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October 5, 2021

VIA ELECTRONIC FILING

Attention: Filing Center
Public Utility Commission of Oregon
P.O. Box 1088
Salem, Oregon 97308-1088

Re: UE 390 – *In the Matter of PacifiCorp, dba Pacific Power, 2022 Transition Adjustment Mechanism*

Attention Filing Center:

Attached for filing in the above-referenced docket is PacifiCorp d/b/a Pacific Power's Rebuttal Brief. Confidential material in support of the filing will be provided to qualified parties under Protective Order No. 16-128 via encrypted zip file.

Please contact this office with any questions.

Sincerely,

Katherine McDowell

Attachment

CERTIFICATE OF SERVICE

I certify that I delivered a true and correct copy of the confidential pages of PacifiCorp's **Rebuttal Brief** on the parties listed below that have signed the protective order via electronic mail in compliance with OAR 860-001-0180.

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Dated this 5th day of October, 2021.

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 390

In the Matter of PACIFICORP, dba PACIFIC POWER, 2022 Transition Adjustment Mechanism	**PACIFICORP'S REBUTTAL BRIEF**

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I. INTRODUCTION

PacifiCorp, dba Pacific Power's (PacifiCorp or Company) Transition Adjustment Mechanism (TAM) is "an annual filing with the objective to update the forecast net power costs to account for changes in market conditions."[1] By design, the TAM is a limited-issue case that is narrowly focused on forecasting PacifiCorp's expected net power costs (NPC) for the upcoming year. The TAM's scope and procedures are governed by the TAM Guidelines, which were adopted through stipulations among the Company, Commission Staff (Staff), the Oregon Citizens' Utility Board (CUB), and the Industrial Customers of Northwest Utilities (ICNU, the predecessor of the Alliance of Western Energy Consumers (AWEC)) and approved by the Commission in 2009 and thereafter.[2]

PacifiCorp has proposed a TAM increase of only $1.1 million or less than 0.1 percent. This price change is particularly reasonable in light of current and forecast energy market conditions. In 2021, natural gas prices have risen to their highest levels since 2014, with prices more than doubling since the start of the year.[3] Widespread drought has significantly reduced hydro generation.[4] Demand for coal generation has rebounded, with a forecast increase of 100 million tons in 2021, leading to coal supply shortages and a sharp increase in spot market coal prices.[5] Powder River Basin coal prices are the highest in 15 years and nearly [redacted] percent higher than the contract price secured by PacifiCorp.[6] Had PacifiCorp followed Sierra Club's recommendations

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[1] *See In re PacifiCorp, dba Pac. Power 2009 Transition Adjustment Mechanism*, Docket No. UE 199, Order No. 09-274, App'x A at 9 (July 16, 2009).

[2] Order No. 09-274, App'x A, *amended In re PacifiCorp, dba Pac. Power, 2010 Transition Adjustment Mechanism*, Docket No. UE 207, Order No. 09-432, App'x A at 5 (Oct. 30, 2009) and *In re PacifiCorp, dba Pac. Power, 2011 Transition Adjustment Mechanism*, Docket No. UE 216, Order No. 10-363, App'x A at 4 (Sept. 16, 2010) [hereinafter 2011 TAM] [collectively hereinafter TAM Guidelines].

[3] *Natural gas prices are rising and could be the most expensive in 13 years this winter,* CNBC (Sept. 9, 2021) (available at: https://www.cnbc.com/2021/09/09/natural-gas-prices-are-rising-and-could-be-the-most-expensive-in-13-years-this-winter.html).

[4] *EIA expects U.S. hydropower generation to decline 14% in 2021 amid drought*, EIA, Today in Energy (Sept. 23, 2021) (available at: https://www.eia.gov/todayinenergy/detail.php?id=49676).

[5] *See US coal demand is rising, but supplies remain tight*, S&P Global Market Intelligence (Sept. 22, 2021) (available at: https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/us-coal-demand-is-rising-but-supplies-remain-tight-66708145) [hereinafter S&P Article].

[6] *See* S&P Article ("S&P Global Platts assessed Powder River Basin 8,800 Btu/lb coal at $16.90/ton, the highest price for that grade of coal in over 15 years."); PAC/600, Ralston/4-5 (new Dave Johnston agreements for Powder River Basin coal priced at $[redacted]/ton).

for coal procurement, the Company would be part of the national coal shortage right now and reliability would be severely impaired. While Staff has criticized PacifiCorp's new coal supply agreements (CSAs) as imprudent, PacifiCorp's ability to supply almost all of its coal needs in 2021 and 2022 under these and other CSAs has largely insulated its customers from rising coal prices and supply unavailability, and moderated the impact of increased natural gas and market prices.

Even after three rounds of testimony, voluminous discovery responses, and a full hearing, parties contend that PacifiCorp has not met its burden of proof to support this modest rate increase. In fact, as PacifiCorp's rebuttal brief makes clear, it is the parties that have failed to meet their burden of persuasion that the Commission should *reduce* PacifiCorp's NPC in 2022.

Most notably, the parties improperly seek to expand the TAM beyond its intended purpose. For example, Sierra Club has tried to turn the TAM into a long-term planning docket by proposing several adjustments related to PacifiCorp's coal-fired generating units and mining operations that would create significant and irreversible changes to the Company's resource portfolio. But the TAM is not PacifiCorp's Integrated Resource Plan (IRP), and the short-term forecast used to develop 2022 rates is not a substitute for the IRP's rigorous and comprehensive public planning process. Adopting Sierra Club's short-sighted coal adjustments would frustrate PacifiCorp's IRP and undermine the Commission's well-established framework for least-cost, least-risk planning.

Like Sierra Club, AWEC and Staff also seek to expand the TAM beyond its intended purpose by imputing additional non-NPC revenues into the NPC forecast. The Commission has consistently rejected similar attempts to impute revenue into the TAM, including as recently as PacifiCorp's 2020 general rate case, docket UE 374 (2021 Rate Case). Neither AWEC nor Staff acknowledge or respond to the Commission's prior precedent and the TAM Guidelines or make any attempt to reconcile or explain why their proposal here is any different from ICNU's proposal in the 2012 TAM where the Commission concluded that ICNU was "advocating a fundamental revision to the TAM process itself" by bringing revenue items into the TAM.[7] Imputing revenues

[7] *In re PacifiCorp, dba Pac. Power, 2012 Transition Adjustment Mechanism*, Docket No. UE 227, Order No. 11-435 at 6 (Nov. 4, 2011) [hereinafter 2012 TAM].

into the TAM to drive down the NPC forecast is also directly contrary to the Commission's direction in PacifiCorp's last general rate case, docket UE 374 (2021 Rate Case), where the Commission acknowledged PacifiCorp's persistent NPC under-recovery and indicated that the Company could "make targeted forecast adjustments to remedy specific issues with its under-recovery."[8] In the 2021 Rate Case, the Commission observed that all parties (including Staff, CUB and AWEC) "agree that PacifiCorp has generally under-recovered power costs since 2008."[9] Since that time, PacifiCorp has recorded an additional NPC under-recovery of $29.5 million in 2020.[10]

The Commission should reject the parties' attempts to both deny current energy market realities and turn the TAM into a broader docket. When declining to modify PacifiCorp's NPC recovery mechanisms in the 2021 Rate Case, the Commission noted that the TAM had stabilized in recent years, with fewer contested issues.[11] By re-focusing the TAM on its intended purpose, the Commission can lay the groundwork for less controversy in future filings, which will be particularly critical as the Company transitions to Aurora in the 2023 TAM. The Commission can also return the TAM's focus to improving the accuracy of the NPC forecast.

II. MARKET CAPS

A. Staff's claim that PacifiCorp failed to meet its burden of proof contradicts Staff's positions in the 2021 Rate Case and its rebuttal testimony in this proceeding.

In its reply brief, Staff claims that the Company failed to meet its burden of proof for the adoption of average-of-averages market caps because the Company has not demonstrated "that it has chronically over-forecast off-system sales in recent TAMs."[12] Staff's position is surprising because, just last year in the Company's 2021 Rate Case, Staff testified that a "gross over-estimate

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[8] *In re PacifiCorp, dba Pac. Power, Request for a Gen. Rate Revision*, Docket No. UE 374, Order No. 20-473 at 130 (Dec. 18, 2020).
[9] Order No. 20-473 at 126.
[10] *In re PacifiCorp dba Pac. Power, 2020 Power Cost Adjustment Mechanism*, Docket No. UE 392, Stipulation at 2 (Sept. 3, 2021).
[11] Order No. 20-473 at 129.
[12] Staff's Reply Brief at 4 (Sept. 28, 2021).

of the sales benefit" is apparent in the 2017, 2018, and 2019 TAMs.[13] Additionally, Staff stated in its rebuttal testimony in this proceeding that its position on market caps had "evolved" to acknowledge the possibility "that the current 'maximum of averages' approach is not the optimal method for forecasting off-system sales for purposes of setting net power costs"[14] after reviewing PacifiCorp's historical data on its sales over-forecasts from Figure 4 of Mr. Douglas Staples' reply testimony.[15]

Staff fails to reconcile its testimony in the 2021 Rate Case and in rebuttal here with its contradictory reply brief arguments. In the Company's 2021 Rate Case, the Commission noted Staff's concession that "GRID over-optimizes and finds economic sales that PacifiCorp does not realize in actual operations."[16] Furthermore, the Commission rejected PacifiCorp's request for a new Power Cost Adjustment Mechanism (PCAM) model, instead finding that "PacifiCorp may be able to make targeted forecast adjustments to remedy specific issues with its under-recovery."[17] The Commission expressly relied upon Staff's testimony on the gross over-estimation of sales in recent TAMs in reaching this conclusion, noting that PacifiCorp had not addressed "the feasibility of reducing this component of its forecast."[18]

In its reply brief, Staff addresses its prior testimony that the Generation and Regulation Initiative Decision Tools (GRID) over-forecasts sales by claiming that, in the 2021 Rate Case, Staff also found that purchases were over-forecast, which could have an "off-setting effect" on the over-forecast of sales.[19] But in the Company's 2021 Rate Case, Staff compared the sales and purchase forecasts and testified that "only one of the two market transaction types is largely inaccurate in the forecast"—leading Staff to conclude that excess sales costs were *not* apparent while a "gross-overestimation of the sales benefit" was.[20]

[13] PAC/1603 at 5 (Docket No. UE 374, Staff/2400, Gibbens/22).
[14] Staff/1200, Dlouhy/12.
[15] Figure 4 in Mr. Staples' reply testimony shows the persistent over-forecasting of short-term sales since the Commission adopted its current market caps approach in 2013. *See* PAC/400, Staples/23.
[16] Order No. 20-473 at 126.
[17] Order No. 20-473 at 130.
[18] Order No. 20-473 at 130.
[19] Staff's Reply Brief at 5.
[20] PAC/1603 at 5.

Moreover, the same data cited by Staff in its rebuttal testimony as the basis for its "evolving" position questioning maximum-of-averages market caps—Figure 4 in Mr. Staples' testimony—compares nine years of historical sales and purchases forecasts to actuals on a megawatt-hour (MWh) basis.[21] This data demonstrates that the magnitude of the forecast variance for sales has been much larger than the magnitude of the forecast variance for purchases.[22] Figure 5 from Mr. Staples' reply testimony reflects the same data as Figure 4 with forecasts and variances stated in dollars. Figure 5 shows that variances in off-system purchases have never come close to offsetting variances in off-system sales. For example, the most recent four-year average variance in over-forecast sales benefits is $232,634,644 total company. In comparison, the four-year average variance in over-forecast purchase costs is $33,812,242 total company—resulting in an average over-forecast sales benefit of approximately $200 million annually after the offset for over-forecast purchases.[23]

In summary, Staff's position that PacifiCorp has not demonstrated an over-estimation of off-system sales under maximum-of-averages market caps and therefore failed to meet its burden of proof unreasonably requires the Commission to ignore Staff's own testimony here and in the Company's 2021 Rate Case, as well as the evidence from recent TAM proceedings that led Staff to find a "gross over-estimate of the sales benefit."[24]

B. AWEC misstates PacifiCorp's position and forecast sales levels in arguing that PacifiCorp has not met its burden of proof.

AWEC also argues that PacifiCorp has failed to meet its burden of proof, asserting that PacifiCorp has not demonstrated that use of average-of-averages market caps will produce a more accurate NPC forecast. Claiming that PacifiCorp equates increased NPC with increased accuracy, AWEC argues that PacifiCorp is requesting to increase rates "for the sake of an increase."[25]

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[21] Figures 4 and 5 in Mr. Staples' testimony include nine years of data. The first year, 2012, was when PacifiCorp used the average-of-average market caps method. The next eight years demonstrate the operation of the maximum-of-averages market caps method. *See* PAC/400, Staples/23-24.
[22] PAC/400, Staples/24.
[23] PAC/400, Staples/24 (Figure 5).
[24] PAC/1603 at 5.
[25] AWEC's Reply Brief at 6 (Sept. 28, 2021).

AWEC falsely distills PacifiCorp's position. AWEC also claims incorrectly that the evidence suggests a "divergent spectrum of potentials" resulting from the change in market caps, showing that the Company has presented insufficient data.[26]

Figures 4 and 5 in Mr. Staples' reply testimony show that GRID has over-forecasted sales by millions of dollars each year since 2013, leading to a gross over-estimate of the sales benefit in the forecast.[27] PacifiCorp's average-of-averages market caps incrementally reduce forecast sales, bringing them closer to actual sales levels. This change reduces the forecasted sales benefit, bringing it closer to the actual sales benefit. The proposed market caps thereby increase the overall accuracy of the NPC forecast. But with the very high level of forecasted sales in the optimized forecast over the last several years, this incremental change is unlikely to eliminate the over-forecast entirely. Given the Commission's stated concern about the average-of-averages method in 2013—that it would under-estimate the sales benefit and over-state NPC[28]—this fact militates in favor of adopting average-of-averages market caps, not the opposite as AWEC suggests.

