WUTC DOCKET: UE-230172 & UE-210852
EXHIBIT: BGM-1T (R)
ADMIT ☑ W/D ☐ REJECT ☐

Exhibit BGM-1T
Dockets UE-230172 & UE-210852
Witness: Bradley G. Mullins

BEFORE THE

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP d/b/a PACIFIC POWER AND LIGHT COMPANY, Respondent.	DOCKET UE-230172 (*Consolidated*)
In the Matter of ALLIANCE OF WESTERN ENERGY CONSUMERS' Petition for Order Approving Deferral of Increased Fly Ash Revenues	DOCKET UE-210852 (*Consolidated*)

RESPONSE TESTIMONY OF BRADLEY G. MULLINS

ON BEHALF OF

ALLIANCE OF WESTERN ENERGY CONSUMERS

(REDACTED)

September 14, 2023

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RESPONSE TESTIMONY OF BRADLEY G. MULLINS

EXHIBIT LIST

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bradley G. Mullins, and my business address is Tietotie 2, Suite 208, Oulunsalo, Finland FI-90460.

Q. PLEASE STATE YOUR OCCUPATION AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am an independent energy and utilities consultant representing large energy consumers before state regulatory commissions, primarily in the Western United States. I am appearing in this matter on behalf of Alliance of Western Energy Consumers ("AWEC"). AWEC is a non-profit trade association whose members are energy consumers located throughout the Pacific Northwest, including electric service customers of PacifiCorp.

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I have a Master of Accounting degree from the University of Utah. I am the Principal Consultant for MW Analytics, a firm that provides expert witness services to utility customers on matters such as revenue requirement, power cost forecasting, and rate spread and design. I have sponsored testimony in regulatory jurisdictions around the United States, including before the Washington Utilities and Transportation Commission (the "Commission"). A list of recent cases where I have submitted testimony can be found in **Mullins, Exh. BGM-2**.

Q. WHAT IS THE PURPOSE OF YOUR RESPONSE TESTIMONY?

A. I discuss my review of PacifiCorp's request to increase revenue requirement through a two-year rate plan, with an increase of $26,763,219 in Rate Year 1 beginning on March

1, 2024 and $27,944,573 in Rate Year 2 beginning on March 1, 2025.[1] I also discuss, and recommend the Commission approve and commence amortization of AWEC's Petition for Order Approving Deferral of Increased Fly Ash Revenues in Docket UE-210852, which was consolidated with the rate case. Finally, I address PacifiCorp's proposal to modify the Power Cost Adjustment Mechanism ("PCAM").

Q. WHAT WAS THE SCOPE OF YOUR REVIEW?

A. I performed an independent analysis of PacifiCorp's revenue requirements over the two-year rate plan period. That analysis may be found at **Mullins, Exh. BGM-3** for Rate Year 1 and **Mullins, Exh. BGM-4** for Rate Year 2. My analysis was based on review of PacifiCorp's Direct Testimony and workpapers, along with its responses to discovery requests submitted by AWEC and other parties to this proceeding. Responses to relevant discovery requests have been attached as **Mullins, Exh. BGM-5**.

Q. WHAT IS YOUR RECOMMENDATION RELATED TO PACIFICORP'S PROPOSED RATE PLAN?

A. Considering the circumstances of this case, my recommendation is to deny approval of PacifiCorp's proposed two-year rate plan. PacifiCorp's revenue requirement for Rate Year 2 is predominantly driven by substantial new capital additions, and PacifiCorp has not undertaken an evaluation of offsetting factors associated with these additions. Otherwise, my analysis shows that it is necessary to reduce Rate Year 1 revenue requirement, and it is not practical to adopt a rate plan solely for Rate Year 2 provisional capital, which must then be reevaluated in an ex post review. A more practical way to

[1] Exhibit No. SLC-1Tr at 2:28-33.

proceed in this docket would be to establish rates solely for Rate Year 1 and provide PacifiCorp with the opportunity to file a new case for Rate Year 2, which among other things, can address offsetting factors and the removal of coal plant from Washington rates.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE CAPITAL REVIEW PROCESS?

A. I recommend the Commission:

1. Modify the capital review process to be performed on a project-by project-basis;
2. Adopt a procedure that provides parties a full opportunity to perform a prudence review in the capital review process, including the opportunity to propose offsetting adjustments;
3. Reject PacifiCorp's proposal for a Return on Equity ("ROE") floor in the capital review process;
4. Require PacifiCorp to update net power costs ("NPC") and production tax credits ("PTCs") prior to the beginning of Rate Year 1 and Rate Year 2 (if approved) based on an NPC calculation performed in compliance with the methods approved in the Commission's final Order;
5. Perform the NPC updates based on the specific rate years at issue, corresponding to the years beginning March 1, 2024, and March 1, 2025, rather than the calendar year NPC studies presented in PacifiCorp's filing; and,
6. Limit the allowable NPC updates to i) forward price curves, ii) new power contracts, and iii) loads, and provide a process for ratepayers to review and contest the updates.

Q. WHAT ARE YOUR REVENUE REQUIREMENT RECOMMENDATIONS?

A. I recommend the Commission approve a revenue requirement reduction of $20,013,603 for Rate Year 1 relative to current rates. If the Commission approves a rate plan, I recommend a revenue requirement increase of $28,874,572 for Rate Year 2 relative to Rate Year 1, subject to the NPC update and ex-post review discussed above. My specific recommendations, as well as adjustments sponsored by AWEC witness Kaufman, are detailed in **Table BGM-1**, below. Brief descriptions of the adjustments follow the table.

Table BGM-1
Washington Electric Revenue Requirement Recommendation
($000)

		Rate Year 1	Rate Year 2
PacifiCorp Filed		**26,763,219**	**27,947,817**
Adjustments			
	Cost of Capital (Kaufman)	(9,992,615)	(2,325,046)
A1	Projects Less Than $1M	(714,512)	(501,081)
A2	North Temple Office	-	(2,030,404)
A3	Fly Ash Deferral	(4,996,914)	4,996,914
A4	BCC Post-2023 Recl. & Depr	(6,491,783)	-
A5	Washington Balancing Adj.	(5,327,007)	-
A6	Market Caps	341,965	-
A7	Ozone Transport Rule	(8,182,931)	-
A8	PTC Rate at 3.0 Cents/KWh	(822,361)	-
A9	PTC Rate Period Volumes	(644,659)	(4,629,783)
A10	PTC Disallowance Removal	(370,547)	-
A11	Production Factor Adjustment	(1,120,584)	-
A12	COVID Deferral	(5,541,786)	5,541,786
A13	Remove Other A/P	(386,954)	-
A14	ISWC-Pension Settlement	(1,539,506)	-
A15	Pole Attachment Revenue	(654,233)	(247,867)
A16	Two-Year Inj. & Dam. (Kaufman)	(216,300)	-
A17	Fire Litigation Exp. (Kaufman)	(356,434)	-
	Interest Synchronization	240,337	122,235
Total Adjustments		**(46,776,822)**	**926,755**
Adjusted		**(20,013,603)**	**28,874,572**

A1. Remove Capital Projects less than $1 Million because those projects were not specifically identified and cannot be effectively evaluated in the capital review process (Adj. Nos. 6.1, 6.2, 8.4, 14.1, 14.2, & 14.3);

A2. Remove the North Temple Office project because PacifiCorp has not demonstrated that the costs are appropriate for Washington rates (Adj. Nos. 14.1, 14.2, & 14.3);

A3. Approve amortization of the UE-210852 fly-ash deferral over one year (Adj. Nos. 8.2 & 16.1);

A4. Remove post-2023 Bridger Coal Company ("BCC") depreciation and reclamation from Jim Bridger fuel costs as those costs were resolved in the 2020 GRC Stipulation[2] *and are being recovered through a separate regulatory liability (Adj. No. 5.2);*

A5. Consider under-utilized gas plant dispatch in the Washington Balancing Adjustment to fill Washington's net short position (Adj. No.5.2);

A6. Adjust the market capacity limits in Aurora to exclude liquid market hubs(Adj. No.5.2);

A7. Remove the Ozone Transport Rule modeling from Jim Bridger, since the final rule did not apply to Wyoming (Adj. No.5.2);

A8. Update the PTC Rate to 3 cents per KWh for both Rate Year 1 and Rate Year 2 (Adj. No. 7.3);

A9. Update the wind production assumed in the PTC to reflect the rate effective period wind output for both Rate Year 1 and Rate Year 2, including the impact of new wind additions (Adj. No. 7.3);

A10.Include the PTC benefits of "disallowed" PTCs from the Glenrock and Rolling Hills facilities, which were considered in the justification repower those facilities (Adj. No. 7.3);

A11.Remove the production factor adjustment as not supported by PacifiCorp's load forecast (Adj. No. 9.1);

A12.Reject the proposal to amortize the COVID deferral, as PacifiCorp provided no evidence regarding the reasonableness of the costs included in the deferral (Adj. Nos. 8.2 & 16.1);

A13.Remove other accounts receivable from rate base as they are duplicative of the Investor Supplied Working Capital ("ISWC") calculation (Adj. No. 8.7);

A14.Include a prepaid pension settlement as a non-utility asset in the ISWC calculation (Adj. No. 8.7); and,

A15.Include an adjustment for additional pole attachment revenues for the respective Rate Years (Adj. No. 3.4).

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[2] Dockets UE-191024 et al. ("2020 GRC"), Final Order 09, Appendix B at ¶ 27.

Q. DO YOU SUPPORT PACIFICORP'S PROPOSED CHANGES TO THE PCAM?

A. No. The Commission has repeatedly affirmed that a properly designed PCAM must include design elements to protect ratepayers including deadbands and asymmetrical sharing. The Commission has also repeatedly rejected PacifiCorp's proposals for dollar-for-dollar recovery through the PCAM. The current PCAM was established based on a collaborative process that took place in early 2015 at the direction of the Commission in the 2014 GRC after PacifiCorp repeatedly refused to develop a proper PCAM,[3] and I recommend that the existing mechanism be retained.

II. MULTI-YEAR RATE PLAN

a. Multi-Year Rate Plan Background

Q. PLEASE PROVIDE AN OVERVIEW OF PACIFICORP RATE PLAN PROPOSAL.

A. PacifiCorp's rate plan is based on a historical test period, encompassing the 12 months ending June 30, 2022. PacifiCorp subsequently makes a series of sequential restating and pro forma adjustments to calculate a forward-looking revenue requirement for Rate Year 1. It then makes further restating and pro forma adjustments to calculate a forward-looking revenue requirement for Rate Year 2. These pro forma adjustments include both escalated operating expenses and rate base additions in the respective rate years. Importantly, nearly all of the revenue requirements increase in Rate Year 2—and this docket as a whole—is attributable to major new capital additions, including $1.3

3 *See, e.g.,* Dockets UE-140762 et al., Order 08 ¶ 108 (Mar. 25, 2015).

billion in new wind capital additions (total-Company)[4] and $2.0 billion in new transmission additions (total-Company).[5] Notwithstanding assertions with respect to this $3.3 billion investment that the "net benefits more than outweigh net project costs,"[6] none of the corresponding benefits have been included in the Rate Year 2 revenue requirement. Therefore, evaluating the reasonableness of the Rate Year 2 revenue requirement presents a unique challenge in this docket.

Q. WHAT OTHER TEST PERIOD CAPITAL PROJECTS HAS PACIFICORP INCLUDED IN THE RATE PLAN?

A. In addition to the above-mentioned items, PacifiCorp has proposed incorporating other forecast capital additions in the test period. Its proposal encompasses approximately 650 capital projects as detailed in Cheung, Exh. SLC-4 beginning on Page 8.4.33 through 8.4.46. These include both discrete capital projects and programmatic capital projects, as well as a category referred to as "Projects less than $1 Million." On a total-company basis, these capital additions amount to $2.3 billion in Rate Year 1[7] and an additional $1.7 billion in capital additions in Rate Year 2.[8]

Q. PLEASE PROVIDE BACKGROUND ON THE REQUIREMENT FOR UTILITIES TO FILE MULTI-YEAR RATE PLANS.

A. Engrossed Substitute Senate Bill 5295 of the 67th Washington Legislature, hereinafter SB 5295, was enacted into law on May 3, 2021. Among the provisions in that bill is a

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4 Cheung, Exh. SCL-4 at 18.12.
5 *Id*. at 14.10.
6 Link, Exh. RTL-1Tr at 37:13.
7 Cheung, Exh. SLC-4 at 8.4.
8 Cheung, Exh. SLC-4 at 14.1.

requirement for utilities filing rate cases after January 1, 2022 to include a proposal for a multi-year rate plan. The requirement for a proposal for a multi-year rate plan is codified as RCW 80.28.425.

Q. DOES THE REQUIREMENT FOR A MULTI-YEAR RATE PLAN MODIFY THE STANDARD FOR APPROVING RATES?

A. No. RCW 80.28.425(1) specifically states that "[t]he commission's consideration of a proposal for a multiyear rate plan is subject to the same standards applicable to other rate filings made under this title, including the public interest and fair, just, reasonable, and sufficient rates."

Q. DOES THE REQUIREMENT FOR A MULTI-YEAR RATE PLAN MODIFY THE USED AND USEFUL REQUIREMENT FOR VALUING UTILITY PROPERTY?

A. No. RCW 80.28.425(3)(b) states that "[t]he commission shall ascertain and determine the fair value for rate-making purposes of the property of any gas or electrical company that is or will be used and useful under RCW 80.04.250 for service in this state by or during each rate year of the multiyear rate plan." The provisions of RCW 80.04.250 were not modified in conjunction with the passage of SB 5295. Thus, the method for valuing utility property has remained unchanged since the passage of Senate Bill 5116 of 2019, the Clean Energy Transformation Act ("CETA").

