EXH. SEF-1T
DOCKETS UE-240004/UG-240005
2024 PSE GENERAL RATE CASE
WITNESS: SUSAN E. FREE

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-240004** **Docket UG-240005**

PREFILED DIRECT TESTIMONY (NONCONFIDENTIAL) OF

SUSAN E. FREE

ON BEHALF OF PUGET SOUND ENERGY

FEBRUARY 15, 2024

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I. INTRODUCTION

Q. Please state your name, business address, and position with Puget Sound Energy.

A. My name is Susan E. Free, and my business address is Puget Sound Energy, 355 110th Ave. NE, Bellevue, WA 98004. I am the Director of Revenue Requirements and Regulatory Compliance for Puget Sound Energy ("PSE").

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes, I have. It is Exh. SEF-2.

Q. What are your duties as Director of Revenue Requirements and Regulatory Compliance for PSE?

A. As Director of Revenue Requirement and Regulatory Compliance, I am responsible for strategy, policy, direction, and coordination of PSE's interests on state regulatory issues. I oversee state regulatory processes and compliance requirements, including audits, rate cases, and regulatory proceedings. I represent PSE before state regulators and other constituents. I negotiate rate and tariff issues with customers, agencies, interested parties, and regulators.

Q. What topics are you covering in your testimony?

A. In my testimony I address the following topics:

- PSE's two-year multiyear rate plan ("MYRP") that concludes in 2024 ("2023-2024 MYRP") and the lessons learned and modifications that PSE is proposing in this two-year MYRP, which is scheduled to begin in January 2025;

- PSE's need for a rate increase as set forth in PSE's proposal for a two-year MYRP beginning in 2025;

- Discussion of the three new rate schedules that PSE is proposing in this case; the Clean Generation Resources Rate Adjustment ("CGR Tracker"), the Wildfire Prevention Tracker ("Wildfire Tracker") and the Decarbonization Rate Adjustment ("Decarb Tracker"), together referred to as the "three new trackers" and how they will fit with the MYRP PSE is requesting in this case;

- PSE's proposal to recover construction work in progress ("CWIP") in rate base within the CGR Tracker;

- PSE's proposal to retain the power cost only rate case ("PCORC") and why it is still needed along with the Clean Generation Resources Tracker;

- The regulatory and ratemaking treatment of Climate Commitment Act ("CCA") costs and allowance proceeds for gas and electric customers;

- The power cost adjustment ("PCA") mechanism, including a presentation of Exhibit A-1;
- PSE's revenue requirement, including the three new rate trackers (Exhs. SEF-21 through SEF-23), base rates changes requested (Exh. SEF-3 and Exh. SEF-7), with all other rate schedule changes being presented by PSE witnesses Chris Mickelson and John Taylor; electric and natural gas summary pages (Exh. SEF-4 and Exh. SEF-8); electric and natural gas test year data (Exh. SEF-5 and Exh. SEF-10);
- Details regarding individual adjustments, including common adjustments, electric-only adjustments, and natural gas-only adjustments;
- A discussion of the ways in which future benefits such as from the Inflation Reduction Act ("IRA") and Infrastructure Investment and Jobs Act ("IIJA") can be passed back to customers;
- A report on excess deferred income taxes ("EDIT") passed back to customers as required in paragraph 700 of Final Order 08 (as amended) in Dockets UE-190529, et al.
- PSE's proposal to include the true-up for costs being recovered in Schedule 141CEI at a later time than approved in PSE's last general rate case. See the discussion under Adjustment No. 6.48.

- PSE's request to earn a return on power purchase agreements ("PPA") as allowed in RCW 80.28.410; and
- A presentation of the revenue requirement that is subject to refund.

II. MULTIYEAR RATE PLAN

<u>A. Update on the 2023-2024 Multiyear Rate Plan</u>

Q. Please describe what PSE has learned so far under its 2023-2024 MYRP.

A. My testimony, below, discusses the reporting and review process for PSE's revenue requirement that is subject to refund during the 2023-2024 MYRP, and what has been learned so far under this process. Please see the Prefiled Direct Testimony of Daniel A. Doyle, Exh. DAD-1CT for a discussion of the financial and other observations of the 2023-2024 MYRP.

Q. Please describe PSE's first annual review process.

A. When the current case is filed in February 2024, PSE will be entering the second year of the 2023-2024 MYRP. PSE filed its first Annual Provisional Capital Report ("Report") for the 2023-2024 MYRP on March 31, 2023, which the Commission approved on September 14, 2023. The Commission determined the rates set forth in the Report were no longer subject to later review or refund.[1]

[1] *See WUTC v. Puget Sound Energy*, Dockets UE-220066 *et al.*, Letter Order (Sept. 14, 2023).

Q. Did the first annual review of the 2023-2024 MYRP result in a refund of rates to customers?

A. For electric customers, there was no refund as PSE's spending, on a portfolio basis, was greater than the amount projected in rates for 2023. For natural gas customers, there was a small refund, as PSE's gas spending, on a portfolio basis, was slightly below the amount set in the projected rates.

B. Lessons Learned and Proposed Adjustments to PSE's MYRP

Q. Please discuss any lessons learned from PSE's 2023-2024 MYRP.

A. So far, we have learned from the 2023-2024 MYRP that an annual retrospective review of all expected capital additions on a portfolio basis results in rates that are fair, just, reasonable, and sufficient. The portfolio review is combined with a threshold that allows for actual costs for projects that are above or below their estimated amounts to be accepted if they were prudently incurred—provided that, on a portfolio basis, their combined costs are within reason compared to what was used to set rates. This combination has proven to be an effective method for the review process while allowing PSE to prudently manage its capital additions portfolio.

The Used and Useful Policy Statement envisions a process for retrospective review.[2] In its 2023-2024 MYRP filing, PSE recommended—and the

[2] Used and Useful Policy Statement, Docket U-190531, starting at page 13.

Commission approved—an annual review of all expected capital additions, with initial review occurring shortly after new rates became effective for the first rate year (2023) to review the portion of the 2022 plant investment that had been based on forecasts.[3] Following the threshold used in RCW 80.28.425 ("the MYRP Statute") as a guide, the review called for no refund to be issued if the difference between PSE's estimated and actual revenue requirement subject to refund was less than the equivalent of fifty basis points[4] on a portfolio basis, because such a small variance—either positive or negative— should be considered within reason.

The 2023-2024 MYRP revealed that this approach strikes an appropriate balance by (1) putting the safeguard of a potential refund in place if the variance is significant enough on an annual, portfolio basis to result in a materially lower revenue requirement, but also (2) alleviating the uncertainty that comes with having rates subject to refund by issuing refunds only when variances make a material difference to the annual revenue requirement and by limiting the time that rates are subject to refund to a year. For example, the safeguard worked following the initial annual retrospective review in the 2023-2024 MYRP. In concert with the filing of its Report, in Docket UG-230323, PSE made a tariff filing to transfer all rates related to 2022 capital additions so they would no longer be subject to refund. Although PSE's Report showed a very slight refund was due for gas customers, PSE proposed that no refund be provided until an additional review could be conducted to see if a refund would still be required on a

[3] *WUTC v. PSE*, Dockets UE-220066 *et al*., Final Order 24, at 72-73.
[4] RCW 80.28.425(6).

cumulative basis in the 2024 Report. During informal discovery, Commission Staff worked with PSE on the filing and provided an alternative way to calculate the threshold requirement, which slightly increased the amount showing owed to gas customers. During this work, PSE agreed to use Commission Staff's results and refund the small amount of annual revenue requirement ($1.4 million) without waiting for the 2024 review. The outcome of the tariff filing provides an example of the benefits of the annual portfolio review.

Q. Does PSE propose utilizing this same annual retrospective review process on a portfolio basis with a threshold for all expected capital additions during the 2025-2026 MYRP?

A. Yes. There was one minor change that has occurred to the review process. The Administrative Law Division filed a letter in Dockets UE-220066 and UG-220067 allowing PSE to file any necessary tariff filings resulting from the report at the end of the review conducted by parties rather than on March 31st when the initial Report is filed.

III. CLEAN GENERATION RESOURCES RATE ADJUSTMENT MECHANISM

A. PSE's Clean Generation Resources Rate Adjustment Filing

Q. Is PSE filing a Clean Generation Resources Rate Adjustment Tariff?

A. Yes. In this proceeding, PSE is requesting Commission approval of a new tariff schedule, Schedule 141CGR ("CGR Tracker"), that will allow for the recovery of the fixed costs associated with the building or purchase of large utility scale CETA compliant generation resources. In this case, PSE is proposing to recover the Beaver Creek Wind Project ("Beaver Creek") in the CGR Tracker, and PSE is also proposing to recover CWIP in rate base in the tracker, both of which I discuss in more detail below.

Q. Why is PSE proposing the CGR Tracker in this case?

A. As discussed in the Prefiled Direct Testimonies of Daniel A. Doyle and Cara G. Peterman, the CGR Tracker is necessary to improve PSE's cash flows and allow it to maintain credit metrics for reasonable access to capital markets. Approval of the CGR Tracker will provide more timely cash flow to match the construction schedules as PSE undergoes an exponential increase in its acquisition of clean generation resources. In concert with PCORCs, which I discuss in more detail below, the CGR Tracker will also provide flexibility in the timing of recovery as opportunities arise or shift over multiyear rate plans, which will allow PSE to be best positioned to optimize investment opportunities for customers. Treatment of CWIP in Rate Base for the Clean Generation Resources Rate Adjustment

Q. How are utilities typically compensated for the time period when projects are under construction?

A. Traditionally, rate recovery of a project is granted when the project goes into service. In return, investor-owned utilities are provided an allowance for funds used during construction ("AFUDC") to compensate for the period the project is under construction.[5] PSE is allowed to accrue AFUDC at its authorized rate of return, with the portion above or below the FERC rate ("WUTC AFUDC") being added to or subtracted from the regulatory asset.[6] Both forms of AFUDC are included in rate base, either by being capitalized to the project or included in a regulatory asset and recovered over the specific or average life of the asset through approved depreciation expense.

