Increase*, Docket No. UE 170, Order No. 06-1728 (Apr. 12, 2006).
[11] CUB/200, Jenks/2.
[12] CUB/200, Jenks/4.

legislature.[13] The Commission has the authority to consider rate impacts in setting amortization schedules, a position made clear in the Commission's decision regarding recovery of undepreciated investment in the Trojan plant.[14] This is an entirely different determination than unilaterally capping or delaying recovery of costs that have been already approved.

Q. CUB continues to recommend that the Company provide an October NPC update so that the Commission can employ its tools to mitigate rate shock.[15] Has CUB presented evidence suggesting the October update is necessary?

A. No. CUB's overarching recommendation is that the Commission employ mitigation tools *in other dockets* to offset the TAM rate case.[16] CUB acknowledges that the Company is required to file an NPC update by November 8, which means that as of November 8 the Commission will have sufficient information to employ any rate mitigation tool it chooses in other dockets. CUB provided no compelling reason that the Commission must have another update several weeks before November 8 in order to use rate mitigation tools in other dockets. If CUB's goal is to allow the Commission to employ mitigation tools in other dockets—not the TAM—then it is

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[13] See, e.g., *In the Matter of Portland General Electric Company's Proposal to Restructure and Reprice Its Services in Accordance with the Provisions of SB 1149*, Docket No. UE 115, Order No. 01-842 at 4 (rejecting the argument that "regardless of the prudency of the utility's expenditures, rate increases that cause rate shock are not just and reasonable"); *In re Pacific Power Request for a General Rate Increase*, Docket No. UE 170, Order No. 06-172 at 18 (Apr. 12, 2006) (noting that the Commission "may *mitigate* the impact of rate changes to help avoid rate shock," but applying that authority only to the principle of gradualism in allocating rates among different customer classes) (emphasis added).
[14] *See In the Matters of the Application of Portland General Electric Company for an Investigation into Least Cost Plan Plant Retirement; Revised Tariff Schedules for Electric Service in Oregon Filed by Portland General Electric Company; Portland General Electric Company's Application for an Accounting Order and for Order Approving Tariff Sheets Implementing Rate Reduction*, Docket Nos. DR 10, UE 88, UM 989, Order No. 08-487 at 22 (Sept. 30, 2008).
[15] CUB/200, Jenks/4.
[16] CUB/200, Jenks/5–6.

unclear why the Commission cannot employ those mitigation tools to other dockets based on the November indicative filing.

Q. CUB also argues it is "absurd" that there are two post-order NPC updates for direct access customers while "there are no updates for several months before the Commission makes its decision for the remaining non-direct access customers."[17] How do you respond?

A. First, PacifiCorp is required by statute to provide an indicative and final update in November. Second, CUB's proposal is concerning from a procedural standpoint. Accepting CUB's proposal would introduce evidence after the record is closed, the hearing is over, and briefing is complete. This creates the potential that parties might seek to request sixth and seventh rounds of testimony during the time required for the Commission to consider the issues and write its order.

Further, providing an update in mid to late October is not only extremely burdensome, it is illogical, because the Company provides the indicative and final updates in very early November. There is ample time after the final TAM update for parties to review that update for accuracy and determine if they would like to contest it, consistent with the process outlined in the TAM guidelines. CUB's proposal provides very little information and results in a massive increase in logistical difficulty and administrative burden for every party involved in the TAM. CUB has provided no compelling reason to impose such an obligation when CUB's concerns can be adequately addressed in the existing November update.

[17] CUB/200, Jenks/5.

Q. CUB argues that the Commission could use its order in the TAM to direct the Company to delay or defer collection of other single issue ratemaking schedules, so treatment of those non-TAM costs is appropriate within the TAM.[18] Do you agree?

A. Direction through a TAM order to adjust rate timing in other proceedings does not seem appropriate, but the Company commits to working with CUB to address their concerns in the PCAM or other proceedings with winter rate effective dates, once the final TAM impacts are known.