Q. WHAT CHANGES WERE MADE TO THE USED AND USEFUL REQUIREMENT IN CETA?

A. CETA expanded the Commission's ability to consider plant additions for property in the rate-effective period (i.e., after the rate-effective date). The revisions to RCW 80.04.250 provided the Commission with "power upon complaint or upon its own motion to ascertain and determine the fair value for rate making purposes of the property of any public service company used and useful for service in this state by or during the rate effective period."[9] It also added language that allowed the Commission to consider plant additions in the context of multi-year rate plans of up to four years, stating "[t]he commission may provide changes to rates under this section for up to forty-eight months after the rate effective date using any standard, formula, method, or theory of valuation reasonably calculated to arrive at fair, just, reasonable, and sufficient rates."[10]

Q. IS THE COMMISSION REQUIRED TO CONSIDER PLANT ADDITIONS IN THE RATE EFFECTIVE PERIOD?

A. No. The ability of the Commission to consider plant additions in the rate effective period is not mandatory, but permissive, based on a showing that inclusion of such plant additions is "necessary or proper."[11] From this perspective, when evaluating the inclusion of plant additions in the rate effective period it is appropriate for the Commission to focus on the reasonableness of the utility's estimates and the consistency of the overall revenue requirement calculation, including consideration of offsetting factors associated with the plant additions that will reduce costs.

Q. HAS THE COMMISSION SINCE ESTABLISHED A POLICY FOR HOW IT WILL VALUE PROPERTY IN A MULTI-YEAR RATE PLAN?

A. Yes. In Docket U-190531 the Commission issued a policy statement that addressed in detail the process by which the Commission will identify, review, and approve public service company property that becomes used and useful for service in this state on or

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9 RCW 80.04.250(2).
10 RCW 80.04.250(3).
11 RCW 80.04.250(2).

after the rate effective date, including in the context of multi-year rate plans.[12] That policy remains the most recent standard the Commission has established for evaluating multi-year rate plans.

Q. HAS THE COMMISSION'S STANDARD FOR APPROVING PRO-FORMA ADJUSTMENTS CHANGED?

A. No. In the context of a multi-year rate plan, the Commission is required to "ascertain and determine the revenues and operating expenses for rate-making purposes of any gas or electrical company for each rate year of the multiyear rate plan."[13] The known and measurable standard for approving pro forma adjustments, and for making such a determination, however, has not changed. This was described in the Commission's used and useful policy statement as follows:

> WAC 480-07-510(3)(c)(ii), which defines pro forma adjustments, remains unchanged, applicable, and relevant. In particular, this rule defines the known and measurable standard and the offsetting factors standard, both of which are elements of the matching principle, and both of which are necessary to ensure that costs and offsetting benefits are accounted for during the period in which they occur. The known and measurable standard continues to require that an event that causes a change to revenue, expenses, or rate base must be "known" to have occurred during or after the historical 12-months of actual results of operations. It must also be demonstrated *(i.e.*, known) that the effect of the event will be in place during the rate year.[14]

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12 *In the Matter of the Commission Inquiry into the Valuation of Public Service Company Property that Becomes Used and Useful after Rate Effective Date*, Docket U-190531, Policy Statement on Property that Becomes Used and Useful After Rate Effective Date ("Policy Statement") (Jan. 31, 2020).

13 RCW 80.28.425(3)(c).

14 Policy Statement ¶ 22.

Q. IS IT POSSIBLE TO EVALUATE THE PRUDENCY OR REASONABLENESS OF THE APPROXIMATE 650 PRO FORMA CAPITAL PROJECTS THAT PACIFICORP IS PROPOSING?

A. Not in this proceeding. Review of the prudence of PacifiCorp's capital investments and its decisions to make them will inherently need to occur in the context of a backward-looking review, as discussed in the Policy Statement.

Q. HAS PACIFICORP INCLUDED ANY OFFSETTING ADJUSTMENTS WITH RESPECT TO ITS PROPOSED CAPITAL ADDITIONS?

A. No. In the Policy Statement, the Commission stated "[I]ncluding post-test-year plant in rates without considering these offsetting factors creates a mismatch that overstates the effect of the known and measurable event, thus distorting the rate-year relationship among revenues, expenses, and rate base."[15] The Commission also stated that "[w]ithout incorporating these offsetting factors, a proposal will not be considered to be in the public interest because resulting rates would not be fair, just, reasonable, and sufficient, as required by RCW 80.28.010(1)."[16]. PacifiCorp's filing, and Rate Year 2 in particular, includes an unprecedented amount of capital. While much of that capital includes, for instance, new wind facilities and new transmission facilities. There is also a significant amount of new customer service-related investments in new customer service systems. Notwithstanding these major investments, PacifiCorp undertook no legitimate analysis of the expected savings and offsetting factors associated with these investments.

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15 Policy Statement ¶ 24.

16 Policy Statement ¶ 20 fn. 25.

b. Reasonableness of Rate Plan

Q. IS IT REASONABLE TO ADOPT A RATE PLAN FOR PACIFICORP IN THIS CASE?

A. It is important to note that the entire increase in revenue requirement for this proceeding stems from the introduction of new capital additions in Rate Year 2 of the rate plan. PacifiCorp has not taken into account any potential offsetting factors related to these investments, including those linked to power costs. As a result, the true rate impact of Rate Year 2 and PacifiCorp's corresponding need for rate relief in that year remains unknown.

Q. IS IT PRACTICAL TO INCLUDE DISTANT PLANT IN RATES ON A PROVISIONAL BASIS WITHOUT CONSIDERING THE WHOLE PICTURE?

A. No. Adopting a rate plan mainly to provisionally include distant capital costs in rates, only to have to subsequently review that capital and associated offsetting factors after the fact, is a not a practical approach. It is also unfair to ratepayers, as they will be saddled with the provisional capital costs, with the expectation of a refund when the offsetting factors are ultimately reviewed in the capital review process. While it is understood that these investments are provisional and that there will be a review process, that does not diminish the need to consider the whole picture when setting provisional rates. Pushing the entire ratemaking process off into the after-the-fact review process is impractical and should be avoided.

Q. WILL THE OFFSETTING FACTORS BE CONSIDERED IN AN NPC UPDATE?

A. It is possible that some, but not all, of the offsetting factors will be reflected in an updated NPC calculation for Rate Year 2, but that is not something that can be taken for granted.

The absence of an NPC calculation incorporating the benefits of the new capital additions in the Rate Year 2 leaves the Commission without sufficient information to evaluate the overall reasonableness of revenue requirement for Rate Year 2, even on a provisional basis. The Rate Year 2 revenue impact could be zero, or it could be double what PacifiCorp proposed. Taking a "wait and see" approach, however, places both the Commission and ratepayers in a challenging position.

Q. WOULD UPDATING NPC RESOLVE ALL OFFSETTING FACTORS?

A. No. NPC is only a portion of the offsetting factors expected. PacifiCorp's investments in new office buildings, customer service centers, and information systems, for example, would result in operating expense savings that was also not considered in the rate plan. While these benefits could be evaluated in the ex-post review, such a process also puts the Commission and ratepayers in a difficult position, one in which where ratepayers must later attempt to recover funds that should not have been paid in the first place.

Q. ARE THERE OTHER COMPLICATIONS WITH PACIFICORP'S FILING?

A. Yes. The treatment of coal plants following the 2025 deadline to remove those resources from Washington rates has not been adequately addressed in PacifiCorp's filing. Year 2 of the rate plan will span into the first two months of 2026. Notwithstanding, many of the details regarding how the resources will be handled in Rate Year 2 are unclear. Some of these details might be addressed in a power cost update, although such a process would place the Rate Year 2 revenue requirement into even greater limbo. Similar to the other issues, adopting a rate plan in this docket, only to have to deal with the coal removal issues after the fact, is also impractical.

Q. GIVEN THE CIRCUMSTANCES OF THIS CASE, WHAT DO YOU RECOMMEND?

A. I recommend the Commission establish rates for PacifiCorp based on the Rate Year 1 levels and provide PacifiCorp with the opportunity to file a new rate case addressing the major capital additions that it proposes for Rate Year 2, including offsetting factors, and addressing the treatment of coal resources after 2025.

Q. WHAT IS YOUR RECOMMENDATION IF THE COMMISSION DECIDES TO APPROVE A RATE PLAN?

A. Notwithstanding my recommendation to reject the rate plan, I provide several recommendations below that would be applicable if the Commission ultimately decides to approve a rate plan.

c. Capital Review Proposal

Q. HOW HAS PACIFICORP ADDRESSED THE USED AND USEFUL REQUIREMENT?

A. Rather than proposing separately refundable rates, as recently done with the Puget Sound Energy's 2022 General Rate Case, PacifiCorp has proposed an annual review process based on a holistic "portfolio basis" that relies primarily on PacifiCorp's earnings, not whether the projects in question are in service and used and useful to customers. The process is described generally in the Direct Testimony of Matthew D. McVee,[17] though the specific details and effect of the review are unclear. PacifiCorp Witness Cheung provides some further discussion of the annual review process, describing that refunds would be subject to an ROE floor:

[17] McVee, Exh. MDM-1T at 25:3-16.

> [T]he Company views recalculated revenue requirement for any reporting period as reflective of costs "within reason compared to what was used to set rates" so long as the recalculated revenue requirement reports a rate of return that is within .5 percent (or fifty basis points) higher or lower than its authorized rate of return from the most recent rate case. In such instances … costs in rates should be considered reasonable, and the Company should not be required to refund any earnings variances.[18]

Q. HOW DOES PACIFICORP INTEND ON MEASURING IF A REFUND IS TO BE GIVEN?

A. Witness Cheung recommends using the annual Commission Basis Report ("CBR") as the basis for the review, rather than considering the specific assets included in rates.[19]

Q. IS PACIFICORP'S PROPOSED ROE FLOOR CONSISTENT WITH THE USED AND USEFUL REQUIREMENT?

A. No. The ROE floor was only mentioned in passing, though it would be a key detail of PacifiCorp's proposal, which would be harmful to ratepayers and inconsistent with the used and useful standard. Foremost, applying an ROE floor to a potential refund is not consistent with the Policy Statement. The Policy Statement did not suggest that a refund for plant found to not be used and useful would only be given if a utility's earnings were lower than a certain threshold. It would also run counter to the used and useful standard, since it would allow PacifiCorp to keep revenues from plant that were not used and useful in instances when its ROE is lower than the floor. I recommend that PacifiCorp's proposal for an ROE floor be rejected.

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[18] Cheung, Exh.SLC-1Tr at 22:3-10.

[19] *Id.* at 25:19-26:11.

Q. IS IT REASONABLE TO CONSIDER THE CBR AS THE BASIS FOR REFUNDS?

A. No. Such a high-level approach directly contradicts the Commission's Policy Statement, which stated the following:

> Review of rate-effective period investment will depend on a company's request and the type of identified property. The review will not, however, simply be a matter of matching identified rate base to the rate base provided in rate-year Commission Basis Reports. The review process must provide adequate opportunity for parties to review, and, if necessary, challenge the recovery of provisional pro forma adjustments previously included in rates.[20]

With the new more-permissive policy towards rate period capital additions, the review process in a rate case has more to do with having accountability over capital budgets. A budget is the utility's creation, and in a general rate case, there is little concrete evidence that can be established to demonstrate whether it is prudent and reasonable. In a rate case, forward-looking rates are now being established based on the expectation that certain projects will be placed in service at specified capital amounts. If a capital project fails to come online in the specified timeframe or is delivered at a lower cost, providing the utility with the opportunity to recover the originally filed costs due to the fact that it overspent on other projects is not reasonable. Overspending on one project does not satisfy the used and useful requirement for another (and may not be prudent). The used and useful standard, and the ability for a utility to consider test period plant additions in revenue requirement in general, is not to be understood as a capital tracking mechanism. Under the CBR approach, a utility could simply file a rate case with highly

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20 Policy Statement ¶ 42.

exaggerated costs, and lacking a project-by-project review, would be certain to recover whatever costs it might incur, even if it failed to deliver on key elements of its capital budget or spent imprudently. Just comparing back to the CBR as PacifiCorp proposes is not consistent with the Commission's Policy Statement; not consistent with the used and useful standards; and not reasonable. Therefore, I recommend that a project-by-project review process be undertaken.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. Subject to some discrete adjustments described below, I recommend a more comprehensive review process than PacifiCorp has proposed. As noted, I recommend rejecting PacifiCorp's ROE floor. I also recommend that the review be conducted on a project-by-project basis based on the specific projects identified in Cheung, Exh. SLC-4 beginning on Page 8.4.33 through 8.4.46, rather than a capital tracker through the CBR. As part of this process, I recommend that PacifiCorp be required to submit supplemental testimony discussing the prudence of each project included in the list, including a comparison between the actual spending for each project and the forecast spending for each project; an explanation of variances; economic analysis supporting its investments; an evaluation of how effectively PacifiCorp executed on its projects; discussion and quantification of offsetting factors; and any other information necessary to demonstrate that its spending was prudent. Parties should be afforded formal discovery rights and, if requested, the full ability to respond to PacifiCorp's filing through testimony.

Q. SHOULD DEPRECIATION EXPENSES BE CONSIDERED IN A REFUND AMOUNT?

A. Yes. While PacifiCorp does not necessarily discuss the depreciation impacts, I recommend that the impact on depreciation be considered in any refund amount approved by the Commission. If a particular investment is removed from revenue requirement, both the rate base and the depreciation expense impacts need to be considered.

