Exh. SLC-6T
Docket UE-250224
Witness: Sherona L. Cheung

BEFORE THE WASHINGTON

UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFICORP dba PACIFIC POWER & LIGHT COMPANY Respondent.	Docket UE-250224

PACIFICORP

REBUTTAL TESTIMONY OF SHERONA L. CHEUNG

September 2025

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ATTACHED EXHIBITS

Exhibit SLC-7—Staff Response to PacifiCorp Data Request 1[1]

Exhibit SLC-8—Docket UE-050684—Exhibit No. DLT-3

[1] For the sake of brevity, only the summary tab of Attachment 1 accompanying Staff Response to PacifiCorp Data Request 1 has been included in Exhibit No. SLC-7.

Q. Are you the same Sherona L. Cheung that previously provided testimony in this case on behalf of PacifiCorp d/b/a Pacific Power & Light Company (PacifiCorp or Company)?

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to respond to various issues raised in the testimonies of John D. Wilson, on behalf of the Washington Utilities and Transportation Commission (Commission) Staff (Staff), Alliance of Western Energy Coalition (AWEC) witness Bradley G. Mullins, and the Public Counsel Unit of the Washington State Attorney General's Office (Public Counsel) witness Callahan Moriyasu (collectively, the Parties).[2]

Q. Please summarize your testimony.

A. My testimony responds to Staff witness Wilson's concerns regarding the potential for temporary double-recovery of costs during the implementation of the 2026 Protocol and specifically addresses the analysis Staff witness Wilson relies upon to claim that Chehalis generation facility costs are over-recovered. Further, my testimony addresses the Parties' positions on the System Generation-Fixed (SG-F) and System Overhead (SO) allocation factor methodologies proposed by the Company as part of the Washington 2026 Protocol. Finally, my testimony clarifies and corrects some of the assertions Parties made pertaining to the Company's proposal to reallocate specific generation resources under the 2026 Protocol.

[2] Unless personal pronouns are specified by a witness in their testimony, in my rebuttal testimony I use "they/them" when using a pronoun to refer to a witness.

II. WASHINGTON 2026 PROTOCOL IMPLEMENTATION

Q. Does Staff witness Wilson support the Company's proposal to revise non-Net Power Costs (non-NPC) revenue requirement in this proceeding?

A. No. Staff witness Wilson challenges the reasonableness of the Company's proposal to update non-NPC recovery in a power cost only rate case (PCORC) such as this proceeding. While Company witnesses Joelle R. Steward and Rick T. Link address Staff witness Wilson's general concerns, my testimony specifically addresses Staff witness Wilson's assertion that "there is a clear risk of temporary double recovery" if non-NPC rates are updated in this PCORC.[3] I also evaluate the Staff witness Wilson's analysis supporting their assertion that Chehalis generation facility costs are over-recovered.

Q. Please elaborate on Staff witness Wilson's concern around the risk of double-recovery.

A. Staff witness Wilson states that because the Company proposes shifting the costs of Chehalis from multi-jurisdictional cost recovery to 100 percent recovery in Washington rates, the Company will double-recover if the non-NPC expenses associated with Chehalis are placed in Washington rates through this PCORC but not concurrently removed from the rates of other jurisdictions. Staff witness Wilson provides Table 2,[4] "Total Jurisdictional Allocation Percentages," as evidence that the Company may have double-recovered costs for plants subject to reallocation in the Washington 2026 Protocol.[5] While Staff witness Wilson acknowledges that Table 2 alone does not prove that the Company has been over- (or under-) recovering its total

[3] Wilson, Exh. JDW-1T at 16:13.
[4] Wilson, Exh. JDW-1T at 17:14.
[5] Wilson, Exh. JDW-1T at 17:4-7.

non-NPC expenses for all plants over the past six years,[6] Staff witness Wilson nevertheless suggests that the table is a meaningful indicator that such double-recovery could exist.

Q. What are the percentages shown in Table 2?

A. Table 2 presents actual total historical allocation percentages for the Chehalis, Colstrip, Hermiston, Jim Bridger, and Rolling Hills generation plants across the Company's six states, as provided in the Company's response to Public Counsel Informal Data Request 71, presented also as Exhibit No. JDW-26. In the table, the allocation percentages are calculated with historical reporting period inputs from the Company's annual results of operations filed with each state commission.[7] Annual results of operations filings are made in support of regulatory oversight and transparency over a regulated utility company's on-going operations. Accordingly, the table's allocation percentages for 2019 were calculated using normalized loads and energy inputs from calendar year (CY) 2019's result of operations report.

Q. Are the percentages presented in Table 2 indicative of the level of cost recovery across the Company's six states for each resource?

A. No. The Company calculates allocation factors for its annual results of operations reports filed in five of the six states in which the Company provides electric service to customers. But cost allocations in rates do not change as allocation factors are recalculated for purposes of the Company's annual results of operations. Costs allocated in each state's rates for recovery are updated only in a general rate case (GRC). Accordingly, the allocation factor percentages presented in Table 2—from the

[6] Wilson, Exh. JDW-1T at 17:15-16.
[7] Annual results of operations filings are referred to as Commission Basis Reports in Washington.

results of operations report—are not at all indicative of cost allocation or recovery levels approved in customer rates.

Q. Without a uniform cost allocation methodology in all PacifiCorp states, will the Company's rate recovery (*i.e.*, costs allocations reflected in approved rates) across the states add up to 100 percent at a given point in time?

A. No. While the allocation methodologies (both the Washington Inter-Jurisdictional Allocation Methodology (WIJAM) and the 2020 Protocol) are designed to allocate 100 percent of costs across the Company's jurisdictions, the current reality is that the Company's six jurisdictions do not allocate costs for ratemaking purposes using a synchronized methodology. PacifiCorp's non-Washington jurisdictions use the 2020 Protocol and Washington uses the WIJAM. Ever since Washington adopted a different allocation methodology, the West Control Area Inter-Jurisdictional Allocation Methodology (WCA) in 2006, the allocation of costs across PacifiCorp's six jurisdictions typically has not added up to 100 percent cost recovery for PacifiCorp. This dynamic continued to exist under the currently approved WIJAM, though the WIJAM made progress towards resolving the issue with the implementation of system-allocation of transmission costs and non-emitting generation costs. The Washington 2026 Protocol, in conjunction with the 2026 Protocol filed for approval in the other states, is designed to move toward a uniform approach across the states, where costs are neither over- nor under-allocated.