Q. What concerns do you have with the use of AFUDC?

A. While AFUDC has been adequate at times in the past, in a period of exponential growth in capital investment this approach does not provide adequate cash flow because the recovery of AFUDC spans the life of the asset. PSE is facing the need for an unprecedented level of investment in clean energy resources now and in the upcoming years to satisfy its CETA obligations, as discussed in the Prefiled Direct Testimony of Matt Steuerwalt, Exh. MS-1T, and the Prefiled Direct Testimony of Joshua J. Jacobs, Exh.JJJ-1T. In order to maintain PSE's credit metrics and cash flow, recovery of CWIP in rate base is necessary, as discussed in the Prefiled Direct Testimony of Daniel A. Doyle, Exh. DAD-1CT and the Prefiled Direct Testimony of Cara G. Peterman, Exh. CGP-1CT.

[5] Code of Federal Regulations, Title 18, chapter I, subchapter C, part 101, Uniform System of Accounts, Electric Plant Instruction (17).

[6] See Exh. SEF-24 for documentation of this treatment.

Q. Please explain how including CWIP in rate base addresses financial challenges during periods of exponential growth in investment.

A. One solution for helping to address financing needs during periods of exponential growth in investment is to allow recovery of CWIP balances in rate base. Under such treatment, property is allowed in rates as it is being constructed and before it is in-service. This allows for more current recovery of the financing costs of a project than does AFUDC, which is recovered over the longer life of the underlying asset. When CWIP in rate base is used, AFUDC is not allowed during the time that the construction balances are earning a return in rates, which results in a lower cost capitalized to the project. Because PSE's AFUDC is accrued at its full rate of return, theoretically, the main difference between AFUDC treatment and CWIP in rate base treatment is the time period over which it is recovered.

Q. What is the history of CWIP in rate base in the State of Washington and its justification for use in the CGR Tracker?

A. Mr. Doyle provides a comprehensive background of the history of CWIP in rate base treatment in the state of Washington, including the change in law that allows the Commission to approve recovery of CWIP in rate base.[7] Mr. Doyle also provides justification for why CWIP in rate base treatment for the CGR Tracker is appropriate for the Commission to approve.

[7] *See* RCW 80.04.250.

Q. How does including CWIP in rate base compare to the conventional method for recovery of utility plant assets?

A. I have prepared Exh. SEF-25 also shown in the table below, which utilizes equivalent information as was used for developing the revenue requirement requested in this proceeding as supported in Exh. SEF-21. Exh. SEF-25 provides a calculation of the revenue requirement for Schedule 141CGR that would result if the conventional method of recovering rate base with AFUDC at its in-service date were utilized. This exhibit demonstrates that PSE's proposed CWIP in rate base treatment provides an additional revenue requirement over the conventional method of recovery, thus providing the cash relief that is needed as discussed by Mr. Doyle and Ms. Peterman.

Table 1. Comparison of Recovery Methods for Generation Resources

Description	Conventional	Proposed (Hybrid)	CWIP in Rate Base Only (No AFUDC)
2024 Rev Req on Rate Base	$ -	$ -	$ 28,579,805
2025 Rev Req on Rate Base	29,708,951	57,253,404	54,203,639
2026 Rev Req on Rate Base	79,010,751	75,347,695	71,484,909
Tot Rev Req 2025-2026	$ 108,719,702	$ 132,601,099	$ 154,268,354
Lifetime Sum of Rev Req	$ 1,018,354,981	$ 1,000,063,659	$ 977,260,095
Net Present Value Rev Req 1st 3 years	$97,967,639	$120,430,733	$142,122,018
Net Present Value Rev Req Life	$ 663,969,973	$ 660,192,269	$ 654,212,146

Q. Has PSE analyzed the revenue requirement impacts of allowing CWIP in rate base instead of capitalizing AFUDC for the entire life of a project?

A. Yes. Table 1 and Exh. SEF-25 also provides a comparison of the differences in revenue requirement for allowing CWIP in rate base from the beginning of construction versus recovering under the conventional method of accruing AFUDC through the in-service date. Also provided for comparison is the methodology PSE is proposing in this rate case. Each method calculates an annual revenue requirement over the life of the project.

Q. Please describe the three methodologies that you present in Table 1 and Exh. SEF-25.

A. Below is a brief description of each methodology.

Conventional method:

This method assumes the project accrues AFUDC until it is in service. It is first eligible for rate recovery on an AMA basis in the rate year during which the project goes into service.

Proposed (Hybrid) method:

This method reflects what PSE is proposing in this case for recovery of the Beaver Creek Wind Project in the CGR Tracker. It assumes the project is first eligible for recovery in the first rate case after construction begins. The asset accrues AFUDC until it is included in rates with CWIP in rate base treatment, at which time AFUDC ceases.[8]

<u>CWIP in Rate Base Only (No AFUDC) method:</u>

This method assumes the project gets only CWIP in rate base treatment, so it accrues no AFUDC, and is first eligible for rate recovery at the beginning of construction.

Q. Please summarize the results of the analyses.

A. This analysis shows that, over the life a project, cash flow improves for PSE in the near term and customers experience lower overall financing costs over the life of the asset using both the proposed hybrid methodology and the CWIP in rate base only methodology.[9] The discount rate used for this analysis is supported by Mr. Doyle.

<u>B. Structure of the CGR Tracker.</u>

Q. Please describe the proposed structure for the CGR Tracker.

A. As stated above, PSE is proposing that the CGR Tracker be utilized to recover the fixed costs for the building or purchase of large utility scale CETA compliant generation resources. Variable costs of such resources will be recovered in base rates in a general rate case or through Schedule 95 in a PCORC or other rate

[8] This method agrees to Exh. SEF-21 without Prod O&M and with standard AMA on ADIT.

[9] The net present value of the first three years is the highest under the CWIP in rate base method while it is lowest for the life of the analysis.

filing. PSE is also requesting to recover CWIP in rate base for generation resources within the CGR Tracker. PSE proposes that Schedule 141CGR be applicable to all electric schedules except Schedule Nos. 448, 449, 458, and 459 and Special Contracts.

Q. Is PSE proposing new rates in the CGR Tracker in this proceeding?

A. Yes. The rates for Schedule 141CGR are only filed for the first year of the MYRP. Because a different filing schedule for this tariff is proposed than the filing schedule for base rates changes in the MYRP, PSE has not formally filed rates for Schedule 141CGR for the second rate year. However, for informational purposes, PSE has provided the revenue requirement and bill impacts for Schedule 141CGR for the second rate year based on present estimates.[10]

Q. Please continue to explain the amounts that are included in the CGR Tracker.

A. The Beaver Creek Wind Project, discussed in the Prefiled Direct Testimony of Colin Crowley, Exh. CPC-1HCT, is the first project eligible for the proposed CGR Tracker. This project is well suited for recovery in the CGR Tracker. It is a utility scale, CETA compliant resource that has progressed far enough through the selection and procurement process to be ready for a threshold prudency determination and is currently under construction. PSE has developed rates under

[10] Amounts for the second rate year for Schedule 141CGR are presented in Exh. SEF-3 and Exh. CTM-8. They are also presented in Tables 2 through 5 of my testimony.

the CGR Tracker to recover the revenue requirement for the Beaver Creek Wind project.

Q. What is PSE's proposal with respect to CWIP in rate base?

A. PSE is proposing that it accrue AFUDC on the Beaver Creek Project during the course of this proceeding. At the conclusion of this case, if the Commission approves the CGR Tracker and determines that PSE has demonstrated threshold prudence for the Beaver Creek project, then PSE would begin recovering CWIP in rate base until the project is placed into service.

Q. Is PSE requesting that the CGR Tracker be established as an ongoing mechanism?

A. Yes. Once future ownership opportunities of utility scale CETA compliant resources receive a threshold prudence determination in a general rate case, power cost only rate case or other proceeding, the CGR Tracker will be utilized to begin recovery of CWIP in rate base for the resources.

Q. Will the tracker also include recovery of the revenue requirement associated with the time the plant is in service?

A. Yes. If a project is expected to go into service during the rate period being set in the CGR Tracker, then the revenue requirement will be calculated to cover both the amounts related to the CWIP in rate base during the construction period and the amounts related to the net rate base associated with the period the project will be in service. Thus, the total rate base on which a return will be calculated will include both CWIP and in-service balances for the project. This is the case for the Beaver Creek Wind Project and is demonstrated in the work papers that support Exh. SEF-21.[11]

Q. Will the costs in the CGR Tracker be forecasted?

A. Yes. To achieve timely recovery to support financing costs of projects, rates initially set for each project will be based on forecasts. The proposed CGR Tracker provides for a true-up mechanism that will adjust rates up or down[12] to reflect the actual costs and the actual in-service date of the project. Schedule 141CGR also provides for a true-up mechanism related to the amount expected to be collected when rates were set versus the amount actually collected.

Q. Will the Schedule 141CGR provide parties the opportunity to review the projects for a final prudence determination?

A. Yes. The filing made to true-up actual costs and in-service dates for a project will provide for a final prudence review in the same manner that the filing of the Annual Provisional Capital Report discussed in Section II of my testimony provides. This treatment keeps the process for recovery and final approval of these capital additions as close to the existing MYRP framework as possible. Costs are forecasted for setting rates and a final review is conducted to determine rates were set fairly or whether a refund is required under either method.

[11] I fully describe the revenue requirement calculation in Exh. SEF-21 for the Beaver Creek Wind Project later in my testimony.

[12] Such treatment results in the rates being inherently subject to refund.

Q. What filing cadence is being requested for the CGR Tracker?

A. Because there is no repetitive time frame for when new projects may be added to or removed from the Tracker, Schedule 141CGR does not define recurring filing dates for adding new resources, but provides that the recovery of new resources within the Tracker may not occur until a threshold prudence determination is received from the Commission. It is envisioned that PSE will file rates under the CGR Tracker in the proceeding in which a threshold prudence determination will be made by the Commission, which will allow rate recovery under the CGR Tracker to begin with the conclusion of the proceeding. In addition, to promote transparency in the review process and to allow for a final prudence determination of resources in the CGR Tracker, there will be one of two ways in which final prudence will be reviewed. A final prudence review could happen in a general rate case should the timing of one coincide with the in-service date of a resource. Or, if there is no general rate case filing with the appropriate timing, then, by the end of the twelfth month after a resource reaches commercial operation, PSE will make a separate 120 day filing under Schedule 141CGR. The optionality for the final prudence review is intended to minimize the need for a new filing by utilizing a general rate case if possible, but also providing assurance that a review is conducted without undue delay in the event PSE enters into a longer multiyear rate plan.