Relying on Exhibit AWEC/202, AWEC also claims that it has shown that the average-of-averages approach will under-forecast sales and result in an "over-collection of revenue from ratepayers."[29] Importantly, AWEC's claim incorrectly assumes that the Company has actually removed sales related to the Public Service Company of Colorado (PSCo) Exchange and the "Day Ahead, Real Time" (DA/RT) adjustment from the NPC forecast in this case. To be clear, those sales remain in the NPC forecast and are unaffected by the proposed change in market caps. The sales forecast for 2022 using average-of-averages market caps is approximately 7.5 million MWh (including the DA/RT and PSCo sales), which is higher than the average actual sales volumes of 6.1 million MWh for the last five years.[30]

PacifiCorp discussed the effect of removing these sales from the forecast for illustrative

[26] AWEC's Reply Brief at 7.
[27] PAC/400, Staples/23-24.
[28] *In re PacifiCorp, dba Pac. Power, 2013 Transition Adjustment Mechanism*, Docket No. 245, Order No. 13-008 at 1-2 (Jan. 15, 2013).
[29] AWEC's Reply Brief at 7.
[30] *See* PAC/400, Staples/23 (Figure 4).

purposes only to respond to AWEC's improper reliance on bookout sales.[31] PacifiCorp showed that even after removing these sales from the forecast, sales were still over-estimated compared to historical averages. Specifically, PacifiCorp showed that even after removing all PSCo and DA/RT sales from the NPC forecast, GRID still over-forecasted sales by an average of approximately 4.2 million MWh total company per year.[32] PacifiCorp's proposed market cap methodological change would only result in a [redacted] reduction in sales, leaving a [redacted] over-estimation based on the historical over-estimation averages *after* accounting for the DA/RT and PSCo Exchange.[33]

Lastly, even if AWEC were correct that the average-of-averages method could produce a range of different outcomes, this does not show that the method is unreasonable. What makes a method problematic is persistent and one-sided forecast error—like that demonstrated by the maximum-of-averages approach since 2013. In summary, AWEC's contention that PacifiCorp's market caps proposal is justified only by the fact that it increases NPC is untrue, as is AWEC's contention that this proposal is likely to over-forecast NPC.

C. CUB incorrectly claims that the Company failed to meet its burden of proof by proposing a market caps approach previously rejected by the Commission, and by not fully addressing the factors that impact sales levels.

CUB claims that the Company has not met its burden to support adoption of average-of averages market caps for two reasons. First, CUB suggests that the Company has a higher burden because the Commission previously rejected the average-of-averages method.[34] But the Commission rejected this method out of concern that it would under-estimate sales levels and over-state NPC, positing that the maximum-of-averages method would produce a more accurate forecast.[35] PacifiCorp has produced eight years of data establishing that this premise was incorrect because the maximum-of-averages method has systematically over-forecasted off-system sales.

[31] See Section II.D for a more in-depth discussion of bookouts.
[32] PAC/1000, Staples/34 (Confidential Figure 3).
[33] *See* PAC/1000, Staples/34.
[34] CUB's Reply Brief at 8 (Sept. 28, 2021).
[35] Order No. 13-008 at 1-2.

CUB itself agrees that the maximum-of-averages method "has proven itself to be too expansive."[36] Furthermore, the maximum-of-averages method, average-of-averages method, and CUB's mid-point-between-the-two method, all rely on the same basic framework (i.e., a four-year average by month, by market, and by heavy-load and light-load hours)—with the difference being the exact level at which the cap is set. Thus, while CUB complains that PacifiCorp has used an "old patch,"[37] CUB ultimately has endorsed a similar approach, albeit one that allows the next level up in sales.

Second, CUB argues that factors other than the maximum-of-averages market caps have led to PacifiCorp's over-estimation of sales, including weather-normalized conditions and external factors such as the COVID-19 pandemic.[38] While PacifiCorp admits that external factors such as weather and the pandemic can play a role in the over-estimation of sales, the fact remains that sales over-estimation has been present every year since adoption of maximum-of-averages market caps, including years with historic hydro which depressed power prices and years with historically high natural gas prices.[39] Every year will present different conditions that can affect power sales but in *every year* since 2013 sales have been over-estimated, in part, because of artificially high market caps. Given that the average-of-averages method reduces sales volumes by only 16 percent and the historical over-forecasts have been much greater, the likelihood of a sales under-forecast due to changed conditions is very low.

D. In analyzing the data in this case, the Commission should rely on audited and comparable PCAM data for actual NPC sales, not data that includes bookouts.

In this case, PacifiCorp has relied on the evidence of its actual NPC submitted in its PCAM

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[36] CUB/200, Jenks/11.

[37] CUB's Reply Brief at 8.

[38] CUB's Reply Brief at 6-7. CUB also argues that the expansion of the Energy Imbalance Market (EIM) will limit the Company's ability to sell in real-time market hubs. CUB's Reply Brief at 7. Indeed, equating EIM exports with market benefits could logically close the gap between the observed historical sales and the higher forecasts in GRID. But including both the sales revenue for GRID sales forecasts that are later replaced by EIM transfers *and* including the EIM benefits as a separate adjustment in the TAM would constitute a double counting of benefits. PAC/1000, Staples/49. In other words, any benefits achieved by the transfer of sales into EIM are accounted for by the EIM adjustment the Commission already includes in GRID. Either GRID sales or EIM benefits would then need to be adjusted post hoc to avoid double counting. PAC/1000, Staples/49. Rather than proposing a complex new adjustment to account for this double counting problem, PacifiCorp's approach of simply adjusting the market caps follows the Commission's directive to propose "straightforward inputs or limits" to address sales overestimations. Order No. 20-473 at 130.

[39] PAC/1000, Staples/49.

dockets, filings that are audited and reviewed by the parties and approved by the Commission. The Company used this PCAM data to populate Figures 4 and 5 in Mr. Staples' reply testimony; Staff and the Commission used this same data in the 2021 Rate Case to analyze the role that off-system sales forecasts have played in PacifiCorp's historical NPC under-recovery. Staff now questions the use of PCAM data because the PCAMs have been settled, and the settlements include boilerplate language limiting the precedential nature of PCAM settlements in future proceedings.[40] But the stipulations do not prevent PacifiCorp from relying on past PCAM data, the existence of an audit and review process in the PCAM dockets, and the Commission's orders approving PacifiCorp's PCAM filings as reasonable and compliant. For example, in the 2021 Rate Case, Staff questioned PacifiCorp's reliance on 2019 actual NPC data as "preliminary" and "unverified" because it had not yet been "properly reviewed and analyzed by Staff and other parties, much less determined valid by the Commission" in the pending PCAM docket.[41]

Staff and AWEC point to another data set to suggest that PacifiCorp has not actually over-estimated sales in its NPC forecasts. This data set is PacifiCorp's total wholesale sales, including bookouts. Staff implies that because PacifiCorp provided this data set to Staff in response to a discovery request, PacifiCorp somehow endorsed its use for comparative purposes.[42] However, PacifiCorp specifically noted in its response to the Staff discovery request that the information was not comparable.[43] PacifiCorp has never agreed that it is proper to compare normalized NPC sales forecasts in the TAM (which does not account for the possibility of bookouts) to actual sales forecasts including bookouts.[44] PacifiCorp has taken this position since the 2013 TAM, where the Commission acknowledged PacifiCorp's argument that comparing historical averages inclusive of bookouts against a GRID model exclusive of bookouts is akin to comparing apples and oranges.[45]

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[40] Staff's Reply Brief at 6.
[41] Docket No. UE 374, Staff/2400, Gibbens/10 (July 24, 2020). This is the same Staff testimony excerpted in PAC/1603; the Company requests that the Commission take official notice of this additional portion of the testimony.
[42] Staff's Reply Brief at 5.
[43] PAC/1000, Staples/44.
[44] *See* PAC/400, Staples/25.
[45] *See In re PacifiCorp, dba Pac. Power, 2013 Transition Adjustment Mechanism*, Docket No. UE 245, Order No. 12-409 at 5 (Oct. 29, 2012) [hereinafter 2013 TAM].

This position is also implicit in every PCAM filing the Company has made since its inception because PCAM filings have never included bookout transactions.

PacifiCorp's response to AWEC's arguments on bookouts is entirely consistent. As described above, when AWEC claimed that certain transactions modeled in GRID were the functional equivalent of a bookout, PacifiCorp simply removed these transactions for illustrative purposes to demonstrate that sales remained over-stated compared to actual NPC, with or without consideration of these bookout-like sales.

E. The alternative approaches proposed by the parties are inadequate.

As discussed above, even with PacifiCorp's average-of-averages approach, the Company will likely over-estimate sales in the 2022 TAM. Staff does not dispute this reality. In fact, Staff criticizes PacifiCorp's approach for not "mov[ing] the needle" enough.[46] Nonetheless, Staff still insists that its alternative third-quartile-of-averages approach represents a superior methodology if the Commission wants to address PacifiCorp's concerns about sales over-estimations.[47] Thus, Staff argues that the Commission should reject PacifiCorp's proposal because it fails to address the entirety of GRID's over-estimation problems and then argues that Staff's approach—which will result in higher sales estimations—is somehow superior. Staff cannot have it both ways. Any approach that does less to address sales over-estimations is by definition less accurate than PacifiCorp's proposal.[48] The Commission should reject Staff's alternative proposal to adopt a third-quartile-of-averages approach.

In contrast to the similar alternative approaches proposed by CUB and Staff, AWEC's alternative approach is a complex iterative market cap model that would address sales over-estimations individually at specific market hubs. AWEC contends that PacifiCorp has identified no significant flaw with AWEC's proposed methodology.[49] That is incorrect. In addition to

[46] Staff's Reply Brief at 7.
[47] Staff's Reply Brief at 9. Staff argues that PacifiCorp does not effectively criticize its proposal in its opening brief but fails to quote the relevant language discussing Staff's proposal as an inadequate middle ground between the Commission's current approach and PacifiCorp's proposal. PacifiCorp's Opening Brief at 14 (Sept. 15, 2021).
[48] PAC/1000, Staples/51.
[49] AWEC's Reply Brief at 12.

PacifiCorp's implementation concerns, as PacifiCorp noted in its Opening Brief, AWEC's approach is highly prescriptive, designed to produce a level of sales that reflects the historical average. This approach is contrary to standard NPC modeling, which sets parameters and allows the model to determine the optimal level of sales activity within that limit.[50]

III. OTHER REVENUES

A. The Commission should not include fly-ash sales revenue as part of the Other Revenues line item.

1. Fly-ash revenues were never intended to be included in Other Revenues.

AWEC has proposed an adjustment to add an entirely new category of revenues to the Other Revenues line item that the Commission adopted through a stipulated settlement in the 2011 TAM.[51] Staff now supports AWEC's adjustment based on an assertion that inclusion of these revenues would ensure that these "benefits are captured fully between rate cases."[52] Both AWEC and Staff also argue that because fly-ash sales have a "direct relation" to coal energy generation, they should be included in Other Revenues.[53]

In its Opening Brief, PacifiCorp explained that (1) revenue is included in the TAM only if Order No. 10-363 from the 2011 TAM specifically identified the revenue source; (2) since the 2011 TAM, PacifiCorp has updated Other Revenues in all stand-alone TAM filings based on the specific revenue items listed in Order No. 10-363; (3) the Commission has never recognized additional Other Revenues items in the TAM and has rejected attempts to include revenue items not specified in Order No. 10-363; (4) revenues from fly-ash sales are not specifically identified in Order No. 10-363 as an Other Revenues item that can be updated as part of a stand-alone TAM proceeding; (5) if AWEC wants to include additional sources of revenue in the TAM, the TAM Guidelines require that "such changes are to be appropriately addressed in a general rate revision docket or other proceeding, *not part of a stand-alone TAM proceeding*"[54]; (6) in PacifiCorp's 2021

[50] PacifiCorp's Opening Brief at 15.
[51] *See In re PacifiCorp, dba Pac. Power, 2011 Transition Adjustment Mechanism*, Docket No. UE 216, Order No. 10-363 at 3 (Sept. 16, 2010) [hereinafter 2011 TAM].
[52] Staff's Reply Brief at 28.
[53] AWEC's Reply Brief at 15; Staff's Reply Brief at 28.
[54] 2012 TAM, Order No. 11-435 at 6 (emphasis added) (citing TAM Guidelines, Order No. 09-274, App'x A at 9).

Rate Case, the Commission rejected CUB's attempt to bring wheeling revenues into the TAM because it would increase PacifiCorp's risk by making wheeling revenue subject to the PCAM deadbands and because the Commission "hesitate[s] to make changes to the [TAM] guidelines absent consensus"[55]; and (7) including revenue from fly-ash sales without including all the costs incurred to generate fly-ash violates the matching principle and the rationale for including revenues in the TAM.[56]

Neither AWEC nor Staff rebut these arguments, which are now undisputed. Rather than addressing the Company's arguments, AWEC ignores prior Commission precedent and repeats its same argument that Other Revenues (1) was not intended to include only the stipulated accounts in the 2011 TAM, (2) the Federal Energy Regulatory Commission (FERC) account where PacifiCorp records fly-ash sales revenue includes Other Revenue line items, and (3) a baseline amount for fly-ash sales revenue was included in the Company's 2010 Rate Case, docket UE 217.[57]

First, AWEC argues that because the Seattle City Light—Stateline Wind Farm account is listed in the same FERC account as fly-ash sales revenue (FERC account 456), fly-ash sales revenue should also be included in the TAM.[58] But revenues from the Stateline Wind Farm contract were specifically listed in the 2011 TAM settlement that created the Other Revenues line item.[59] FERC account 456 is not included in TAM under the TAM Guidelines.[60] If any party would like to propose this adjustment to the TAM Guidelines, it must do so as part of a future general rate case or separate standalone proceeding.[61] Making such a change in a standalone TAM is improper, and the Commission should reject AWEC's proposal.