Q. Does the ratemaking process inherently lead to temporary periods of over- and under-allocation of costs?

A. Yes. In order for rate recovery across the six states to add up to 100 percent, the rates for all states would need to be calculated using the same base period inputs and test

period assumptions, and to be filed and processed concurrently, for rates to take effect at the same point in time. This is not realistic, considering the volume of work required for a GRC to be prepared and reviewed across six states. In short, Washington's unique requirements and overall differences in timing of when GRCs are filed in each state lead to incongruent allocation factors at any given point in time. This results in aggregate recovery of costs across the Company's six-state system that likely will differ from 100 percent when evaluated at any single point in time.

Q. Staff witness Wilson claims that the Company has over-recovered approximately $4.9 million for the Chehalis generating facility between 2019 to 2024.[8] Was the analysis performed supporting this assertion reasonable?

A. No, the analysis was not reasonable. Staff witness Wilson's analysis does not correctly reflect how revenue requirement is established and recovered through the ratemaking processes across the Company's six states. Staff's analysis is predicated on the assumption that the six states' approved costs should add up to 100 percent cost allocation, which as discussed above, is not a reasonable expectation due to the timing of GRCs and the fact that Washington currently uses a different allocation methodology than the rest of the system. A copy of Staff's response to PacifiCorp Data Request 1 is provided as Exhibit No. SLC-7. I address the flaws in the analysis presented by Staff witness Wilson in this data response more specifically below.

[8] Wilson, Exh. JDW-1Tr at 18:7-8. Staff originally calculated an alleged over-recovery of $5.8 million. However, Staff updated this calculation in its revised testimony, which was filed September 5, 2025.

Q. How did Staff witness Wilson establish the approved revenue requirement for recovery on which they based the analysis to determine whether the Company has over- or under-recovered its costs associated with Chehalis generating facility?

A. As the basis of the analysis, Staff witness Wilson establishes each year's approved recovery level on a system basis using the total company revenue requirement (before gross-up) from any GRC that took effect in that calendar year, regardless of where the GRC was filed.[9] Where multiple states had GRCs take effect in a given year, Staff witness Wilson averaged the total company revenue requirement from all those cases and established that as the approved recovery level on Chehalis.[10]

Q. Is this an appropriate way to establish the Company's authorized recovery levels related to Chehalis generation plant?

A. No. It is not appropriate to extrapolate the total company revenue requirement calculated in one specific jurisdiction's rate filing as the total "approved revenue requirement" the Company is authorized to recover across the system. The reason for this is because the revenue requirement calculated in each state's GRC uses variables and inputs specifically approved in that state. Variables and inputs that frequently differ across states include allowed return on equity, cost of debt, capital structure, base periods, and test period assumptions, as well as the rate base methodology accepted in each state for ratemaking purposes. Additionally, Washington uses a different allocation methodology than the rest of the PacifiCorp system, which means

[9] Except for calendar year 2019, where witness Wilson used the 2020 California GRC amount as proxy. Witness Wilson also described the referenced figures as "filed" amounts, but in fact the figures being utilized are approved amounts supporting rates that were put into effect in the referenced calendar year.
[10] Cheung, Exh. SLC-7 at 1 (Staff response to PacifiCorp Data Request No. 1).

Washington's revenue requirement calculation is prepared under a completely different set of assumptions than the other five states. This is an anomaly that was created and accepted for Washington customers under the Commission's prior rulings, which adopted the WCA/WIJAM, instead of using the 2020 Protocol.

Q. Can you provide a specific example that demonstrates the problems with Staff's approach?

A. Yes. To illustrate this with more specificity, in calendar year (CY) 2020, Staff witness Wilson extrapolates Chehalis' revenue requirement based on the California GRC that took effect in CY 2020. In that year, Staff witness Wilson assumes the total company approved revenue requirement for recovery on Chehalis generation plant is $35.8 million across the Company's six jurisdictions.[11] This is a demonstrably incorrect assumption. In CY 2020, rates in effect in each of the Company's six states were approved in the proceedings listed in Table 1 below, based on variables and inputs outlined below:

[11] Cheung, Exh. SLC-7 at 3 (Staff response to PacifiCorp Data Request No. 1).

Table 1 – Rate Cases with Rates Effective CY 2020

State	Docket	Rate Effective Date	Base Period/Test Period[12]	Rate Base Methodology	Rate of Return	Total Company Chehalis Revenue Requirement in Rates
California	A.18-04-002	2/6/2020	Base: 12 Months Ended (ME) June 2017 Test: 12 ME December 2019	13 Month Average through Test Period	7.62%	$35.8 million
Idaho	PAC-E-11-12	1/1/2012	Test: 12 ME December 2010 (with known and measurable changes)	End-of-Period through Test Period	7.93%	$42.0 million
Oregon	UE-263	1/1/2014	Base: 12 ME June 2012 Test: 12 ME Dec 2014	End-of-Period through Rate Effective Date	7.62%	$40.6 million
Utah	13-035-184	9/1/2014	Base: 12 ME June 2013 Test: 12 ME June 2015	13 Month Average through Test Period	7.57%	$38.6 million
Washington	UE-152253	9/15/2017	Test: 12 ME June 2015 (with known and measurable changes)	End-of-Period through Test Period	7.30%	$35.7 million
Wyoming	20000-469-ER-15	1/1/2016	Base: 12 ME June 2014 Test: 12 ME December 2015	13 Month Average through Test Period	7.41%	$39.1 million

As shown in Table 1, in CY 2020 alone, the range of approved revenue requirement assumed in rates, on a total-company basis, ranges from $35.7 million to $42.0 million depending on the underlying assumptions adopted in each state. Staff witness Wilson ignores that range and instead relies on a single, low-end result from the Company's smallest jurisdiction. And even within any one state, with each GRC filed, the assumed total company revenue requirement changes over time, as base

[12] Idaho and Washington both utilize historical test periods in GRCs, so base periods and test periods are one and the same in these two states.

periods and test periods shift (causing rate base reflected in revenue requirement calculations to shift), and the allowed rates of return change over time.

Additionally, it is important to note that revenue requirement is not just the recovery of costs but also includes an allowed return on investments. Because each state's commission independently approves a return on investments, it is inappropriate to extrapolate the calculated total-company revenue requirement determined under the premises specific to one state (in this example, California) as the approved revenue requirement to be recovered in the other five states. Each state's approved return on investment is different based on the allowed return (on both debt and equity) authorized by each state's commission. The Company is allowed to earn up to that level of return in all six states and is not limited to an "average" of the states. It would be inappropriate to then also view any amounts above that average return as an "over-recovered" amount.