Q. CUB also points to the settlement of the Company's last general rate case, docket UE 399, as an example where the Commission lessened the impact of rate changes during the winter months based on an assessment of the rate changes occurring in several different cases.[19] How do you respond?

A. The Company agreed to the settlement in docket UE 399 as part of a comprehensive resolution of issues in that case and the agreement was expressly non-precedential.[20] Furthermore, the majority of the rate changes that were delayed were related to the amortization of specific deferrals that had been consolidated in the general rate case. Due to the nature of deferrals, there was more flexibility at that time to amortize those costs. That being said, as I stated above, PacifiCorp is committed to working with CUB to address their winter rate impact concern in the PCAM or other rate mechanisms.

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[18] CUB/200, Jenks/6.
[19] CUB/200, Jenks/8.
[20] *In the Matter of PacifiCorp, dba Pacific Power, Request for a General Rate Revision*, Docket No. UE 399, Order No. 22-491, App. C at 14–15 (Dec. 16, 2022).

Q. Does this conclude your surrebuttal testimony?

A. Yes.

Docket No. UE 420
Exhibit PAC/1100
Witness: Ryan Fuller

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Surrebuttal Testimony of Ryan Fuller

August 2023

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Exhibit PAC/1102—Quick Guide: Some Popular BEA Price Indexes

Exhibit PAC/1103—Projections of the 2023 GDP Implicit Price Deflator

Exhibit PAC 1104—Congressional Budget Office 2023 GDP Price Index Forecast

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company).

A. My name is Ryan Fuller, and my business address is 825 NE Multnomah Street, Suite 1900, Portland, Oregon 97232. My present position is Senior Tax Director.

Q. Please describe your education and professional experience.

A. I graduated from the University of Idaho in 1997 with a Bachelor of Science Degree in Accounting. I am a licensed CPA (Inactive Status). Before joining the PacifiCorp tax department in 2003, I worked in public accounting for six years, first with Talbot, Korvola and Warwick, LLP and then for PricewaterhouseCoopers LLP. From November 2016 through May 2018, I was employed as Tax Director for Avangrid Renewables, LLC, before rejoining PacifiCorp as Senior Tax Director in May 2018. As Senior Tax Director, I am responsible for management and oversight of the Company's tax function.

Q. Have you testified in other regulatory proceedings?

A. Yes. I have testified in regulatory proceedings in each of the Company's six state jurisdictions on various tax-related matters.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony responds to the proposal made by Alliance of Western Energy Consumers (AWEC) witness Mr. Bradley G. Mullins to use a 2024 Federal Production Tax Credit (PTC) Rate of 3.0 cents per kilowatt hour (kWh) in

PacifiCorp's TAM. More specifically, in recommending the Commission reject Mr. Mullins' proposal:

- I explain how Mr. Mullins' reliance on a dissimilar price index renders his conclusions invalid; and
- I provide objective evidence that supports a 2024 PTC of 2.9 cents per kWh as used by the Company in its filing.

III. AWEC'S PROPOSED 2024 PTC RATE

Q. Please explain how the 2024 PTC Rate will be calculated.

A. Please refer to Exhibit PAC/1101. The formula for calculating the 2024 PTC Rate is provided in Section A and includes three inputs: (1) the 2023 Gross Domestic Product (GDP) Implicit Price Deflator, (2) the 1992 GDP Implicit Price Deflator, and (3) the Base PTC Rate. As illustrated in Section B of Exhibit PAC/1101, of these three inputs, only the 2023 GDP Implicit Price Deflator is unknown at this time, and it will not be known until it is published by the Department of Commerce's Bureau of Economic Analysis (BEA) in February 2024.