Second, AWEC argues that revenue items specifically identified in Order No. 10-363 for inclusion in the TAM are only "examples" of the types of accounts that can be considered Other

[55] Order No. 20-473 at 130.
[56] *See* PacifiCorp's Opening Brief at 15-21 (internal citations omitted).
[57] AWEC Reply Brief at 13-15.
[58] AWEC Reply Brief at 13.
[59] PacifiCorp's Opening Brief at 17; *see also* 2011 TAM, Order No. 10-363, App'x A at 4 (listing the specific accounts also listed in the Other Revenues line item).
[60] PAC/1000, Staples/55.
[61] TAM Guidelines, Order No. 09-274, App'x A at 9.

Revenue and that nothing in the order precludes other sources of revenue from inclusion in the TAM.[62] This argument cannot be squared with the undisputed fact that since Order No. 10-363, the only sources of revenue included as Other Revenues in the TAM are those specifically identified in Order No. 10-363, and the Commission specifically rejected attempts to include additional sources of revenue in the TAM.[63] Even when CUB properly sought to include wheeling revenues in the TAM in PacifiCorp's general rate case, the Commission did not do so. There is no support for AWEC's claim that Order No. 10-363 is an open-ended invitation to include any and all revenue generally related to NPC in the TAM.

Third, AWEC claims that if only revenue items listed in Order No. 10-363 are included in the TAM, it would render Other Revenues "superfluous and provide no benefit to ratepayers" because the revenue items listed in Order No. 10-363 have all expired.[64] AWEC claims that "[t]here is no suggestion in Order No. 10-363 that the Other Revenues adjustment was intended to be temporary."[65] This argument also contradicts the reality that the Commission has never approved any Other Revenues that were not included in Order No. 10-363, even as the items listed in that order expired in prior TAMs. Moreover, even if one assumes that the parties and Commission intended for additional sources of revenue to be included in the Other Revenues category, the TAM Guidelines are clear that such a change must occur in a general rate case, just as CUB proposed for wheeling revenue.

Fourth, AWEC argues that because fly-ash revenue was included in rates in PacifiCorp's 2010 rate case, it fits within the scope of Other Revenues that can be included in the TAM.[66] This argument also fails. If parties intended to include fly-ash revenues as part of the Other Revenues line item, they could have listed it with the other five accounts specifically identified in Order No. 10-363. By specifically identifying the sources of revenue that would be included in the TAM as

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[62] AWEC's Reply Brief at 14.
[63] *See, e.g.*, 2012 TAM, Order No. 11-435 at 6.
[64] AWEC's Reply Brief at 14 (citing *In re Idaho Power Co., Request for a Gen. Rate Revision*, Docket No. UE 233, Order No. 13-416 at 4 (Nov. 12, 2013) (deciding that reading the earnings test requirement out of amortization amounts would render language in ORS 757.259(1)(a)(A) meaningless)).
[65] AWEC's Reply Brief at 14.
[66] AWEC's Reply Brief at 15.

Other Revenues and *excluding* fly-ash revenue, it shows that the parties did not intend for fly-ash revenues to be included in TAM as Other Revenue.[67] AWEC's argument requires the Commission to write the words "for example" into Order No. 10-363 and allow AWEC and Staff to include a sixth item known at the time but not included in a list that specifically includes all other line items and does not include a catch-all phrase at the end of the list. Such a result would be against the plain reading of Order No. 10-363.

Fifth, AWEC acknowledges that fly-ash revenues have never been included in the TAM but claims that fly-ash revenues should now be included in the TAM because of the "factual scenario" present in this year's TAM.[68] But nothing in Order No. 10-363, prior Commission precedent, or the TAM Guidelines suggests that additional revenues can be brought into the TAM through a stand-alone TAM filing simply because the revenues have increased since the last rate case. In fact, as discussed in PacifiCorp's testimony, there are many costs and revenues in base rates that may fluctuate based on generation.[69]

Staff's brief offers little argument in support of AWEC's adjustment but does claim that PacifiCorp "appears to be selectively including, and thus updating, elements of Other Revenues in the TAM."[70] As outlined above and in PacifiCorp's Opening Brief, the Company has consistently updated all the revenue items listed in Order No. 10-363 in every TAM since the 2011 TAM. The Company has not included other sources of revenue in stand-alone TAMs because doing so is contrary to Order No. 10-363, Commission precedent, and the TAM Guidelines.

2. AWEC has repeatedly changed its position on fly-ash sales, and neither Staff nor AWEC have presented consistent numbers to the Commission.

AWEC has changed its adjustment for fly-ash revenues during each round of testimony

[67] *Cf. Crimson Trace Corp. v. Davis Wright Tremaine, LLP*, 355 Or 476, 497 (2014) ("The *expressio unius* principle is simply one of inference. And the strength of that inference will depend on the circumstances. For example, the longer the list of enumerated items and the greater the specificity with which they are stated, the stronger the inference that the legislature intended the list to be exhaustive.").
[68] AWEC's Reply Brief at 15.
[69] PAC/1000, Staples/55.
[70] Staff's Reply Brief at 28.

and again at hearing.[71] Despite repeatedly changing its quantification of the adjustment, AWEC claims in its brief that the "amount associated with that adjustment is not reasonably disputable[.]"[72] AWEC then changes the amount yet again. Now in its reply brief, AWEC appears to quantify its adjustment as the $15.7 million number cited during the hearing subtracted from the $6.8 million the Commission already included in the Company's 2021 Rate Case.[73] On a total-Company basis, it appears that AWEC is recommending a downward adjustment of $8.9 million. AWEC then appears to quantify its adjustment as a net decrease of $395,055 when netted against the expiring revenues from the Seattle City Light Stateline, which was based on the calculation in a cross-examination exhibit, AWEC/303.[74] AWEC/303, which was a cross-examination exhibit, includes errors making it unreliable and further undermining the basis for AWEC's adjustment. First, AWEC incorrectly calculated the revenue from the Seattle City Light Stateline contract included in base rates in docket UE 374. The correct amount is $11,351,003, not $10,024,343.[75] Second, AWEC erroneously accounted for changes in load. Correcting for these errors makes the adjustment a net increase of $67,826 (i.e., a decrease of $3,054,108 from PacifiCorp's Reply Update filing).[76] AWEC's inability to quantify its adjustment provides strong evidence that it should be rejected. Moreover, AWEC's inconsistent data and shifting positions underscore the need to address changes in these revenues in a general rate case, not the TAM, unless and until the TAM Guidelines are expressly revised to include this item.[77]

Staff has also failed to provide any specific data in its briefing to support a particular number for fly-ash revenues in this proceeding, instead opting to support fully capturing unquantified benefits in its briefing.[78] However, in its rebuttal testimony, Staff took the position

[71] PacifiCorp's Opening Brief at 20-21.
[72] AWEC's Reply Brief at 16.
[73] AWEC's Reply Brief at 16-17.
[74] AWEC/303 at 1.
[75] Docket No. UE 374, PAC/1302, McCoy/62 (Feb. 14, 2020). PacifiCorp requests that the Commission take official notice of this testimony.
[76] These calculations are derived from AWEC/303, introduced for the first time at hearing.
[77] *See* TAM Guidelines, Order No. 09-274, App'x A at 9.
[78] Staff's Reply Brief at 28.

that the Commission should use 2020 fly-ash revenues as the basis for the 2022 forecast.[79] Now Staff indicates support for AWEC's adjustment,[80] which recommends 2021 fly-ash sales as a baseline.[81] Staff does not address this difference and give no principled reason why its briefing does not reflect its own testimony on the issue. Considering that both AWEC and Staff have repeatedly changed their positions on fly-ash revenues and neither party has presented accurate and fully supported data on fly-ash sales, the Commission should reject this adjustment as unsupported in the record.

IV. NODAL PRICING MODEL

A. The Commission should reject Staff's proposal to impute speculative Nodal Pricing Model (NPM) benefits into the TAM.

As part of the Company's ongoing implementation of a NPM, PacifiCorp started receiving day-ahead optimal unit commitment and hourly energy schedules in January 2021.[82] Staff supports the prudence of the Company's use of NPM but recommends an adjustment that would effectively disallow cost recovery based on Staff's speculation that NPM will provide NPC savings that are not reflected in GRID. The Commission should reject Staff's attempt to rescind its prior support for the Company's transition to NPM and Staff's poorly supported adjustment.

1. Staff mischaracterizes NPM to suggest that it is something more than receipt of better optimized day-ahead schedules.

The only operational change from implementing NPM is PacifiCorp's receipt of day-ahead optimal unit commitment and hourly energy schedules from the California Independent System Operator (CAISO).[83] The use of NPM will not change how PacifiCorp dispatches its system after receiving the CAISO schedules. Until the intra-hour EIM is implemented, PacifiCorp's system will continue to be dispatched in actual operations based on information that cannot predict with perfect accuracy what the load and resource balance will be in the next hour.

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[79] Staff/1000, Enright/11.
[80] Staff's Reply Brief at 28.
[81] AWEC's Reply Brief at 16-17.
[82] PAC/1100, Wilding/3. PacifiCorp does not plan to start using NPM to track power costs, its primary purpose, until 2024. PAC/400, Staples/76.
[83] PAC/1100, Wilding/5.

PacifiCorp incurs costs in actual operations because of differences between the day-ahead and real-time schedule. NPM will reduce these costs by providing better optimized day-ahead schedules.[84] As the Company has explained in its testimony accompanying the 2020 Inter-Jurisdictional Allocation Protocol (2020 Protocol),[85] its rebuttal testimony,[86] its surrebuttal testimony,[87] and its Opening Brief,[88] GRID already assumes perfect alignment between all day-ahead schedules and real-time dispatch; therefore, the use of better optimized day-ahead schedules will not reduce costs relative to the GRID forecast.[89] Rather, the use of optimized day-ahead schedules will make actual operations more like the perfectly optimized dispatch modeled in GRID.[90]

Staff acknowledges that the receipt of more granular day ahead schedules will provide the operational benefits PacifiCorp has identified.[91] But Staff claims there is a "second operational benefit" that results from the "switch in dispatch logic" provided by the use of a nodal model instead of GRID's zonal model used to forecast NPC.[92] Staff's testimony and brief imply that PacifiCorp will now be using NPM to make *real-time dispatch decisions in actual operations* and that doing so will create operational benefits that are not captured in the zonal modeling used by GRID.[93] For example, Staff testifies that "perfect planning is not what provides the cost savings associated with the nodal model."[94] Rather, Staff claims NPM provides an "optimization tool that GRID does not possess."[95] Staff's apparent belief that NPM is used to make real-time dispatch decisions—and thereby produce this "second operational benefit"—is also reflected in Staff's position that once the Company switches to Aurora there will no longer be a need to impute NPM

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[84] PAC/1100, Wilding/5.
[85] *In re Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues*, Docket No. UM 1050, PAC/300, Wilding/10-11 (Dec. 3, 2019).
[86] PAC/400, Staples/78.
[87] PAC/1100, Wilding/6.
[88] PacifiCorp's Opening Brief at 23-24.
[89] PAC/1100, Wilding/6.
[90] PacifiCorp's Opening Brief at 23-24.
[91] Staff's Reply Brief at 20.
[92] Staff's Reply Brief at 20-21; Staff/1300, Gibbens/5.
[93] *See, e.g.*, Staff's Reply Brief at 21.
[94] Staff/900, Gibbens/11.
[95] Staff/1300, Gibbens/5.

benefits because Aurora already includes Staff's "second operational benefit."[96] Implicit in Staff's position is Staff's view that the Company's actual operational real-time dispatch using NPM matches the nodal pricing dispatch used by Aurora, which further assumes that Aurora will use a nodal topology. This is not true.[97]

To be clear, the *only* operational change resulting from implementing NPM is more accurate day-ahead schedules. Those schedules are created by CAISO using a nodal model and are more granular than the schedules used before NPM and therefore reflect the advantages of nodal modeling Staff discusses in its brief.[98] In other words, the benefits of nodal modeling Staff describes are embedded in the day-ahead schedules but nothing more. Specifically, PacifiCorp's testimony explained that the more efficient day-ahead setup results from NPM providing more transparency into PacifiCorp's transmission scheduling rights, allowing for a more granular day-ahead setup.[99] This more granular setup results in fewer changes between the day-ahead schedules and real-time dispatch, thereby lowering NPC by avoiding those changes.[100] Importantly, the benefits of NPM end at the day-ahead setup and are not carried forward into real-time dispatch in actual operations. Thus, more "perfect planning" is the *only operational benefit* because it is the only operational change resulting from the implementation of NPM; actual operations can never be more perfect than GRID's perfect foresight.[101] Thus, Staff's "second operational benefit" does not exist.