Q. DO YOU RECOMMEND THAT REFUNDS ACCRUE INTEREST?

A. Yes. Since such a refund is distinct from an ordinary deferral, in that it consists of amounts collected in base rates based on plant that PacifiCorp asserted would be used and useful, I recommend that refunds accrue interest at PacifiCorp's approved cost of

Q. capital. **WHEN DO YOU RECOMMEND THE REVIEW PROCESS TAKE**

A. **PLACE?** Foremost, I recommend that the review process explicitly include formal discovery rights for parties and affirm a party's ability to request a contested case process, if necessary. Given the significant rate pressures at issue, and the urgency to return any refunds to ratepayers, I recommend that the review process filing commence on February 1 of the year following the pro forma period, with a four-month review period. This would be consistent with the review period utilized for PSE's and Avista's capital review process.[21] A party requesting a contested case should be required to make such a request within 90 days of the Company's filing. To the extent this requires expeditious work by PacifiCorp to prepare its initial filing, that is reasonable considering the significant rate impacts that

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[21] *See, e.g.,* Dockets UE-220066 and UG-220067 (consolidated) - PSE's 2022 Annual Provisional Capital Report in Dockets (March 31, 2023); Dockets UE-220053, UG-220054 and UE-210854 (consolidated) - Avista's 2022 Annual Provisional Capital Report (March 31, 2023).

it is proposing for new capital additions in this case. Such a schedule would be beneficial as it would also better accommodate the typical rate case cycle for other utilities, which are typically involved in litigation process over the summer months.

Q. IS IT APPROPRIATE FOR PARTIES TO BE ABLE TO PRESENT ADDITIONAL OFFSETTING FACTORS IN THE REVIEW?

A. Yes. My recommendation is that parties also be given the opportunity to propose offsetting adjustments in the context of the capital review process. As noted, PacifiCorp's filing in this case considers virtually no offsetting factors associated with its capital forecast. Accordingly, as part of its initial filing in the capital review process, such offsetting factors should be included. However, this should not prevent parties from proposing additional offsetting factors. This recommendation would also apply to both rate years, depending on whether the Commission decides to approve the rate plan.

d. NPC Update Process

Q. OVER WHAT TIME PERIOD DID PACIFICORP CALCULATE NPC IN THIS DOCKET?

A. PacifiCorp calculated NPC using calendar years. Rate Year 1 was based on calendar year 2024 and Rate Year 2 was based on calendar year 2025. The rate effective period for Rate Year 1, however, is the year beginning in March 2024 and ending February 2025. The rate effective period for Rate Year 2 is the year beginning in March 2025 and ending February 2026. Thus, PacifiCorp calculated NPC for the respective rate years spanning different time periods than the corresponding rate effective periods.

Q. WHAT ARE THE CONSEQUENCES OF PACIFICORP CALCULATING NPC OVER A TIME PERIOD THAT IS DIFFERENT THAN THE RATE EFFECTIVE PERIOD?

A. There are several temporal drivers of NPC in this case, including the effects of the conversion of Jim Bridger Units 1 and 2 into gas fired operations and the addition of new wind resources. Jim Bridger Units 1 and 2 are to be taken out of service in January 2024 to undergo the conversion process, which is expected to be completed sometime between March through May of 2024. Under the Washington Inter-Jurisdictional Allocation Method ("WIJAM"), Washington-allocated NPC is highly sensitive to changes in production from Washington-allocated generation resources. Accordingly, in months when the Jim Bridger 1 and 2 gas units are out of service, Washington is in a net short position and Washington-allocated NPC is elevated. Most of that elevated cost, however, will occur prior to the rate effective date. Therefore, by calculating NPC over a calendar year period, rather than the rate effective period, the rate period power cost implications of the Jim Bridger Units 1 and 2 gas conversion are being misstated. Further, several wind facilities are expected to be online in the test period, and by using a calendar year NPC calculation, the benefits from those facilities in the rate effective period are also being misstated. This timing difference also impacts the amount of PTCs that ratepayers are being provided from the new wind facilities, which are similarly calculated based on calendar years, not the rate effective period.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that PacifiCorp be required to perform an update of NPC corresponding to the specific rate effective periods at issue in this case. Specifically, I recommend that the update encompass the 12-months ending February 2025 for Rate Year 1 and the 12-months ending February 2026 for Rate Year 2

Q. WHEN DO YOU RECOMMEND THE UPDATE TAKE PLACE?

A. Provided that the NPC updates are limited in scope and do not include any new modeling changes, I recommend the Rate Year 1 update take place on January 15, 2024, providing parties with approximately 1.5 months to respond to the NPC forecast updates through written comments and with the ability to request further adjudication as necessary. As a practical matter with respect to the Rate Year 1, the Commission could issue a bench request asking PacifiCorp to perform the update based upon its desired modeling assumptions to have the updated results prior to its final order. If the Commission decides to approve a rate plan, I recommend that the update for Rate Year 2 take place on January 15, 2025.

Q. WHAT ITEMS DO YOU RECOMMEND BE CONSIDERED IN THE UPDATE?

A. I recommend that the updates be very limited in scope. This is particularly important for Washington, where small changes can have greater influencing on NPC compared to other states. Specifically, other than updating the study periods, I recommend limiting the updates to 1) the most recent official forward price curve; 2) executed power purchase agreements; and 3) loads.

Q. DO YOU RECOMMEND THAT ANY MODELING METHOD CHANGES BE PERMITTED IN THE UPDATE?

A. No. I recommend the modeling methods included in the Commission's final order be applied in the respective updates, with no exception, including treatment of items such as the Washington Balancing Adjustment and market caps, which I discuss below.

Q. DO YOU RECOMMEND THAT PRODUCTION TAX CREDITS ALSO BE UPDATED?

A. Yes. Production tax credits change based on the level of production assumed for wind resources in the NPC study. Since new wind resources are coming online in the respective Rate Years, it will be necessary to update the PTC calculations to reflect the higher output. I also address this issue further below.

Q. PACIFICORP HAS ALSO PROPOSED TO UPDATE NPC ON OCTOBER 31, 2025 WITH A RATE EFFECTIVE DATE OF JANUARY 1, 2026 TO REMOVE JIM BRIDGER UNITS 3 AND 4 AND COLSTRIP FROM RATES. DO YOU AGREE WITH THIS PROPOSAL?

A. Depending on whether the Commission approves a rate plan, it may be necessary for PacifiCorp to update NPC to remove Jim Bridger Units 3 and 4 and Colstrip from rates, but I do not agree with the process PacifiCorp has proposed. Removing Jim Bridger Units 3 and 4 and Colstrip will have a major impact on NPC. Reviewing that impact in a stand-alone update is not reasonable because it will not consider other aspects of revenue requirement that may offset the increases to NPC. The wind facilities that PacifiCorp has proposed, as well as the existing Washington allocated wind production facilities depreciate rapidly, for example, and absent considering the overall impacts of this declining rate base which is used to fill the short position lost by removing Jim Bridger Units 3 and 4 and Colstrip, a single-issue NPC update will not produce an overall reasonable result.

Q. IS IT POSSIBLE TO PERFORM A LIMITED UPDATE TO REMOVE THE COAL PLANTS?

A. No. As I understand it, PacifiCorp is only proposing a limited update in which it would simply remove Jim Bridger Units 3 and 4 and Colstrip from rates and make no other changes to NPC. However, PacifiCorp's NPC will have substantially changed between now and then and it is not likely that simply removing coal from NPC will result in an inconsistent NPC forecast. A holistic review of PacifiCorp's NPC is more appropriate. One alternative would be for PacifiCorp to file a Limited Issue Rate Case on April 1, 2025, with an effective date of January 1, 2026, which considers both the NPC, as well as the impact of declining wind production rate base. This will give interested parties the ability to fully audit PacifiCorp's forecast in a holistic manner to ensure the forecast is consistent. This timing would be similar to the Transition Adjustment Mechanism filing PacifiCorp makes in Oregon.

III. CAPITAL FORECAST

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR RESPONSE TESTIMONY?

A. In this section of my Response Testimony, I discuss specific capital items that I recommend not be considered in PacifiCorp's capital forecast, even on a provisional basis.

a. Projects Less than $1 Million (Adj. Nos. 6.1, 6.2, 8.4, 14.1, 14.2, 14.3)

Q. WHAT AMOUNT OF CAPITAL DOES PACIFICORP INCLUDE FOR PROJECTS LESS THAN $1 MILLION?

A. In Cheung, Exh. SLC-4, it can be observed that PacifiCorp's capital forecast includes approximately $158,755,693 in total-company capital that it characterizes as "Less than $1 Million."[22] Approximately $9,861,688 of these capital projects were allocated to

[22] *See* Cheung, Exh. SLC-4 at 8.4.33-8.4.4

Washington, although no discrete descriptions were provided with respect to these small capital projects.

Q. ARE THESE CAPITAL PROJECTS IN ADDITION TO PACIFICORP'S PROGRAMMATIC CAPITAL FORECAST?

A. Yes. These small capital items were included in addition to programmatic capital. Therefore, it is difficult to differentiate them from other capital project categories.

Q. IS IT REASONABLE TO INCLUDE THESE PROJECTS IN THE PROVISIONAL CAPITAL FORECAST?

A. No. Since PacifiCorp did not specify what the projects were, it will be impossible to evaluate whether the projects were indeed placed into service and whether the investments were prudent. Further, most capital projects are a collection of smaller capital projects, so it will also be difficult, after the fact, to evaluate whether a project was less than $1 million, or not. This could lead to issues in the review process where capital is being shifted between the programmatic category to the less than $1 million category for purposes of avoiding the effects of the ex-post review process.

Q. WHAT DO YOU RECOMMEND?

A. I recommend the capital projects less than $1 million be removed from revenue requirement.

Q. WHAT IS THE IMPACT OF THIS RECOMMENDATION?

A. This adjustment reduces Washington revenue requirement by approximately $714,512 in Rate Year 1 and $501,081 in Rate Year 2.

b. North Temple Office (Adj. Nos. 14.1, 14.2, 14.3)

Q. WHAT IS PACIFICORP'S PROPOSAL RELATED TO THE NORTH TEMPLE OFFICE?

A. PacifiCorp is proposing to demolish and rebuild the North Temple office. Its new headquarters is expected to cost $235,323,236 and to be placed into service in 2025. The North Temple Office is PacifiCorp's administrative office located in Salt Lake City adjacent to the Gadsby natural gas power plants. The footprint of the property includes both a stockyard and warehouse that stores non-Washington distribution equipment and equipment related to the Gadsby power plant. While very little is known about the project scope at this time, it is probable that remediation efforts will be required at the site. The existing building at which Rocky Mountain Power employees have worked for decades is known to contain lead paint and asbestos.[23] Further, Gadsby power plants, the original of which date back to at least the 1950s and have a physical foot print that abuts the Jordan River, likely have resulted in some site contamination in the area, some of which may be necessary to address when demolishing and rebuilding the new office. The Gadsby units 1-3 were originally constructed to burn coal, as well as tar from nearby refineries, so environmental complications from these plants could be extensive, although little is known at this time about what the North Temple Office construction project will actually entail.

[23] Branch, Exh. JB-2 at 7.

Q. DID PACIFICORP COMMIT TO KEEPING ITS HEADQUARTERS IN THE NORTHWEST AT THE TIME THAT UTAH POWER AND LIGHT AND PACIFIC POWER MERGED?

A. Yes. In discovery PacifiCorp described its new building at the North Temple Office as its new headquarters.[24] My recollection is that a condition of the 1989 merger between Utah Power and Light and Pacific Power was that PacifiCorp would keep its corporate headquarters in the Northwest. Thus, by building its new headquarters next to the Gadsby power plants in Utah, it is not clear if PacifiCorp is going back on that commitment. In Branch, Exh. JB-2, PacifiCorp describes the new building as Rocky Mountain Power's new headquarters, not the corporate headquarters. If that is the case, however, the degree to which the new building should be paid for by Washington customers is questionable.

Q. DID YOU ASK DISCOVERY ON THE NEW OFFICE BUILDING?

A. Yes. In AWEC Data Request 77, PacifiCorp was asked to provide detailed capital cost estimates of each phase of the project. The goal of this was to try to understand where the building was being built, and how it might impact other parts of the property, which are unrelated to Washington operations. PacifiCorp responded as follows:

> Inasmuch as Washington uses a historical test year with known and measurable updates, PacifiCorp has not yet developed detailed work plans for demolition of the North Temple Office (NTO).[25]

This response is somewhat problematic because PacifiCorp wants to consider rate period capital additions in rates, but then refuses to provide supporting information

[24] Mullins, Exh. BGM-5 at 10 (PacifiCorp's Resp. to AWEC DR 80).

[25] Mullins, Exh. BGM-5 at 8 (PacifiCorp's Resp. to AWEC DR 77).

because Washington uses a historical test period. Similarly problematic responses followed in later answers to similar questions. When asked for contractor plans and cost estimates for demolishing the North Temple Office, PacifiCorp responded "[p]lease refer to the Company's response to AWEC Data Request 077,"[26] the same response where PacifiCorp declined to provide any additional information. When asked to identify expected salvage proceeds with respect to the North Temple Office, PacifiCorp responded "[p]lease refer to the Company's response to AWEC Data Request 077,"[27] the same response. The North Temple property is unlike any other property owned by PacifiCorp and has unique ramifications on the rates charged to customers in Washington. It is imperative to assess these concerns before contemplating including the new office in rates. By not addressing them, PacifiCorp fails to establish any justification for incorporating the new office into the rate, even on a provisional basis.

Q. IS THERE ENOUGH INFORMATION TO EVALUATE THE NEW NORTH TEMPLE OFFICE IN THIS DOCKET?

A. No. Due to PacifiCorp's inability to furnish detailed information about its construction plans, there is no foundation for determining whether it is justifiable to include the new building in the rates. Accordingly, I recommend removing the North Temple Office from revenue requirement.