Finally, Staff witness Wilson stated that because no filings were made in 2019, the total company revenue requirement established in the CY 2020 California GRC was used as an approximation for CY 2019's approved revenue requirement.[13] This is also inappropriate, because in addition to the jurisdictional uniqueness described above, the rates in effect in California in 2019 were established in the GRC prior to Docket A.18-04-002, *i.e.*, in Docket A. 09-11-015, which took effect on January 1, 2011. Based on that GRC, the total-company imputed revenue requirement for Chehalis, assuming California's approved ratemaking assumptions, was $44.1 million. This further highlights the inappropriateness of extrapolating the Chehalis revenue requirement from a specific state's GRC, approved based on a specific test

[13] Cheung, Exh. SLC-7 at 1 (Staff response to PacifiCorp Data Request No. 1).

year, as the approved recovery "limit" in all states within the PacifiCorp system. Staff witness Wilson's analysis does not reflect reasonable ratemaking assumptions and revenue requirement derivations, and the approach taken to calculate any over- or under-recovery amount is fundamentally flawed.

Q. Having established what Staff witness Wilson is considering the "approved revenue requirement," how does Staff witness Wilson then calculate the alleged over-recovery amount?

A. According to Staff witness Wilson's response to PacifiCorp Data Request 1, "the over-recovery value is calculated as the sum of the jurisdictional cost recovery factors, minus 100%."[14]

Q. Is this the correct approach?

A. No. The "jurisdictional cost recovery factors" that Staff witness Wilson is using in this calculation are the approved allocation factors from each state's GRC with rates presently effective in the year that the over-/under- recovery amount is being calculated. As alluded to in my testimony above, similar to the discussion of actual historical allocation percentages, the approved allocation percentages in any given year should also not be expected to sum to 100 percent. Approved allocation percentages should not be expected to sum to 100 percent for all of the reasons related to actual historical allocation factors discussed above, but also because of the reasons that approved revenue requirements may differ across the Company's six jurisdictions in any given year. Depending on the timing of when each GRC is prepared for rates that were effective in a given year, the underlying loads input reflected in the calculation of approved allocation factors are inevitably different.

[14] Cheung, Exh. SLC-7 at 1 (Staff response to PacifiCorp Data Request No. 1).

In general, California, Oregon, Utah, and Wyoming calculate load-based allocation factors (including the System Generation (SG) factor) on a forecasted basis, using test period forecast loads input to calculate their respective approved allocation factors. In contrast, Idaho and Washington rely on historical loads input to calculate their SG factors, or Control Area Generation-West (CAGW) factors in GRCs. This means that the underlying methodology used to calculate allocation factor percentages approved in rates in any given year is different across the six states.

When the Company prepares a GRC in any jurisdiction, the Company first calculates revenue requirement on a total-company basis, incorporating all the state-specific parameters accepted in that state, and then it applies the relevant allocation factors to arrive at a jurisdictionally allocated recovery request for the state in which the GRC is being filed. Because of this, to build the California GRC for example, the revenue requirement model in that case calculates the assumed allocation factors for all states using all the California-specific assumptions, even though the GRC is prepared only to set rates in California. This exercise is performed in each state for each GRC filed. Table 2 below provides a summary of the approved allocation factors for all six states assumed in each referenced GRC docket with rates effective in CY 2020 from Table 2. While the allocation factor percentages derived within any one docket do add up to 100 percent, the summation of allocation factor percentages across dockets would not, and should not be expected to, result in the same outcome.

Table 2 - Approved Allocation for Chehalis In-Rates for CY 2020 By Docket

Docket No.	California	Idaho	Oregon	Utah	Washington	Wyoming	FERC	Total
CA A.18-04-002	1.58%	6.02%	26.72%	42.50%	8.02%	15.12%	0.04%	100.00%
ID PAC-E-11-12	1.68%	6.05%	26.04%	41.87%	7.97%	16.01%	0.38%	100.00%
OR UE-263	1.53%	5.67%	26.05%	42.98%	7.76%	15.67%	0.34%	100.00%
UT 13-035-184	1.57%	5.57%	26.02%	42.63%	7.86%	15.97%	0.38%	100.00%
WA UE-152253	4.43%	0.00%	73.00%	0.00%	22.57%	0.00%	0.00%	100.00%
WY 20000-469-ER-15	1.56%	5.55%	25.61%	43.35%	7.79%	15.96%	0.18%	100.00%

Adding allocation percentages across different GRCs results in the summation of allocation factors that reflect inconsistent underlying inputs and assumptions. This leads to outputs that are not meaningful measures for any purpose. Specifically addressing the CY 2020 example, the non-California allocation percentages imputed as part of the CY 2020 California GRC have no bearing on ratemaking in any other states, and no other state's California-allocation percentages have any impact on ratemaking in California. With each GRC, the jurisdiction in which that GRC is filed is only reviewing an iteration of revenue requirement calculated based on that state's accepted premises. Within each case, the total allocation of costs across states is calculated to assume only up to 100 percent cost allocation under its state-specific regulatory view. Accordingly, there is no inherent "over-recovery" built into each state's jurisdictional revenue requirement. The approved jurisdictional revenue requirement reflects exactly the amount the Company is authorized to collect through customer rates in that jurisdiction.

Q. Has Staff witness Wilson presented calculations that appropriately measure over-/under- recovery?

A. No, they have not. Over- or under-recovery is only reasonably assessed as the

difference between the Company's *actual* earnings, and the Company's *approved* level of earnings. In the context of revenue requirement analysis prepared by Staff witness Wilson, the approved level of revenue requirement, setting aside all the issues identified and discussed above, should be compared to the actual level of costs incurred in the same year to determine whether any over- or under-recovery of costs exists. But there is no data considered in Staff witness Wilson's analysis that informs actual costs or investment levels in each calendar period analyzed. Simply adding together all the approved allocation percentages in a given year based on GRCs with rates in effect across the Company's six state jurisdictions is not in itself an indication of over- or under-recovery. However, as discussed further below, even if the comparison was made between approved revenue requirement and actual revenue requirement, there still would be other aspects to Staff witness Wilson's analysis that are problematic.