2. Staff's focus on the differences between GRID and Aurora is irrelevant.

Staff's testimony and briefing discuss at length the differences between GRID and Aurora, which Staff uses to distinguish zonal from nodal modeling.[102] Aurora is entirely irrelevant for two reasons. First, PacifiCorp explained in its testimony that Aurora *will not* use a nodal topology.[103]

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[96] *See* Staff's Reply Brief at 20-21.
[97] *See* PAC/1100, Wilding/9 (explaining that Aurora will not use a nodal topology).
[98] *See* Staff's Reply Brief at 21-22.
[99] PAC/1100, Wilding/10.
[100] PAC/1100, Wilding/5.
[101] Staff's Reply Brief at 21 (agreeing GRID has perfect foresight).
[102] *See, e.g.¸* Staff's Reply Brief at 21.
[103] PAC/1100, Wilding/9.

Staff focuses extensively on the purported differences between Aurora and GRID as a basis for imputing NPM benefits without ever acknowledging the Company's testimony or explaining how Aurora will use a nodal topology. Second, differences between GRID and Aurora are irrelevant because what matters is the difference between the NPC forecasting model—regardless of whether the Company uses GRID or Aurora—and actual operations.

Staff admits that PacifiCorp explained in the Multi-State Protocol proceeding that "the NPM potentially provides more granular day-ahead setup information resulting in potential cost savings and the cost savings will be embedded in actual NPC."[104] But Staff suggests that this testimony assumed the Company was using Aurora to forecast NPC, not GRID.[105] As explained repeatedly, the benefits resulting from more granular day-ahead schedules are not captured by GRID because GRID does not reflect any uncertainty between day-ahead and real-time dispatch, which is what the Company explained in docket UM 1050.[106] The contemplated use of Aurora does not change this fact.

3. GRID does not include costs incurred because of changes from the day-ahead schedules.

For the first time in its brief, Staff disputes the Company's claim that GRID does not include costs associated with changes between the day-ahead and real-time dispatch.[107] Staff does not point to any evidence in the record to support this claim. Instead, Staff cites to testimony that is *not* in the record and claims that PacifiCorp justified the need for the DA/RT adjustment because there are "unaccounted for costs related to rebalancing the system and planning to meet load when moving from day-ahead to real-time."[108] It is unclear why Staff believes this prior testimony is contrary to PacifiCorp's testimony here. In both cases, the Company explained that GRID does not capture the costs incurred to balance the system because it has perfect foresight. The

[104] Staff's Reply Brief at 22 (quoting Docket No. UM 1050, PAC/300, Wilding/11).
[105] Staff's Reply Brief at 22.
[106] *See* PAC/1100, Wilding/10 ("PacifiCorp identified that there might be operational cost savings but has been clear from the beginning that '[t]he potential operational cost savings will be the result of a more efficient day ahead setup and the cost savings will be embedded in the actual NPC.'") (quoting Docket No. UM 1050, PAC/300, Wilding/11).
[107] Staff's Reply Brief at 23.
[108] Staff's Reply Brief at 23.

Company's prior testimony is perfectly consistent with its testimony here.

To the extent that Staff is now arguing that NPM should be an offset to the DA/RT adjustment, there is no evidence in the record supporting such a novel adjustment raised for the first time in Staff's reply brief.

4. The benefits of NPM are analogous to intra-regional EIM benefits.

The Commission rejected the inclusion of EIM intra-regional benefits as an offset to the GRID forecast after finding that GRID's perfect optimization already captured the benefits of more efficient dispatch of the Company's own resources.[109] Staff attempts to distinguish NPM from the EIM's intra-regional benefits by pointing out that GRID "estimates what the actual dispatch will be, similar to the EIM," while the NPM schedule is simply "advisory" and that there are "substantive differences" between the day-ahead and real-time operation of a system.[110] Staff appears to argue that intra-regional benefits are embedded in GRID because both GRID and the EIM relate to actual dispatch, while NPM does not. While it is true that NPM does not affect actual dispatch beyond providing day-ahead schedules,[111] that does not mean that GRID includes in its NPC forecast the costs associated with the "substantive differences" between day-ahead and real-time dispatch. GRID does not. The benefits from PacifiCorp's receipt of more granular day-ahead schedules are already included in GRID because GRID's perfect foresight always assumes a perfect match between the day-ahead schedule and real-time dispatch and does not account for the "substantive differences" Staff identifies.[112]

Moreover, Staff's concession that NPM does not impact real-time dispatch undermines Staff's claim that NPM provides benefits beyond a "perfect schedule." Indeed, Staff's concession undermines the entire rationale for Staff's imputation of additional benefits.

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[109] *In re PacifiCorp, dba Pac. Power, 2017 Transition Adjustment Mechanism*, Docket No. UE 307, Order No. 16-482 at 16 (Dec. 20, 2016) [hereinafter 2017 TAM].
[110] Staff's Reply Brief at 23.
[111] See Section IV.A.1 for a more through discussion of this point.
[112] PacifiCorp's Opening Brief at 23.

5. NPM benefits are not forecastable.

Staff claims that the operational benefits resulting from the receipt of more granular day-ahead schedules are "forecastable" and therefore should be included as a reduction to the GRID results in this case.[113] But Staff has conceded that NPM benefits result from a more granular day-ahead schedule.[114] Furthermore, Staff's brief appears to concede that the only way to track those benefits would be to develop a counterfactual based on the day-ahead setup that would have occurred without NPM, which Staff's brief correctly states is "impossible to forecast."[115]

Staff instead recommends that the Commission adjust total company NPC by $8.4 million, or the entire CAISO service fee.[116] Staff criticizes PacifiCorp's inability to quantify any benefits and therefore believes without any evidence that NPM costs should match the alleged "benefits."[117] But Staff's own testimony concedes that the anticipated benefits of the NPM are "difficult or impossible to quantify."[118]

Staff argues that setting benefits equal to costs "is consistent with prior Commission precedent under similar circumstances."[119] But in the case of EIM costs, there was no dispute that the EIM provided inter-regional and other benefits, and the benefit offset was the result of a stipulation. That is not the case here.

6. The Commission should reject Staff's alternative proposal to require PacifiCorp to perform a comparative 2022 NPC run in Aurora.

Staff recommends that the Commission require the Company to run a comparative 2022 NPC run in Aurora as part of the 2022 PCAM to "isolate dispatch benefits associated with the NPM."[120] Staff argues that such a run "will likely provide meaningful information" because Aurora's nodal model aligns with CAISO's nodal model.[121] But as discussed above, PacifiCorp's

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[113] Staff's Reply Brief at 20.
[114] Staff's Reply Brief at 23.
[115] Staff's Reply Brief at 20.
[116] Staff's Reply Brief at 25.
[117] Staff's Reply Brief at 25.
[118] Staff/900, Gibbens/12.
[119] Staff's Reply Brief at 24.
[120] Staff's Reply Brief at 25.
[121] Staff's Reply Brief at 25.

Aurora model will not implement a nodal topology, making this comparison irrelevant and unhelpful.[122] Staff also argues that providing this run will give parties time to assess any differences between the Aurora and GRID and propose adjustments.[123] This argument depends on Staff's flawed assumption that a zonal model does not contain transmission constraints, which is simply inaccurate.[124] This is especially true because the benefits that Staff is trying to capture are already reflected in the perfect foresight of both GRID and Aurora.[125] Any differences between a GRID and Aurora output could be due to numerous changes as a result of the transition.[126]

V. QF FORECASTING

A. The Commission should reject Staff's adjustment to Qualified Facility (QF) modeling because the Company uses the best data available to forecast QF power costs.

Staff argues that TAM rates are "forward-looking in nature" and "[t]o go back and attempt a 'make up call' in the current TAM proceeding based on a history of under-recovery is akin to retroactive ratemaking."[127] Yet Staff's QF adjustment is exactly the type of "make up call" Staff derides. Staff has taken a single NPC cost element, determined that the historical forecast was over-forecast, and therefore "makes up" for that historical over-forecast by decreasing the forward-looking forecast by the same amount as the historical over-forecast. Staff did not rebut the Company's argument that applying this same rationale to every single NPC element would have increased the NPC forecast by 8 percent.[128]

Staff falsely claims that "it is undisputed on the record of this proceeding that . . . PacifiCorp's forecast of NPC continues to be over-stated due to its consistent over-forecast of QF costs."[129] In fact, the evidence in the record—which Staff did not dispute—shows that

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[122] PAC/1100, Wilding/9.
[123] Staff's Reply Brief at 25-26.
[124] PAC/1100, Wilding/8.
[125] *See* PAC/1000, Staples/9 (describing GRID's perfect foresight).
[126] PAC/1100, Wilding/9.
[127] Staff's Reply Brief at 3.
[128] PacifiCorp's Opening Brief at 28.
[129] Staff's Reply Brief at 27.

PacifiCorp's "forecast of NPC" has been consistently *under-stated*.[130] Exacerbating the under-stated NPC by isolating a single cost and applying a historical true-up is one-sided and should be rejected.

VI. COAL ISSUES

A. PacifiCorp's NPC modeling produces reliable, cost-effective plant dispatch and does not improperly favor coal generation.

1. PacifiCorp's CSA modeling produces optimized plant dispatch.

In modeling coal dispatch in GRID, PacifiCorp uses an iterative process because GRID cannot accept multiple pricing tiers.[131] If a CSA has multiple pricing tiers, PacifiCorp must use as the initial input to GRID the best incremental price. But if the results are substantially off the supply curve (i.e., the volume consumed does not match the price for the volume consumed), then PacifiCorp must use an iterative process to develop a dispatch price that will optimize the CSA's supply curve and minimize NPC. When the iterative process results in a lower dispatch price to ensure that the plant meets its minimum take, that solution is least-cost for customers because the minimum take obligation is a sunk cost that cannot be avoided. The Commission expressly approved PacifiCorp's iterative modeling in the 2017 TAM.[132]

Sierra Club argues that PacifiCorp "manipulates" the dispatch prices to inhibit GRID's ability to "neutrally" dispatch the "least-cost, least-risk generation mix for the Company's customers."[133] In particular, Sierra Club argues that "forcing the model to project minimum quantities of coal burn does not demonstrate that PacifiCorp is operating its system in the most economically prudent manner for the benefit of ratepayers."[134] But PacifiCorp only adjusts the dispatch price for a coal plant if doing so is necessary to cover a minimum take obligation, which undoubtedly reduces overall customer costs.[135] Indeed, Sierra Club does not—and cannot—argue

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[130] *See* PAC/400, Staples/14 (2020 NPC collected through rates was $307.4 million, while actual NPC was $335.6 million).
[131] *See* PacifiCorp's Response to ALJ Bench Request 5(a) (Sept. 17, 2021).
[132] 2017 TAM, Order No. 16-482 at 10-11.
[133] Sierra Club's Reply Brief at 3 (Sept. 28, 2021).
[134] Sierra Club's Reply Brief at 4.
[135] Confidential Evidentiary Hearing Transcript 23:22-24:9 (Aug. 26, 2021) [hereinafter Evid. Tr.]; PacifiCorp's Response to ALJ Bench Request 5(a).

that it is lower cost for customers to pay for coal that is not burned and also pay for alternative generation.

Sierra Club concedes in its brief that: (1) making dispatch decisions based on incremental or marginal prices is "economically sound"; (2) "most fuel costs may be unavoidable and thus appropriately treated as fixed and excluded from" the incremental price used to dispatch the plant; and (3) the "majority of PacifiCorp's [CSAs] contain minimum take provisions which may be unavoidable in the near or short term."[136] Sierra Club does not dispute that GRID can only accept one price and that a CSA with a minimum take provision has at least two incremental pricing tiers—a zero price tier for the volumes up to the minimum take and a second tier for volumes above the minimum take.[137] Given Sierra Club's concessions and these undisputed facts, Sierra Club has no basis to claim that PacifiCorp improperly "manipulates" dispatch prices to drive up coal generation. Rather, PacifiCorp's practice of determining the optimum dispatch price appropriately responds to model limitations and real-world contracting obligations.

In PacifiCorp's 2021 Energy Cost Adjustment Clause (ECAC) proceeding before the California Public Utilities Commission (CPUC), Sierra Club made an identical argument that PacifiCorp improperly "manipulated" the incremental price by using the iterative process to arrive at an optimal dispatch price. In the Proposed Decision issued September 30, 2021, the Administrative Law Judge rejected Sierra Club's argument, finding that the "least-cost methodology for estimating NPC remains the adjusted incremental cost approach used by PacifiCorp and approved by the [CPUC] in the 2020 ECAC proceeding."[138] The Proposed Decision agreed with PacifiCorp's argument that it "makes iterative adjustments to the dispatch tier because the GRID model only recognizes a single value for the incremental fuel cost and cannot optimize multiple pricing tiers," that "PacifiCorp's modeling inputs optimize PacifiCorp's overall resource portfolio without unnecessary increases in NPC," and "these modeling

[136] Sierra Club's Reply Brief at 6.
[137] PacifiCorp's Response to ALJ Bench Request 5(a).
[138] *In re the Application of PacifiCorp (U901E) for Approval of its 2021 Energy Cost Adjustment Clause & Greenhouse Gas-Related Forecast & Reconciliation of Costs & Revenue*, CPUC Application 20-08-002, proposed Decision of ALJ Larsen at 15 (Sept. 30, 2021) [hereinafter 2021 ECAC Proposed Decision].

adjustments do not result in a substantial increase in coal consumption."[139]

2. Sierra Club falsely accuses PacifiCorp of manipulating the dispatch tier price for plants with new CSAs or open positions in 2022.