Q. Will recovery of these clean generation resources always remain in the CGR Tracker?

A. No. The proposed Schedule 141CGR provides that once a project has reached commercial operation and been placed in service, it will be transitioned into base rates in PSE's next multiyear rate plan, or the one following, depending on the timing of the in-service date and the procedural calendar of the multiyear rate plan.

Q. What else should the Commission consider with respect to PSE's proposal for the CGR Tracker?

A. If the Commission does not approve the CGR Tracker but does determine the Beaver Creek Wind Project has met its threshold prudence requirement and is eligible for provisional recovery, at the final compliance filing, PSE will need to adjust the revenue requirement for base rates to include Beaver Creek, with or without CWIP in rate base treatment, as ordered by the Commission.

IV. WILDFIRE PREVENTION TRACKER

Q. Please describe the Wildfire Prevention Tracker that PSE is proposing in this case.

A. PSE is proposing to recover the forecasted capital and operations and maintenance ("O&M") costs, including insurance premiums attributable to wildfire,[13] which are necessary to implement PSE's Wildfire Mitigation Plan. Recovery will occur through Schedule 141WFP, Wildfire Prevention Tracker ("Wildfire Tracker").[14] The Prefiled Direct Testimony of Ryan Murphy, Exh. RM-1T, provides detail regarding PSE's Wildfire Mitigation and Response Plan ("the Wildfire Plan"), which PSE updates annually, and the work PSE will carry out to mitigate wildfire risk. PSE witnesses Daniel A. Doyle and Cara G. Peterman discuss the need for a separate tracker to recover these costs; they explain that a transparent form of rate recovery will be credit supportive as PSE works to ramp up its mitigation efforts to address the increasing wildfire risk that PSE and its customers face.

Q. Please describe the proposed structure for the Wildfire Prevention Tracker.

A. The Wildfire Plan is managed on an ongoing basis and is updated annually; therefore, PSE is proposing that the Wildfire Prevention Tracker also be updated annually to be in alignment with this process. Because both capital and O&M costs are incurred in the implementation of the Wildfire Plan, PSE is proposing to include forecasted rate base (gross plant, accumulated depreciation and accumulated deferred income taxes), depreciation and O&M, including insurance premiums attributable to wildfire in the Wildfire Tracker. PSE is also proposing that the one-time deferral of increased insurance premiums attributable to

[13] Exhs. SEF-27 and SEF-28 contain a copy of the accounting petition associated with wildfire costs filed in Docket UE-231048 and Attachment B to the accounting petition. Attachment A to the accounting petition is included in Exh. DAD-7. Exh. SEF-28 provides the calculation used to attribute insurance premiums to wildfire.

[14] I fully describe the revenue requirement calculation in Exh. SEF-22 for the Wildfire Tracker later in my testimony.

wildfire, filed in Docket UE-231048, be included in the Wildfire Tracker, if approved for recovery by the Commission. A filing will be made once a year to true-up amounts from prior periods and to set the rate for the next rate period. Finally, PSE is proposing that the Wildfire Tracker be applicable to all electric rate schedules including special contracts.

Q. How long does PSE propose that the Wildfire Tracker remain in place?

A. PSE does not propose an end date for the Wildfire Tracker. As PSE witness Ryan Murphy testifies, the circumstances PSE faces are not normal, but are extraordinary, and are affected by climate change. The Wildfire Tracker, in concert with PSE's wildfire plan, is intended to allow PSE to adjust its current normal operations to accommodate for these increased risks. PSE anticipates the Wildfire Tracker may no longer be necessary once there is no longer an increased wildfire risk that requires incremental mitigation. However, it cannot be known at this time when the relative threat, risk and cost of wildfires will no longer be extraordinary and will become more normal. A future general rate case would be the time to address whether the mechanism may no longer be warranted.

Q. Is there an existing framework PSE followed in designing the Wildfire Tracker?

A. Yes. PSE's proposal is very similar to a Cost Recovery Mechanism ("CRM") as allowed by the Commission's Policy Statement in Docket UG-120715 that addressed gas utilities' Pipeline Replacement Program Plans ("PRPP"). Under previous CRMs, the Commission allowed accelerated recovery of elevated risk pipeline assets that were addressed under PRPPs. PSE utilized a CRM for nine years; it was beneficial to PSE as it allowed for more timely recovery of investments in safety that were reviewed by Commission Pipeline Safety Staff, while allowing accelerated and incremental investment above what would otherwise normally occur under modified historical test year ratemaking with regulatory lag. Customers benefited from enhanced safety through the accelerated replacement of at risk pipe, and the companies benefited from the certainty of recovery for the accelerated pipe replacement.[15]

Q. Please discuss the similarities between PSE's proposed Wildfire Tracker and CRMs.

A. The Wildfire Tracker and CRMs are both based on program plans meant to address the mitigation of risk. Additionally, they both use an annual rate setting process to set rates to recover the costs of the plan. The primary difference is that the Wildfire Tracker will use forecasted costs, while CRMs used eleven months of actuals and one month of forecast for setting rates. However, the requirement to use mostly actual costs is no longer necessary with the passing of the MYRP Statute.

[15] As MYRPs now allow for forecasted recovery of investment, PSE no longer utilizes a CRM.

Q. Has the Commission previously provided separate rate recovery for wildfire mitigation?

A. Yes. In Final Order 08/05 in Avista's 2020 general rate case in Dockets UE-200900, UG-200901, UE-200894 *(Consolidated)*, the Commission approved a settlement agreement that provided for recovery of wildfire mitigation costs in a tracker.

Q. How does PSE's proposed mechanism compare to Avista's?

A. I am not knowledgeable about the full details of Avista's mechanism. However, it appears Avista's mechanism provides for a level of recovery in base rates, and any incremental variations from the base level of recovery are deferred and subsequently recovered in Avista's rate schedule 88, which is referred to as the Wildfire Balancing Account.

Q. What thoughts do you have with respect to the structure of Avista's Wildfire mechanism?

A. A mechanism whereby some costs are recovered in base rates and some in a tracker is a unique design that may have developed for any number of reasons, especially considering it was established as part of a settlement. A balancing account does not appear to me to be an integral part of wildfire rate recovery. Additionally, CRMs did not require such a balancing account. I chose not to replicate this aspect of Avista's mechanism in PSE's Wildfire Tracker. Maintaining cost recovery and review in one filing seems preferable.

Q. What else should the Commission consider with respect to PSE's proposal for the Wildfire Tracker?

A. If the Commission does not approve the Wildfire Tracker, but does determine the wildfire rate base return, depreciation and O&M are appropriate for recovery in rates, PSE will need to adjust the revenue requirement for base rates to include these costs at the final compliance filing.

V. DECARBONIZATION RATE ADJUSTMENT

Q. Please explain PSE's proposal for a Decarbonization Rate Adjustment.

A. The third new rate schedule that PSE is proposing in this rate case is Schedule 141DCARB, Decarbonization Rate Adjustment. The purpose of this proposed schedule is to recover the costs of incremental decarbonization efforts that are not recovered in MYRP base rates.[16] The Prefiled Direct Testimony of John Mannetti, Exh. JM-1CT, discusses the Targeted Electrification Pilot Phase 2 ("Phase 2 Pilot") that PSE is requesting be recovered in Schedule 141DCARB. The Prefiled Direct Testimony of Christopher T. Mickelson, Exh. CTM-1T, discusses cost allocation and rate design considerations for the Decarbonization Rate Adjustment.

[16] I fully describe the revenue requirement calculation in Exh. SEF-23 for the Decarbonization Rate Adjustment later in my testimony.

Q. Why is it appropriate to recover the costs of the Phase 2 Pilot in a separate tracker?

A. Certain parties to PSE's general rate cases, and more recently to its CCA tariff filings, strongly advocate that PSE invest more in decarbonization efforts. However, PSE finds there are few alternatives that meet cost effectiveness tests that would establish a basis for cost recovery under the Commission's standard prudence requirements. Accordingly, PSE is proposing a separate tariff that can be used for programs in which the Commission finds value in having PSE pursue—and that PSE is capable of pursuing—but that may not meet the traditional cost effectiveness standards.

Q. Please describe the proposed structure of Schedule 141DCARB.

A. PSE is proposing that Schedule 141DCARB be applicable to all electric and natural gas rate schedules. PSE is proposing to include a return on forecasted rate base (gross plant, accumulated depreciation, and accumulated deferred income taxes), depreciation, income tax and O&M expense in Schedule 141DCARB. However, the initial Phase 2 Pilot discussed in Mr. Mannetti's testimony only requires O&M costs, and thus no rate base return, income taxes, or depreciation expense is currently being requested in Schedule 141DCARB. Similar to PSE's Schedule 141TEP – Transportation Electrification Plan Adjustment Rider, a 30-day filing will be made once a year to true-up amounts from prior periods and to set the rate for the next rate period.

Q. How long does PSE propose Schedule 141DCARB remain in place?

A. PSE proposes that Schedule 141DCARB remain in place as long as there are decarbonization programs agreed to by parties and the Commission.

VI. POWER COST ONLY RATE CASE

A. History and Current Status of PSE's PCORC

Q. Please briefly describe the origins of PSE's PCORC.

A. PSE's PCA mechanism and PCORC were established as part of a settlement of PSE's 2001 general rate case[17] and have been operating since that time, with certain modifications discussed later in my testimony. Together the PCA mechanism, and the PCORC, were established to address volatility in wholesale energy markets, variations in power supply and load volumes, and the addition of new resources, all of which can lead to significant differences between the actual cost of PSE's power supply portfolio and the costs included in customer rates. The 2002 settlement of PSE's rate case recognized this issue and sought to address it by establishing the PCA mechanism—which balances the risk of unexpected and acute power cost volatility between customers and PSE by providing a method to share costs and benefits if power costs deviate significantly from those embedded in rates. The PCORC gives PSE the ability to periodically update rates to reflect power supply costs more accurately, including costs

[17] *WUTC v. PSE*, Dockets UE-011570/UG-011571, Twelfth Supplemental Order (June 20, 2002).

associated with new resources. Quoting Commission Staff witness Mr. Lott, the Commission stated in its Twelfth Supplemental Order:

> new resources will not be recovered directly through the PCA, but the Company may periodically update its general rates to reflect increased power supply costs associated with new resources or increased costs of existing resources.[18]

The intention of the PCORC was for costs of new resources and increased costs of existing resources to undergo a prudence review and be put into the baseline rate on a timely basis rather than flow through the PCA sharing bands. As the Commission stated, "[t]he objective is to minimize deferral balances by only capturing power cost variability that is extraordinary"[19] through the PCA bands and to "set the Power Cost Baseline Rate as close as possible to what is expected to be experienced in the rate year."[20]

Q. How are costs of new resources intended to be recovered?

A. One of the main purposes of the PCORC is to allow for new resources to undergo a prudence review and be added to the baseline rate when they enter service. As the 2002 Settlement Stipulation explains:

> One objective of a new resource proceeding is to have the new Power Cost Rate in effect by the time the new resource would go into service.[21]

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[18] *Id*. at 25.
[19] *WUTC v. PSE,* Docket UE-0702300, Order 13, ¶ 9 (January 15, 2009).
[20] *Id.* ¶ 11.
[21] *WUTC v. PSE*, Dockets UE-011570/UG-011571, Appendix A Settlement Stipulation, C.11.