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26 Mullins, Exh. BGM-5 at 9 (PacifiCorp's Resp. to AWEC DR 78)

27 Mullins, Exh. BGM-5 at 11 (PacifiCorp's Resp. to AWEC DR 82)

Q. WHAT IS THE IMPACT OF REMOVING THE NORTH TEMPLE OFFICE?

A. Removing the North Temple Office results in a $2,030,404 reduction to Rate Year 2 revenue requirement.

IV. FLY ASH DEFERRAL (ADJ. NOS. 8.2 & 16.1)

Q. WHAT IS FLY ASH?

A. Fly ash is a byproduct of the combustion of coal and is used in construction to develop concrete, bricks, and other building supply products.

Q. DOES PACIFICORP EARN REVENUE FROM FLY ASH?

A. Yes. In conjunction with generating electricity, PacifiCorp sells fly ash produced from its coal plants, including the Jim Bridger power plant.

Q. HOW ARE FLY ASH REVENUES ALLOCATED TO WASHINGTON RATEPAYERS?

A. A portion of the Jim Bridger power plant is allocated to Washington under the WIJAM method. In the 2020 GRC, for example, a JBG factor of 21.58% was used to allocate fly ash revenues from Jim Bridger to the Washington jurisdiction.[28]

Q. WHAT AMOUNT OF FLY ASH REVENUES WERE INCLUDED IN BASE RATES IN THE 2020 GRC?

A. In the 2020 GRC, PacifiCorp included Jim Bridger fly ash revenues of $2,325,000 on a system basis, with $502,000 allocated to Washington.[29]

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28 Dockets UE-191024 et al., B1- Electric Operations Revenue, at row 386.

29 *Id.*

Q. WAS THAT AMOUNT ACCURATE?

A. No. In October 2020, PacifiCorp executed a new fly ash sales agreement that provided for significantly greater revenues. Specifically, under the new contract, fly ash sales were expected to increase to $13,895,142 on a system basis in 2021, with $2,998,182 allocated to Washington.[30]

Q. DID AWEC REQUEST THAT THE COMMISSION DEFER THE INCREMENTAL REVENUES FROM THE CONTRACT?

A. Yes. On November 8, 2021, AWEC filed a petition with the Commission requesting to defer the incremental revenues from the new fly ash sales agreement. The Commission has yet to take action on AWEC's petition. A motion to consolidate AWEC's petition with this general rate case was granted on May 24, 2023.

Q. IS IT APPROPRIATE TO GRANT THE DEFERRAL IN THIS DOCKET?

A. Yes. The change in fly ash revenues was material and produced a material impact on PacifiCorp's revenue requirement. Other aspects of operating the Jim Bridger Power plant, such as NPC, have been deferred through the PCAM and updated in the Power Cost Only Rate Case and Limited Issue Rate Filing. Yet these material incremental revenues, from a contract that was executed prior to the rate effective date in the 2020 GRC, have not been considered, leading to an asymmetry. Although it is advisable to limit the use of single-issue ratemaking, in this instance the impact of this contract justifies making an exception. An exception is particularly relevant because PacifiCorp would have been aware of the potential for higher revenues at the time it submitted

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[30] Docket UE-210852, AWEC Petition for an Accounting Order at ¶ 5.

testimony and testified in the 2020 GRC. There is an information imbalance involved in a situation such as this. PacifiCorp can propose pro forma adjustments and deferrals for expected cost increases it is aware of but overlook others simply because other parties are unaware of them. Therefore, addressing this issue through a deferral is an appropriate course of action in this docket.

Q. WHAT LEVEL OF AMORTIZATION DO YOU RECOMMEND?

A. In **Mullins, Exh. BGM-6**, I provide a schedule detailing the deferral balance calculations and AWEC's proposed amortization. As can be seen, a balance of approximately $4,561,893 will have accrued in ratepayers' favor as of the rate effective date in this docket.

Q. WHAT AMORTIZATION PERIOD HAVE YOU USED?

A. Since I am proposing that the Commission reject PacifiCorp's rate plan, I propose a one-year amortization. This will help to reduce the expected 2022 PCAM rate impacts, which are anticipated to be significant and are also amortizable over a one-year period.

Q. HAVE YOU INCLUDED INTEREST?

A. Yes. I have included interest on the balance at the FERC quarterly interest rate for refunds.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. My recommendation produces a $4,996,914 Washington-allocated reduction to revenue requirement in Rate Year 1.

V. BRIDGER MINE DEPRECIATION AND RECLAMATION (ADJ. NO. 5.2)

Q. WHAT INCREMENTAL COSTS HAS PACIFICORP INCLUDED WITH RESPECT TO THE BCC MINE?

A. In the 2020 GRC, Parties agreed to the establishment of a regulatory liability to provide PacifiCorp with recovery for its post-2023 costs associated with depreciation and reclamation of the BCC mine. In Adjustment 6.4, PacifiCorp includes a $2,233,092 the incremental expenses to recover the Post-2023 reclamation and depreciation expenses resulting from Washington's early exit from the Jim Bridger power plant based on the parameters agreed in the 2020 GRC.[31]

Q. HOW ARE BCC DEPRECIATION AND RECLAMATION EXPENSES FUNDED?

A. Depreciation and reclamation expenses at BCC are otherwise recovered through the cost of coal consumed by the Jim Bridger power plant. For many years, BCC has established a separate trust fund reclamation expense. The trust fund is an interest-bearing account to which BCC contributes every month. As of March 31, 2022, the balance in the account was $[redacted], excluding incremental regulatory liability expenses paid for by Washington ratepayers.[32] These costs are included in the cost of coal from the BCC mine delivered to the Jim Bridger power plant. Depreciation expenses for the BCC mine are similarly included in the cost of coal delivered to the Jim Bridger power plant. In **Mullins, Exh. BGM-7C,** I have attached the BCC operating budgets that were used to establish coal costs for the Jim Bridger mine in the NPC forecast detailing these

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[31] Docket UE-191024 et al., Final Order 09, Appendix B at ¶27.

[32] Mullins, Exh. BGM-7C at 10.

expenses. Note that PacifiCorp is a 2/3rds owner of the mine; thus, 2/3rds of the expenses in the exhibit are included in PacifiCorp's rates. The other 1/3rd is owned and paid for by Idaho Power.

Q. HOW WERE THE DEPRECIATION AND RECLAMATION COSTS RESOLVED IN THE 2020 GRC?

A. In the 2020 GRC, Parties agreed as follows:

> The Company's current baseline NPC include $18,753,699 (total company) of contributions to the Bridger Coal Company (BCC) Reclamation Trust Fund through fuels costs for the Jim Bridger Plant. The Parties' stipulated revenue requirement also includes recovery of additional, incremental reclamation and depreciation over 10 years (2021 through 2030) in the amount of $11,815,290 per year (total company), for Bridger Mine reclamation and depreciation costs beyond 2023.[33]

Thus, all depreciation and reclamation costs incurred after 2023 have been accounted for within the ten-year regulatory liability the Commission established in the 2020 GRC. Under the Stipulation, no further depreciation or reclamation costs beyond 2023 were to be recovered from ratepayers other than through the regulatory liability.

Q. IS PACIFICORP CONSISTENTLY APPLYING THAT TREATMENT IN THIS DOCKET?

A. No. In its filing PacifiCorp continued to include the Jim Bridger mine in rates in conjunction with its proposal to operate the Jim Bridger power plants through 2025. When determining the cost of coal for Jim Bridger power plant, however, PacifiCorp neglected to make an adjustment to exclude the depreciation and reclamation costs beyond 2023, which are already being recovered through the regulatory liability.

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[33] Docket UE-191024 et al., Final Order 09, Appendix B at ¶ 27.

Q. HOW DO YOU KNOW PACIFICORP DID NOT MAKE AN ADJUSTMENT TO EXCLUDE THESE COSTS?

A. In response to AWEC Data Request 62, PacifiCorp provided the coal budgets for the BCC mine, which I have attached as **Mullins, Exh. BGM-7C**. In total, PacifiCorp's 2024 BCC budget includes depreciation expenses of $[redacted].[34] PacifiCorp's share of this depreciation was $[redacted] with $[redacted] allocated to Washington.[35] Similarly, the BCC budget includes mine reclamation contributions of $[redacted] in the cost of coal.[36] PacifiCorp's share of these reclamation contributions is $[redacted] with $[redacted] allocated to Washington. Hence, in addition to the regulatory liability recovery earmarked for all costs beyond 2023, PacifiCorp is pursuing recovery of an additional $27,320,265 (total-Company) in depreciation and reclamation expenditures in 2024 through the cost of coal sourced from the BCC mine. On a Washington-allocated basis, this additional recovery amounts to $6,178,041.

Q. IS IT REASONABLE FOR RATEPAYERS TO BE RESPONSIBLE FOR POST-2023 DEPRECIATION OR RECLAMATION EXPENSES BEYOND THE AMOUNTS MUTUALLY AGREED IN THE 2020 GRC STIPULATION?

A. No. PacifiCorp's inclusion of 2024 BCC depreciation and reclamation expenses in revenue requirement, alongside regulatory liability for post-2023 costs, will result in over-recovery for the BCC mine. While the mine will continue to operate and supply the Jim Bridger power plant in rate years, the Stipulation in the 2020 GRC outlined the framework for cost recovery of reclamation after 2023, which was to apply regardless of

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34 Mullins, Exh. BGM-7C at 4.

35 Using the Jim Bridger Energy ("JBE") factor of 22.6134%.

36 Mullins, Exh. BGM-7C at 4.

whether Jim Bridger continued to operate. Consequently, deviating from the agreed-upon approach is not justified.

Q. HOW LONG DOES PACIFICORP PLAN TO OPERATE THE BCC MINE?

A PacifiCorp plans to operate the mine through 2029, although it is possible that PacifiCorp may explore new leases to extend the life.[37]

Q IS IT REASONABLE FOR RATEPAYERS TO PAY FOR ADDITIONAL RECLAMATION AND DEPRECIATION EXPENSES AFTER EXITING THE JIM BRIDGER POWER PLANT?

A. No. The ongoing burden of depreciation and reclamation costs rightfully fall upon the states and entities that consume the coal and run the Jim Bridger Power Plant after Washington exits. Up to its departure on December 31, 2025, and based upon the Stipulation the Commission approved in the 2020 GRC, Washington will have fulfilled its responsibility for depreciation and reclamation expenses. Assuming any extra depreciation or reclamation costs beyond the amounts agreed in the 2020 GRC would result in subsidizing coal costs for other states, or potentially PacifiCorp's merchant operations.

Q. WHAT DO YOU RECOMMEND?

A. It is my recommendation to remove the supplementary recovery amount of $6,178,041 for 2024 BCC depreciation and reclamation expenses, as such recovery would be duplicative of the post-2023 recovery of those items being recovered through the regulatory liability approved in the 2020 GRC. This recommendation reduces the

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[37] Exh. No BGM-5 at 6 (PacifiCorp's resp. to AWEC DR 74).

Rate Year 1 revenue requirement deficiency by $6,491,783 after consideration of revenue sensitive costs.

VI. NET POWER COST MODELING (ADJ. NO. 5.2)

Q. HOW DOES PACIFICORP CALCULATE WASHINGTON ALLOCATED NPC?

A. PacifiCorp starts the calculation by performing a total-system power cost simulation using the AURORA model. The total-system simulation is established based on resources both in and out of Washington rates under the WIJAM method. Accordingly, the modeling produces a scenario where the modeled output from Washington's allocated share of its resources is less than Washington's load in some months, and greater than Washington's loads in other months. To address this short or long position, PacifiCorp has adopted a procedure to assign a cost to Washington's position based on the modeled cost of sales and purchases. First, PacifiCorp assigns a cost based on the average rate for short term sales up to the monthly level of sales modeled in the total system simulation. Second, PacifiCorp assigns a cost for the remaining short position based on the average rate for short-term purchases. Collectively these costs assigned to Washington's net position are referred to generally as the "Washington Balancing Adjustment."

Q. WHAT IS THE AMOUNT OF THE WASHINGTON BALANCING ADJUSTMENT?

A. The Washington Balancing adjustment is a major contributor to Washington-allocated NPC. In PacifiCorp's filed NPC study, Washington is in a net short position of [redacted] MWh, which results in a net cost of $[redacted] to Washington customers. This short position varies from month to month, with approximately [redacted]% occurring in the months of December through February. As noted above, the removal of Jim Bridger Units 1 and 2 for gas conversion in January and February, are a key driver of Washington's short postion in this docket. I estimate that approximately 71% of Washington's short position can be attributed to the outage when Jim Bridger Units 1 and 2 are converted to gas fired operations.

Q. WHAT FACTORS INFLUENCE WASHINGTON'S NET SHORT POSITION?

A. The dispatch of gas plants, including Chehalis, Hermiston, Colstrip and Jim Bridger Units 1 and 2, in the total-Company scenario is the primary factor that contributes to Washington's short position. If those gas plants dispatch less, in the total-company scenario, Washington's short position is larger. If those resources dispatch more, Washington's short position is smaller. Otherwise, all of the other variables in the NPC study used to calculate Washington's net short position are based on fixed load and dispatch profiles.

Q. DO YOU SUPPORT INCLUDING THE BRIDGER UNITS 1 AND 2 GAS CONVERSION IN REVENUE REQUIREMENT?

A. Yes. The investment to convert Bridger Units 1 and 2 into Gas fired operations is relatively modest in comparison with the benefits.

Q. DO YOU SUPPORT INCLUDING COLSTRIP AND JIM BRIDGER UNITS 3 & 4 IN RATES THROUGH 2025?

A. Yes. Given the magnitude of Washington's short position, as calculated in the Washington Balancing Adjustment, keeping Colstrip and Jim Bridger Units 3 & 4 in rates through 2025 is a sensible alternative. Given the rate pressures facing ratepayers in this docket, particularly with the heightened market prices, AWEC is supportive of

PacifiCorp's proposal to continue operating these resources. Importantly, whether Colstrip and Jim Bridger Units 3 units 4 are in Washington rates or not has no impact on the level of emissions from these plants because the allocation of these costs to Washington does not impact the plants' dispatch. Further, there is the possibility that market conditions will improve after 2025, which is being seen in recent forward curves, which will alleviate the cost of removing those resources from Washington rates.