Sierra Club claims that PacifiCorp "fails to accurately reflect" the variable costs at Craig, Dave Johnston, Hunter, Naughton, Jim Bridger, and Wyodak because PacifiCorp assumes that it will be bound by minimum take obligations at these plants even though, according to Sierra Club, the minimum take obligations are not yet a sunk cost.[140] Setting aside whether the minimum take obligations are a sunk cost, which they are, Sierra Club's claim that PacifiCorp "manipulated" the dispatch price for these plants is entirely untrue.[141] None of these plants required any modification to the dispatch tier price in order to meet a minimum take obligation.[142] Sierra Club's false claims are particularly egregious because, only two pages later, its brief concedes that there were no changes to the dispatch price for the six plants that Sierra Club accuses PacifiCorp of manipulating.[143]

PacifiCorp also disagrees that it was unreasonable to assume a minimum take obligation for Jim Bridger and Naughton even though the Company has yet to execute new CSAs for 2022.[144] The Company explained that it reasonably assumed that the open position for those plants in 2022 will be filled with CSAs that include minimum take provisions because the plants have limited supply options and that future CSAs will include a minimum purchase obligation as is typical of most coal contracts.[145] As noted above, these assumptions had no impact on the dispatch tier price or the level of generation at either plant.

[139] 2021 ECAC Proposed Decision at 14-15.
[140] Sierra Club's Reply Brief at 7.
[141] Sierra Club's Reply Brief at 7-8.
[142] *See* Sierra Club's Reply Brief at 9; Staff/702, Anderson 5 (PacifiCorp's Response to OPUC Data Request 66: "In the initial filing of the 2022 transition adjustment mechanism (TAM), the coal units requiring adjustment to meet the minimum take obligation are Colstrip, Hayden, and Huntington. The Craig, Dave Johnston, Hunter, Jim Bridger, Naughton, and Wyodak coal units required no adjustment.").
[143] Sierra Club's Reply Brief at 9.
[144] Sierra Club's Reply Brief at 7.
[145] PAC/600, Ralston/39.

B. PacifiCorp's coal procurement strategy and dispatch practices ensure system reliability.

Although PacifiCorp's coal generation has steadily declined in recent years, it remains a vital component of the Company's generation mix and is necessary to ensure reliable service to retail customers. The continued addition of renewable resources into the Company's generation fleet also requires the presence of significant online dispatchable resource capacity to integrate and reliably serve load with those new resources,[146] particularly in years with low hydro generation and high gas prices, like 2021.[147]

To provide reliable service, PacifiCorp must have a reliable fuel supply.[148] Minimum take obligations are therefore essential because they ensure that fuel is available when needed.[149] Without a commitment by PacifiCorp to purchase a specified volume of coal, the coal producer would have no assurance that any coal would be purchased and therefore could not invest sufficient capital in the mine to ensure a reliable supply.[150] Under such scenario, when PacifiCorp needs fuel, it may not be available. "Relying exclusively on the spot market is an extremely risky strategy that would expose customers to substantial and unreasonable price and supply risk, especially in the illiquid markets in which most of PacifiCorp's coal generation is located."[151]

Moreover, coal mines cannot ramp up supply overnight to respond to increased demand. Market conditions in 2021 vividly illustrate the risk and potential consequences of an unreliable fuel supply. This year, hydro conditions are low and natural gas prices are high, which has increased demand for coal. But producers cannot turn on a dime and increase production, which has led to tight supplies and limited access to additional coal.[152] Executing CSAs with reasonable minimum take provisions better ensures that coal will be available when needed.

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[146] PAC/1000, Staples/8; PAC/500, Schwartz/6-7.
[147] PAC/500, Schwartz/9-10.
[148] PAC/500, Schwartz/10-11.
[149] PAC/500, Schwartz/10-11, 14.
[150] PAC/500, Schwartz/14.
[151] PAC/600, Ralston/11.
[152] *See* S&P Article.

The parties' singular focus on whether the incremental price[153] is sufficient to ensure that the Company meets its minimum take obligations ignores the very real—and entirely undisputed—reliability benefits provided by CSAs with minimum take provisions. Sierra Club selectively quotes the hearing transcript to claim that PacifiCorp conceded that "manual adjustments [to a CSA's dispatch price] year-over-year *would* indicate uneconomic generation."[154] But PacifiCorp also explained that whether generation is uneconomic must also consider reliability benefits provided by a plant; so focusing on just the dispatch price and minimum take level is an incomplete assessment of a plant's economics.[155] Moreover, PacifiCorp explained that it is cost reducing to adjust the dispatch price to clear the minimum take volumes, which means that it would be higher cost (or less economic) to not adjust the dispatch price.[156]

CSAs with minimum take obligations are akin to a hedging transaction. The Company enters hedges to provide supply certainty and price stability, not to "beat the market."[157] Similarly, CSAs—which necessarily include a minimum take obligation—ensure a reliable supply of fuel at a stable price. And just as hedges are not imprudent if they ultimately do not "beat the market," CSAs are also not imprudent or uneconomic if the price and minimum take obligation do not at all times "beat the market."

C. PacifiCorp's CSA negotiation process is reasonable.

Consistent with industry practice and to ensure a reliable and low-cost fuel supply, PacifiCorp relies on reasonable minimum take provisions in virtually all of its CSAs. Sierra Club recommends that the Commission apply a heightened prudence review for all CSAs that include a minimum take level above 50 percent of the forecasted generation.[158] Sierra Club produced no evidence that PacifiCorp could actually execute a CSA with a 50 percent minimum take level and

[153] The parties and PacifiCorp use the terms incremental, marginal, or dispatch price interchangeably in this proceeding.
[154] Sierra Club's Reply Brief at 9 (emphasis in original).
[155] Evid. Tr. at 112:23-113:11.
[156] Confidential Evid. Tr. 23:22-24:9; PacifiCorp's Response to ALJ Bench Request 5(a).
[157] 2012 TAM, Order No. 11-435 at 9 (acknowledging PacifiCorp's hedging policy designed "to reduce price volatility and provide price certainty, a goal that customers value, but which comes with a cost").
[158] Sierra Club's Reply Brief at 26.

concedes in its brief that a "50 percent threshold is not the current industry standard."[159] Therefore, Sierra Club's recommendation should be rejected.

Sierra Club criticizes the Company for signing new CSAs that do not allow it to reduce or avoid its minimum take obligations.[160] But PacifiCorp cannot unilaterally impose such a requirement on a counterparty and producers are generally unwilling to contract away the certainty provided by a minimum take provision without receiving other assurances, such as a longer contract term or a much higher price.[161] The Company will continue to pursue risk mitigation clauses in all its CSAs, but cannot guarantee that it will be successful in every instance, particularly because none of the Company's plants except Dave Johnston are served by a liquid market and the Company is also pursuing shorter-term contracts.

Sierra Club faults the Company's general policy of not executing CSAs longer than five years as "arbitrary," and yet Sierra Club recommends an equally "arbitrary" two-year term limit.[162] Sierra Club's recommendation fails to acknowledge commercial realities applicable to negotiating CSAs in illiquid markets and fails to account for the likely increase in costs that would accompany a shorter contract term.[163] Ultimately, Sierra Club provides no evidence supporting its recommendation.

Sierra Club further recommends that when negotiating a new CSA, PacifiCorp should forecast anticipated generation based on the plant's average cost, should examine multiple demand scenarios, as it did when evaluating the new Hunter CSAs, and model economic cycling in its generation forecasts.[164] PacifiCorp already forecasts generation using the plant's average cost, has incorporated cycling consistent with the modeling used in the TAM and agrees to continue to do so, and PacifiCorp agrees to model multiple demand scenarios, as it did with Hunter.

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[159] Sierra Club's Reply Brief at 26.
[160] Sierra Club's Reply Brief at 26.
[161] *See* PAC/500, Schwartz/30-32 (discussing the "highly risky" strategy of minimum takes as low as 50 percent). Evid. Tr. 113-114.
[162] Sierra Club's Reply Brief at 27.
[163] PAC/600, Ralston/34-35.
[164] Sierra Club's Reply Brief at 24-25.

D. PacifiCorp reasonably models Jim Bridger plant dispatch and Sierra Club's disallowance is unsupported in the record.

1. PacifiCorp correctly accounts for Bridger Coal Company's (BCC) fixed costs when determining the dispatch price for Jim Bridger.

PacifiCorp dispatches the Jim Bridger plant based on the incremental cost to generate additional energy, consistent with basic economic principles that even Sierra Club no longer disputes.[165] For Jim Bridger, the incremental cost is the supplemental cost for BCC coal, which represents the cost to produce additional coal volumes over and above the base mine plan volumes. PacifiCorp determines the incremental (i.e., supplemental) cost based on the cost differential between two mine plans with different production volumes.[166] This methodology, which Sierra Club supports,[167] isolates the fixed costs of the BCC mine that are incurred regardless of production levels.

Sierra Club criticizes the use of the BCC supplemental price for dispatch decisions because it is significantly less than the base price, which Sierra Club claims results in uneconomic dispatch of the plant.[168] But there is nothing unusual or uneconomic about using an incremental cost to dispatch a plant even if the incremental price is significantly less than the average cost (i.e., when the supplemental price is less than the base price). Indeed, Charles F. Phillips, Jr. explains in his treatise *The Regulation of Public Utilities*, that "price-output [i.e., dispatch] decisions should be governed by short-run marginal costs" even though when a generating "plant is operating at less than full capacity and fixed costs are high, short-run marginal costs will represent a small fraction of average total costs."[169] James Bonbright concurs, noting in his treatise *Principles of Public Utility Rates* that the utility pricing should be based on incremental costs even though the exclusion of fixed costs from the short-run marginal cost means that marginal costs are "sometimes found to

[165] *See* Sierra Club's Reply Brief at 6 ("Making generation projections and dispatch decisions based on marginal or incremental costs may be economically sound. . .").
[166] PAC/1200, Ralston/36-37.
[167] Sierra Club/200, Burgess/5-6.
[168] Sierra Club's Reply Brief at 12-13.
[169] Charles F. Phillips, Jr., *The Regulation of Public Utilities* 443-44 (1993).

constitute mere fractions of average total costs."[170] In *Fundamentals of Energy Regulation*, the authors make the same point: "Once a firm is operating, producing one more unit may be less expensive than the average cost, because capital and administrative expenses do not change with the additional unit produced." [171] The authors further explain, "For an electric generator, producing an extra megawatt-hour (MWh) may just mean burning a bit more fuel."[172] Thus, "if the market price is $10, the firm will be willing sell (supply) output as long as it costs no more than $10 to produce each additional unit of output."[173] The Commission has also long recognized that "economic efficiency occurs when prices equal short-run marginal costs and the firm's capacity is at the optimal level."[174] Sierra Club's assertion that BCC is uneconomic because its average/base cost is higher than the incremental/supplemental cost is therefore contrary to well-established economic principles.

Sierra Club claims that PacifiCorp admitted at hearing that even if dispatching using the incremental price is profitable, PacifiCorp could still lose money overall if the losses on the base quantity were higher than the profit from the supplemental production.[175] This claim mischaracterizes the Company's testimony. At hearing, PacifiCorp explained that if the base price for an item were $30, for example, and PacifiCorp could sell it for $25, it makes economic sense to sell the item "if the $30 represents sunk costs" because the Company" would incur the same expenses either way, so they may as well generate the revenue."[176] Sierra Club's argument ignores fixed costs, which are properly excluded from short-run incremental costs but included in the average cost.

Sierra Club contends that the Company "structures its GRID modeling to ensure that

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[170] James C. Bonbright, Albert L. Danielsen, David R. Kamerschen, *Principles of Public Utility Rates* 418-419 (1988); *id.* at 421 ("Let the current rate of output be even slightly below the maximum output permitted by plant capacity (after adequate allowance for emergency reserve), and *marginal cost of service may be a mere fraction of average cost*.") (emphasis added).
[171] Jonathan A. Lesser, Ph.D., Leonardo R. Giacchino, Ph.D., *Fundamentals of Energy Regulation* 21 (2013).
[172] Lesser, *Fundamentals of Energy Regulation* at 21.
[173] Lesser, *Fundamentals of Energy Regulation* at 21.
[174] *In re Revised Tariff Schedules Applicable to Gas Serv. in the State of Or.*, Docket No. UG 14, Order No. 85-832 (Sept. 12, 1985).
[175] Sierra Club's Reply Brief at 13.
[176] Evid. Tr. 24:12-26:1-25.

supplemental BCC coal, [i.e.] incremental production, is consumed, even though the Company incurs a loss on the large quantity of 'base' BCC coal required before the supplemental price is available."[177] But the Company explained that it "would be impossible to enjoy the benefits of lower priced supplemental coal without first having to incur" the fixed and in the short-term unavoidable costs to "permit and develop a mine, purchase equipment, hire employees, pay taxes and reclaim the disturbed property."[178]

Sierra Club argues that "in the long-run" it is unsustainable for PacifiCorp to dispatch based on the incremental costs because those costs do not cover the costs of the base mine plan volumes.[179] This argument, however, improperly conflates long and short-run incremental costs. In the TAM—which is a short-term forecast—dispatch decisions are made using the incremental cost, even when the incremental cost is less than the average cost, as discussed above. In long-term forecasts, such as the IRP, PacifiCorp uses average costs, which are comparable to long-run marginal costs, to make resource decisions related to Jim Bridger.[180] This distinction is key, as Phillips explains: dispatch decisions should be made using short-run marginal costs, while "[i]t is long-run marginal costs that should govern investment decisions."[181] The TAM is not the correct forum for assessing long-term resource decisions, which is effectively what Sierra Club proposes for Jim Bridger.