Q. Can you explain the other ways in which Staff witness Wilson's analysis is not indicative of over- or under-recovery?

A. Yes, I can. Using CY 2020 again as an example, Staff witness Wilson's assertion is that the total-company revenue requirement approved per the California GRC that went into effect that year is $35.8 million.[15] Staff witness Wilson then sums the *approved* allocation factor percentages in CY 2020 from each of the six states PacifiCorp operates in. They claim that because the total is 114.85 percent, the Company recovered in rates 114.85 percent of $38.5 million that year, and the

[15] Cheung, Exh. SLC-7 at 3 (Staff response to PacifiCorp Data Request No. 1). I have discussed at length previously in my testimony why this is not an appropriate way to establish total revenue requirement, but for the sake of this example, I temporarily ignore those shortcomings and accept this figure as given.

Company is therefore over-recovering on Chehalis generation costs. This assertion is inappropriate in several ways.

First, as discussed at length above, the approved revenue requirement in each state for any given year is expected to be different and not add to 100 percent, based on the GRC assumptions and timing of when the most recently concluded GRC was filed.

Second, and more importantly, the *authorized* level of revenue requirement is not the same as the *actual* level of revenues collected by the Company in any given year. GRCs establish an annual level of revenue requirement based on a particular test year's projected conditions on a normalized basis. The Company set rates billed to customers according to the authorized annual revenue requirement, but actual revenue requirement inevitably will differ, depending on actual levels of cost spending, investment in capital, and customer usage. Some costs and revenues will be higher than test year projections, while others may be lower. So long as overall these variances materially offset, a utility would continue to operate its business under the most recently approved levels of revenues from its most recently concluded GRC, rather than constantly seeking rate adjustments based on these variabilities. This is why Staff witness Wilson's analysis is flawed: it fails to account for the actual costs and revenues during each period being analyzed, instead relying only on authorized revenue levels. This approach ignores the real-world financial performance of the utility and the natural variances that occur between projected and actual operational outcomes.

Q. If Staff witness Wilson's analysis considered actual Chehalis generation costs, investment capital levels, and actual recorded returns, would the analysis then be informative and suitable for the purpose they are using it for?

A. No, it would not be. Revenue requirement in GRCs is established holistically inclusive of all costs to establish an annual level of required revenues in a test year. This revenue requirement calculation is also performed for each GRC in each jurisdiction reflecting the regulatory paradigm of that state only. Accordingly, over- or under-recovery assessment should be evaluated holistically (*i.e.*, inclusive of all base rate components), and on a state-by-state basis, which I will illustrate below.

Q. What is the appropriate way to examine whether over- or under-recovery of costs has occurred?

A. Over- or under-recovery assessment must be evaluated on a state-by-state basis. The over- or under-recovery amount is also only reasonably assessed as the difference between the Company's actual earnings and the Company's authorized level of earnings. This comparison is the appropriate one to make to determine whether the Company's approved levels of revenue collection is providing adequate recovery of overall costs incurred.

Q. How did the Company's actual earnings compare to authorized levels between 2019 and 2024?

A. Please refer to Table 3 below, summarizing the Type 1 (restated) return on equity (ROE) as reported in the Company's annual results of operations filed in each state,[16] compared to the authorized ROE in each state over 2019–2024. On average, every

[16] Annual results of operations filings not required in the state of California.

state has underperformed relative to the authorized ROE in that jurisdiction over this period of time.

Table 3 – Comparison of Earned vs. Authorized ROE

Type 1 Normalized ROE[17]

	2019	2020	2021	2022	2023	2024	Average
Oregon	9.61%	8.06%	5.60%	2.84%	0.74%	4.03%	5.15%
Washington	11.31%	10.33%	6.93%	0.81%	(7.30%)	(0.80%)	3.55%
Utah	9.56%	9.83%	10.07%	6.97%	(0.21%)	(2.13%)	5.68%
Idaho	9.67%	N/A	8.81%	7.66%	N/A	(6.17%)	4.99%
Wyoming	8.02%	7.86%	8.02%	4.93%	(12.76%)	(5.05%)	1.84%

Authorized ROE[18]

	2019	2020	2021	2022	2023	2024	Average	Over/(Under)
Oregon	9.80%	9.80%	9.50%	9.50%	9.50%	9.50%	9.60%	(4.45%)
Washington	9.50%	9.50%	9.50%	9.50%	9.50%	N/A	9.50%	(5.95%)
Utah	9.80%	9.80%	9.65%	9.65%	9.65%	9.65%	9.70%	(4.02%)
Idaho	9.90%	9.90%	9.90%	N/A	N/A	N/A	9.90%	(4.91%)
Wyoming	9.50%	9.50%	9.50%	9.50%	9.50%	9.35%	9.48%	(7.64%)

Q. Will the implementation of the Washington 2026 Protocol result in over-recovery of costs?

A. No. The Washington 2026 Protocol establishes that generation resources will continue to be dynamically allocated for Oregon, California, Idaho, Utah, and Wyoming (the Five States), excluding the fixed portion allocated to Washington as identified in the Washington 2026 Protocol, and with one exception—the Chehalis generation facility, where the Washington 2026 Protocol reflects an immediate reassignment of costs to Washington. Accordingly, the implementation of the Washington 2026 Protocol in Washington continues the progress that started with the WIJAM towards ensuring there is no under- or over-allocation issues amongst states

[17] Idaho results of operations not filed for years where a GRC is also filed.
[18] Washington (2024) and Idaho (2022-2024) rate of returns were stipulated in settlement, based on unspecified assumptions for capital structure and cost components.

by re-integrating all the states' cost allocation methodology under one unified protocol.

Q. How does PacifiCorp plan on accounting for any over- or under-recovery of costs that may happen because of the timing of the implementation of 2026 Protocol?

A. As explained by Company witness Steward, the Company filed its 2026 Protocol proposal in all jurisdictions (except California). The 2026 Protocol will be utilized in the next GRC for each state. Review and adoption timelines will depend on the jurisdiction and the individual processes and ratemaking mechanisms approved in each jurisdiction. Accordingly, as necessary, the Company will request deferred accounting or specific treatment in various NPC mechanisms as the transition occurs to ensure against temporary over- or under-recovery.