Q. HAS PACIFICORP EFFECTIVELY PLANNED FOR WASHINGTON'S SHORT POSITION?

A. Washington has a unique portfolio, and PacifiCorp's system planning focuses on its total-Company operations. It may have been more cost effective, for instance, to purchase a dedicated resource to serve Washington load than the Washington Balancing Adjustment, although the integrated resource planning process is not necessarily designed to consider Washington's unique circumstances, potentially leading to higher costs This is a factor the Commission should consider when evaluating PacifiCorp's planning in future dockets.

Q. ARE YOU PROPOSING MODIFICATIONS TO PACIFICORP'S MODELING OF WASHINGTON-ALLOCATED NPC?

A. Yes. I recommend three adjustments. First, I recommend modifying the Washington System Balancing adjustment to first consider the cost of under-utilized gas plant dispatch, prior to considering the cost of market purchases or sales. Second, I recommend modifying the market capacity limits in AURORA to exclude the Four Corners, Palo Verde, and Mid-Columbia liquid market hubs, consistent with the 2020

GRC. Third, I recommend removing the Ozone Transport Rule modeling from NPC, since the final rule did not apply to Wyoming.

a. Washington Balancing Adjustment Modifications

Q. DOES PACIFICORP'S POWER COST MODELING RESULT IN OPTIMAL DISPATCH FOR SERVING WASHINGTON CUSTOMERS?

A. No. The AURORA model is based on a total-Company simulation that includes resources both in and out of Washington rates. Because the dispatch of Chehalis, Hermiston, and Jim Bridger Units 1 and 2 are being calculated on a total-system basis, rather than on a Washington-only basis, they are not being optimized to serve Washington load. In the total-company scenario, the model will, where economic, ramp down Washington's gas plants and use other generators to serve Washington's load more cost effectively, even though those generators may not be included in Washington rates. In place of the other resources, the Washington Balancing Adjustment assumes that only market purchases and sales are used to fill Washington's short position. Notwithstanding, because Washington's gas plants are not being dispatched specifically to Washington's load, Chehalis and Jim Bridger Units 1 and 2 could, in many instances, have otherwise ramped up to serve Washington's short position more cost effectively than the market.

Q. HOW DO YOU RECOMMEND ADDRESSING THIS ISSUE?

A. My recommendation is that, when determining the cost of Washington's short position in the Washington Balancing Adjustment, we should first consider the cost of Chehalis, Hermiston, and Jim Bridger Gas Units 1 and 2, before resorting to a cost calculation based on market purchases and sales. Specifically, if the cost of any of these resources is less than the average market prices assigned to Washington's short position, my recommendation is to assume the resource's output, up to its derated capacity, to fulfill Washington's short position. This is particularly important for Jim Bridger Gas Units 1 and 2 as those units are lower in the resource stack, but can be used to satisfy Washington's short position, when not running at their maximum or holding reserves.

Q. DO YOU PROPOSE TO CONSIDER CLIMATE COMMITMENT ACT ("CCA") ALLOWANCES IN THE EVALUATION?

A. No. PacifiCorp has excluded CCA allowance costs from the cost of Chehalis in NPC, and therefore, I have also excluded them when calculating the Washington Balancing Adjustment in the manner described above.

Q. HOW DO YOU PROPOSE TO ADDRESS WASHINGTON'S REMAINING SHORT OR LONG POSITION?

A. Rather than using the monthly average sales and purchase costs as the basis for the remaining cost, I recommend calculating the cost of Washington's hourly load on an hourly basis, based on the specific markets where purchases and sales were being made in each hour. In doing this, I used the same weightings between purchases and sales as the Company did. I calculated the impact on an hourly basis based on the hourly prices in the forward price curve. I viewed this as appropriate as the gas plants will ultimately dispatch based on hourly prices.

Q. WHY IS IT INACCURATE TO USE THE MONTHLY AVERAGE?

A. Using the monthly average cost of short-term sales and purchases in PacifiCorp's NPC study is not accurate because those include the impact of the other extraneous modeling adjustments, such as the Day-Ahead / Real-Time ("DA/RT") adjustment and emergency purchases. The DA/RT adjustment represents the total cost of balancing between monthly and short-term markets for the entire system. The impact of these balancing activities would not necessarily increase if more costs from Washington were served by the market. Stated differently, the cost of balancing for Washington's load is the same regardless of the proportion of market purchases used to serve Washington's short postion. Accordingly, in my calculation, I have excluded the impacts of the DA/RT adjustment from the hourly prices and volumes assumed with respect to the Washington Balancing Adjustment. I relied solely on the hourly forward market prices in PacifiCorp's OFPC.

Q. HAS PACIFICORP APPLIED THE ENERGY IMBALANCE MARKET IN A CONSISTENT WAY?

A. No. For example, PacifiCorp treats EIM benefits as a system cost and does not allocate more EIM benefits to Washington because of Washington's net short position, even though those are considered in short-term purchases. This is not necessarily an inaccurate assumption, though I recommend the same approach apply to the DA/RT adjustment.

Q. WHAT IS THE IMPACT OF YOUR ADJUSTMENT?

A. I detail my recommendation in **Mullins, Exh. BGM-8C**. In PacifiCorp's filing, it assigned a net cost of $28,906,374 or $105.14/MWh to Washington's net short position. In my approach, which considers under-utilized gas plant dispatch and calculates the hourly cost of Washington's loads, I calculate a system balancing adjustment of

$23,836,817 or $86.70/MWh. The impact of my adjustment is an approximate $5,327,007 reduction to revenue requirement after considering revenue sensitive costs.

b. Market Capacity Limits

Q. WHAT ARE MARKET CAPACITY LIMITS?

A. Market caps were a modeling parameter programed into the former GRID model to address alleged over-optimization of the model algorithm at certain illiquid market hubs. The parameter established a hard limit on the maximum volume of sales that could be made at a market hub in any hour. The use of market caps in GRID has been a source of modeling controversy since the GRID model was implemented and was one of the justifications for moving to a new model, such as AURORA, to avoid the need for exogenous modeling limitations such as market caps.

Q. DOES THE AURORA MODEL CONTAIN A MARKET CAP MODELING PARAMETER?

A. No. The AURORA model contains no specific modeling parameter limiting the volume of off-system sales as GRID did. In fact, the AURORA model lacks capability to evaluate off-system sales altogether; the AURORA model was designed to simulate market prices using regional dispatch, not to develop a closed-system dispatch as GRID was designed to do. It is only by means of modeling workarounds that PacifiCorp was able to incorporate off-system sales, and a closed system dispatch in AURORA. The workaround, which involved displacement of fictionalized loads at each market hub, will not fully be evaluated here, although it is likely that there are issues with it.

Nevertheless, when implementing this workaround, PacifiCorp limited the volume of fictional loads used to simulate off-system sales included in an AURORA table called "Hub Demand." This was done with the apparent objective of duplicating market caps.

Q. WHAT MODELING METHOD HAS THE COMMISSION APPROVED FOR MARKET CAPS IN GRID?

A. Since the implementation of the GRID model, the Commission has approved various modeling methods for market caps. The method proposed in this case is based on the four-year average historical short term firm transactions, broken down by market, month and hour class. For each monthly diurnal period, PacifiCorp took the average of the average level of sales in the same monthly diurnal period in the four-year history. Thus, the market caps in each monthly diurnal period were calculated based on the average of only four values. For example, as applied to the Test Period, the market cap applicable for heavy-load-hours ("HLH") in June 2024 at Mona would otherwise be based on the average of the average sales made at Mona in HLH of June 2022, HLH of June 2021, HLH of June 2020 and HLH of June 2019.

Q. DO MARKET CAPS APPLY TO ALL MARKET HUBS?

A. Historically not. In its 2020 GRC, PacifiCorp excluded liquid market hubs from the calculation of market caps. I confirmed this based on the workpapers that PacifiCorp provided in response to AWEC Data Request 92.[38] Notwithstanding, in its 2021 Power Cost Only Rate Case it changed the method, without explanation, applying it also to liquid market hubs.

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[38] Mullins, Exh. BGM-5 at 13 (PacifiCorp's Resp. to AWEC DR 92).

Q. HAS PACIFICORP DISCUSSED THE TREATMENT OF LIQUID MARKET HUBS?

A. Not in this docket. The reasoning for excluding the liquid market hubs was discussed in detail in the Direct Testimony of Gregory N. Duvall in PacifiCorp's Wyoming 2014 GRC, where PacifiCorp proposed removing market caps for the Mid-Columbia and Palo Verde markets. As PacifiCorp witness Duvall stated, "sales restrictions on the Mid-Columbia and Palo Verde markets have been removed."[39] PacifiCorp presented several reasons for excluding a market cap limitation on these markets. First, the markets were liquid, with robust forward markets. PacifiCorp stated that "markets have many participants and are often used to balance the Company's load and resource position on a forward basis."[40] The level of sales at these markets is also more dependent on the level of its generation, rather than liquidity in the market. PacifiCorp witness Duvall stated, "the Company's historical sales at the Mid-Columbia and Palo Verde markets may be more strongly aligned with the Company's resource position, rather than the position of the other counterparties in the market."[41] While I have found no similar discussion in contemporaneous Washington GRCs, I did confirm that PacifiCorp used the same method in the 2020 GRC, which excluded liquid markets, as was discussed in the 2014 Wyoming GRC.

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39 *In the Matter of the Application of Rocky Mountain Power for Approval of a General Rate Increase in its Retail Electric Utility Service Rates in Wyoming of $36.1 Million per Year or 5.3 Percent, Wyoming PSC Docket No. 20000-446-ER-14 (Record No. 13816), Direct Testimony of Gregory N. Duvall* at 14:22-15:1.

40 *Id.* at 19:15-16.

41 *Id.* at 19:17-20.

Q. DID PACIFICORP APPLY THE SAME METHOD TO THE HUB DEMAND LIMITS IN AURORA?

A. No. When applying the market cap method in the AURORA hub demands in the 2020 PCORC, PacifiCorp added back sales restrictions on the liquid markets, including the Mid-Columbia market and the Palo Verde market. This was unknown to me at the time PacifiCorp made its 2021 PCORC filing, as there was no explanation of this change in its supporting testimony.

Q. HAVE YOU APPLIED A MARKET CAP LIMITATION TO LIQUID MARKETS IN YOUR MODELING?

A. No. Consistent with the method used in the 2020 GRC, I have removed the market caps limitations from liquid market hubs. For the reasons PacifiCorp discussed in the Wyoming 2014 GRC, there is no reason to apply market caps to liquid markets. Further, I expanded the definition of liquid markets to include the Mid-Columbia market hub, the Palo Verde market hub, *and* the Four-Corners market hub.

Q. WHY HAVE YOU INCLUDED THE FOUR-CORNERS MARKET HUB AS A LIQUID MARKET?

A. PacifiCorp no longer has firm transmission access to the Palo Verde market following the retirement of Cholla Unit 4, and accordingly, is increasingly relying on the Four-Corners market to make sales in the Desert Southwest. Four-Corners is also traded on the liquid Intercontinental Exchange platform, with forward market pricing.

Q. HOW MUCH DOES PACIFICORP RELY ON FOUR CORNERS FOR MAKING SALES TRANSACTIONS?

A. In 12-months ending June 2022, PacifiCorp made [redacted] MWh of short-term sales at the Four-Corners market, which was greater than any other market.[42] In comparison, short-term sales at the Mid-Columbia market in 2022 were [redacted] MWh and short-term sales at the Palo Verde market were [redacted] MWh. The relative level of short-term sales transactions indicates that the market liquidity at the Four-Corners market hub is comparable to the other two market hubs, and that it is appropriate to model it consistent with other liquid markets in the NPC study.

Q. HOW DID THE REMOVAL OF SALES RESTRICTIONS ON THESE LIQUID MARKET HUBS IMPACT REVENUE REQUIREMENT?

A. Relative to PacifiCorp's forecast, removal of sales restrictions on liquid market hubs produced an approximate $341,965 increase to Washington-allocated revenue requirement. Part of the reason this change resulted in an increase is due to the relationship between the total system sales modeled in the NPC study and the Washington System Balancing Adjustment. Notwithstanding the small impact, I recommend modeling market caps in this manner.

Q. DOES THIS RESULT IN THE AURORA MODEL MAKING UNLIMITED SALES AT THOSE MARKETS?

A. No. The capacity for AURORA to make sales at any particular market hub is limited by transmission constraints in the model, which is consistent with the constraints that PacifiCorp faces in actual operations. The market cap limit on these liquid markets

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42 *See* PacifiCorp workpaper 230172-PAC-RJM-GNMarket Capacity (C), Tab "48 Month Pivot."

would otherwise reduce the capability to sell at such markets below the transmission limitation to an arbitrarily low level, which is not consistent with PacifiCorp's actual ability to make sales at such markets.

c. Ozone Transport Rule

Q. WHAT IS THE OZONE TRANSPORT RULE?

A. The Ozone Transport Rule was published by the Environmental Protection Agency ("EPA") on June 5, 2023.[43] Among other things, the rule was designed to reduce the amount of ozone-forming emissions of nitrogen oxides transported into neighboring states. Under the rule, electric generators are required to follow specific state implementation plans ("SIP") designed to limit nitrogen oxide emissions. In the recent rule implementation, the EPA issued SIPs for 22 different states, including Utah.