2. Sierra Club's recommendations focus on long-term resource decisions that are outside the scope of the TAM.

Long-term resource decisions, including the composition of PacifiCorp's resource portfolio, are evaluated biennially in PacifiCorp's IRP, which utilizes a 20-year planning horizon and comprehensively selects a "portfolio of resources with the best combination of expected costs

[177] Sierra Club's Reply Brief at 13.
[178] PAC/1200, Ralston/42.
[179] Sierra Club's Reply Brief at 15.
[180] Evid. Tr. 107:18-109:4108.
[181] Charles F. Phillips, Jr., *The Regulation of Public Utilities* 444 (1993).

and associated risks and uncertainties for the utility and its customers."[182] Recent IRPs have included robust and comprehensive analysis addressing the ongoing economic viability of the Company's coal units to determine whether the least-cost, least-risk resource portfolio should include early closure of a particular unit or units. When acknowledging PacifiCorp's 2019 IRP, the Commission noted that the plan "reflects significant analytical advances in least-cost, least-risk planning, *particularly in its economic analysis of existing coal units*."[183]

Unlike the IRP, the purpose of a TAM is to forecast expected NPC based on the current resource mix, i.e., the TAM optimizes the dispatch of the existing resources to minimize costs while ensuring reliable service.[184] The TAM is not designed to second-guess previously made resource decisions or act as a substitute for the comprehensive resource planning process embodied in the IRP.

Sierra Club's recommendations for the Jim Bridger plant go far beyond a one-year NPC forecast and instead reflect resource decision-making that is properly addressed in an IRP. Sierra Club's recommends using long-run incremental costs—in other words, average costs[185]—to dispatch the Jim Bridger plant even though doing so is appropriate for making long-term resource decisions in the IRP, not short-term dispatch decisions in the TAM. Sierra Club additionally recommends dramatically and irreversibly reducing BCC production based on its unsupported claim that the "long-term trajectory of coal economics" supports large and permanent reductions in BCC production.[186] PacifiCorp's 2019 IRP evaluated the economics of early closure of the BCC mine and determined that it was higher cost.[187]

Moreover, Sierra Club's dismissal of the possibility that coal demand could increase is undermined by current circumstances. In 2021, coal demand increased but producers have been

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[182] *In re PacifiCorp, dba Pac. Power, 2019 Integrated Res. Plan*, Docket No. LC 70, Order No. 20-186 at 3 (June 8, 2020) (quoting *In re Investigation into Integrated Res. Planning*, Docket No. UM 1056, Order No. 07-002, App'x A, Guideline 1 (Jan. 8, 2007)) [hereinafter 2019 IRP].
[183] 2019 IRP, Order No. 20-186 at 1 (emphasis added).
[184] *See* 2017 TAM, Order No. 16-482 at 2-3.
[185] Sierra Club/100, Burgess/29.
[186] Sierra Club's Reply Brief at 19.
[187] PAC/600, Ralston/51.

unable to respond to that higher demand, in part, because of the long-lead times required to increase production.[188] Implementing Sierra Club's recommendation would significantly increase customer risk if the demand for coal at the Jim Bridger plant increased and BCC was unable to respond. Increasing customer risk to chase the possibility of single-year cost savings is particularly unreasonable given that Jim Bridger plays such a critical role in the Company's system.

3. Sierra Club's adjustment incorrectly dismisses significant fixed costs that cannot be avoided on a year-ahead basis.

Sierra Club's Jim Bridger plant adjustment assumes that BCC could reduce production by [redacted] percent and that doing so would also reduce the mine's fixed costs by the same percentage.[189] This is incorrect, and when fixed and unavoidable costs are appropriately considered, Sierra Club's recommendation becomes untenable.

First, Sierra Club argues that BCC's $[redacted] in 2022 reclamation costs can be avoided if PacifiCorp reduced production at the mine because reclamation costs are tied to disturbed land and less mining would disturb less land.[190] But in its testimony, Sierra Club agrees that "final reclamation costs are unavoidable" and agrees that they are "only partly based upon additional volumes that are yet to be mined."[191] Sierra Club's argument in the brief that the entire cost of reclamation is avoidable is therefore undercut by its own testimony.

Second, Sierra Club claims that the Company "has *never* quantified the fixed portion" of materials and supplies, electricity, outside services, and other miscellaneous costs that are independent of coal production.[192] This is not true. The Company's surrebuttal testimony explained exactly how it calculated BCC's total fixed costs for 2022 as the cost differential between two mine plans with different volumes.[193] This methodology, which Sierra Club supports,[194] produced total BCC fixed costs of $[redacted]. The difference between this figure

[188] *See* S&P Article.
[189] *See* Sierra Club/200, Burgess/24, n.39.
[190] Sierra Club's Reply Brief at 17.
[191] Sierra Club/100, Burgess/57.
[192] Sierra Club's Reply Brief at 17 (emphasis in original).
[193] PAC/1200, Ralston/40-41.
[194] Sierra Club/200, Burgess/5-6; PAC/1200, Ralston/27-28.

and the $[redacted] in fixed costs identified in response to Sierra Club Data Request 2.5[195] represents that fixed cost portion of these remaining cost categories.

Third, Sierra Club claims that the [redacted] in fixed labor costs for 2022 could actually be avoided if PacifiCorp just laid off a significant portion of its workforce as a result of decreasing production by [redacted] percent.[196] Sierra Club does not dispute the Company's evidence that the real world impact of this recommendation would be a substantive and irreversible reduction in BCC coal production for the long-term because PacifiCorp could not rehire a work force in subsequent years.[197] Rather, Sierra Club claims that "there is no indication that the economics of coal would suddenly support ramping production back up in coming years," and therefore it would be reasonable to irreversibly decrease BCC production based on a "long-term trajectory of coal economics."[198] This argument is far outside the scope of a TAM because it implicates fundamental and far-reaching resource decisions that are made in an IRP, not a one-year power cost forecast. It would be imprudent for PacifiCorp to make an irreversible decision to lay off nearly half BCC's workforce based on a one-year forecast of generation at the Jim Bridger plant, especially given current resource adequacy issues in the West.

Fourth, Sierra Club claims that the labor costs would be avoided if the work force were shifted to reclamation activities because those costs are separately accounted for and already include labor costs.[199] But if the reclamation activities are higher than expected, because the Company shifted labor from production to reclamation, the costs of reclamation would be commensurately higher. Moving fixed costs from labor to reclamation does not make the cost avoidable it simply moves the cost from one fixed cost category to another.

4. Dispatching using BCC's average or base price will increase customer risk without reducing costs.

Sierra Club claims that NPC would be reduced by $[redacted] if PacifiCorp decreased BCC

[195] Sierra Club/112, Burgess/5-7.
[196] Sierra Club's Reply Brief at 18.
[197] PAC/1200, Ralston/30.
[198] Sierra Club's Reply Brief at 18-19.
[199] Sierra Club's Reply Brief at 18.

production by [redacted] percent by dispatching BCC using its base price, which is comparable to an average cost dispatch.[200] To justify this claim, Sierra Club argues that PacifiCorp would recover $[redacted] in Jim Bridger expenses using its average price dispatch, which Sierra Club claims is sufficient to recover the $[redacted] of "fixed BCC costs under a reduced production schedule [.]"[201] Sierra Club's numbers, however, do not add up. First, Sierra Club admits that its $[redacted] figure ignores fixed reclamation costs of $[redacted].[202] This means that Sierra Club's own calculations show BCC fixed costs of $[redacted]—more than the fueling expense for the Jim Bridger plant that would be recovered under Sierra Club's reduced production scenario. But Sierra Club's analysis in its brief also ignores the costs of Black Butte coal that are required under its reduced-BCC production scenario.[203] When Black Butte costs are added to the BCC fixed costs, the total coal expense under Sierra Club's reduced production scenario is $[redacted], which far exceeds the $82.1 million that would be recovered in rates and virtually eliminates any claimed cost savings resulting from using average price dispatch.

PacifiCorp's testimony explained how using average price dispatch increased overall customer costs when fixed costs are appropriately modeled.[204]

In PacifiCorp's 2021 ECAC, Sierra Club made similar arguments to "raise doubt regarding the accuracy of PacifiCorp's coal unit incremental prices, using Jim Bridger coal mining costs as an example."[205] Like here, Sierra Club argued to the CPUC "that PacifiCorp inappropriately sets an initial incremental price by excluding costs associated with Bridger Coal Company mine."[206] The Proposed Decision rejected Sierra Club's argument in its entirety and affirmed the use of

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200 Sierra Club's Reply Brief at 20-21.
201 Sierra Club's Reply Brief at 21.
202 Sierra Club's Reply Brief at 21, n. 108.
203 Sierra Club/200, Burgess/24 (Confidential Table 3 shows $[redacted] in Black Butte costs).
204 *See* PAC/1200, Ralston/39-42.
205 2021 ECAC Proposed Decision at 12.
206 2021 ECAC Proposed Decision at 12 ("Sierra Club argues PacifiCorp should improve the accuracy of its incremental prices for forecasted and actual dispatch of coal units by including all variable costs. Sierra Club believes PacifiCorp excludes certain coal-related costs as fixed, which Sierra Clubs contends are variable, so PacifiCorp can lower the cost of coal to meet contractual minimum coal supply requirements. Sierra Club argues that if the incremental price is not lowered in this manner, PacifiCorp could purchase renewable sources of power at a lower price instead and save consumers money.").

incremental pricing to dispatch PacifiCorp's coal plants, including Jim Bridger.[207]

5. PacifiCorp's new Hunter, Dave Johnston, and Craig CSAs are prudent.

In this case, there is no dispute that: (1) economic cycling is rare in actual operations[208]; (2) GRID over forecasts cycling opportunities[209]; (3) PacifiCorp modeled economic cycling of its entire fleet in the Economic Cycling Study based on 2021 TAM inputs and it showed [redacted][210]; (4) PacifiCorp's 2022 TAM also modeled economic cycling of the entire fleet and it showed [redacted][211]; (5) the generation forecasts used to inform the Hunter and Dave Johnston CSAs specifically modeled cycling of the studied plants[212]; (6) the Craig forecast did not include cycling, but if it had the results would not have impacted the minimum take level[213]; (7) PacifiCorp has flexibility to adjust the Craig minimum take level if needed[214]; (8) the Company's modeling used to forecast generation for the new CSAs conformed to the economic cycling modeling that Staff agreed was reasonable in prior TAMs and that the Commission approved to set customer rates[215]; and (9) the average cost of these plants including these CSAs in the 2022 TAM ranges from $[redacted]MWh (Dave Johnston) to $[redacted]/MWh (Hunter) to $[redacted]/MWh (Craig), all of which are below the overall coal fleet average price of $[redacted]/MWh and well below the average price of natural gas generation in the 2022 TAM of $[redacted]/ MWh. Despite these undisputed facts, Staff claims that PacifiCorp's CSAs are imprudent for failure to reasonably consider economic cycling opportunities.[216]

6. PacifiCorp's holistic economic cycling studies show that cycling produces minimal NPC savings.

Staff argues that PacifiCorp did not perform a holistic analysis of economic cycling

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[207] 2021 ECAC Proposed Decision at 13.
[208] PAC/1000, Staples/7.
[209] PAC/100, Webb/16.
[210] PAC/107, Webb/2.
[211] PAC/100, Webb/17.
[212] PAC/700, MacNeil/2-4; PAC/1000, Staples/12.
[213] PAC/1000, Staples/13.
[214] PAC/1200, Ralston/10-11.
[215] *See* PAC/700, MacNeil/2-4; PAC/1000, Staples/12; 2017 TAM, Order No. 16-482 at 10-11.
[216] Staff's Reply Brief at 10.

because the "Company's studies do not [redacted]."[217] This is simply incorrect. Both PacifiCorp's Economic Cycling Study and the 2022 TAM allowed every single coal unit to cycle if doing so was economic in GRID.[218] These studies, therefore, provided the exact analysis Staff recommends by accounting for the interrelated nature of the generation fleet, i.e., if generation at one plant decreased, generation at another plant may increase.[219] Both studies likely overstated economic cycling opportunities and still produced minimal NPC savings.[220] These study results negate the entire rationale for Staff's belief that economic cycling will produce significant customer benefits.[221]

Staff's only real criticism of the Company's economic cycling studies is that the studies "lack a reliability constraint."[222] But Staff does not dispute the Company's evidence that the 2022 TAM GRID run that allowed all units to economically cycle produced results that "were rational and consistent with prudent utility practice and feasible operations."[223] Staff also does not dispute that imposing reliability constraints will *decrease* overall economic cycling and therefore the Company's studies overstated the potential economic cycling as compared to actual operations.[224]

Staff claims that PacifiCorp cannot "know with certainty the results of an analysis that was never done,"[225] but Staff cannot square this accusation with the results of the analysis that was done, and that Staff simply ignores.