III. REVISION TO ALLOCATION FACTORS

A. System Generation-Fixed Factor

Q. Please summarize Parties' positions regarding the Company's proposed transition to a fixed system generation factor.

A. AWEC witness Mullins recommends that the Commission accept fixed generation factors while emphasizing that the Commission should ensure that in future proceedings that Washington customers receive the full value of their fixed share of resources they are paying for.[19] Staff witness Wilson expresses support for PacifiCorp's proposal to move from dynamic generation allocation factors to fixed generation allocation actors conditioned on three changes, two of which I discuss:

[19] Mullins, Exh. BGM-1CT at 65:3-6.

1. The SG-F factor should be updated in each GRC or PCORC unless the GRC or PCORC is filed within 30 months of the most recent update of the SG-F factor.
2. The weighting of the underlying SG factor, used to calculate the SG-F, should reflect a system load factor weighting that results in about 67 percent energy and 33 percent demand.[20]

Q. How does the Company's proposal for fixed generation allocation factors under the Washington 2026 Protocol differ from the generation allocation factors used under the currently approved WIJAM?

A. Currently, under WIJAM, generation allocation relies on the SG factor, which is dynamic. Annually, the SG factor is recalculated based on relative loads and demands of the individual states[21] reported for that calendar period for specific regulatory reporting purpose—*i.e.*, for results of operations filings. These recalculated factors, however, are only used for regulatory reporting purposes. For rate recovery, the SG factor is only updated at the time a GRC filing is made. Specifically, in Washington GRCs, load-based allocation factors like the SG factor are calculated based on historical loads and energy inputs from the historical test period of each GRC. To establish costs being recovered in base rates, the SG factor approved in the most recently concluded GRC is used for rate recovery filings made after rates become effective, until a subsequent update of the SG factor is produced in the next GRC.

In contrast, under the Washington 2026 Protocol, the Company is proposing to move away from dynamically calculated generation allocation factors and to fix

[20] Wilson, Exh. JDW-1T at 7:19-8:19.
[21] *See* Mullins, Exh. BGM-1CT at 63:5-9.

the factor for the life of the underlying resources assuming a four-year historical average of SG factors.[22]

Q. How does Staff witness Wilson's first condition to periodically update the SG-F factor align with PacifiCorp's proposed change to generation allocation factors?

A. The proposal to update generation allocation factors in each GRC essentially reverts the system generation factor calculation back to a dynamic basis. It fundamentally defeats the purpose of PacifiCorp's proposal to fix generation allocation factors and is contrary to Staff's purported support of fixed factors. Please refer to the rebuttal testimony of Company witness Link for a more detailed discussion in support of the transition to fixed generation allocation factors.

Q. Can you provide further context around the demand and energy weighting issue in the SG factor that Staff witness Wilson raised?

A. Yes. The SG factor as implemented for use in the allocation of resource costs through the historically approved WCA and subsequently WIJAM is derived from the following approved algebraic formula assuming a 75 percent demand weighting and a 25 percent energy weighting:

Figure 1 – Algebraic Derivation of SG Factor under 2020 Protocol

System Generation Factor ("SG") – Effective during the Interim Period

$$SG_i = 0.75 * SC_i + 0.25 * SE_i$$

where:

SG_i	=	**System Generation Factor** for jurisdiction i.
SC_i	=	System Capacity Factor for jurisdiction i.
SE_i	=	System Energy Factor for jurisdiction i.

The SG factor is used to allocate generation and transmission costs. It is calculated using a weighting of 75% of the SC factor and 25% of the SE factor for a jurisdiction.

[22] A four-year average fixed system generation factor is presented in the Framework Issues section of the 2020 Protocol, in Appendix C.

The derivation of the SG factor is based on this prescribed formula, which was agreed upon by the Multi-State Process (MSP) negotiating parties and subsequently adopted and implemented with Commission orders approving the allocation methodologies. The WCA was first approved by the Commission in Order 08, docket UE-061546,[23] and again reaffirmed in the approval of subsequent rate proceedings until docket UE-191024, where the Company's proposal to adopt the 2020 Protocol and the WIJAM was then approved in Final Order 09/07/12.[24] The WIJAM has been used in all rate proceedings to allocate costs and benefits into Washington's rates ever since.

In this PCORC filing, the Company is not proposing any changes to the underlying derivation of the SG factor. Rather, the Company is proposing that, instead of a dynamic factor that is updated with each GRC, the SG factor be fixed. This fixed SG allocation factor is established using a four-year historical averaging calculation and will hold constant going forward.

Q. How long has PacifiCorp used the 75 percent demand and 25 percent energy weighting in the allocation of generation resources?

A. PacifiCorp has used that weighting for more than 35 years. The 75 percent demand/25 percent energy weighting used in allocation of generation resources has been in place since the PacifiCorp Inter-jurisdictional Task Force on Allocations (PITA) implemented the first jurisdictional allocation methodology implemented. The PITA convened shortly after the 1989 merger approval to address and seek a resolution to

[23] *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket Nos. UE-061546 and UE-060817 (consolidated), Order 08 at ¶ 57 (Jun. 21, 2007).
[24] *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Co.*, Docket Nos. UE-191024 *et al.*, Final Order 09/07/12 at ¶ 102 (Dec. 14, 2020).

the issue of inter-jurisdictional cost allocations following the merger.

Q. Can you summarize the relevant procedural history in Washington around inter-jurisdictional cost allocations?

A. Yes. As of the time of the 1989 merger, PacifiCorp's last fully litigated rate case in Washington was in 1986. The Company made no rate case filings in Washington between 1986 and 1999. The PITA was established in 1989 as a means for dealing with inter-jurisdictional allocation issues, with members of the Staff as active participants in PITA during the 1990s. In the meantime, without an explicit order from the Commission, the Company made its routine filings since 1990 based on the methodologies developed by the PITA group. In November 1999, PacifiCorp filed a GRC, which eventually reached an all-party settlement.[25] However, the settlement stipulation from this case did not address inter-jurisdictional allocations of resources. In the years following, the Company filed GRCs addressing inter-jurisdictional allocations in the 2003 GRC and the 2005 GRC consistent with the protocol methodologies developed by PITA and later, MSP.[26] Through collaboration with parties and incorporation of Commission feedback through the iteration of proposals made, PacifiCorp created the WCA, which was approved in the 2006 GRC, docket UE-061546.[27]

[25] *Wash. Utils. & Transp. Comm'n v. PacifiCorp, d/b/a Pacific Power & Light Co.*, Docket No. UE-991832, Third Supplemental Order Approving and Adopting Settlement Agreements (Aug. 9, 2000).
[26] *Wash. Utils. & Transp. Comm'n v. PacifiCorp, d/b/a Pacific Power & Light Co.*, Docket No. UE-032065, Order 06 (Oct. 27, 2004); *Wash. Utils. & Transp. Comm'n v. PacifiCorp, d/b/a Pacific Power & Light Co.*, Docket Nos. UE-050684 and No. UE-050412, Order 04/03 (Apr. 17, 2006).
[27] Docket Nos. UE-061546 and No. UE-060817 (consolidated), Order 08 at ¶ 57.