Q. Is the PCORC only intended to address power cost updates associated with the acquisition of new resources?

A. No. As the Commission has recognized,

> the PCORC was never intended to be limited to power cost updates associated with the acquisition of new resources. The PCORC's update of the power cost baseline under the PCA is an important feature that helps keep deferral balances within reasonable bounds, making the PCA better suited to its purpose, which is to address unexpected and acute volatility in power costs while generally avoiding the trigger of surcharges or bill credits.[22]

Q. Has the question of whether the PCORC should continue been presented to the Commission in prior proceedings since the inception of the PCORC?

A. Yes. In Docket UE-072300, Public Counsel and Industrial Customers of Northwest Utilities ("ICNU") recommended elimination of the PCORC.[23] The issue was ultimately referred to the Commission for a determination.

Q. What was the outcome in that proceeding?

A. The Commission concluded that the PCORC should be retained, with a few modifications.[24] The Commission commented in its order:

> The PCORC has proven to be a useful mechanism that allows for timely consideration of PSE's major resource acquisitions, which are part of an ongoing process to make the Company less dependent on short- and intermediate-term power transactions in sometimes volatile wholesale power markets. Furthermore, the PCORC and the PCA mechanisms have worked together to provide for timely updates to PSE's power costs in rates and to adjust the Company's power cost baseline, which has prevented the accumulation of unhealthy positive or negative imbalances in its power cost deferral

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[22] *WUTC v. PSE,* Docket UE-072300, Order 13, ¶ 53 (January 15, 2009).
[23] *Id.* ¶ 20.
[24] *Id.* ¶ 59.

> accounts. In short, the benefits of the PCORC outweigh the arguments for its elimination.[25]

The Commission also said in that order:

> Complementing the PCA's purpose of addressing short-term, significant imbalances between expected and actual power costs, the PCORC was intended to adjust rates in response to long-term trends in production-related costs. The PCORC was designed to allow for adjustment of both fixed and variable power costs, and to allow for the more timely inclusion of resource acquisitions in rates.[26]

Q. Does the underlying rationale for the Commission's support of the PCORC continue to exist?

A. Yes. As will be discussed in more detail below, the factors that weighed in favor of the continuation of the PCORC in that proceeding continue to exist today, perhaps even more so than the last time the Commission considered this issue.

Q. What is the current status of PSE's PCORC?

A. In the Settlement Stipulation and Agreement on Revenue Requirement and All Other Issues Except Tacoma LNG and Green Direct ("2022 Revenue Requirement Settlement"), PSE agreed to a PCORC stay-out through the pendency of the 2023-2024 MYRP. Additionally, parties to that settlement reserved their right to challenge whether PSE's ability to file PCORCs as allowed under its PCA mechanism should continue in future proceedings.[27]

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[25] *Id.* ¶ 25.
[26] *Id.* ¶ 10.
[27] *WUTC v. PSE*, Dockets UE-220066 *et al.*, Final Order Appendix A ("Revenue Requirement Settlement") ¶ 27 (Dec. 22, 2022).

B. The PCORC Is Needed for PSE to Successfully Transition to a Clean Energy Future as Required by CETA

Q. Is there still a need for major resource acquisitions and reduced dependence on short- and intermediate-term power transactions?

A. Yes. CETA requires PSE to supply Washington customers with electricity that is 100 percent renewable or non-emitting by 2045 and greenhouse gas ("GHG") neutral by 2030, and to eliminate coal-fired power by the end of 2025.[28] CETA requires a transformation of PSE's resource base over the next several years. The Prefiled Direct Testimony of Joshua J. Jacobs, Exh. JJJ-1T, discusses PSE's substantial peak capacity need, energy need, and renewable and non-emitting energy target need through 2030 to comply with CETA. As Mr. Jacobs demonstrates, PSE faces a peak capacity need of 2,406 MW in the winter of 2030 and will need 6.3 million MWhs of additional renewable and non-emitting resources by 2030 to comply with CETA. This reality qualifies as a "long-term trend in production-related costs."[29] PSE filed its first Clean Energy Implementation Plan with the Commission in December 2021,[30] and must submit a new Clean Energy Implementation Plan every four years going forward, as required by CETA.

[28] RCW 19.405.

[29] *See WUTC v. PSE*, Dockets UE-072300/UG-072301, Order 13, ¶ 10 (noting the PCORC was intended to adjust rates in response to long-term trends in production-related costs).

[30] *WUTC v. PSE*, Docket UE-210795, Final 2021 Clean Energy Implementation Plan (Dec. 17, 2021).

Q. Will the PCORC be needed in the future?

A. Yes, as I discussed above, PSE must be financially stable enough through credit supportive cash flow to invest in CETA compliant, utility scale, owned resources when the opportunities arise. The PCORC allows PSE to bring these new resources into rates on an expedited basis—whether through a full prudence determination or a threshold prudence determination. The use of a PCORC to establish threshold prudency coupled with the CGR Tracker will allow PSE this flexibility. The PCORC is an important tool to have in the context of MYRPs that are two to four years in length because future generation resource opportunities may not be known at the time the MYRP is decided.

Q. Does the annual power cost update obviate the need for the PCORC?

A. No. In this case, PSE is proposing the continuation of annual power cost updates during the course of the MYRP as discussed in the Prefiled Direct Testimony of Brennan D. Mueller, Exh. BDM-1T. However, the annual power cost update only addresses variable power costs and does not provide for recovery of fixed costs related to new resources. The annual power cost update could serve to lessen the need to use a PCORC to provide timely updates to PSE's variable power costs in rates and to adjust the power cost baseline, but it does not allow PSE to bring the fixed costs of new utility-scale resources into rates.

Q. What is PSE's specific proposal for its PCORCs?

A. PSE requests the Commission allow PSE's PCORCs to remain in place, as it continues to be an important tool for PSE to use to help to comply with CETA. PSE proposes that the PCORC also be used as a potential alternative regulatory pathway to establish a threshold prudence determination and provisional recovery in rates through the CGR Tracker for resources that are not yet put in service. PSE further proposes that the Commission allow PSE to recover CWIP in rate base for new clean generation resources included in the PCORC as discussed in Section III of my testimony.

VII. CLIMATE COMMITMENT ACT

Q. What steps has PSE taken since the final order in PSE 2022 GRC to address CCA costs and allowances?

A. In February 2023, PSE began holding meetings with interested persons to discuss the CCA and associated implementation issues. The intent of these meetings was to inform interested persons about the CCA and to obtain input on potential design considerations for tariffs that would collect and distribute costs and proceeds related to the CCA.

PSE filed petitions for accounting orders,[31] which were granted, and PSE filed a tariff schedule,[32] which the Commission allowed to take effect on August 15, 2023 through December 31, 2023. The treatment of costs and allowances for gas customers and electric customers differs, as described further below.

The Commission is developing a process within Docket UG-230968 by which it will consider a risk sharing mechanism.

A. Gas CCA Filings

Q. What filings with the Commission did PSE make regarding treatment of costs and allowances for gas customers?

A. On June 9, 2023, PSE filed revisions to its currently effective natural gas tariff WN U-2 to propose a new tariff schedule (Schedule 111 – Greenhouse Gas Emissions Cap and Invest Adjustment) that would allow PSE to recover allowance costs and pass back to customers the auction proceeds mandated under the CCA. The schedule would implement a customer surcharge that would recover costs through charges and provide benefits through credits. The Commission approved this tariff revision, effective August 15, 2023 through December 31, 2023, subject to conditions.[33] One condition was that PSE continue to work with interested parties through the CCA workshop series in Docket U-

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[31] *In re PSE*, Docket UG-230471, Petition for Accounting Order (June 9, 2023); *In re PSE,* Docket UG-220975, Petition for Accounting Order (Dec. 29, 2022); *see also In re PSE*, Docket UE-220797, Forecast Petition (Oct. 31, 2022).

[32] *WUTC v. PSE*, Docket UG-230470, Tariff Revision (June 9, 2023); Docket UG-230756, Tariff Revision (September 15, 2023); *WUTC v. PSE*, Docket UG-230968, Tariff Revision (November 22, 2023).

[33] *WUTC v. PSE*, Docket UG-230470, Order 01 (Aug. 3, 2023).

230161 and its Low-Income Advisory Group to develop and then propose a risk sharing mechanism.[34] PSE subsequently filed tariff revisions for Schedule 111 on November 22, 2023 for rates effective January 1, 2024.

PSE also filed an accounting petition on June 9, 2023 in Docket UG-230471 seeking an Accounting Order under WAC 480-07-370(3) authorizing PSE to (1) begin accounting for the above gas tariff schedule as a pass-through tariff, (2) end the deferred accounting treatment previously approved under a prior petition for accounting order (Docket UG-220975), and (3) defer differences between Schedule 111 charges/credits and recorded expenses/proceeds to be trued-up each time rates are set under Schedule 111.[35] The Commission granted the petition and issued an accounting order on August 10, 2023.

When the November 22, 2023 Schedule 111 tariff filing was made, PSE filed an amended petition in Docket UG-230471 to, among other things, obtain approval for the accounting associated with the withholding of auction proceeds as was approved in the November 22, 2023 tariff filing. The amended petition was approved in Order 02 in Docket UG-230471.