7. Economic cycling will not materially reduce minimum take levels.

Both the Economic Cycling Study and the 2022 TAM without the "must run" setting resulted in a modest [redacted] percent reduction in coal generation and [redacted].[226] Staff claims that a [redacted] percent reduction in overall coal generation is not insignificant because it is

[217] Staff's Reply Brief at 12.
[218] Confidential Evid. Tr. 3:5-5:4; Staff/700, Anderson/2, 4; Staff/100, Enright/6; PAC/100, Webb/14-16.
[219] *See, e.g.*, PAC/107, Webb/4 (showing changes in generation at each plant; some increase and some decrease).
[220] PAC/100, Webb/17; PAC/107, Webb/2.
[221] *See* PAC/1600 at 4 (Staff Response to PacifiCorp Data Request 3) (purpose of cycling studies is to identify units "that could provide *significant benefits* through economic cycling") (emphasis added).
[222] Staff's Reply Brief at 13.
[223] PAC/100, Webb/14.
[224] PacifiCorp's Opening Brief at 39-40.
[225] Staff's Reply Brief at 13.
[226] PAC/100, Webb/17; PAC/107, Webb/2.

equivalent to a coal plant running at [redacted].[227] But in the context of negotiating a minimum take level in a CSA, a potential generation reduction of 3 percent will not materially change the nature of the negotiations or the end result.[228] Moreover, the benefit of economic cycling is not simply reducing coal generation—it is producing lower NPC.[229] And both the Economic Cycling Study and 2022 TAM show [redacted] as a result of economic cycling—results that Staff does not dispute are *de minimus*.[230]

8. Staff's arguments actually support higher minimum take levels for Hunter, Dave Johnston, and Craig.

Staff argues that the Company must holistically consider economic cycling before executing the new CSAs because the "generation forecast at each plant is dependent on economic cycling outcomes at all of the other plants."[231] Staff cites an example where the Jim Bridger plant reduces generation as a result of economic cycling, which causes the "generation forecast at other coal plants to increase in response."[232]

Staff's argument supports imputing a *higher* minimum take level for Hunter, Dave Johnston, and Craig, not a finding of imprudence.[233] Staff agrees that lower cost coal plants are less likely to economically cycle.[234] So, in the example Staff cites where Jim Bridger economically cycles, the coal plants that will increase their generation are lower cost plants. Staff agrees that Hunter, Dave Johnston, and Craig are some of the [redacted] cost coal plants in the fleet[235] and therefore in a study that allows all coal units to economically cycle, generation at these three plants will likely increase, as confirmed by the Company's economic cycling studies.[236] Staff does not dispute that in both the Economic Cycling Study and 2022 TAM, when all units were allowed to

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[227] Staff's Reply Brief at 13.
[228] *See* PAC/1000, Staples/13 (determining that a projected [redacted] percent [redacted] in projected generation at Craig from economic cycling "would still have supported the volumetric requirements of the CSA").
[229] PAC/1600 at 4.
[230] PAC/100, Webb/17; PAC/107, Webb/2.
[231] Staff's Reply Brief at 12.
[232] Staff's Reply Brief at 12.
[233] PAC/1000, Staples/15.
[234] Confidential Evid. Tr. 2:24-3:4.
[235] Staff/600, Fox/14 (Confidential Staff Table 4).
[236] PAC/107, Webb/3-4; PAC/1601 at 1-2.

economically cycle, generation at Hunter and Dave Johnston increased.[237] And Craig's generation increased in the 2022 TAM when all units were allowed to cycle.[238]

Staff's argument demonstrates that the minimum take levels in the new CSAs are, if anything, too low given that the record indicates broader economic cycling increases generation at Hunter, Dave Johnston, and Craig. Staff appears to concede that the economic cycling would increase generation at the relevant plants, which would, if anything, suggest that the minimum take levels in the new CSAs are too low. Eliminating the minimum take obligations altogether is therefore contrary to Staff's own arguments.

9. PacifiCorp reasonably considered economic cycling opportunities in the generation forecasts used to inform the CSA negotiations.

Staff incorrectly claims that PacifiCorp's Dave Johnston generation forecast did not "include the ability to economically cycle" the plant.[239] To be clear, PacifiCorp's generation forecasts used for Hunter *and Dave Johnston* allowed those plants to economically cycle.[240] Although the Craig generation forecast did not allow economic cycling because the plant is jointly owned, the undisputed evidence shows that the generation level would have decreased by only [redacted] percent if it had cycled, which would not have impacted the minimum take level in the CSA.[241]

10. PacifiCorp's generation forecasts conformed to the Commission-approved economic cycling modeling used in the TAM.

Staff claims that PacifiCorp has been aware for some time that it should be considering economic cycling for its coal units and therefore a reasonable utility would have analyzed economic cycling before executing new CSAs.[242] To support this claim, Staff points to the 2018 TAM, where Staff "advocat[ed] for inclusion of economic shutdowns" in the TAM modeling.[243] In that case, however, the Commission rejected Staff's recommendation, concluding that the "must

[237] PAC/107, Webb/3-4; PAC/1601 at 1-2.
[238] PAC/1601 at 1-2.
[239] Staff's Reply Brief at 10.
[240] PAC/700, MacNeil/2-4; PAC/1000, Staples/12.
[241] PAC/1000, Staples/13.
[242] Staff's Reply Brief at 14.
[243] Staff's Reply Brief at 14.

run" settings in GRID reflected "historic, normalized practices regarding economic shutdowns of coal units."[244]

Since the 2018 TAM, in response to Staff and party recommendations, PacifiCorp agreed to model economic cycling in the 2019, 2020, 2021, and 2022 TAMs and the Commission approved the agreed-upon modeling.[245] Staff does not dispute that the Company's generation forecasts used to inform the new CSAs conformed to the economic cycling modeling approved by the Commission in the TAM. Rather, Staff argues that it was imprudent to rely on the Commission-approved TAM modeling because that "analysis provides insight into the economics of the Company's coal fleet for ratemaking purposes in power cost proceedings, but not as a justification for the prudence of the Company's contracting decisions."[246] This argument makes little sense. If the TAM modeling is sufficient to forecast coal generation for purposes of setting customer rates, then it is also reasonable for forecasting coal generation for negotiating CSAs. Staff points out that the TAM only looks ahead one year, as opposed to the [redacted] forecast used for the Hunter CSA, for example.[247] But Staff does not explain why the modeling must be different for multiple years or why it is prudent to use the TAM modeling to forecast generation for one year but imprudent to use the TAM modeling to forecast generation for [redacted].

11. Sierra Club misrepresents the evidence to argue the new Hunter CSAs are imprudent.

Sierra Club claims that the minimum take level in the new Hunter CSAs is excessive and "it is likely that within the contracts' time frame, Hunter will not economically meet its minimum take obligation."[248] Sierra Club's argument relies on misrepresentations of the evidence that, when corrected, demonstrate that minimum take levels in the new Hunter CSAs are reasonable given

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[244] *In re PacifiCorp, dba Pac. Power, 2018 Transition Adjustment Mechanism*, Docket No. UE 323, Order No. 17-444 at 11 (Nov. 1, 2017) [hereinafter 2018 TAM].
[245] *See, e.g.*, *In re PacifiCorp, dba Pac. Power, 2019 Transition Adjustment Mechanism*, Docket No. UE 339, Order No. 18-421, App'x A at 6 (Oct. 26, 2018) [hereinafter 2019 TAM]; *In re PacifiCorp, dba Pac. Power, 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Order No. 20-392, App'x A at 8 (Oct. 30, 2020) [hereinafter 2021 TAM]; PAC/100, Webb/14.
[246] Staff's Reply Brief at 15.
[247] Staff's Reply Brief at 15.
[248] Sierra Club's Reply Brief at 33.

historical and forecasted generation levels.

First, Sierra Club claims that Hunter's "minimum take requirements could be as high as [redacted] percent of expected consumption *in the contract's first year*[.]"[249] In fact, total plant forecast coal deliveries for the first contract year (2021) are [redacted] tons, which means that the minimum take obligation ([redacted] tons) is roughly [redacted] percent of the expected deliveries.[250] Deliveries for 2021 exceed the [redacted] tons in the "expected" generation forecast used to negotiate the CSA.[251] PacifiCorp's share of *consumed* coal for 2021 is only [redacted] percent of the contract minimum.[252] This means that in the first year of the contract, generation at Hunter would need to decrease by over [redacted] percent to reach the minimum take level.

Second, Sierra Club claims that "if actual burn is [redacted] percent lower than the current GRID forecast [presumably for 2022], PacifiCorp will either incur minimum take penalties or force the plant to operate uneconomically."[253] PacifiCorp's expected coal deliveries and consumption for 2022 are [redacted] percent of the minimum take obligation.[254] To reach the minimum take level, PacifiCorp's expected burn would have to decrease by [redacted] percent, to [redacted] tons, which is far below any level of coal consumption at the plant since 2017.[255] PacifiCorp's share of the average Hunter coal consumption from 2017 to 2021 was [redacted] tons and during that time consumption never dropped below [redacted] tons—which exceeds PacifiCorp's share of the minimum take by [redacted] tons, or [redacted] percent.[256] Given these facts, it is highly unlikely that generation at Hunter would unexpectedly drop by [redacted] percent; the evidence does not support Sierra Club's claim that the minimum take level is too high.

Third, Sierra Club claims that Hunter's generation decreased by [redacted] percent between 2018

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249 Sierra Club's Reply Brief at 31 (emphasis in original). Although Sierra Club does not explain the basis for its [redacted] percent figure, it appears to have used the "2022 Filing" figure from PacifiCorp's Response to ALJ Bench Request 2, which is not the first year of the new CSA terms.
250 PacifiCorp's Response to ALJ Bench Request 2.
251 PacifiCorp's Response to ALJ Bench Request 3.
252 PacifiCorp's Response to ALJ Bench Request 2.
253 Sierra Club's Reply Brief at 32.
254 PacifiCorp's Response to ALJ Bench Request 2.
255 PacifiCorp's Response to ALJ Bench Request 2.
256 PacifiCorp's Response to ALJ Bench Request 2.

and 2020, which suggests that generation could decrease by that same amount over the new CSA term.[257] Sierra Club again mischaracterizes the evidence. PacifiCorp's share of Hunter's coal consumption was [redacted] tons in 2018 and [redacted] tons in 2020, an *increase* of [redacted] percent, not a decrease of [redacted] percent.[258] The average coal deliveries from 2017 to 2020 were only [redacted] percent of the contract minimum and PacifiCorp's average share of consumed coal during that time was also only [redacted] percent of the contract minimum; PacifiCorp's share never exceeded [redacted] percent of the contract minimums.[259]

Fourth, Sierra Club questions PacifiCorp's 2022 forecast of consumed coal included in the response to ALJ Bench Request 2 because it is higher than the comparable amount reflected in the Company's initial filing.[260] Sierra Club ignores the Reply Update, which included increased purchases at Hunter.[261]

Fifth, Sierra Club criticizes PacifiCorp for not including a provision in the new CSAs that would allow it to avoid minimum take obligations, [redacted] But the [redacted], which was critical to the Company's ability to negotiate the relevant provision.[262] PacifiCorp could not obtain a comparable provision in a [redacted] CSA.

Finally, Sierra Club argued in the 2021 ECAC that the minimum take level in the new Hunter CSAs was imprudent and that argument was flatly rejected in the Proposed Decision.[263]

E. PacifiCorp reasonably studied economic cycling.

1. Removal of the "must run" setting from the TAM addresses concerns over economic cycling.

In the 2022 TAM, every single coal unit can be economically cycled.[264] Removing the "must run" setting and allowing largely unconstrained cycling reduced coal generation by [redacted]

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[257] Sierra Club's Reply Brief at 32.
[258] PacifiCorp's Response to ALJ Bench Request 2.
[259] PacifiCorp's Response to ALJ Bench Request 2.
[260] Sierra Club's Reply Brief at 31.
[261] PAC/600, Ralston/3.
[262] Evid. Tr. 113:17-114:6.
[263] 2021 ECAC Proposed Decision at 15.
[264] PAC/100, Webb/14.

percent and produced [redacted].[265] Yet, parties still insist that PacifiCorp should continue to study economic cycling without acknowledging that the TAM now includes economic cycling that is consistent with the parties' prior recommendations. For example, Sierra Club argues that the Company's Economic Cycling Study is insufficient because the study did not include [redacted].[266] But Sierra Club ignores the fact that the Company explicitly stated that these costs were modeled in the removal of the "must run" setting in the TAM but are not included in NPC.[267] These costs are not included in NPC because they are not part of the FERC accounts that are included in the TAM, consistent with the TAM Guidelines.[268]

CUB also recommends that the Company enable Jim Bridger Unit 1 to cycle in the TAM.[269] To be clear, in the 2022 TAM PacifiCorp removed the "must run" setting for all coal units, including Jim Bridger Unit 1 and PacifiCorp intends to continue doing so in future TAMs. Therefore, to the extent that the NPC model's optimized dispatch includes economically cycling Jim Bridger Unit 1, it can do so.

2. Parties can request model runs with Jim Bridger Unit 1 shut down.

Staff, CUB, and Sierra Club all recommend that PacifiCorp perform a cycling study that examines the impact of cycling Jim Bridger Unit 1 for [redacted].[270] Each party to the TAM can request and PacifiCorp will provide a single model run based on whatever assumptions the party requests.[271] To the extent that Staff, CUB, or Sierra Club want the Company to run Aurora in the 2023 TAM with the assumption that Unit 1 is cycled off for [redacted] they can make that request. There is no reason for the Commission to order such a study when it is already available to the parties.

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[265] PAC/100, Webb/17; Staff/600, Fox/7 (Staff Table 1).
[266] Sierra Club's Reply Brief at 34.
[267] PAC/100, Webb/16.
[268] TAM Guidelines, Order No. 09-274, App'x A at 14.
[269] CUB's Reply Brief at 9.
[270] Staff's Reply Brief at 16; CUB's Reply Brief at 9; Sierra Club's Reply Brief at 35.
[271] 2021 TAM, Order No. 20-392, App'x A at 6.

CUB further recommends that the Commission address "procedures PAC and utilities should undertake when coal plants exhibit questionable economics," which would include "various model runs in the TAM examining various closure dates once a resource's economics become closer to the threshold at which they are uneconomic."[272] This request will effectively convert the TAM into a resource planning docket akin to an IRP, which is improper for the reasons discussed above. Moreover, to the extent that CUB's recommendation applies generally to all utilities, it should not be resolved in PacifiCorp's TAM docket, even if it were within the proper scope of a TAM.

F. AWEC's adjustment to BCC materials and supply expense will not improve the NPC forecast.

1. BCC coal costs have been accurately forecast.

AWEC and Staff proposed an adjustment to decrease one line item embedded within BCC coal costs related to the materials and supplies expense.[273] But AWEC has conceded that overall BCC coal costs have been within [redacted] percent of the forecasted amount over the last five years.[274] AWEC has presented no evidence that reducing one line item in isolation will increase the overall accuracy of the coal cost forecast. Given that BCC coal costs are accurate to within [redacted] percent, reducing the materials and supplies line item embedded within an overall accurate cost estimate will create a larger inaccuracy in the overall BCC expense.