Q. Have there been studies or analyses performed to determine the appropriate allocation of generation costs throughout PITA and MSP efforts that ultimately resulted in the implementation of the WCA?

A. Yes. As part of the MSP, more than 50 individuals representing 18 parties attended a series of collaborative meetings to discuss allocation issues among the states. In all, more than 40 separate studies were completed to example potential allocation mechanisms, and technical sessions were held to review the details of different methods.[28] Finally in 2004, PacifiCorp filed the method known as the "Revised Protocol" with Idaho, Oregon, Utah, and Wyoming. The Revised Protocol was then filed in Washington as part of the 2005 GRC, Docket No. UE-050684. While the Revised Protocol was not adopted, generally due to concerns around allocation of costs for resources outside of the west control area,[29] the resulting WCA adopted in the 2006 GRC did reflect fundamentally the same methodology behind the allocation of generation resources. This methodology assumed a 75 percent demand/25 energy classification.[30] The Company is not proposing to deviate from this demand/energy classification—which has been studied significantly—in this proceeding.

Q. Are you able to provide any documentation supporting the allocation of generation resources, in particular, the choice of the 75 percent demand/25 percent energy classification for generation plants in PacifiCorp's historical and currently approved inter-jurisdictional cost allocation methodologies?

A. Yes. Please refer to Exhibit No. SLC-8, which provides a copy of a discussion paper filed in support of the direct testimony of Company witness David L. Taylor

[28] Docket No. UE-032065, Status Report on Inter-Jurisdictional Cost Allocations at 3 (Mar. 31, 2005).
[29] Docket Nos. UE-050684 and No. UE-050412, Order 04/03 at ¶ 49.
[30] Docket Nos. UE-061546 and No. UE-060817 (consolidated), Order 08 at ¶ 44 n.19.

in docket UE-050684. This discussion paper, filed as Exhibit No. DLT-3, is titled "Classification and Allocation of Generation Fixed Costs" and dated March 4, 2003. This paper reviews the methodologies used by PacifiCorp and its predecessors in the past, some of the methods used by other utilities, and those proposed by participants in MSP, specifically around the classification and allocation of generation resources. On page 3 of the report, it concluded that:

> The choice of the 75% demand 25% energy classification for generation . . . plant was the last allocation decision made by PITA after the merger. The PITA analysis indicated that a wide range of demand and energy classification could be supported on a technical basis. The demand energy classification was the swing issue employed to balance the sharing of merger benefits between all the states and 75% demand 25% energy was selected because it produced an overall cost allocation result that was acceptable to all the states.[31]

Following the conclusion documented in this discussion paper, a 75 percent demand/25 percent energy classification in the calculation of the SG factors was selected as an acceptable outcome in all states.

Q. How would Staff witness Wilson's proposed 67 percent energy and 33 percent demand weighting change the proposed SG-F factor?[32]

A. Assuming a 67 percent energy and a 33 percent demand weighting in the calculation of the underlying historical SG factor used to calculate a four-year average would reduce the SG-F factor from 7.897 percent to 7.654 percent.

Q. How would this resulting SG-F factor change impact the revenue requirement requested in this PCORC?

A. This reduction in the SG-F factor would result in a reduction to the Company's

[31] Docket Nos. UE-061546 and UE-060817 (consolidated), Taylor, Exh. DLT-3 at 3 (a copy of this exhibit is provided in this docket as Exh. SLC-8).
[32] Wilson, Exh. JDW-1T at 8:4-10.

proposed non-NPC revenue requirement change by approximately $1.8 million.[33] Staff witness Wilson's proposal also would have implications on the NPC revenue requirement, as resource allocation would be different under this 67 percent energy and 33 percent demand classification assumption. After conferring with the net power cost team, the estimated impact to NPC is expected to be an increase of approximately $2 million.

Q. Is the Company supportive of a change from the existing demand/energy weighting in the SG factor, to the 33/67 demand/energy weighting proposed by Staff witness Wilson?

A. No. As noted above, the 75 percent demand/25 percent energy classification for generation resources has been relied upon to allocate costs associated with these resources dating back through inter-jurisdictional allocation methodologies developed shortly after the 1989 merger. This weighting was thoroughly studied and was ultimately selected because it produced an overall cost allocation result that was acceptable to all the states. The Company is seeking to implement a cost allocation methodology that will work for all states, and that will result in 100 percent allocation of costs across PacifiCorp's six jurisdictions. Accordingly, the longstanding 75 percent demand and 25 percent energy classification on the allocation of generation resources should be upheld. Consistency and harmonization with other states in regard to allocation factors is an important goal.

[33] Before state deferred tax synchronization adjustment.

B. System Overhead Factor

Q. Please summarize the Company's proposed change to the System Overhead (SO) factor under the Washington 2026 Protocol.

A. With the implementation of the Washington 2026 Protocol, the Company is proposing to simplify the formulaic derivation of the SO factor from what is approved in the WIJAM (and also 2020 Protocol) to one that simply reflect a three-way average of the System Capacity (SC) factor, the System Energy (SE) factor and the System Gross Distribution Plant (SGPD) factor.