Q. IS PACIFICORP'S MODELING CONSISTENT WITH THE FINAL RULE?

A. No. PacifiCorp has modeled the Ozone Transport Rule in its NPC, including for the Jim Briger power plant. This modeling, however, was not consistent with the final rule. Foremost, Wyoming was not subject to the final rule issued by the EPA. The Federal Register notice states "we are deferring final action at this time on the proposed [Federal Implementation Plans] for Tennessee and Wyoming pending further review of the updated air quality and contribution modeling and analysis developed for this final action."[44] The EPA is conducting additional analysis and review of Wyoming's SIP

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43 EPA, Federal "Good Neighbor Plan" for the 2015 Ozone National Ambient Air Quality Standards, 88 Fed. Reg 36654 (June 5, 2023).

44 88 Fed. Reg. 36654, pp. 36715-16.

because the EPA's analysis to date suggests that it is uncertain if Wyoming is contributing to air quality problems in amounts sufficient to link them to the downwind air quality problems. EPA stated, "[w]ith respect to Wyoming, our methodology when applied using the 2016v3 modeling suggests that whether the state is linked is uncertain and warrants further analysis."[45] The EPA deferred its final action on Wyoming's SIP until December 15, 2023.

Q. IS THE RULE BEING CHALLENGED?

A. Yes. The rules have been challenged and have already been stayed in several jurisdictions, including a stay issued on May 1, 2023 for Texas and Louisiana.[46] On April 5, 2023, Wyoming similarly submitted a lawsuit to the 10th Circuit Court of Appeals to review the decision for deferred action on the Wyoming SIP.[47] Further, a lawsuit was filed by Utah on June 20, 2023, similarly requesting review of the rule,[48] and the application of the Ozone Transport Rule for Utah was stayed.[49] Thus, it is highly unlikely that the rule will be applied to Wyoming or Utah in the 2024 ozone season.

Q. WHAT DO YOU RECOMMEND?

A. I recommend excluding the Ozone Transport Rule from Wyoming in the final NPC studies performed in this docket. In my study, this adjustment reduced Washington-allocated revenue requirement by $8,182,931. Since Washington allocated NPC is highly

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45 *Id.* at 36717.

46 *See Texas v. United States EPA*, No. 23-60069, 2023 U.S. App. LEXIS 13898 (5th Cir. May 1, 2023).

47 *State of Wyoming v. EPA,* No. 23-9529, (10th Cir. filed Apr. 5, 2023).

48 *See State of Utah v. United States EPA*, No. 23-1157, Petition for Review (D.C. Cir. filed June 20, 2023). Available at https://attorneygeneral.utah.gov/wp-content/uploads/2023/06/2023-06-20-Utah-DC-Petition-for-Review-of-FIP-1.pdf

49 *See* https://attorneygeneral.utah.gov/tenth-circuit-halts-enforcement-of-epas-ozone-transfer-rule/

sensitive to changes in in the Washington net short position, the minor change in output that resulted from Jim Bridger with the Wyoming OTR restrictions removed produced a large impact on NPC in my study.

VII. PRODUCTION TAX CREDITS (ADJ. NO. 7.3)

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS RELATED TO THE PRODUCTION TAX CREDIT RATE.

A. In its initial filing in this proceeding, PacifiCorp forecast a PTC rate of [redacted] cents per kWh. As I demonstrate in **Mullins, Exh. BGM-9**, however, the PTC rate, which is set annually based on an index of inflation, will likely increase to 3.0 cents per kWh in 2024, and in no circumstance will the 2024 PTC rate be less than 2.9 cents per kWh. Further, in Rate Year 2, the PTC rate is virtually guaranteed to be at least 3.0 cents per kWh. Accordingly, I recommend using a 3.0 cents per kWh PTC rate in calculating revenue requirement in both Rate Years

In addition, due to the timing of the NPC calculation that was performed, a material portion of the PTC revenues from new resource additions in the respective rate years is being excluded from revenue requirement. Therefore, I recommend updating the PTC calculation to be based on wind production in the respective rate years, rather than the calendar years that PacifiCorp has used.

Finally, PacifiCorp's PTC workpaper contained the following statement:

> "Total available KWh is reflected net of the generation that is not considered PTC eligible because the facility was not fully repowered. For Glenrock, the disallowed KWh represents 8.3% of the total. For Glenrock

> III, the disallowed KWh represents 17% disallowed. For Rolling Hills, the disallowed KWh represents 23.4% disallowed."[50]

The repowering projects were justified based on ratepayers receiving 100% of the PTCs for the repowered output. Therefore, I recommend that the impact of these disallowances be eliminated from the calculation of PTCs.

a. Production Tax Credit Rate Forecast

Q. HOW DOES THE PTC RATE CHANGE FROM YEAR TO YEAR?

A. The PTC rate is established pursuant to IRC § 45.[51] The PTC rate was first authorized in 1993 and established at a baseline of 1.5¢/kWh. To account for inflation, the IRS adjusts the PTC rate each year by applying an "inflation adjustment factor." In IRC § 45(e)(2)(B), the calculation of the inflation adjustment factor is outlined as follows:

> The term "inflation adjustment factor" means, with respect to a calendar year, a fraction the numerator of which is the [Gross Domestic Product ("GDP")] implicit price deflator for the preceding calendar year and the denominator of which is the GDP implicit price deflator for the calendar year 1992. The term "GDP implicit price deflator" means the most recent revision of the implicit price deflator for the gross domestic product as computed and published by the Department of Commerce before March 15 of the calendar year.[52]

In addition, when applying the inflation adjustment factor, the credit rate is rounded to the nearest multiple of 0.1 cents per kWh. Consequently, while the inflation adjustment factor changes every year, the PTC rate does not necessarily change each year. In 2024, for example, the unrounded PTC rate would need to exceed 2.95 cents per kWh to trigger an increase to 3.0 cents per kWh.

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50 See PacifiCorp Workpaper "230172-PAC-SLC-7.3ProductionTaxCreditY1-ExhSLC4.xlsx"

51 26 U.S.C. § 45(b)(2) (2021).

52 *Id.* at § 45(e)(2)(B).

Q. HOW DID YOU FORECAST THE PTC RATE FOR 2024?

A. **Mullins, Exh. BGM-9** contains an analysis showing how the GDP implicit price deflator is used to calculate the PTC inflation adjustment factor. As noted in IRC § 45(e)(2)(B), the calculation of the inflation adjustment factor is a simple fraction.

The numerator of the fraction is equal to the GDP implicit price deflator for the calendar year prior to the tax year. For tax year 2024, for example, the numerator will be based on the GDP implicit price deflator from calendar year 2023, which won't be published until the spring of 2024. For tax year 2025, the numerator will be based on the GDP implicit price deflator from calendar year 2024, which won't be published until the spring of 2025.

The denominator of the fraction is equal to the GDP implicit price deflator for 1992, the calendar year prior to the 1993 tax year when the PTC was first implemented.

The denominator of the inflation adjustment factor is a known value. The GDP implicit price deflator for calendar year 1992 was 67.325.[53] Thus, while the precise value for the inflation adjustment factor for calendar year 2024 is not yet known, the periodically published GDP price deflator values can be used to determine whether the ultimate inflation adjustment factor will trigger an increase to the PTC rate.

Q. WHAT WAS THE INFLATION ADJUSTMENT FACTOR FOR 2023?

A. The inflation adjustment factor for 2023 was 1.8909, resulting in an unrounded PTC rate of 2.83 cents per kWh.[54] Thus, while the PTC rate rounded down to 2.8¢/kWh in 2023,

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53 This is based on the current index values. Note that the baseline year used to establish the GDP implicit price deflator index value has been updated, which can be seen in WIEC Exhibit 202.10.

the unrounded PTC credit rate was within 0.02¢/kWh of 2.85¢/kWh and rounding up to 2.9¢/kWh in 2023.

Q. WHAT INFLATION ADJUSTMENT FACTOR WILL RESULT IN AN INCREASE TO THE PTC RATE IN 2024?

A. Based on the year end inflation adjustment factor, the PTC rate is guaranteed to increase to at least 2.9 cents per kWh in 2024, even if zero inflation were to occur in 2023. Further, given high inflation rates, it is more likely than not that the PTC rate will increase to 3.0 cents per kWh for calendar year 2024. The inflation adjustment factor must equal or exceed 1.9667 to trigger an increase in the PTC rate to 3.0 cents per kWh. Whether this level is achieved, however, depends on the 2023 GDP implicit price deflator, which, as noted above, is an economic index of inflation that will be published by the Department of Commerce, Bureau of Economic Analysis in the spring of 2024.. Based on information that is known about the GDP implicit price deflator today, however, it can be determined that it is likely that the inflation adjustment factor will be sufficient to cause the PTC rate to round up to 3.0 cents per kWh in 2024, and the inflation adjustment factor is nearly certain to be at least 3.0 cents per kWh in 2025

Q. WHAT LEVEL OF INFLATION THROUGH THE END OF 2023 IS REQUIRED FOR THE PTC TO INCREASE TO 3.0 CENTS PER KWH?

A. At the time of drafting this testimony, the Bureau of Economic Analysis has published its GDP implicit price deflator for the second quarter of 2023. Based on that publication, it can be determined that the PTC rate will increase to 3.0 cents per kWh in 2024 so long as

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Credit for Renewable Electricity Production and Publication of Inflation Adjustment Factor and Reference Price for Calendar Year 2023, 88 Fed. Reg. 40400-40401 (Jun. 21, 2023).

inflation equals or exceeds 3.62% on an annualized basis for 2023, as measured by the GDP implicit price deflator. Given recent indications, it is likely that inflation will exceed this level for the year. For example, the annualized inflation rates, using the GDP implicit price deflator for calendar years 2021 and 2022, were 6.418% and 6.409% respectively. Recent federal reserve projections published on June 14, 2023, for example, forecast Core Personal Consumption Expenditures ("PCE") Inflation of 3.7% to 4.2% in calendar year 2023, and Core PCE Inflation was approximately 1.6% less than the inflation rate measured using the GDP implicit price deflator in 2021 and 2022.[55] Thus, these levels of Core PCI Inflation would imply inflation measured by the GDP implicit price deflator of 5.3% to 5.8%. Further information surrounding the actual inflation rates for 2023, however, will become available as this proceeding progresses.

Q. WHAT IS THE IMPACT OF A 3.0 CENTS PER KWH PTC RATE?

A. A 3.0 cents per kWh PTC rate will result in an approximate $7,748,874 increase to PacifiCorp's overall PTCs, which on a Washington-allocated basis represents an approximate $ 618,267 increase to PTCs, before tax gross-up. On a revenue requirement basis, this change produces a $822,361 reduction to revenue requirement for Rate Year 1

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55 Federal Reserve Open Market Committee, June 14, 2023: FOMC Projections, Summary of Economic Projections at 2. *See also* https://www.federalreserve.gov/monetarypolicy/fomcprojtabl20230614.htm (accessed Aug. 8, 2023).

b. Production Tax Credit Rate Year Volumes

Q. WHAT IS THE IMPACT OF UPDATING TO THE WIND PRODUCTION LEVELS IN THE RESPECTIVE RATE YEARS?

A. Due to the addition of new wind resources, more wind production is expected in both rate years than the calendar year 2024 net power cost study that PacifiCorp performed. For example, Rock River 1 and Rock Creek 2 are expected to come online in late 2024, and the much larger, Rock River 2, is expected to come online in late 2025. Because PacifiCorp used calendar year 2024 volumes to calculate PTCs, it missed approximately two months—January 2025 and February 2025—of production from Rock River 1 and Rock Creek 2 that will occur in Rate Year 1. Further, by not updating PTCs for Rate Year 2, PacifiCorp has excluded the full annual PTC benefits of Rock River 1 and Rock Creek 1, as well as any PTCs for Rock Creek 2

Q. WHAT ARE THE PTC IMPACTS OF INCLUDING THE RATE YEAR VOLUMES FOR PTCS?

A. Using the Aurora model inputs supplied with PacifiCorp's filing, I calculated the production from the three wind facilities in the respective rate years. Based on those updated production levels, I calculated the Washington-allocated production tax credits using the 3.0 cents per KWh rate noted above. Based on that analysis, updating the production tax credit to the rate effective period will reduce Washington revenue requirement by approximately $822,361 in Rate Year 1 and an *additional* $4,629,783 in Rate Year 2.

c. Production Tax Credit Disallowance

Q. DID PACIFICORP IDENTIFY REPOWERING PTCS THAT WERE BEING DISALLOWED?

A. Yes. In its workpaper "230172-PAC-SLC-7.3ProductionTaxCreditY1-ExhSLC4.xlsx" PacifiCorp made a note stating that a portion of the PTCs associated with the Glenrock and Rolling Hills facilities had been disallowed.

Q. WERE THE REPOWERING PROJECTS JUSTIFIED BASED ON RATEPAYERS RECEIVING 100% OF THE PTCS FROM THOSE RESOURCES?

A. Yes. Accordingly, disallowance of PTCs would materially impact the economic justification for PacifiCorp's investment in repowering. Therefore, passing the cost of disallowance onto ratepayers is not reasonable. However, I only discovered this issue shortly before filing testimony and did not have an opportunity to conduct discovery on it. Accordingly, I request PacifiCorp provide further information about this disallowance in Rebuttal Testimony for the Commission to make a decision on this issue.

Q. WHAT DO YOU RECOMMEND?

A. In my revenue requirement analysis, I added back the benefit of the disallowed PTCs. The impact of this treatment is a $370,547 reduction to Rate Year 1 revenue requirement.