Q. With respect to the 2024 PTC Rate, what facts should be agreed upon by PacifiCorp and AWEC?

A. Both PacifiCorp and AWEC agree, the minimum 2024 Inflation Adjustment Factor needed to produce a 2024 PTC Rate of 3.0 cents per kWh is 1.9667. Filling in this blank allows for the derivation of the minimum 2023 GDP Implicit Price Deflator needed to produce a 2024 Inflation Adjustment Factor of 1.9667; the value derived is 132.321 as illustrated in Exhibit PAC/1101, Section C. If the 2023 GDP Implicit

Price Deflator is lower by just one-thousandth, as illustrated in Section D, it will produce a 2024 Inflation Adjustment Factor of 1.9666 and a 2024 PTC Rate of 2.9 cents per kWh. In summary, both PacifiCorp and AWEC should agree to the following three facts:

1. The minimum 2024 Inflation Adjustment Factor needed to produce a 2024 PTC Rate of 3.0 cents per kWh is 1.9667.
2. The minimum 2023 GDP Implicit Price Deflator needed to produce a 2024 Inflation Adjustment Factor is 132.321.[1]
3. The 2022 GDP Implicit Price used for determining the 2023 PTC rate is 127.224.[2]

Q. What issue is before the Commission to decide the 2024 PTC Rate used in the TAM?

A. PacifiCorp used a projected 2024 PTC Rate of 2.9 cents per kWh for the purpose of the TAM. AWEC proposes using a projected 2024 PTC Rate of 3.0 cents per kWh.

The 2024 PTC Rate is entirely dependent on the value of the 2023 GDP Implicit Price Deflator that will be published by the Department of Commerce Bureau of Economic Analysis (BEA) in February 2024. The issue before the Commission is whether or not the price index will be less than 132.321, in which case, the PTC rate will be 2.9 cents per kWh as projected by the Company.

[1] AWEC incorrectly calculates a minimum 2023 GDP Implicit Price Deflators of 132.313 in Exhibit AWEC/203 due to the erroneous use of a 1992 GDP Implicit Price Deflator of 67.277, which can be seen in the Excel version of the Exhibit. The correct 1992 GDP Implicit Price Deflator is 67.282 as provided in Exhibit PAC/1103, Table 3.

[2] In Exhibit AWEC/203, AWEC unnecessarily estimates the annual value of the 2022 GDP Implicit Price deflator as the average of the quarterly GDP Implicit Price Deflator values published by the BEA for 2022. The actual annual value of the 2022 GDP Implicit Price Deflator used for the purposes of determining the 2023 PTC rate is 127.224 as provided in Exhibit PAC/1103, Table 3.

Q. Please summarize the analysis performed by AWEC witness, Bradley G. Mullins.

A. Albeit using incorrect values, in Exhibit AWEC/203, Mr. Mullins simply calculates the year-on-year change in value of the GDP Implicit Price Deflator needed to achieve a 2024 PTC Rate of 3.0 cents per kWh and converts the change in value to a percentage change in a manner consistent with following table (in which the correct values are used):

GDP Implicit Price Deflator	
Mimimum 2023 value needed to achieve a 2024 PTC rate of 3.0 cents per kWh	132.321
Actual 2022 Value	127.224
Change in Value	**5.097**
Percentage Change In Value	**4.006%**

Mr. Mullins, then observes that "it can be determined that the PTC rate will increase to 3.0 cents per kWh in 2024 so long as inflation equals or exceeds 4.0% on an annualized basis for 2023, *as measured by the GDP Implicit Price Deflator* (emphasis added)."[3]

Q. Does Mr. Mullins provide evidence that inflation will equal or exceed 4.0 percent on an annualized basis for 2023, as measured by the GDP Implicit Price Deflator?

A. No. To support the likelihood that inflation will exceed his calculated target, Mr. Mullins does not cite forecast percentage rate changes for the price index by which he says inflation must be measured, the GDP Implicit Price Deflator.

Instead, Mr. Mullins cites a forecast annualized percentage change range for a price index that does not even closely mirror the GDP Implicit Price Deflator: The

[3] AWEC/200, Mullins/41:18–20.