Q. Please summarize Parties' positions regarding the Company's proposed transition to the SO factor.

A. Because Staff witness Wilson's primary recommendation is against changing the jurisdictional allocation of system generation resources, they do not believe it is necessary for the Commission to rule on the Company's proposed SO factor method revision at this juncture. Nonetheless, they do express that they are "generally supportive" of this proposal, as the current method is overly complex.[34] Staff witness Wilson also recommends that the SO factor be updated in each GRC should the Commission rule on the Company's proposed SO factor method modification.[35]

AWEC, through AWEC witness Mullins, is not supportive of changes to the SO factor in this case because they view the allocation of administrative and general (A&G) costs to fall outside of the scope of this proceeding. They also express concerns that the new SO factor method converts the SO factor into a predominantly

[34] Wilson, Exh. JDW-1T at 28:17-21.
[35] Wilson, Exh. JDW-1T at 29:3-4.

energy and capacity-related factor.[36] They assert that this is contrary to cost-causation principles because the underlying costs being allocated on an SO factor are not necessarily related to the energy and capacity requirements of individual states.[37] Accordingly, AWEC's position is that the SO factor method, as currently approved in the WIJAM, be retained should the Commission decide to consider the issue.[38] The impact of undoing the proposed SO factor method update in the Company's proposal, according to AWEC, is a reduction of $2.2 million to the Company's non-NPC revenue requirement rate change request.[39]

Public Counsel witness Moriyasu characterizes the Company's proposed change to the SO factor methodology as "included for the Company's convenience, not for a better alignment with any stated principle."[40]

Q. Would Staff witness Wilson's recommendation to update the SO factor at each GRC result in any changes to the Company's proposal?[41]

A. No. PacifiCorp is not proposing to fix the SO factor in this case. The SO factor will continue to be a dynamic factor calculated across the six-state service area. As is currently done with dynamic allocation factors under WIJAM, allocation factors are already updated in each GRC. The Company is not proposing to change that in this PCORC. The Company's proposal is simply to replace the 2020 Protocol/WIJAM SO factor methodology with the Washington 2026 Protocol SO factor methodology, which Staff witness Wilson has expressed support for if the Commission were to

[36] Mullins, Exh. BGM-1CT at 73:1-6.
[37] Mullins, Exh. BGM-1CT at 73:1-6.
[38] Mullins, Exh. BGM-1CT at 73:6-8.
[39] Mullins, Exh. BGM-1CT at 3, Table 1.
[40] Moriyasu, Exh. CM-1T at 11:6-8.
[41] Wilson, Exh. JDW-1T at 29:3-4.

consider a SO factor methodology update in this proceeding.[42]

Q. How is the proposed change to the SO factor methodology in better alignment with the Company's proposal to fix the allocation of generation resources in Washington?

A. In addition to the Company's proposal for fixed generation resources allocation causing a major component of the SO allocation factor to be fixed, the Company is also proposing that specific generation resources move from a system-allocation to a situs-assignment. If the SO factor were to continue to be calculated as it is currently approved, it would result in a substantial shift in A&G costs being borne by the state that is paying for 100 percent of a specific generation resource. In reality, A&G cost dynamics are not likely to see such significant swings, simply from the reallocation of a generation resource. The SO factor is used to allocate system overhead costs, which by definition are costs that support *more than a single function* (*i.e.*, more than just generation).[43] As such, strongly correlating and anchoring the allocation of system overhead costs heavily on any single function—in this instance, generation—would result in outcomes that are less consistent with cost causation principles.

Q. Please explain.

A. The SO factor calculated under the 2020 Protocol and WIJAM is based on the ratio of gross plant allocated or situs-assigned to each state, excluding any gross plant allocated by the SO factor. In deriving the jurisdictional gross plant balances to calculate the SO factor, generation and transmission gross plant is allocated using the SG factor, which is a 75/25 weighting of the SC factor and the SE factor, and

[42] Wilson, Exh. JDW-1T at 28:17-21.
[43] Link, Exh. RTL-2 at 3.

distribution plant is directly assigned to the states where the plant is located. The Company's new proposal for the SO allocation factor continues to preserve a similar dynamic nature, where generation, transmission, and distribution functions serve together as the basis to calculate an allocation factor that is used in the allocation of A&G costs. However, it is doing so in a more simplistic manner by relying on a one-third weighting on the SC factor, one-third weighting on the SE factor, and one-third weighting on the SGDP factor. AWEC's representation that the Washington 2026 Protocol SO factor formula introduces a disproportionate reliance on capacity- and energy-related weightings is misleading[44]: the underlying influence of capacity- and energy-related weightings were pre-existing in the currently approved SO factor formula under WIJAM.

Q. Can you provide a visual representation of this relationship underlying the generation, transmission and distribution function serving as the basis of the SO factor as you have discussed above?

A. Yes, I can. Under the currently-approved WIJAM, Washington's SO factor formula is as follows:

(Generation Plant (SG or Control Area Generation-West (CAGW))[45]
+ Transmission Plant (SG/CAGW)
+ Distribution Plant (Situs)
+ General Plant (Excluding SO-allocated)
+ Intangible Plant (Excluding SO-allocated)
Divided by Total Gross Plant (Excluding SO-allocated)

While the 2020 Protocol/WIJAM SO factor is calculated using plant balances, each state's allocation of plant balances actually relies on SG/CAGW factors to a material extent. Both generation and transmission plant balances were allocated

[44] Mullins, Exh. BGM-1CT at 73:1-4.
[45] Also, Jim Bridger-Generation (JBG), but JBG factor is mathematically the same as CAGW.

using the SG/CAGW factors, which are derived assuming a 75 percent capacity and 25 percent energy weightings. Similarly, approximately 30 percent of General Plant (excluding SO-allocated amounts) and over 60 percent of Intangible Plant (excluding SO-allocated amounts) are allocated to Washington using an SG/CAGW/JBG allocation factor.[46] Distribution plant balances are situs-assigned. Therefore, as the SO factor formula is approved today, SO factor derivation is already reliant on capacity and energy inputs. The proposed Washington 2026 Protocol SO factor methodology strives to preserve this multi-faceted functional consideration in the calculation of an appropriate allocation factor used to allocate costs that serves more than a single function. The proposed SO factor methodology simplifies the overall calculation and delineates it from generation asset balances, which are being reallocated from system-allocation to situs-assignment and locked-in at an SG-F share in Washington's rate base.

Q. With regards to Public Counsel witness Moriyasu's perspective that the SO factor update is included only for the Company's convenience,[47] how do you respond?

A. As discussed in my direct testimony and echoed in Staff witness Wilson's testimony,[48] the current SO factor methodology is overly complex. In addition to circumventing the formulaic circularity of the existing SO factor formula as discussed in my direct testimony, the conversion from the currently approved methodology to the Washington 2026 Protocol SO factor methodology better supports a transition

[46] Based on base period unadjusted data as filed in the Company's 2023 Multi-Year Rate Plan (Docket No. UE-230172).
[47] Moriyasu, Exh. CM-1T at 11:6-8.
[48] Wilson, Exh. JDW-1T at 28:20-21.

to fixed generation allocation.[49] As the Company begins to adapt its cost allocation methodology to accommodate diverging resource portfolios, changes in the allocation of generation resources will have an impact on the calculation of the SO factor under the 2020 Protocol. As more resource allocations become fixed, a major component in the 2020 Protocol SO factor also becomes fixed. However, because A&G costs are dynamic, it follows that the allocation of these costs also should remain dynamic and not be anchored to fixed shares of allocated generation resource costs. Accordingly, the implementation of the Washington 2026 Protocol SO factor methodology is not proposed only for "the Company's convenience," as Public Counsel alleges.[50] The transition is designed to serve important purposes.