Q. What is the status of the risk sharing proposal at the time of this filing?

A. On December 22, 2023, the Commission issued Order 01 in Docket UG-230968 stating that the issue of a risk sharing mechanism of CCA compliance costs is a

[34] *Id*. ¶¶ 22-23.
[35] *In re PSE*, Docket UG-230471, Order 01 (Aug. 10, 2023).

complex one that would benefit from a full record.[36] The issue of a risk sharing mechanism was set for hearing. A prehearing conference was held on January 30, 2024 to set a procedural schedule. Therefore, the outcome of the proceeding related to a risk sharing mechanism is pending before the Commission at this time.

<u>B. Electric CCA Filings</u>

Q. What filings with the Commission did PSE make regarding treatment of costs and allowances for electric customers?

A. PSE submitted a petition to the Commission on October 31, 2022 for approval of PSE's forecasts of demand and resource supply for the first compliance period under the CCA.[37] In that filing, PSE suggested that the Commission should allow, but not require, electric utilities to submit annual updates to the utility-specific demand and resource supply forecasts for a compliance period.[38] In its Final Order, the Commission agreed with PSE's recommendation.[39]

PSE has also noted that uncertainty and ambiguity around the Department of Ecology ("Ecology") methodology for annual determination of the allocation of no-cost allowances to electric utilities creates considerable complications and uncertainty for how utilities should approach mitigating costs to customers, understanding the ultimate scale of the cost impacts, and evaluating approaches

[36] *WUTC v. PSE*, Docket UG-230968, Order 01 ¶ 14 (Dec. 22, 2023).
[37] *In re PSE*, Docket UE-220797, Forecast Petition (Oct. 31, 2022).
[38] *Id*. at 10-11.
[39] *In re PSE*, Docket UE-220797, Order 01 (Jan. 24, 2023), at 5.

for cost recovery.[40] It is anticipated that the methodology for allocation of no-cost allowances will mitigate but not eliminate costs to electric customers from the CCA, meaning even electric customers will incur additional costs based on the CCA in addition to increasing costs associated with CETA. For instance, electrification actions taken to decarbonize the gas system will result in increasing costs on the electric system associated with generation and transmission resources needed to serve these loads, in addition to CCA compliance costs. PSE has thus urged the Commission to consider to what extent utility allowance revenue is an appropriate source of funding for decarbonization investments, or whether state revenue derived from the overall program is a more appropriate source of funding.[41]

Q. Are the indirect costs of the CCA on PSE's dispatch of its generation resources a part of this proceeding?

A. Yes. Mr. Mueller addresses how PSE is including the indirect costs of CCA compliance in the power costs requested in this proceeding. This treatment is influenced by the recent Commission ruling in Docket UE-230805, which is PSE's 2024 power cost update filing made in compliance with the 2023-2024 MYRP.

[40] *See* Docket U-230161, PSE Comments (May 10, 2023), at 2, 5.
[41] *Id*. at 5.

C. PSE's Proposal For the CCA Tariffs Going Forward

Q. What does PSE propose for the electric and gas CCA tariffs going forward?

A. PSE currently does not have an electric CCA tariff on file as there is too much uncertainty related to its ultimate electric CCA obligation. PSE proposes to keep costs and allowance proceeds for both gas and electric CCA out of general rates. Specifically, PSE proposes that its gas tariffs not be suspended or considered in the current MYRP, but that they continue to be updated outside of this case, through annual tariff filings.

Q. Why should the CCA costs and allowances be kept out of general rates?

A. There remains considerable uncertainty about the CCA. For example, Ecology will not provide an electric true-up until November 2024. PSE needs to have a flexible mechanism so that the Company can adapt to changes that are evolving during these initial stages of the CCA—especially considering the first compliance period is four years in length, and all the rules associated with determining and establishing compliance have not yet been worked through.

Q. Will PSE continue its current treatment for the CCA for gas customers?

A. Yes, PSE will continue to account for its gas CCA tariff as a pass-through tariff as allowed under Order 02 in UG-230471.

VIII. REVENUE REQUIREMENTS

A. Net Revenue Change Requested – Exhs. SEF-3 and SEF-7

Q. Please summarize PSE's requested net revenue change to electric and natural gas revenue.

A. PSE is requesting a net revenue change as summarized in Table 2 below:

Table 2. Total Revenue Change Requested

Description	2025 Electric	2025 Gas	2026 Electric*	2026 Gas	Full Period Electric	Full Period Gas
a Revenue Deficiency - Grossed Up	$ 584.4	$ 247.6	$ 259.9	$ 25.4	$ 844.3	$ 273.0
b Rate Schedules Set to Zero	(499.0)	(55.6)			(499.0)	(55.6)
c Deficiencies for New Rate Adjustments and Tracker*	106.9	4.0	25.3	-	132.1	4.0
d Total Revenue Change	$ 192.2	$ 196.0	$ 285.2	$ 25.4	$ 477.4	$ 221.4

* - PSE has not formally filed for rates in 2026 for the new rate adjustments and tracker and amounts are presented for informational purposes only.

The need for the revenue change primarily results from increased return, depreciation, and income tax expense associated with increased rate base. Table 3, below, demonstrates the change in rate base that has occurred since rates were last set.

Table 3. Change in Rate Base

(in millions)

Line	Energy	2024 in 2022 GRC+	2025 in 2024 GRC	Increase (Decrease)	2026 in 2024 GRC	Increase (Decrease)	2025 and 2026 Source
a	Electric	$ 5,947.8	$ 7,123.0	$ 1,175.2	$ 7,949.7	$ 826.7	Exh. SEF-4, SEF-21, SEF-22
b	Gas	2,777.0	2,866.5	89.5	2,863.1	(3.4)	Exh. SEF-8
c	Total	$ 8,724.8	$ 9,989.5	$ 1,264.7	$ 10,812.8	$ 823.3	

	Decription	2025 Electric	2025 Gas	2025 Combined	2026 Electric	2026 Gas	2026 Combined
d	Base Rates	$ 6,606.4	$ 2,866.5	$ 9,472.9	$ 7,417.0	$ 2,863.1	$ 10,280.1
e	Schedule 141CGR*	492.7		492.7	470.5		470.5
f	Schedule 141WFP*	23.9		23.9	62.2		62.2
g	Total Rate Base Requested	$ 7,123.0	$ 2,866.5	$ 9,989.5	$ 7,949.7	$ 2,863.1	$ 10,812.8
h	* 2026 amounts are for information only as PSE has not filed rates for year 2 in this filing for these tariff schedules.						

On the gas side, much of the increase to depreciation is due to updated depreciation rates that are presented in the Prefiled Direct Testimony of Ned W. Allis, Exh. NWA-1T. Additionally, higher operating and regulatory amortization expenses contribute to the net revenue change requested. For electric, these increases are offset by a decrease in power costs,[42] as discussed by Mr. Mueller as well as growth in revenues between periods. For natural gas, an additional contributor to the net revenue change requested comes from a change between the load forecasts used in the 2023-2024 MYRP and the one used in this filing. The impacts of the load changes are discussed in the Prefiled Direct Testimony of Joshua J. Jacobs, Exh. JJJ-1T, the Prefiled Direct Testimony of Christopher T. Mickelson, Exh. CTM-1T and the Prefiled Direct Testimony of John D. Taylor, Exh. JDT-1T. Table 4, below, provides an overview of the drivers of the net revenue change requested in this proceeding.

[42] Related to power costs, amounts included in the original filing are at a level that represent a decrease over what was set in rates in PSE's 2024 power cost update in Docket UE-230805. Please see Mr. Mueller's testimony for a discussion of the anticipated increases associated with the replacement of expiring capacity contracts that would occur in PSE's proposed filing to update power costs prior to rates becoming effective in this proceeding.

Table 4. Causes of Requested Revenue Changes[43]

Decription	2025 Electric	2025 Gas	2025 Combined	2026 Electric	2026 Gas	2026 Combined	Total Rate Years Electric	Total Rate Years Gas	Total Rate Years Combined
RATE BASE	$ 168.5	$ 32.4	$ 200.9	$ 118.9	$ 12.6	$ 131.5	$ 287.4	$ 45.0	$ 332.4
POWER COSTS	(133.0)	-	(133.0)	110.5	-	110.5	(22.5)	-	(22.5)
OPERATING EXPENSES	65.3	17.2	82.5	21.3	(0.1)	21.2	86.6	17.1	103.8
CUSTOMER AND A&G	44.9	(16.8)	28.0	8.6	6.2	14.8	53.5	(10.7)	42.8
PLANT DEPRECIATION / AMORTIZATION	69.6	89.9	159.5	62.3	10.9	73.2	131.9	100.8	232.7
REGULATORY AMORTIZATIONS	20.8	6.2	26.9	(16.7)	(6.8)	(23.6)	4.0	(0.7)	3.4
REVENUE (GROWTH) DECLINE	(61.3)	64.6	3.3	(22.4)	2.5	(19.9)	(83.7)	67.0	(16.7)
OTHER (INCL GROSS UP FOR RSI/TAXES)	17.5	2.6	20.1	2.6	0.1	2.8	20.1	2.7	22.8
REVENUE DEFICIENCY - GROSSED UP	$ 192.2	$ 196.0	$ 388.3	$ 285.2	$ 25.4	$ 310.5	$ 477.4	$ 221.4	$ 698.8

NOTE: INCLUDES CHANGES RELATED TO SCHEDULES 141CGR (INCLUDING RATE YEAR 2), WFP AND DCARB

B. Overview of the Calculation of the Net Revenue Change Requested.

Q. Would you please explain Exhs. SEF-3 and SEF-7?

A. Exh. SEF-3 presents the calculation of the electric revenue change requested based on the restated, pro forma, and provisional adjustments for each year of the multiyear rate plan. It also presents the pro forma cost of capital for the test year and each of the rate years and the electric conversion factor.

Exh. SEF-7 presents the calculation of the natural gas base revenue change requested based on the restated, pro forma, and provisional adjustments for each year of the multiyear rate plan. It also presents the pro forma cost of capital for the test year and each of the rate years, and the natural gas conversion factor.

The following are descriptions of the individual pages in Exh. SEF-3 and Exh. SEF-8.

[43] Amounts include contributions related to the three newly proposed Trackers including Schedule 141CGR for the second rate year, the presentation of which was discussed earlier in my testimony.