Core Personal Consumption Expenditures (PCE) Price Index.[4]

The Core PCE Index measures prices for goods and services that are produced in or imported to the U.S. and bought by consumers; the index also excludes food and *energy*. In contrast, the GDP Implicit Price Deflator measures prices for goods and services that are produced in or exported from the U.S. and bought by consumers, business, and governments.

These significant differences, illustrated in Exhibit PAC/1102, make the conclusions drawn from the Core PCE Price Index by Mr. Mullins invalid, especially because objectively better information is readily available.

Q. What objectively better information is available to make an informed decision on the value of the 2023 GDP Implicit Price Deflator?

A. While the Company is not presently aware of a publicly available forecast of the GDP Implicit Price Deflator, there is another price index which closely mirrors the GDP Implicit Price Deflator for which a forecast is publicly available – the GDP Price Index.[5]

In Exhibit PAC/1103, Table 3, the Company provides a comparison of the historical price index values for the annual GDP Implicit Price Deflator and the annual GDP Price Index for the years 1992 through 2022,[6] a period that covers the duration of the existence of the PTC. Exhibit PAC/1103, Table 2 summarizes the maximum variance between the two price indexes, both positive and negative, and the

[4] AWEC/200, Mullins/41–42.
[5] Please see the BEA's "Quick Guide: Some Popular BEA Price Indexes" provided as Exhibit PAC/902. In this document the BEA makes this note about the GDP Implicit Price Deflator: "Closely mirrors the GDP Price index, although calculated differently."
[6] The data for Exhibit PAC/1103, Table 3, is sourced from BEA Data Archive: National Accounts (NIPA); Year, Quarter: 2022, Q4, Vintage: Second. The historical GDP Price Index values are located in Tab T10104-A, row 9. The historical GDP Implicit Price Deflator values are located in Tab T10109-A, row 9.

average variance over the subject time period. These two tables demonstrate and establish that the GDP Implicit Price Deflator closely mirrors the GDP Price Index as noted by the BEA.

The Congressional Budget Office's July 2023 report, *An Update to the Economic Outlook: 2023 to 2025*, forecasts the 2023 GDP Price Index at 132.003, a 3.776 percent increase over the 2022 GDP Price Index.[7] This forecast is below the GDP IPD of 132.312, or 4.006 percent increase over the 2022 GDP Price Index, needed to achieve AWEC's proposed 2024 PTC rate of 3.0 cents per kWh, even when adjusted for the maximum and average variances as summarized in Exhibit PAC/1103, Table 1.

Q. Based on this information, what 2024 PTC Rate should be used for the TAM?

A. The Congressional Budget Office forecast of the 2023 GDP Price Index is independent and objective data to which weight can be given and is of a far better quality than the data cited by AWEC. Based on the Congressional Budget Office forecast, the 2023 GDP Implicit Price Deflator will be less than 132.321, making the best estimate of the 2024 PTC Rate 2.9 cents per kilowatt hour.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

[7] See Exhibit PAC/1104, Tab 2. Calendar Year, Cell H57. Exhibit PAC/1104 is provided in electronic format only. The Exhibit was downloaded from https://www.cbo.gov/data/budget-economic-data#11. Under 10-Year Economic Projections, select the link for July 2023.

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Exhibit PAC/1101
Witness: Ryan Fuller

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

Exhibit Accompanying Surrebuttal Testimony of Ryan Fuller

Example 2024 PTC Rate Calculations

August 2023

A	$\frac{\text{2023 GDP Implicit Price Deflator}}{\text{1992 GDP Implicit Price Deflator}}$	=	2024 Inflation Adjustment Factor	X	Base PTC Rate	=	2024 PTC Rate
B	$\frac{X}{67.282}$	=	?	X	0.015	=	?
C	$\frac{132.321}{67.282}$	=	1.9667	X	0.015	=	0.030
D	$\frac{132.320}{67.282}$	=	1.9666	X	0.015	=	0.029

Note 1: The Department of Commerce Bureau of Economic Analysis publishes the GDP Implicit Price Deflator to the thousandth. The Internal Revenue Service publishes the Inflation Adjustment Factor to the ten-thousandth. Internal Revenue Code (IRC) Section 45 requires the PTC rate to be rounded to the nearest 0.1 cent.