Q. Has the Washington 2026 Protocol SO factor methodology been contemplated previously under the currently approved allocation methodologies?

A. Yes. The Company's Washington 2026 Protocol SO factor methodology proposed in this PCORC is outlined in "Section 5.4 – Resolved Issues" of the executed version of the 2020 Protocol.

IV. GENERATION RESOURCE REALLOCATION ISSUES

A. Jim Bridger Units 1 and 2

Q. What issue are you specifically responding to in regard to AWEC's proposal to remove Jim Bridger Units 1 and 2 from Washington rates?[51]

A. I respond to AWEC witness Mullins' characterization of the net credit of plant rate base for Jim Bridger Units 1 and 2 as an "overpayment" or a credit balance that

[49] Cheung, Exh. SLC-1T at 8:9-9:2.
[50] Moriyasu, Exh. CM-1T at 11:6-8.
[51] Mullins, Exh. BGM-1CT at 68:2-3.

should be refunded to customers.[52] Company witnesses Michael G. Wilding, Ramon J. Mitchell, and Link also respond to the overall proposal to remove Jim Bridger Units 1 and 2 from Washington rates in their respective rebuttal testimonies.

Q. Did AWEC appropriately establish the negative net plant balance for Jim Bridger Units 1 and 2?

A. No. AWEC claims that as of December 31, 2025, the estimated plant balance for Jim Bridger Units 1 and 2 is ($9,231,047), with a Washington-allocated balance being ($2,045,875).[53] They note that the calculation was derived by summing the December 31, 2025 amounts from two tabs referenced in the Company's filed workpapers outlining the projected Jim Bridger Units 1 and 2 balances forecasted in the Company's 2023 Multi-Year Rate Plan.[54] However, there is a formula error in the derivation of the net plant balance AWEC presented: the accumulated depreciation balance developed by AWEC partially reflects an average-of-monthly-average (AMA) balance, rather than the end-of-period (EOP) balance that AWEC was intending to quantify. Correcting for this formula error, the EOP December 31, 2025, net plant balance of Jim Bridger Units 1 and 2 is ($12,393,785) on a total-Company basis and ($2,746,832) on a Washington-allocated basis. However, the net plant balances reflected in approved rates is not the EOP balance as of December 31, 2025. It is instead the AMA balance of ($9,115,421), with a Washington-allocated balance of ($2,020,249) for rate year 2 rates, which became effective April 2025.

[52] Mullins, Exh. BGM-1CT at 69:16-20.
[53] Mullins, Exh. BGM-1CT at 69:11-12.
[54] Mullins, Exh. BGM-1CT at 69 n.88.

Q. Do you agree with AWEC's characterization that the negative net plant balance associated with Jim Bridger Units 1 and 2 represent an "overpayment" from Washington customers on the recovery of these generation units?[55]

A. No, I do not because the negative net plant balance is not in fact an "overpayment" as characterized by AWEC, which I will explain in detail below.

Q. Please explain why a negative net plant balance exists.

A. To understand why a negative net plant balance exists for Jim Bridger Units 1 & 2, one must understand how depreciation works in utility plant accounting and what the depreciation rates used to record depreciation expenses encompass.

Depreciation is an accounting method used to allocate the full cost of a tangible asset over its useful life. In utility terms, recording depreciation expense over the life of an asset also ensures generational equity is maintained, so that costs and benefits of utility services and infrastructure are fairly distributed across the appropriate generation of customers. In other words, customers who are benefiting today from the asset being used to generate electricity on their behalf are not then paid for by future generations; and customers today are not paying for the full cost of an asset that will be used to serve customers for decades to come.

The ***full*** cost of an asset, however, is not limited to the value paid to acquire the asset itself. Under utility plant accounting, the full cost of an asset typically contemplates some level of cost of removal for decommissioning and remediation activities that would be incurred at the end of the life of an asset. Accordingly, depreciation rates, used to record depreciation expense over the life of an asset, are calculated to include an estimate for cost of removal. This is reflected as negative

[55] Mullins, Exh. BGM-1CT at 69:16-17.

net salvage in a depreciation study. As a result, the net plant balance of an asset that has been fully depreciated should not be expected to be zero at the end of its depreciable life. Rather, it should be a negative net plant balance position that is equal to the cost of removal estimate assumed for the asset. Due to the magnitude of estimated removal costs included in depreciation rates, combined with a long service life, it is natural for an asset's net plant balance to become negative several years prior to the end of the depreciable life of the asset.

To put it simply, depreciation rates, and the resulting depreciation expense, reflect more than just the acquisition cost of the asset, spread over the asset's depreciable life. The depreciation expense collected from customers also reflects payments for estimated cost of removal. This additional collected cost, which is reflected as accumulated depreciation that is netted against the gross plant balance of an asset, is why a negative net plant balance exists towards the end of an asset's depreciable life. This credit represents on-going payments made by customers to pay for future cost of removal that will be incurred when it comes time to decommission the asset and remediation work is performed. They are not "overpayments" as characterized by AWEC witness Mullins.

Q. Should this net negative plant balance be refunded to customers?

A. No. As explained above, the negative net plant balance represents funds collected through depreciation expense to be used against decommissioning and remediation costs that will be incurred at the end of the asset's operational life. Under the currently-approved WIJAM, decommissioning and reclamation costs will be trued-up once final costs are known, and Washington customers will be expected to pay their

share of final, known decommissioning and reclamation costs.[56] It would be premature to refund this amount to customers now while the asset is still operational and decommissioning and remediation work has yet to be completed.

Q. How will decommissioning costs be allocated to Washington customers?

A. The Company's proposals for decommissioning costs allocation are discussed in the direct testimony of Company witness Link, and Sections 10 and 11 of the proposed Washington 2026 Protocol.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

[56] *See* Section 8 of the WIJAM Memorandum of Understanding ("Washington will continue to be allocated ongoing and expected decommissioning expenses for a WCA share of Jim Bridger Units 1-4 and Colstrip Unit 4.").