VIII. OTHER REVENUE REQUIREMENT ISSUES

a. Production Factor Adjustment (Adj. No. 9.1)

Q. WHAT PRODUCTION FACTOR ADJUSTMENT HAS PACIFICORP INCLUDED IN REVENUE REQUIREMENT?

A. PacifiCorp applies a production factor adjustment "to the generation-related pro forma capital additions and associated revenue requirement components to adjust the pro forma cost levels back to the historical Test Period levels."[56] This adjustment results in an approximate $1,120,584 increase to revenue requirement.[57] Effectively, this adjustment grosses up net power costs to account for lower expected Washington loads in Rate Year 1. PacifiCorp states that it may need to perform a similar adjustment for Rate Year 2, although that adjustment is unknown at this time.

Q. HOW DID PACIFICORP CALCULATE THE PRODUCTION FACTOR ADJUSTMENT?

A. PacifiCorp performed the production factor calculation by comparing the 4,194,177 kWh of sales in the historical period to forecast sales of 4,171,557 KWh in Rate Year 1.[58] Based on this relationship, PacifiCorp calculated a production factor of 100.542%. PacifiCorp subsequently multiplied this by NPC, and other related costs, to estimate the production factor adjustment.

Q. WAS PACIFICORP'S FORECAST OF RATE YEAR SALES CONSISTENT WITH ITS LOAD FORECAST?

A. No. PacifiCorp's NPC forecast for Rate Year 1 was based on Washington loads (i.e., at input) of [redacted] kWh.[59] The normalized Washington loads in the historical period were 4,572,362 kWh.[60] This relationship would imply a production factor adjustment of just 100.111%, or almost no production factor at all. Thus, PacifiCorp's calculation of its production factor adjustment was not consistent with the load forecast used for NPC.

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56 Cheung, Exh. SLC-1Tr at 8:2-5.

57 Cheung, Exh. SLC-2 at 1:60.

58 *See* Workpaper 9-1ProductionFactorAdjustmentYear1.

59 *See* PacifiCorp workpaper 230172-PAC-RJM-NPC 1(C) at

60 *See* PacifiCorp workpaper WAJAM2023GRC, Tab "Factors", Cell "BZ25"

Q. HAVE YOU INVESTIGATED THE CAUSE OF THE VARIANCE?

A. Yes. Part of the variance may be related to different assumed loss factors in calculating sales in the historical period versus the forecast period. The historical sales implied a loss factor of 9.0%. PacifiCorp's forecast sales implied a loss factor of 9.7%. To investigate this difference, PacifiCorp was requested in discovery to provide the total loss factor (i.e., between load and sales) assumed when calculating Washington normalized kWh sales in this docket. In response, PacifiCorp stated "[l]oss factors are not used when calculating Washington normalized kilowatt-hour (kWh) sales in this general rate case (GRC) proceeding."[61] Based on this response, PacifiCorp provided no reason to assume a different loss factor with the forecast data than assumed in the historical data. Thus, the accuracy of PacifiCorp's sales forecast relative to its load forecast cannot be confirmed in any way.

Q. DO CHANGING SALES LEVELS IN WASHINGTON IMPACT COSTS OTHER THAN NPC?

A. Yes. Foremost, changing levels of sales in Washington, and other states, impacts Washington's share of other system costs. If Washington's load declines, its share of other system costs decline as a result of changes to Washington's allocation factors under the WIJAM adopted in conjunction with the 2020 Protocol. These changes might be significant, and absent a holistic view it would not necessarily be accurate to adjust Washington load, through the production factor adjustment, viewed in isolation.

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[61] Mullins, Exh. BGM-5 at 3 (PacifiCorp's Resp. to AWEC DR 58).

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE PRODUCTION FACTOR?

A. Since Washington loads are forecast to be substantially the same in Rate Year 1 as the historical period, I recommend removing the production factor adjustment when calculating revenue requirement.

b. COVID Deferral Amortization (Adj. Nos. 8.2 & 16.1)

Q. WHAT AMOUNT OF COSTS HAS PACIFICORP ACCRUED TO THE COVID DEFERRAL?

A. PacifiCorp has accrued $5,273,956 to its COVID deferral.[62]

Q. WHAT INFORMATION DID PACIFICORP PRESENT REGARDING THESE COSTS?

A. Other than a general description,[63] no information was provided about what was included in the requested recovery, nor why it is reasonable.

Q. DID PACIFICORP COMPLY WITH THE COMMISSION ORDER IN DOCKET UE-200234?

A. No. The Commission's Order in Docket UE-200234 required PacifiCorp to "to defer as a regulatory liability all operational cost savings in addition to all cost savings, credits, payments, or other benefits received by the Company from a federal, state, or local government that are directly related to COVID-19 relief programs, including but not limited to federal, state, or local tax credits or benefits."[64] .The Commission Order also stated "[a]t the time PacifiCorp seeks recovery of deferred costs, it should simultaneously present its tracked savings and demonstrate how it has used those savings to offset its

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62 Cheung, Exh. SLC-4 at 8.2.

63 *Id.*

64 Docket UE-200234, Order ¶ 29 (Dec. 10, 2020).

costs, which will inform the Commission's prudence review."[65] PacifiCorp, however, has performed no such analysis in its filing.

Q. WHAT COST ITEMS DID PACIFICORP INCLUDE IN THE BALANCE PACIFICORP IS SEEKING TO RECOVER?

A. In AWEC Data Request 29, PacifiCorp identified the amounts that had been accrued to the COVID deferral since its inception.[66] In the workpapers provided in the response, PacifiCorp stated that the amount "[r]epresents the deferral of costs associated with providing bill assistance (waiver of arrearages) to Oregon [sic] customers due to the COVID-19 pandemic by helping to reduce residential customer arrearages and bad debt write-offs (WUTC Docket U-200281)."[67] While these costs were at issue in Docket UE-200234, PacifiCorp did not file testimony attempting to justify their inclusion in this docket.

Q. THROUGH WHAT DATE IS THE COMPANY REQUESTING RECOVERY?

A. Based on the value included in this docket and a comparison to AWEC Data Request 29, PacifiCorp has included a balance with costs through November 2022.

Q. DO YOU AGREE THAT IT IS REASONABLE TO PROVIDE PACIFICORP WITH RECOVERY OF LOST REVENUES?

A. No. Lost revenues, in the form of waived late payment fees, are not reasonable to be considered in the context of the COVID deferral. COVID was a challenging situation for many ratepayers, whereas electric utilities were not necessarily negatively impacted by the circumstances. Having PacifiCorp forgo a small amount of revenues to protect the

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65 Id. ¶ 20 (Dec. 10, 2020).

66 Mullins, Exh. BGM-5 at 1-2 (PacifiCorp's Resp. to AWEC DR 29, Attachment AWEC 29)

67 *Id*.

interest of the individuals that were disproportionately impacted by the event is not unreasonable.

Q. WHAT RETURN ON EQUITY DID PACIFICORP EARN IN 2021?

A. The majority of the deferral occurred in 2021. Notwithstanding, in 2021 PacifiCorp earned a 11.58% ROE on a non-normalized basis.[68] While perhaps there were lost revenues from waived late fees, PacifiCorp correspondingly gained revenues, likely due in part to higher residential loads and higher industrial demand that occurred after the COVID situation.

Q. WHAT AMORTIZATION PERIOD HAS PACIFICORP USED FOR THESE BALANCES?

A. PacifiCorp has proposed a one-year amortization period.[69]

Q. DID PACIFICORP PROVIDE ANY REASONING BEHIND ITS ONE-YEAR AMORTIZATION PERIOD?

A. No.

Q. WHAT IS YOUR RECOMMENDATION?

A. PacifiCorp has failed to meet its burden of proof with respect to the reasonableness of the funds that it seeks to recover with respect to the COVID deferral. It is proposing to recover lost revenues, even though its revenues produced a 11.58% non-normalized ROE in 2021. Finally, PacifiCorp has failed to recognize any savings in the deferral. Given these circumstances, I recommend the Commission reject PacifiCorp's proposal to recover costs associated with the COVID deferral.

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[68] See Docket 220300. Washington Results of Operations at 2.2 (Apr. 27, 2022).

[69] Cheung, Exh. SLC-1Tr at 44:4-10.

Q. IF THE COMMISSION DOES PROVIDE RECOVERY OF SOME AMOUNT FOR THE COVID DEFERRAL, DO YOU HAVE ANY SUGGESTIONS?

A. Yes. First, I recommend that the balance be adjusted to exclude deferred revenues. In Docket UE-200234, PacifiCorp identified deferred late fee revenues of $2,354,809 included in the deferred accounts through June 30, 2023.[70] Second, I recommend the balance be reduced for savings. In Docket No. UE-200234, PacifiCorp estimated savings of $10,285,958 on a total-Company basis through June 30, 2023. On a Washington allocated basis, using the System Overhead factor, this amounts to a further $728,717 reduction to the balance. Third, I recommend the balance be amortized over a five-year period, to equitably spread the costs to ratepayers over time. A summary of this recommendation based on the June 30, 2023 balances, is provided in **Table BGM-2**, below.

Table BGM-2
COVID Deferral Amortization Calculation
Whole Dollars

	Balance
Bad Debt Expense	1,192,876
Bill Payment Assistance Funds	3,101,325
Net Savings	(728,717)
Total	3,565,484
Five Year Amortizaion	**713,097**

Q. WHAT IS THE IMPACT OF THIS RECOMMENDATION?

A. This alternative proposal would produce an approximate $4,802,983 reduction to Rate Year 1 revenue requirement, although my primary recommendation reflected in my

70 Docket UE-200234, PacifiCorp's Quarterly Report for Q2 2023 at 1 (July 26, 2023).

revenue requirement analysis removes the deferral in its entirety due to lack of supporting documentation provided by PacifiCorp.

c. Working Capital – Other Accounts Receivable (Adj. No. 8.7)

Q. WHAT AMOUNT OF WORKING CAPITAL DOES PACIFICORP INCLUDE IN REVENUE REQUIREMENT?

A. PacifiCorp includes $29,873,668 in rate base using its Investor Supplied Working Capital ("ISWC") model.[71]

Q. DOES PACIFICORP INCLUDE OTHER FORMS OF WORKING CAPITAL, IN ADDITION OT THE ISWC CALCULATION?

A. Yes. PacifiCorp's test period results of operations included $3,475,500 of Washington-allocated accounts receivable in FERC Account 143. PacifiCorp's test period results of operations also included $728,541 in various accounts payable in FERC Account 232. These amounts may be found in PacifiCorp's workpapers titled "B14WorkingCapital."

Q. DID PACIFICORP REMOVE THOSE BALANCES WHEN IT APPLIED ITS ISWC CALCULATION?

A. No. Therefore, PacifiCorp has overstated its working capital requirements by including discrete payables and receivables balances, while also using its ISWC calculation.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the discrete balances in workpapers titled "B14WorkingCapital" be removed from rate base. This recommendation results in an approximate $386,954 reduction to Rate Year 1 revenue requirement.

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71 *See* workpaper "8-7InvestorSuppliedWorkingCapital"

d. Investor Supplied Working Capital – Prepaid Settlement (Adj. No. 8.7)

Q. HOW HAS PACIFICORP CLASSIFIED ITS DEFERRED PENSION ASSET IN ITS ISWC MODEL?

A. PacifiCorp classified its prepaid pension asset as a current asset and excludes it from its calculation of investor supplied capital. These items may be found on Excel rows 611-617 of PacifiCorp's ISWC model.

Q. DO YOU AGREE WITH THAT TREATMENT?

A. No. A pension asset is typically considered a non-current asset. Therefore, excluding it from the investor supplied working capital model results in overstating PacifiCorp's working capital requirements. While the pension settlement may not be reflected in rates as a reduction to rate base, it is appropriate to consider the financing implications of the settlement when performing the ISWC calculation. By including it as a current asset, however, PacifiCorp has basically included the settlement in rate base through the ISWC calculation, even though ratepayer responsibility for the settlement has not been established.

Q. WHAT DO YOU RECOMMEND?

A. I recommend the pension settlement be included as an investment and classified as non-utility in the ISWC calculation. This treatment resulted in a reduction to PacifiCorp's ISWC calculation of $16,725,883, which produced a $1,539,506 reduction to revenue requirement.

e. Pole Attachment Revenue (Adj. No. 3.4)

Q. WHAT AMOUNT OF POLE ATTACHMENT REVENUE DID PACIFICORP INCUR IN THE HISTORICAL PERIOD?

A. PacifiCorp provided its historical pole attachment revenues in response to AWEC Data Request 84. Based on that response, PacifiCorp had recorded Washington-allocated pole attachment revenues of $905,333 for the historical test period ending June 2022.

Q. HAS THAT AMOUNT BEEN INCREASING?

A. Yes. In the same response, it can be noted that PacifiCorp recorded Washington-allocated pole attachment revenues of $1,259,340 over the 12-months ending June 2023.

Q. WILL POLE ATTACHMENT REVENUES INCREASE IN THE RATE YEARS?

A. On average, PacifiCorp's Washington-allocated pole attachment revenues increased by 15.9% per year on average since 2019. Thus, it is probable that pole attachment revenues will increase by similar rates in the future. Pole attachment rates are driven both by PacifiCorp's actual rental rate calculations and the number of pole attachments. With PacifiCorp's increased investment in wildfire and other distribution expenses, the cost of a bare pole, which is the key driver of the rental rate calculations, is likely increasing. With an aggressive push to install broadband, particularly in rural areas, and supported by significant Federal funding, it is also likely that the number of attachers is also increasing.

Q. WHAT DO YOU RECOMMEND?

A I recommend including a provision for increased pole attachment revenues in revenue requirement based on the year ending June 2023 values and applying escalation through the two rate periods.

Q. WHAT IS THE IMPACT OF YOUR RECOMMENDATION?

A. This recommendation produces a $654,233 reduction to Rate Year 1 revenue requirement and a $247,867 reduction to Rate Year 2 revenue requirement.