Note 2: IRC Section 45 requires the revision of the GDP Implicit Price Deflator used for the purposes of calculating the Inflation Adjustment Factor is the most recent revision of GDP Implicit Price Deflator for the preceding calendar year published by the Department of Commerce before March 15 of the calendar year for which the PTC rate is being determined.

Docket No. UE 420
Exhibit PAC/1102
Witness: Ryan Fuller

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Exhibit Accompanying Surrebuttal Testimony of Ryan Fuller

Quick Guide: Some Popular BEA Price Indexes

August 2023

Quick Guide: Some Popular BEA Price Indexes

Bureau of Economic Analysis
U.S. DEPARTMENT OF COMMERCE

Measures prices for final goods and services that are:

Index	Bought by consumers	Bought by businesses & governments	Produced in U.S.	Imported to U.S.	Exported from U.S.	Notes
PCE Price Index Personal Consumption Expenditures Price Index	✓	✗	✓	✓	✗	• Closely watched by the Federal Reserve • Similar to the BLS Consumer Price Index; the formulas and uses differ • Captures consumers' changing behavior and a wide range of expenses
Core PCE Price Index PCE Price Index, Excluding Food and Energy	✓	✗	✓	✓	✗	• Closely watched by the Federal Reserve • Excludes two categories prone to volatile prices that may distort overall trends
Gross Domestic Purchases Price Index	✓	✓	✓	✓	✗	• BEA's featured measure of inflation in the U.S. economy overall
GDP Price Index Gross Domestic Product Price Index	✓	✓	✓	✗	✓	• Measures only U.S.-produced goods and services
GDP Price Deflator Gross Domestic Product Implicit Price Deflator	✓	✓	✓	✗	✓	• Closely mirrors the GDP price index, although calculated differently • Used by some firms to adjust payments in contracts

PAC/1102
Fuller/1

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Exhibit PAC/1103
Witness: Ryan Fuller

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Projections of the 2023 GDP Implicit Price Deflator

August 2023

TABLE 1: Representative Projections of the GDP Implicit Price Deflator based on the GDP Price Index			
	Projected	Increase as Compared to 2022	
Projection	**2023 Value**	**Value**	**%**
Projected GDP Price Index	132.003	4.779	3.756%
Projected GDP Price Index + Minimum Negative Variance	131.972	4.748	3.732%
Projected GDP Price Index + Maximum Positive Variance	132.040	4.816	3.785%
Projected GDP Price Index + Average Variance	132.005	4.781	3.758%

TABLE 2: Variance Summary	
Maximum Negative Variance	(0.031)
Maximum Positive Variance	0.037
Average Variance	0.002

TABLE 3: Historical Price Index Values (2012 =100)			
Year	**GDP Implicit Price Deflator**	**GDP Price Index**	**Variance (1)**
1992	67.282	67.278	0.004
1993	68.877	68.874	0.003
1994	70.347	70.342	0.005
1995	71.823	71.819	0.004
1996	73.138	73.132	0.006
1997	74.399	74.399	0.000
1998	75.236	75.219	0.017
1999	76.296	76.272	0.024
2000	78.025	78.016	0.009
2001	79.783	79.814	(0.031)
2002	81.026	81.013	0.013
2003	82.625	82.635	(0.010)
2004	84.843	84.842	0.001
2005	87.504	87.490	0.014
2006	90.204	90.212	(0.008)
2007	92.642	92.653	(0.011)
2008	94.419	94.397	0.022
2009	95.024	95.019	0.005
2010	96.166	96.164	0.002
2011	98.164	98.157	0.007
2012	100.000	100.000	0.000
2013	101.751	101.769	(0.018)
2014	103.654	103.662	(0.008)
2015	104.691	104.662	0.029
2016	105.740	105.703	0.037
2017	107.749	107.743	0.006
2018	110.339	110.344	(0.005)
2019	112.318	112.303	0.015
2020	113.784	113.814	(0.030)
2021	118.895	118.924	(0.029)
2022	127.224	127.225	(0.001)

(1) Positive variances reflect years for which the GDP Implicit Price Deflator is greater than the GDP Price Index. Negative variances reflect years for which the GDP Implicit Price Deflator is less than the GDP Price Index.