AWEC implies that the historical variance between forecasted and actual materials and supplies expense was "passed on to ratepayers through coal costs included within the NPC baseline."[275] This assertion is not entirely accurate to the extent it implies customers overpaid for BCC coal. In fact, as already noted overall BCC costs have been within [redacted] percent of the forecasted amount over the last five years, indicating that customers have not overpaid for BCC coal.[276]

Staff claims that if the historical variance in materials and supplies expenses was due to

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[272] CUB's Reply Brief at 10.
[273] AWEC's Reply Brief at 17; Staff's Reply Brief at 28-29.
[274] PAC/1200, Ralston/17-18.
[275] AWEC's Reply Brief at 17.
[276] PAC/1200, Ralston/18.

shifting those costs between production and reclamation activities, as PacifiCorp explained, then PacifiCorp should have updated its forecasted reclamation in this case.[277] But that is exactly what the Company's filing has done—it has forecasted the expected materials and supplies expense for 2022 based on the expected production and reclamation activities in 2022. Neither Staff nor AWEC disputed the Company's forward-looking forecast. Instead, Staff and AWEC simply looked at historical forecast variance and applied that historical variance to 2022. This adjustment is exactly the type of adjustment Staff's own brief derides when Staff argues that "[t]o go back and attempt a 'make up call' in the current TAM proceeding based on a history of under-recovery is akin to retroactive ratemaking."[278] If making up for past under-recovery is "akin to retroactive ratemaking," then making up for past over-recovery is also "akin to retroactive ratemaking" and therefore must be rejected.

2. Neither AWEC nor Staff oppose the Company's adjustment for BCC "outside services" expense, which largely offsets AWEC's adjustment to BCC materials and supplies expense.

PacifiCorp proposed an offsetting adjustment that is based on the exact same rationale but applies to the "outside services" line item.[279] While materials and supplies expense has been historically overstated, outside services expense has been historically understated. When these two line items are netted together, it reduces AWEC's proposed adjustment to $[redacted].[280] Neither AWEC nor Staff oppose the Company's adjustment and therefore if the Commission is inclined to adopt AWEC's adjustment it should also adopt the Company's *unopposed* offsetting adjustment.

G. The Company does not object to providing additional information regarding new CSAs in its TAM filings.

Staff recommends that PacifiCorp include in future TAM filings certain information related to new CSAs, including, for example, an explanation of how economic cycling was considered, a

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[277] Staff's Reply Brief at 29.
[278] Staff's Reply Brief at 3.
[279] PAC/600, Ralston/31; PAC/1200, Ralston/17-18.
[280] PAC/1200, Ralston/18.

comparison of forecasted generation to minimum take levels, and workpapers used to inform the range of generation used in negotiations.[281] The Company does not object to these requests.

H. Parties have not demonstrated that the existing Modified Protective Order provides insufficient access to CSAs.

PacifiCorp's CSAs are extremely commercially sensitive, and PacifiCorp is contractually bound to maintain the confidentiality of the agreements.[282] Because of this sensitivity, the Company does not file CSAs with the Commission or provide full and unredacted copies to parties. Instead, the Commission has approved a Modified Protective Order that, among other provisions, specifically allows parties to seek copies of relevant sections of any CSA for use in developing their testimony:

> After reviewing the Highly Protected Information at PacifiCorp's offices, if a party reasonably believes that a limited, specific part of a document containing Highly Protected Information is necessary for inclusion in testimony in this proceeding or for use at hearing, the party may request a copy. In response to such a request, PacifiCorp will prepare a copy of the required portion of the document and provide it to that party.[283]

In this TAM, no party utilized this provision to request copies of CSA provisions.

Staff, CUB, and Sierra Club recommend that PacifiCorp be required to provide complete copies of all CSAs to the Commission and parties.[284] The parties complain about the burden of having to review the CSAs in person or via a web platform but do not provide a reasonable explanation of why the ability to obtain copies of specific parts of the CSA is insufficient. Staff simply ignores its ability to obtain copies and Sierra Club claims that there is no ability to obtain sectional copies "simply for a more thorough review" but not to include in the record.[285] But it is unclear why Sierra Club would want to review sections of a CSA but not include those sections in

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[281] Staff's Reply Brief at 17-19.
[282] PAC/1200, Ralston/6-7.
[283] Docket No. UE 390, Order No. 21-086 (Mar. 23, 2021).
[284] Staff's Reply Brief at 17; CUB's Reply Brief at 17; Sierra Club's Reply Brief at 28-29.
[285] Sierra Club's Reply Brief at 29.

the record when it initially intended to include all PacifiCorp's CSAs in the record.[286]

Sierra Club recently requested that the CPUC direct PacifiCorp to file CSAs as part of its annual ECAC proceeding.[287] The Proposed Decision rejected this recommendation.[288]

I. Sierra Club's reporting requirements are outside the scope of the TAM.

Sierra Club recommends that the Commission require PacifiCorp to submit reports in the TAM addressing actual dispatch decisions.[289] This recommendation should be rejected. First, Sierra Club justifies its recommendation by incorrectly claiming that PacifiCorp's actual dispatch practices use improper incremental pricing, which is incorrect, as discussed above. Second, addressing actual operations is outside the scope of the TAM, a fact that Sierra Club appears to concede.[290]

J. Parties can request another Informational Run consistent with their right to request a model run with their own chosen assumptions.

Staff and Sierra Club request that PacifiCorp provide another Informational Run that dispatches coal units using average cost but also ignores the impact of minimum take obligations.[291] As noted above, Staff or Sierra Club can request such a model run and it will be provided in accordance with PacifiCorp's commitment to provide each party with a model run based on the parties' preferred inputs and assumptions.

VII. CONSUMER OPT-OUT CHARGE

A. The Commission should not allow the Consumer Opt-Out Charge (COOC) to go negative.

Since the Commission adopted the COOC in docket UE 267,[292] the COOC has never dropped below zero.[293] Indeed, PacifiCorp and the Commission have never contemplated turning

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[286] *See, e.g.,* Sierra Club/109.
[287] 2021 ECAC Proposed Decision at 24.
[288] 2021 ECAC Proposed Decision at 24.
[289] Sierra Club's Reply Brief at 22.
[290] *See* Sierra Club's Reply Brief at 22 ("While actual commitment and dispatch decisions are reviewed in the PCAM . . .").
[291] Sierra Club's Reply Brief at 35.
[292] *In re PacifiCorp, dba Pac. Power, Transition Adjustment, Five-Year Cost of Serv. Opt-Out*, Docket No. UE 267, Order No. 15-060 at 6-7 (Feb. 24, 2015).
[293] PAC/900, Meredith/4.

the opt-out charge into an opt-out credit.[294] Now Calpine Energy Solutions, LLC (Calpine), AWEC, and Staff argue that the COOC should be allowed to become a credit, and the Commission should mechanically apply the current valuation method without any eye towards the broader policy implications of such a decision.[295] But as CUB points out, the Commission is currently considering the effects of direct access cost-shifting holistically in docket UM 2024.[296] To address the issues surrounding the COOC in a more holistic manner, any decisions regarding turning the COOC into a credit should be reserved for docket UM 2024 and addressed in the context of all other direct access policy issues.

AWEC and Calpine argue that applying the current evaluation method to turn the COOC into a credit "is not policy, it is just math."[297] But deciding in this docket to allow the COOC to become a credit has broader policy implications on PacifiCorp's direct access program because it could exacerbate cost-shifting that is already occurring within PacifiCorp's direct access programs and that is being considered by the Commission in docket UM 2024.[298] CUB points out that many costs—such as renewable resource subsidization, grid improvements, and reliability concerns—are shifted to cost-of-service customers when larger, sophisticated direct access customers leave PacifiCorp's system.[299]

The COOC is not the only component of the Commission's direct access program that can result in unwarranted cost shifting. By addressing the issue holistically in docket UM 2024, the Commission can determine whether the issues surrounding the COOC should impact how the charge is calculated and valued in future TAM proceedings. As Staff recognizes, the Commission is prohibited from authorizing rate schedules, including Schedule 296, unless the rates are fair,

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[294] PacifiCorp's Opening Brief at 61.
[295] Staff's Reply Brief at 30-31, AWEC's Reply Brief at 20-21; Calpine's Reply Brief at 9-10 (Sept. 28, 2021). Even though Staff recommends addressing the COOC broadly in UM 2024, it nonetheless supports allowing a negative COOC in this proceeding.
[296] CUB's Reply Brief at 15.
[297] AWEC's Reply Brief at 21; *see also* Calpine Solutions/200, Higgins/4 (arguing that costs are not shifted to customers as a result of a negative COOC because customers already receive NPC savings from reduced load).
[298] *See* CUB/200, Jenks/28-29.
[299] CUB's Reply Brief at 15.

just, and reasonable.[300] Mechanically applying the COOC calculation—without assessing whether the results are just and reasonable—is contrary to the Commission's obligation to customers. Without the broader picture of direct access in Oregon provided by UM 2024, the Commission cannot reasonably make such a determination. In this proceeding, the Commission should allow the COOC to have a floor of zero and transfer further discussion of the issue to docket UM 2024 to allow for a comprehensive review of the COOC together with all of the other aspects of the Commission's direct access programs. Approving an opt-out credit in this TAM will irreversibly impact cost-of-service customers if large customers leave the system; deferring this issue to docket UM 2024 will not.

VIII. MISCELLANEOUS ISSUES

A. The Small Business Utility Advocates' (SBUA) recommendation to eliminate any increase to the TAM based on the COVID-19 pandemic or the 2020 Protocol is not supported by sufficient evidence.

In its reply brief, SBUA seems to make two arguments. First, SBUA argues that the state of Oregon's employment data shows that the state will not have recovered to full employment from the COVID-19 pandemic until the fourth quarter of 2022.[301] Second, based on this data, SBUA argues that the Commission should apply a specific provision of the 2020 Protocol that allows for changes in "Load-Based Dynamic Allocation Factors" as a result of "changes in economic conditions."[302] Based on depressed employment statistics for the entirety of Oregon, SBUA argues that these conditions should be reflected in the Company's load forecasting for Oregon, which SBUA asserts is too high for 2022.[303] SBUA's recommendations are not adequately supported on the record, and therefore the Commission should reject its proposal.

As an initial matter, SBUA has not provided enough data to support its contention that PacifiCorp's internal forecasting is not reflective of its service territory load forecasts in 2022.

[300] Staff's Reply Brief at 2; ORS 757.210(1)(a).
[301] SBUA's Reply Brief at 7 (Sept. 28, 2021).
[302] SBUA's Reply Brief at 4; *see* Docket No. UM 1050, Order No. 20-024, App'x B at 8 (Jan. 23, 2020).
[303] SBUA's Reply Brief at 8.

Aside from a single chart on employment changes resulting from the recession,[304] SBUA has not provided any evidence to address specific issues with the Company's load forecast. Even the chart used by SBUA is not appropriate because it accounts for the entirety of Oregon and not PacifiCorp's service territory, inviting an inapt comparison.[305] In contrast, PacifiCorp's load forecasts rigorously analyze the Company's service territory to produce a forecast specifically for the TAM.[306] Based on the minimal evidence provided by SBUA, the Commission should not find any infirmities with the Company's load forecast.

Further, SBUA does not draw a clear connection between the alleged infirmities in PacifiCorp's load forecast, the 2020 Protocol, and its recommendation to remove all increases to NPC in the TAM. PacifiCorp's load forecast is robust, and no other party to this proceeding has questioned the general reasonableness of the Company's load forecast. SBUA's alleged infirmities are based on a single employment chart that does not even address employment specifically in the Company's service territory. The Commission should reject SBUA's proposal and recommendations as insufficiently supported in the record.

B. The Commission should set the 2023 TAM filing date for March 1, 2022.

Over the course of this docket, Staff and CUB have proposed various early filing dates for the TAM because of PacifiCorp's transition to Aurora for next year's proceeding. PacifiCorp has generally opposed an earlier filing date because it will give the Company less time to provide Aurora workshops before filing the 2023 TAM, and an especially early date would inhibit PacifiCorp's ability to implement the December 31 forward price curve into the NPC forecast. While Staff continues to recommend a filing date of February 14, 2022, Staff is now amenable to CUB's proposal to set a filing deadline of March 1, 2022.[307] PacifiCorp also agrees that March 1, 2022, will be a reasonable filing deadline for the 2023 TAM.[308] The Commission should also

[304] *See* SBUA/202.
[305] *See* Evid. Tr. 161:15-25.
[306] Evid. Tr. 162:16-19.
[307] Staff's Reply Brief at 31.
[308] CUB's Reply Brief at 17.

forego an April 1, 2022 update and allow PacifiCorp to provide its Schedule 296 calculation on May 30, 2022. No parties oppose these changes.[309]

IX. CONCLUSION

The Company respectfully requests that the Commission approve PacifiCorp's proposed 2022 TAM increase of approximately $1.1 million, or less than 0.1 percent. The Commission should reject the parties' adjustments, which will perpetuate the Company's NPC under-recovery, decrease the Company's flexibility to manage the complex transition from thermal to renewable resources, and ultimately make it more difficult for the Company to maintain reliable service and affordable rates.

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[309] *See* Staff's Reply Brief at 31 ("Staff is agreeable to PacifiCorp foregoing an update on April 1, 2022 as well as the Company's request to provide its Schedule 296 TAM calculation on May 30, 2022.)