Electric Net Revenue Change Requested

The electric net revenue change requested for each year of the multiyear rate plan period is shown on page one of Exh. SEF-3. The schedule shows the rate base, line 12; requested rate of return, line 13; operating income requirement, line 15; pro forma operating income or loss, line 17; and operating income deficiency, line 18. The requested revenue change before other price schedule changes, line 21, for each year of the multiyear rate plan are also presented. The incremental net revenue change to base rates is presented on line 23. After the expected changes to other price schedules, supported by Mr. Mickelson on line 39 for electric, the incremental net revenue change for each year of the multiyear rate plan is presented on line 41.

Electric Rate Year One - 2025

Based on $6.6 billion invested in rate base, a 7.65 percent rate of return and $66.3 million of pro forma operating income, PSE requires a base rates revenue change for electric of $584.4 million for year one of the rate plan.[44] After the expected changes to other price schedules,[45] which represent an overall decrease of $392.2 million,[46] the net revenue change requested, presented on line 41, is $192.2 million. This represents the requested net revenue change in year one and contains amounts associated with the value of property in service as of the first rate

[44] This amount does not include the revenue requirement for the three newly proposed Trackers.
[45] Which includes the revenue requirement for the three newly proposed Trackers.
[46] Changes to other price schedules include setting rate schedules from the 2023-2024 MYRP to zero as well as the addition of the three new trackers discussed previously.

effective period on an end of period basis as well as the value of property placed in service during the first rate effective period on an AMA basis.[47] I discuss later in my testimony how the requested rate change is assigned to each of the tariff schedules that will be used for setting rates for each year of the multiyear rate plan.

<u>Electric Rate Year Two – 2026</u>

Based on $7.4 billion invested in rate base, a 7.99 percent rate of return and $41.7 million of pro forma operating loss, PSE requires a revenue change for electric base rates of $844.2 million for year two of the rate plan. This represents an additional $259.9 million over the requested revenue change from rate year one. After the expected increase to other price schedules, the net revenue change requested for year two[48], presented on line 41, is $285.2 million.

<u>Natural Gas Net Revenue Change Requested</u>

The gas net revenue change requested for each year of the multiyear rate plan period is shown on page one of Exh. SEF-7. This page shows the test period rate base, line 12; requested rate of return, line 13; operating income requirement, line 15; pro forma operating income, line 17; and operating income deficiency, line 18. The revenue changes before other price schedule changes, line 21, for each year of the multiyear rate plan are also presented. The incremental net revenue

[47] Used and Useful Policy Statement, ¶ 36.

[48] These amounts are presented for informational purposes based on present estimates and have not been formally included in the rates filed as discussed previously; PSE's request is to update them separately during the MYRP period.

change is presented on line 23. After the expected reduction to other price schedules on line 31, supported in the Prefiled Direct Testimony of John D. Taylor, Exh. JDT-1T, the incremental net revenue change for each year of the multiyear rate plan is presented on line 33.

<u>Natural Gas Rate Year One - 2025</u>

Based on $2.87 billion invested in rate base, a 7.65 percent rate of return, and $32.5 million of pro forma operating income, PSE requires a net base rates revenue change for natural gas revenues of $247.6 million for year one of the multiyear rate plan.[49] After the expected reduction to other price schedules of $51.6 million,[50] PSE's net revenue change requested for natural gas shown on line 33 is $196.0 million. This represents the requested net revenue change in year one and contains amounts associated with the value of property in service as of the first rate effective period on an end of period basis as well as the value of property placed in service during the first rate effective period on an AMA basis. I discuss later in my testimony how the requested rate change is assigned to each of the tariff schedules that will be used for setting rates for each year of the multiyear rate plan.

[49] This amount does not include the revenue requirement for the one newly proposed tracker that is applicable to natural gas.

[50] Which includes the revenue requirement for the one newly proposed tracker that is applicable to natural gas.

<u>Natural Gas Rate Year Two – 2026</u>

Based on $2.9 billion invested in rate base, a 7.99 percent rate of return and $22.9 million of pro forma operating income, PSE requires a revenue change for natural gas of $273.0 million for year two of the rate plan. This represents an additional $25.4 million over the requested revenue change from rate year one.

Q. How will the requested revenue changes be assigned to the various tariff schedules that will be used for setting rates for each year of the multiyear rate plan?

A. In PSE's 2023-2024 MYRP, the base rates deficiencies were assigned between base rates, Schedule 141N (rates not subject to refund) and Schedule 141R (rates that are subject to refund). However, in this MYRP, PSE is proposing to eliminate the use of Schedule 141N and repurpose Schedule 141R for a different use. Therefore, aside from the three new tariff schedules PSE is proposing, the deficiencies for both rate years are being set in base rates. This is discussed by Mr. Mickelson and Mr. Taylor.

Q. What unique considerations will be necessary for how rates will be set at the end of this proceeding in PSE's final compliance filing for rates?

A. Mr. Mueller discusses PSE's proposal to set rates for variable power costs annually outside of general rate cases and multiyear rate plans. Variable power costs have been presented for 2026 by Mr. Mueller and incorporated into the revenue requirement and rates filed in this proceeding. If PSE's proposal to update power costs annually is accepted, then PSE will use the same method to set power costs for 2026 as was used in PSE's compliance filing in its last GRC.[51] Essentially, there will be a revenue requirement change in 2026 that will be offset by the change in loads between periods, which will result in no impact on the overall rate change. The amount to include for 2026 power costs should be determined in this way as it will result in no rate change associated with power costs from what will be set for 2025. This approach is reasonable as power costs will be later updated and the 2026 amounts included in the 2025 compliance filing will never actually be in effect but act as a "placeholder" until the formal update is filed for 2026 power cost rates.

Q. How much of the requested revenue changes will be subject to refund?

A. The calculation of the amount of the incremental deficiencies included in base rates that are subject to refund[52] is presented in Exh. SEF-19 for electric and SEF-20 for natural gas. Amounts in these exhibits represent the revenue requirement related to forecasted utility capital additions and retirements and depreciation for projects placed in service after December 31, 2024. For electric, the amounts are $42.7 million in 2025 and incrementally, $203.4 million for 2026 (Exh. SEF-19, line 40). For natural gas, the amounts are $20.2 million in 2025 and incrementally, $45.6 million for 2026 (Exh. SEF-20, line 40).

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[51] *See WUTC v. Puget Sound Energy*, Dockets UE-220066 *et al*., Compliance Filing (Electric) (Dec. 27, 2022), at 5.

[52] The three newly proposed trackers all have true-up provisions, and so are inherently subject to refund and are not included in the amounts including in Exhs. SEF-19 and 20 or discussed in this section.

Q. Please further explain how Exhs. SEF-19 and SEF-20 were prepared.

A. PSE utilized the same process for calculating the rate base impacts from all test year retirements and forecasted capital additions and applied the process to only the capital additions and retirements that are estimated to occur after 2024.[53]

The impacts on accumulated EDIT and EDIT reversals for the forecasted retirements were incorporated into the calculations for Exhs. SEF-19 and SEF-20 as well.

<u>Cost of Capital for Electric and Natural Gas</u>

Q. Turning back to Exh. SEF-3 and Exh. SEF-7, please explain the remaining pages in these exhibits.

A. Page two of both Exh. SEF-3 and Exh. SEF-7 reflect the proposed capital structure for PSE during the rate year and the associated costs for each capital category. The capital structure and costs are presented in the Prefiled Direct Testimony of Cara G. Peterman, Exh. CGP-1CT. The requested rate of return is 7.65 percent and 7.09 percent net of tax for the first rate year. The requested rate of return is 7.99 percent and 7.44 percent net of tax for the second rate year. Ms. Peterman supports the requested capital structure and components of the cost of debt for each year of the multiyear rate plan. Please also see the Prefiled Direct

[53] PSE has followed the same methodology for calculating forecasted rate base as was used in the 2023-2024 MYRP. See Exh. MRM-3 for further details on the process.

Testimony of Ann E. Bulkley, Exh. AEB-1T, for support for the requested return on equity of 9.95 percent and 10.50 percent for 2025 and 2026, respectively.

Electric and Natural Gas Conversion Factors

Page three of both Exh. SEF-3 and Exh. SEF-7 provide the electric and natural gas conversion factors that are used to adjust the electric and natural gas net operating income deficiency for revenue sensitive items and federal income tax to determine the total electric and natural gas requested net revenue change. The revenue sensitive items are the Washington State utility tax, Washington Utilities and Transportation Commission ("WUTC" or "Commission") annual filing fee, and bad debts. These conversion factors are 0.751313 for electric operations and 0.754213 for natural gas operations. These amounts are used for all years within the multiyear rate plan. These conversion factors now include the updated annual filing fee of .04 percent as is reflected in RCW 80.24.010.

C. Electric and Natural Gas Summary Pages – Exhs. SEF-4 and SEF-8

Q. Please explain how the revenue requirement was prepared.

A. Per WAC 480-07-510, PSE must provide a detailed portrayal of the restating and pro forma adjustments in its testimony and exhibits. In order to discuss the restating adjustments independent of the pro forma adjustments, PSE has set up each of its adjustments to show the restating adjustments separately from the pro forma adjustments, as the restating adjustments are the basis upon which pro forma adjustments must be calculated per WAC 480-07-510. Additionally, as discussed above, this case proposes a two-year multiyear rate plan. Therefore, there are pro forma and provisional pro forma adjustments needed to present the rate base in service at the start of the rate effective period, consistent with the requirements of the MYRP Statute, as well as for years one and two of the multiyear rate plan. Accordingly, PSE used the following steps to determine the revenue requirement for this proceeding:

1. **Test Year Results of Operation** – PSE started with the test year results of operations for the twelve months ended June 30, 2023, as presented by Stacy Smith in Exh. SWS-3. The test year rate base is included in Exh. SEF-5 for electric operations and Exh. SEF-10 for natural gas. Consistent with prior general rate cases, PSE's rate base was developed using the historical AMA of the balances for the 13 months ended June 30, 2023. And consistent with the presentation used in the last MYRP, through a restating adjustment, the average net plant in service balances were adjusted to the end of period ("EOP") balances as of June 30, 2023.