Docket No. UE 420
Exhibit PAC/1104
Witness: Ryan Fuller

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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Exhibit Accompanying Surrebuttal Testimony of Ryan Fuller

Congressional Budget Office 2023 GDP Price Index Forecast

August 2023

THIS EXHIBIT HAS BEEN PROVIDED IN EXCEL FORMAT ONLY

REDACTED
Docket No. UE 420
Exhibit PAC/1200
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Surrebuttal Testimony of Michael G. Wilding

August 2023

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ATTACHED EXHIBITS

Confidential Exhibit PAC/1201—Vitesse Data Request 25

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp or Company).

A. My name is Michael G. Wilding, and my business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My title is Vice President, Energy Supply Management.

Q. Please describe your education and professional experience.

A. I received a Master of Accounting from Weber State University and a Bachelor of Science degree in accounting from Utah State University. As Vice President, Energy Supply Management (ESM), my responsibilities include directing PacifiCorp's front office organization in commercial and trading activities. ESM is responsible for commercially managing PacifiCorp's diverse generation portfolio. This includes the electric and natural gas hedging, term and day-ahead trading, real-time trading, and system balancing. I also oversee the Company's regulatory net power cost filings and its environmental reporting. Prior to assuming my current position in February 2021, I worked on various regulatory projects including general rate cases, the multi-state process, and net power cost filings. I have been employed by PacifiCorp since 2014.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have previously provided testimony to the Public Utility Commission of Oregon (Commission) as well as commissions in California, Idaho, Utah, Washington, and Wyoming.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to address the concerns raised by Mr. Steve Johnson, the witness for Vitesse, LLC (Vitesse) regarding PacifiCorp's [redacted] Specifically, I provide additional detail in response to Vitesse's claims that PacifiCorp's update to the EIM GHG benefits should not reflect operational reality.

III. RESPONSE TO VITESSE

Q. Please provide a brief background on the operational update that occurred to EIM GHG benefits in PacifiCorp's reply update.

A. PacifiCorp has increasing compliance obligations regarding clean energy compliance, which include House Bill (HB) 2021 in Oregon and the Clean Energy Transformation Act in Washington. As a result of these increasing obligations, PacifiCorp [redacted].[1]

Q. Please describe the Company's rationale behind this decision.

A. As described in response to Vitesse's data requests, the Company [redacted]

[1] PAC/400, Mitchell/13.

[redacted]"[2]

Q. Can you provide some additional detail on these obligations?

A. Yes, the Company faces an increasing number of tightening emissions-free state standards, contractual obligations to deliver renewable energy certificates to commercial customers, and fuel mix and other power source disclosure-related obligations requiring it to have claim to the environmental attribute of the resource generation. A resource deemed delivery into California constitutes a specified energy sale from that resource, and PacifiCorp's release of any claim of environmental attribute including renewable and non-emitting claim.

Q. Will this decision be necessary to comply with Oregon state energy policies?

A. Yes. Specified exports of power—[redacted]—are deducted from the determination of the Company's system emissions factor, which is used for determining the Company's emissions position under HB 2021. [redacted], the Company would forego the opportunity to claim the energy associated with these resources in its performance to

[2] PAC/1201, Vitesse Data Request 25.

the emissions reduction targets described in Oregon Revised Statute 469A.410 because they would be deemed to be delivered to California.