IX. POWER COST ADJUSTMENT MECHANISM

Q. WHAT CHANGES HAS PACIFICORP PROPOSED WITH RESPECT TO THE PCAM?

A. Witness Painter discusses PacifiCorp's proposal with respect to the PCAM. Specifically, PacifiCorp proposes to eliminate the deadbands and sharing bands that were established in the collaborative process that was undertaken to develop the PCAM in 2015. As justification for this change, PacifiCorp cites difficulty in forecasting NPC, increasing renewable resources as a result of CETA, as well as its potential participation in an organized market.[72] As I discuss below, however, the PCAM is functioning as the Commission intended, and the Commission has repeatedly rejected the arguments that PacifiCorp has raised with respect to the PCAM in this case. Therefore, I recommend the Commission reject PacifiCorp's proposal.

Q. WHEN WAS THE PCAM ESTABLISHED?

A. The PCAM was established based on a collaborative process that took place in early 2015 at the direction of the Commission in the 2014 GRC.[73] The Commission's Order 08 in the 2014 GRC was comprehensive in its analysis as it laid out the long history behind

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[72] Painter, Exh JP-1 at 5:1-15.

[73] *See* Dockets UE-140762 et al., Order 09 (May 26, 2015).

PacifiCorp's various PCAM proposals over the years, which the Commission rejected because they lacked appropriate ratepayer protections.[74]

Q. WHEN HAS THE COMMISSION REJECTED A PCAM PROPOSAL FROM PACIFICORP BECAUSE IT LACKED APPROPRIATE RATEPAYER PROTECTIONS?

A. In the 2006/2007 GRC, PacifiCorp proposed a dollar-for-dollar PCAM "arguing that implementation of such a mechanism was justified by the facts that the Company faced volatility in net power costs"[75] The Commission rejected PacifiCorp's proposal stating:

> PacifiCorp's circumstances include significant exposure to variability in power costs and this variability is sufficient to justify a PCAM. However, PacifiCorp has designed its mechanism on the basis of the PCAM we approved for Avista, the so-called ERM, without making refinements that our record shows are appropriate in light of PacifiCorp's unique circumstances. Specifically, we find that the design features proposed by the Company and modified by Staff do not appropriately balance risk and benefits. There are two principal reasons:
>
> - The accounting for actual and computer-generated-actual costs has not been shown to be reliable.
> - The design of the dead band and sharing bands should reflect the asymmetry of power cost risk that is evident in PacifiCorp's case.[76]

In the 2012 GRC, PacifiCorp again filed for a PCAM requesting dollar-for-dollar recovery, and the Commission again rejected that proposal.[77] In that Docket the Commission stated:

> [T]he Company's proposal here is even more at odds with the direction the Commission has given PacifiCorp than its proposals in prior cases that have been rejected. Contrary to express Commission direction, and in contrast to the power cost adjustment mechanisms approved in other PacifiCorp jurisdictions, the Company's proposal here includes neither dead bands nor sharing bands. These are critically important elements that provide an

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74 Dockets UE-140762 et al., Order 08 ¶ 108 (Mar. 25, 2015).

75 *Id.* ¶ 105

76 Docket UE-061546, Order 08 ¶ 59 (June 21, 2007); *see also id.* ¶¶ 83-87.

77 Docket UE-130043, Order 05 ¶ 170 (Dec. 4, 2013).

> incentive for the Company to manage carefully its power costs and that protect ratepayers in the event of extraordinary power cost excursions that are beyond the Company's ability to control.[78]

In the 2014 GRC, PacifiCorp again proposed a PCAM-like mechanism referred to as a renewable resource tracking mechanism that provided dollar-for-dollar recovery of costs associated with renewable resources. This mechanism was proposed to "address the variability of NPC related to the increase in intermittent wind resources in the Company's resource portfolio."[79] Again, the Commission rejected that mechanism, stating:

> The Company elected in this case not to file "a properly designed PCAM proposal that incorporates the appropriate balance between the Company and ratepayers." Instead, Pacific Power filed another tracker mechanism, a so-called Renewable Resource Tracking Mechanism (RRTM), providing a dollar-for-dollar annual true-up between forecast and actual power costs for the Company's renewable resource generation.[80]

In the 2014 GRC, Staff Witness Gomez also proposed a competing power cost mechanism, which included deadbands and asymmetrical sharing. The Commission responded to Staff's proposal stating "[w]e note that Staff's proposal in this case is well-grounded in precedent, modeled both to be consistent with the ERM the Commission approved for Avista in 2002 and to reflect the guidance the Commission has provided specifically to Pacific Power in earlier cases."[81] Notwithstanding, the Commission expressed concerns with certain elements of Staff's proposal, such as the deadband limits and sharing percentages,[82] and required parties to "conduct further proceedings to

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78 *Id.*
79 Dockets UE-140762 et al., Duvall, Exh GND-1T at 3:9-14.
80 Dockets UE-140762 et al., Order 08 ¶ 108.
81 *Id.* ¶ 122.
82 *Id.* ¶ 123.

identify and resolve the details of designing fully and implementing a PCAM mechanism for Pacific Power."[83]

Q. WHAT WAS THE RESULT OF THOSE FURTHER PROCEEDINGS?

A. The result of the proceedings was a settlement agreement between Staff, PacifiCorp, Boise White Paper, and Public Counsel, which outlined the design elements of the currently existing PCAM, following the general structure of Staff's recommendation from the rate case.[84]

Q. DID PACIFICORP ADDRESS THIS HISTORY BEHIND THE DEADBANDS AND SHARING PERCENTAGES IN ITS REQUEST TO CHANGE THE PCAM?

A. No. The Commission has consistently required PCAMs for all electric utilities in the state, not just PacifiCorp, to contain design elements to protect ratepayers, including deadbands and asymmetrical sharing. Without addressing the explicit directives of the Commission regarding this issue, it is challenging to envision how PacifiCorp can suggest a modification. Nothing has substantially changed to warrant a change to the current practice, nor a change to Commission precedent. Such a change would also implicate the other utilities in the State, a factor the PacifiCorp has also not considered.

Q. DID PACIFICORP AGREE TO THE CURRENT DESIGN ELEMENTS?

A. Yes. PacifiCorp was a party to the stipulation in the 2014 GRC. Accordingly, PacifiCorp is effectively withdrawing from its agreement in that case by proposing to eliminate key elements of the PCAM stipulation, which were expressly required by the

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83 *Id.* ¶ 124.

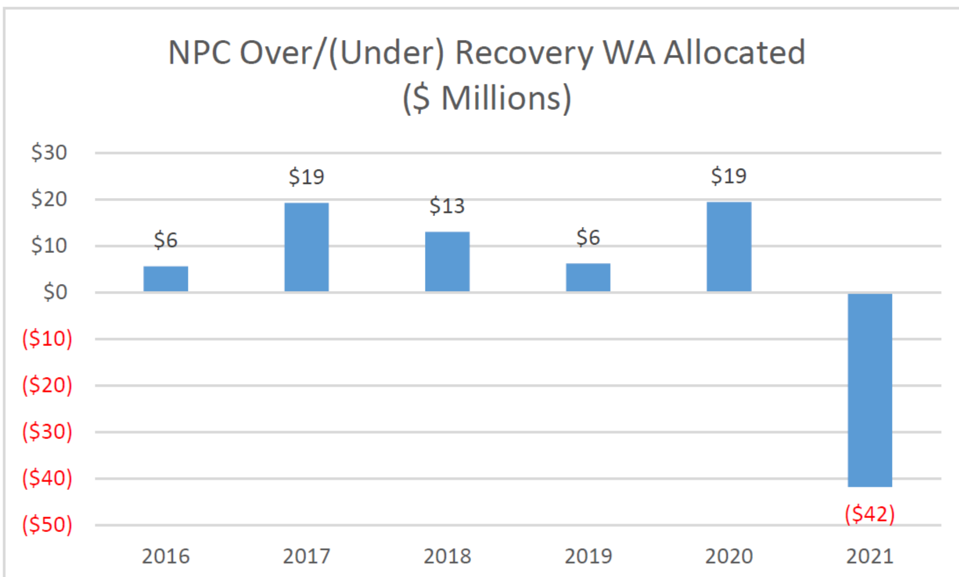
84 Dockets UE-140762 et al., Order 09 (May 26, 2025).

Commission. There may be broader implications to stipulations generally if parties are allowed to unilaterally withdraw from their commitments.

Q. IS THE PCAM FUNCTIONING AS INTENDED?

A. Yes. The figure on page 8 of Painter, Exh. JP-1T, reproduced below, clearly demonstrates that the PCAM is operating as intended and that there is not a systemic problem with NPC recovery in Washington.

Figure BGM-1
<u>NPC Over/(Under) Recovery WA Allocated</u>
<u>($ Millions)</u>



As can be seen from the figure, the actual NPC has been above the baseline in most years. Over this period, PacifiCorp over-collected its NPC in total. In 2021, the negative results are also overstated as a result of the deferred base NPC adjustment that was recovered through the PCAM as a result of the late NPC update that occurred in the 2020 GRC. Further, while the events in 2022 have produced heightened energy prices, the impact of those are being considered in the ongoing PCAM proceeding. Over time, it is expected that power costs will sometimes be higher and sometimes be lower than base NPC, and this data, and the experience of the PCAM to date, is not indicative of a bias, one way or the other.

Q. ARE MARKET PRICE FORECASTS LESS ACCURATE?

A. PacifiCorp makes statements such as "in recent years these [price] forecasts have become less accurate, as indicated in Figure 1 above."[85] Such statements, however, misrepresent what the price forecast is. PacifiCorp's market price forecasts are based on its official forward price curves ("OFPC"). The forward price curves represent the actual cost of purchasing power in the forecast period based on prices in effect at the time that the OFPC is issued. They represent the market expectation of what prices will be in the forecast period. Like anything else, market expectations rise and fall, though the market expectation at any given point in time cannot be viewed to be any more or less accurate than the market expectation at some other point in time. Volatility might increase or decrease over time, though that is different from accuracy. Further, forward markets typically include large premiums to account for expected price volatility. Accordingly, if anything, increasing price volatility results in systematically higher forward market prices, which would tend to overstate NPC.

Q. ARE POWER COSTS OUTSIDE OF PACIFICORP'S CONTROL?

A. No. PacifiCorp also makes several statements that power costs "out of the Company's control."[86] I disagree. The job positions involved in managing the day-to-day operation

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85 Painter, Exh. JP-1 at 9:10-12.

86 *Id.* at 28:20.

of a complex utility such as PacifiCorp's are not entry level positions. Operating a system such as PacifiCorp's requires a great deal of talent, knowledge, discipline and skill to ensure that ratepayers are not being exposed to unnecessary costs and this applies to a broad range of jobs and job responsibilities with respect to managing net power costs.

Q. CAN YOU PROVIDE AN EXAMPLE?

A. PacifiCorp prepares an operational load forecast for every trading day. This forecast takes in a number of variables, such as weather, customer counts, industrial forecasts, and other factors, to ensure that the trading team is purchasing sufficient power in day-ahead, and subsequently real time markets. If the utility prepares a bad forecast, the cost consequences could be enormous. If the load forecasting team understates its load on a critical day, PacifiCorp could be exposed to exceptional prices in real time markets, up to $1,000/MWh. PacifiCorp's inaccurate load forecasting, for example, was likely a key contributor to excessive costs in heat events that occurred in September 2022. While no one can prepare a perfect forecast, highly skilled individuals can prepare sophisticated forecasts which avoid excessive NPC.

Q. CAN PACIFICORP CONTROL MARKET PRICES?

A. No. It can, however, hedge and control how it purchases power in order to avoid the consequences of volatile market prices. To use an analogy, while the weather cannot be controlled, one can control what type of jacket to wear. In other words, there are elements of NPC that PacifiCorp cannot control, but it is how PacifiCorp responds to those elements that is the important thing. This is the reason why it is critical to maintain the PCAM design elements, such as the deadbands and sharing percentages – they incentivize PacifiCorp to control the factors it can.

Q. DO ORGANIZED MARKETS MAKE NPC LESS PREDICTABLE?

A. No. To the contrary, organized markets are expected to increase the predictability and reduce the volatility in NPC. While participating in such markets still requires a great deal of skill and diligence, it is my expectation that such markets will result in a more stable level of NPC than existing bilateral markets. Further, PacifiCorp's assertions that that joining the Extended Day-Ahead Market will somehow allow PacifiCorp to operate its system on autopilot are concerning. Trading in an organized market still requires all the same planning and trading activities as bilateral markets, if not more.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. Like all past proceedings where PacifiCorp has proposed a PCAM with no deadbands or sharing percentages, I recommend that the Commission reject the proposal in this docket to eliminate those design elements. PacifiCorp's actions and management of NPC are impactful on the level of NPC that it incurs, and suggestions that NPC is outside of PacifiCorp's control implies that PacifiCorp's management function is meaningless. I disagree.

X. WASHINGTON CCA ALLOCATION

Q. ARE CUSTOMERS IN OTHER STATES CONCERNED WITH THE ALLOCATION OF CCA COSTS TO THEIR JURISDICTIONS?

A. Yes. Customers in many other states participating in the Multi-State Process have expressed concerns with the effects of the Washington CCA on the costs associated with the Chehalis plant. Much of the concern revolves around the fact that

Washington customers benefit from the allocation of free allowances for their portion of the Chehalis generating facility, whereas out of state customers do not. This is an important issue, and while I am not offering any specific recommendation on CCA allowances in this case, I recommend that the Commission and Washington parties engage collaboratively with the Multi-State Process stakeholder group to devise a solution to this issue, including evaluating a scenario where Washington assumes full responsibility of the costs and benefits of the Chehalis power plant.

Q. DOES THIS CONCLUDE YOUR RESPONSE TESTIMONY?

A. Yes.