   Restating Adjustments – PSE prepared restating adjustments to adjust the test year operating results to reflect the results on a basis the Commission accepts for determining rates. The restating adjustments are necessary to annualize ongoing costs and revenues that PSE began to incur and realize part way through the test year and to adjust the balances to normalized levels consistent with historical ratemaking practices.

   Pro Forma Adjustments – The sum of values resulting from Steps 1 and 2 reflect the restated results of operations upon which pro forma adjustments must be based. Among its traditional pro forma adjustments, PSE has included: adjustments to reflect all capital additions that will be placed in service by December 31, 2023; and adjustments to make other known and measurable changes as discussed in more detail below

   Pro forma and Provisional Pro forma Adjustments – These adjustments, some of which are provisional and subject to the review process[54] and potential refund as outlined earlier in my testimony, are necessary to reflect projects that will be placed in service during each year of the multiyear rate plan. These adjustments also take into consideration the revenue and O&M and offsetting factors expected for the same periods.

[54] See my discussion of Exhs. SEF-19 and 20 above for what is to be considered provisional.

Q. Would you please explain both Exh. SEF-4 and Exh. SEF-8?

A. Exh. SEF-4 and Exh. SEF-8 present an overview of the income statement and rate base starting with the unadjusted test year through the adjusted results of operations for each year in the multiyear rate plan for electric operations, (Exh. SEF-4) and natural gas operations (Exh. SEF-8).

The first page of Exhs. SEF-4 and SEF-8 presents the impact of each of the respective electric and natural gas aggregated adjustments being made by period to the June 30, 2023 operating income statement and rate base.

- Column c presents the unadjusted operating income statement and the AMA rate base for PSE as of June 30, 2023 (the test year). As stated above, the income statement amounts are supported by Mr. Smith. The rate base amounts are provided in Exh. SEF-5.
- Column d presents the total restating adjustments.
- Column e is the sum of columns c and d (test year and plus restating adjustments) and this total is referred to as the restated results of operations.
- Column f presents the adjustments made for the traditional pro forma period, through December 31, 2023, which is six months after the end of the test year.
- Column g is the sum of columns e and f (restated results of operations plus pro forma adjustments) and is referred to as the December 2023 adjusted results of operations.
- Column h presents the 2024 Gap Year Adjustments. These adjustments are necessary to reflect PSE's costs at the start of the rate year. These adjustments are reflected on an end of period basis to allow for measurement of the fair value of plant at the start of the rate year.
- Column i presents the adjusted results at the start of rate year one. It is calculated by adding the adjustments from column h to the December 2023 adjusted results of operations (column g).

- Column j presents the rate year one adjustments. These adjustments are necessary to reflect the costs that will occur during the rate year and, because the rates will be set at the beginning of the period, are presented on an average of monthly averages basis.

- Column k presents the adjusted results of operations for the rate year one period. These amounts are used to calculate the initial revenue change that is requested in this filing for year one, as shown in Exh. SEF 3 and Exh. SEF 7. Lines 65 and 71 of these exhibits present the cumulative and incremental changes to the net revenue change requested.

- Column l presents rate year two adjustments. These adjustments are necessary to reflect the costs that will occur during the second year of the rate plan and are presented on an average of monthly averages basis.

- Column m presents the adjusted results of operations for the rate year two period. These amounts are used to calculate the revenue change that is requested in this filing for year two as shown in Exh. SEF 3 and Exh. SEF 7.

Pages two through thirty-five of Exh. SEF-4 and pages two through twenty six of Exh. SEF-8 present a detailed summary schedule for all the respective electric or natural gas adjustments that support the summary on page one of these exhibits. Each detailed summary provides the amounts for each of the adjustments within each period and are categorized into the same time periods as shown on the first page of these exhibits.

<u>D. Electric and Natural Gas Test Year Data – Exhs. SEF-5 and SEF-10</u>

Q. Would you please explain both Exh. SEF-5 and Exh. SEF-10?

A. Exhs. SEF-5 and SEF-10 present the respective electric and natural gas test year rate base, working capital, and allocation methods.

Rate Base

Pages one and two of Exh. SEF-5 and page one of Exh. SEF-10 present the test year AMA and EOP rate base calculation for electric and natural gas, respectively. The test year rate base and working capital presented for the test year in this proceeding are reported on an AMA basis.

Investor Supplied Working Capital

Page three of Exh. SEF-5 and page two of Exh. SEF-10 present the test year working capital calculation for electric and natural gas, respectively, that are included as part of the respective rate base calculations. Consistent with the approach used in its last rate case, PSE uses the restated value for each of the rate years.

Allocation Factors

Page four of Exh. SEF-5 and page three of Exh. SEF-10 present the allocation methods and factors used in allocating common expenditures between electric and natural gas operations. Common utility plant is that portion of utility operating plant that is used for providing more than one commodity to customers, i.e., both electricity and natural gas service. Common plant includes costs associated with land, structures, and equipment, which are not charged specifically to electric or natural gas operations. PSE allocates its common utility plant for electric and natural gas by using the four-factor allocation method.

Common operating costs are those costs that are incurred on behalf of both electric and natural gas customers. PSE incurs common costs related to customer accounts expenses, customer service expenses, administrative and general expense, depreciation/amortization, other operating expenses, and taxes other than federal income tax. These common costs are allocated to electric and natural gas using the most appropriate allocation method for the type of cost being allocated. Allocation methods used include (1) twelve-month customer average, (2) joint meter reading customers, (3) non-production plant, (4) four-factor allocator, and (5) direct labor allocator. An allocation factor that can be used in assigning total costs between operating costs, capital, and non-utility when warranted is also presented on this exhibit.

IX. INDIVIDUAL ADJUSTMENTS

Q. Please explain the organization of the individual adjustments.

A. Each of the individual adjustments can be restating, pro forma (traditional or provisional), or both restating and pro forma. Exh. SEF-6 contains adjustments that pertain to electric service, and Exh. SEF-11 contains adjustments that pertain to natural gas operations. Exh. SEF-9 provides the impacts of each adjustment on net operating income, rate base (page 1) and the related revenue requirement (page 2). The dollar value of the impact on rate base and net operating income is not presented in my testimony for each adjustment in order to streamline the testimony. Therefore, Exh. SEF-9 is being provided for reference for the impacts on net operating income and rate base when reading the description of each adjustment below. Additionally, Exh. SEF-13 provides, at a glance, an overview of all the revenue requirement adjustments being made and identifies whether the adjustment is electric only or natural gas only or common, and if it has a restating, pro forma and provisional pro forma component.

A. Common Adjustments

Q. Please provide an explanation of the common adjustments included in Exhs. SEF-6 and SEF-11.

A. The common adjustments are those that apply to both electric and natural gas operations and are contained in SEF-6 for electric operations and in SEF-11 for natural gas operations. An explanation of each of the proposed common adjustments is presented below:

1. Adjustment Nos. 6.01 and 11.01 - Revenues and Expenses

The restating adjustments included in this adjustment for electric and natural gas are those that are typically made in a Commission Basis Report ("CBR"). Additional restating adjustments are included for required annualizing adjustments that are not allowed in a CBR but that are required by the rules. The adjustments to electric and natural gas sales to customers are supported by Mr. Mickelson and Mr. Taylor, respectively. A discussion of the electric and natural gas adjustments by type of adjustment is as follows:

Restating Adjustments:

- For electric only, lines 17 and 70, a restating adjustment is made to remove the credits passed back to customers and the related amortization associated with Schedule 95A Federal Incentive Tracker. Lines 68, 69 and 71 remove Schedule 95A and interest that was in rates during the test year. The tax impacts associated with the Schedule 95A revenue and amortization are removed in the federal income tax adjustment, which is Adjustment 6.04;
- For electric only (line 18), a restating adjustment is made to remove revenues from Schedule 95 Power Cost Power Cost Adjustment Clause, which removes the revenues from PSE's 2020 power cost only rate case under Docket UE-200980 which occurred during the test year but which were zeroed out part way through the test year;
- For electric only, a restating adjustment is made to reclassify electric transportation revenues in Other Operating Revenues (line 56) to Sales to Customers (line 33) to support the electric cost of service process;
- For both electric (lines 25, 27, and 57) and natural gas (lines 24, 26, and 50), a restating adjustment is made to remove the credits passed back to customers during the test year that will no longer be in effect for the amortization of protected and unprotected EDIT in rate schedules 141X and 141Z. The amortization and tax impacts associated with these revenues are removed in the federal income tax adjustment, which is restating adjustment 6.04;
- For both electric (lines 26 and 55) and natural gas (lines 25, 45), a restating adjustment is made to remove the credits and related amortization for the amounts collected from customers in Schedule 141Y that will no longer be in effect;
- For both electric (lines 23 and 24) and natural gas (lines 19 and 21), a restating adjustment is made to remove the test year level of revenues from Schedule 141N for rates not subject to refund and Schedule 141R for rates subject to refund from PSE's 2022 general rate case as the full annualized amounts are added on a separate line discussed in the next bullet. For gas only, (line 17 and 41), a restating adjustment is made to remove the test year deferred revenues and reserve from Schedule 141D LNG Distribution Pipeline rates from PSE's 2022 general rate case for the same reason;
- For both electric (lines 29, 30, and 31) and natural gas (lines 20, 22 and 32), a restating adjustment is made to annualize rates from PSE's 2022 general rate case for base rates, Schedule 141N, and Schedule 141R. For gas only, (line 18), a restating adjustment is made to annualize rates from PSE's 2022 general rate case for Schedule 141D;

- For both electric (line 19) and natural gas (lines 23 and 46), a restating adjustment is made to remove the revenues from Schedule 141, which have residual charges in the test year;
- For gas only, the restating adjustments on lines 47, 53 and 61 relate to the removal of inter-book storage revenues and gas costs from Jackson Prairie. These adjustments are associated with the removal of PSE's Schedule 101 revenues and gas costs that are removed in the pass-through restating adjustment 6.02;
- For electric only, line 35 removes the revenues from the industrial customer migration from transportation schedule 449 Industrial to primary service schedule 31;
- For gas only, line 33 removes the revenues from a large Schedule 87T customer shutting down operations in 2023;
- For electric only, line 50 removes other operating revenues for the one time Electric Vehicle incentive credit;
- For electric only, line 34 adjusts the amount of unbilled revenue recognized in the test year for the actual test year billing determinants; and
- Finally, certain other adjustments that are not specifically identified result from the process conducted by cost of service of reconciling the test year and pro forma results that are determined based on applying the most current base rates to the normalized pro forma billing determinants. These amounts are reflected on lines 43 and 45 for electric (restating and proforma) and line 28 for natural gas.