Q. Can you provide more quantitative detail on why the Company made this decision?

A. Yes, as the Company noted in response to Vitesse's data requests, [redacted]

Q. Why was this operational change not incorporated into the Company's initial filing?

A. The operational decision [redacted]. PacifiCorp does update the inputs to its EIM benefits and GHG benefits models to incorporate the latest operational information, this is simply part of that update.

Q. Please summarize Vitesse's argument against incorporating this operational update into the TAM calculation of EIM GHG benefits.

A. Vitesse claims that the Company has not met its "burden of proof" to demonstrate that this operational change is prudent and should be reflected in the TAM, because not enough information is provided, and it has no evidence to determine if the Company is making the least cost decision for customers. Additionally, Mr. Johnson raises concerns that the environmental attributes of the Company's hydroelectric resources will be used to benefit customers in other states outside of Oregon. Finally, Mr. Johnson contends that since he has not had a chance to review the Company's information that will be filed in surrebuttal on this topic, the Commission should not allow PacifiCorp to reflect this operational reality in the calculation of EIM benefits.

Q. How do you respond to Vitesse's criticism PacifiCorp has not provided sufficient qualitative or quantitative evidence that this is the least cost decision for customers?

A. As I noted above, the Company identified to Vitesse through the discovery process that it earns less than [redacted] which is paired with those resources' environment attributes and that it needed those environmental attributes to avoid incurring penalties that are no less than [redacted].

Q. Is it appropriate to incorporate these operational decisions into the EIM benefits calculation?

A. Yes. The Company updates TAM rates for a myriad of operational realities including executed power purchase agreements, long-term firm transmission rights, planned maintenance schedule, and incorporates short-term firm purchases and significant additional new information as the TAM progresses. It would be administratively impossible to discuss each of the decisions in TAM testimony.

Q. Should the Commission adopt Vitesse's recommendation on this topic?

A. No, PacifiCorp is facing significant compliance obligations in Oregon and Washington as a result of new legislation and state policies. PacifiCorp has provided information on the reasoning behind this decision and should not be penalized for planning to meet those compliance obligations. The Commission has the ability to review the prudence of these operational decisions in the Company's power cost adjustment mechanism proceeding.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

REDACTED
Docket No. UE 420
Exhibit PAC/1201
Witness: Michael G. Wilding

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

PACIFICORP

REDACTED
Surrebuttal Testimony of Michael G. Wilding

Vitesse Data Request 25

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Vitesse Data Request 25

CONFIDENTIAL REQUEST - EIM GHG Benefits. In PacifiCorp's reply testimony Ramon Mitchell testifies that [redacted]. PAC/400, Mitchell/13:15-17. The questions below pertain to the cost per [redacted] need it states it has.

(a) Please identify and describe [redacted]

(b) Has the Company calculated the [redacted] as a result of [redacted]

(c) Please provide all documentation of the Company's calculation of the subpart 22(b) and documents used in its decision to [redacted]

(d) Please provide the marginal cost of [redacted] from sources [redacted]

(e) Please provide the NPC change for the 2024 TAM rate year in isolation due to the Company's decision [redacted]

(f) For the calculation in subpart 22(c) please provide the reduction to [redacted]

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Confidential Response to Vitesse Data Request 25

(a) [redacted]

(b) Yes. [redacted]

(c) The Company assumes that the reference to "subpart 22(b)" is intended to be a reference to subpart (b) of this data request, Vitesse Data Request 25. Based on the foregoing assumption, the Company responds as follows:

Please refer to Confidential Attachment Vitesse 25, tab "HR", cell "B20" which provides the calculation of the value that is [redacted] Please refer to the Company's response to subpart (a) for the remainder of the decision.

(d) Please refer to the Company's response to subpart (a) wherein the Company notes that it [redacted]

(e) [redacted] on a total-company basis for the net power costs (NPC) change in isolation. Additionally, [redacted]

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[redacted]

(f) The Company assumes that the reference to "subpart 22(c)" is intended to be a reference to subpart (c) of this data request, Vitesse Data Request 25. Based on the foregoing assumption, the Company responds as follows:

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

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