<u>*Pro Forma Adjustments:*</u>

The pro forma amounts in this adjustment have been determined using the following approach:

- For electric and natural gas, the pro forma adjustments modify the test year revenues to the revenues that would have been collected during the test year if only the base rates from the 2022 general rate case had been in effect for the entire test year. The annualizing of base rates revenue was discussed in the restating section above. For purposes of determining the revenue requirement deficiency, the following steps were taken to reflect the revenue in the test year at 2022 general rate case base rates levels:

- This adjustment removes the decoupling deferrals to reflect the test year revenue on a volumetric basis (line 54 for electric and line 48 for natural gas); and

- The above step results in the test year revenue being reflected on a volumetric basis priced at 2022 general rate case base rates. Therefore, the final step is to weather normalize these revenues, which is performed in Adjustments 6.03 and 11.03 and discussed further below in my testimony.

- For both electric (lines 30 and 31) and natural gas (lines 30 and 31), a pro forma adjustment is made to remove the annualized revenues from Schedule 141N and Schedule 141R. These schedules are incorporated into base rates with this filing.

- For gas only, (line 29), a pro forma adjustment is made to remove the annualized revenues and reserve from Schedule 141D LNG Distribution Pipeline. The costs associated with these revenues are removed in Adjustment 11.39 as the regulatory outcome of these costs and revenues are pending in a separate proceeding in Docket UG-230393;

- For natural gas only, line 27 removes the revenues from Schedule 149, Gas CRM. The recovery of gas CRM investment was transitioned to base rates in PSE's 2022 GRC. Accordingly, these revenues are being set to zero;

- For natural gas only, lines 49 and 60 remove revenues and gas costs related to the curtailment and entitlement charges associated with PSE's Purchased Gas Adjustment; and

- For electric only, lines 36, 37, 38, and 60 remove the revenues and amortizations associated with Schedule 139 as prior Commission orders and statute require that there be no cross-subsidization resulting from this program. Additional costs and rate base for the program are removed in adjustment 6.02 and 6.42.

Adjustments to the Gap Year and Rate Years:

- Line 41 for electric and line 35 for natural gas provide an adjustment to the increase or decrease in revenue at current rates for the forecasted changes in rate year billing determinants. These adjustments are calculated by Mr. Mickelson for electric and Mr. Taylor for natural gas. Included in Electric Other Operating

- Revenue on line 61 is a forecast for the Washington paths and the Southern Intertie retail wheeling, network and ancillary services provided by PSE. Production related transmission revenues are included in the PCA mechanism and are not included in this adjustment. Rate year calculations are a result of estimated transmission usage based on transmission customer reservations and load forecasts multiplied by an estimated rate. Estimated transmission usage for any particular year may also include requests currently being studied and network requests for additional load. The estimated rate adds 3% inflation to Formula rate in the test year.

Q. Please continue to describe the revenue requirement adjustments in Exh. SEF-6 and Exh. SEF-11.

A. The next adjustment is Adjustment 6.02, Pass-through Revenue and Expenses.

2. Adjustment No. 6.02, 11.02 - Pass-through Revenue and Expense

This restating adjustment removes from operating revenues all rate schedules that are a direct pass through of specifically identified costs or credits to customers, such as the conservation rider, municipal and property taxes, the low-income rider and the decoupling adjustment mechanism. The associated expenses that are recorded in the test year for these direct pass-through tariffs are also removed in this adjustment.

3. Adjustment No. 6.03 and 11.03 - Temperature Normalization

PSE's temperature normalization adjustment to load for electric and natural gas is being reflected in the normalization calculations of Mr. Mickelson and Mr. Taylor. As I discussed above, due to adjustments 6.01 and 11.01, revenues have been reflected on a volumetric basis at 2022 general rate case base rates levels; therefore, the temperature normalization adjustment is necessary to restate and pro form test year delivered load and revenue to a level that would have been expected to occur had the temperatures during the test year been "normal." This adjustment is based on the difference between the actual test year loads and loads under normal conditions. The restating adjustment normalizes all non-decoupled revenues in the test year and is consistent with the methodology used in PSE's CBR. The pro forma adjustment normalizes the remaining revenues that were reflected on a volumetric basis as a result of the adjustment to remove the current decoupling deferrals that was discussed above in adjustment 6.01 and 11.01.

The test year was colder than normal requiring an adjustment to net operating income to bring revenues down to what would have occurred under normal conditions. The electric temperature load adjustment increases actual load by 603,690 MWhs. The natural gas load adjustments decrease actual therms by 57.3 million therms.

4. <u>Adjustment Nos. 6.04 and 11.04 - Federal Income Tax</u>

The restating adjustment restates the test year for the appropriate level of federal income tax ("FIT") expense for this case before the deduction for interest and is prepared in the same manner as prior rate cases.

This adjustment also includes the removal of the income tax credit associated with the PTC liability; the amortizations of protected-plus and unprotected EDIT that were included for pass back to customers in Schedules 141X and 141Z; and the tax impacts associated with Schedule 95A that were removed in Adjustment 6.01 discussed earlier.

To properly reflect federal income tax expense in total, aside from this adjustment, PSE applies the statutory rate of 21 percent to all of its rate making adjustments when appropriate. This method of adjusting total federal income tax expense alone would not adequately adjust FIT for permanent and temporary tax differences such as protected-plus EDIT, the tax benefit of PSE's Hydro Treasury Grant amortizations, and other flow-through items. These items result in PSE's effective tax rate being lower than 21 percent.

Additionally, as PSE is filing a multiyear rate plan that projects its utility plant, accumulated depreciation, accumulated deferred income taxes ("ADIT"), and depreciation expense, PSE's EDIT balances and the EDIT reversal must also be projected in the same manner. The pro forma, gap year and rate year adjustments to rate base necessary to properly treat the ADIT and EDIT balances following the IRS normalization rules are included in Adjustment 6.27 and 11.27, the Test Year Plant Roll Forward adjustment.

5. <u>Adjustment Nos. 6.05 and 11.05 - Tax Benefit of Interest</u>

As in prior general rate cases, PSE has included an adjustment to capture the tax benefit of interest for electric and natural gas operations, which in the test year is all recognized below the line. This adjustment recognizes the tax deduction related to the level of interest associated with rate base in each of the adjustment periods. The restating, pro forma, and gap year adjustments are calculated using the rate base for each period and the weighted average cost of debt of 2.63 percent that was realized during the test year as supported by Ms. Peterman and that is shown on page two of Exh. SEF-3 and Exh. SEF-7. The adjustments for each of the rate years are calculated using the rate base and the requested weighted average costs of debt of 2.67 and 2.63 percent for rate year one and rate year two, respectively, which are also shown on page two of both Exh. SEF-3 and Exh. SEF-7. The requested weighted average costs of debt for these periods are also supported by Ms. Peterman.

6. Adjustment Nos. 6.06 and 11.06 - Bad Debt Expense

Consistent with prior cases, this restating adjustment calculates the appropriate bad debt rate by using the average bad debt percentage for three of the last five years after removing the high and low years. Since historically, it takes four months to write-off a bill, the ratio of the write-off versus revenue is offset by four months. For example, a write-off booked in June is related to revenue that was recognized during the previous February. Using this relationship between February revenues and June write-offs results in the calculation of an appropriate percentage of write-offs associated with revenues in the test year. The bad debt percentage for a given year is calculated by taking the actual write-offs for the year ending in June and dividing them by the net revenues for twelve months ending in February for each of the years. The net test year revenues are multiplied by the calculated average bad debt percentage to determine the amount of restated bad debt expense. This normalized amount is compared to the actual test year level of bad debt expense to determine the effect on income. This bad debt percentage is also used in the conversion factor when determining the final revenue requirement. It is also used for any adjustments that are made to revenues, where appropriate, thus keeping the bad debt expense in line with the revenues included in the relevant periods as well as resulting in only a restating adjustment being required here.

Finally, because PSE uses a specific methodology for recovery of bad debt expense, the total bad debt expense on a regulated basis from this adjustment replaces the level of bad debt expense included in the forecasted O&M included in this filing as indicated on page two of Exh. SEF-13.

7. Adjustment Nos. 6.07 and 11.07 - Rate Case Expenses

Consistent with prior rate cases, this restating adjustment uses the average of the last two general rate cases to determine a normalized level of expense. The average cost is then allocated 50 percent to electric and 50 percent to natural gas. The average cost for the last two power cost only rate cases is also included for electric.

Because PSE is filing a two-year multiyear rate plan and the previous two general rate cases were each in place for a two-year period, the average costs for a general rate case were normalized for recovery over two years. Additionally, the normalization period for PCORCs is two years consistent with PSE's last multiyear rate plan and in recognition of the use of PCORCs in concert with the CGR Tracker I discussed earlier in my testimony. These normalized periods result in the restating rate case expense totaling $1.5 million for electric and $1.3 million for natural gas. These amounts are then compared to the amount PSE actually recorded in the test year for each type of rate case expense.

Finally, the forecasted O&M being included in this filing for the rate years does not include a level of expense for rate case expenses. Accordingly, the level of rate case expense from this adjustment is included in the forecasted O&M included in this filing as indicated on page two of Exh. SEF-13.

8. <u>Adjustment Nos. 6.08 and 11.08 - Excise Tax</u>

This restating adjustment adjusts the test year to actual expense for the Washington State excise tax that should be recorded for these costs.

9. <u>Adjustment Nos. 6.09 and 11.09 - Employee Insurance</u>

Please see the Prefiled Direct Testimony of Thomas M. Hunt, Exh. TMH-1T, for a detailed description of PSE's employee benefits. This is both a restating and pro forma adjustment. The restating adjustment annualizes the effect of the benefit cost increases during the test year using average test year participant counts. PSE's benefit costs included in this adjustment are Long Term Disability, Basic Life Insurance, and Wellness Credits. These costs are allocated to O&M based on the distribution of wages during the test year and then to electric and natural gas based on the direct labor allocator.

The pro forma adjustment adjusts the test year employee benefits expense to the most current average cost per participation based on the test year end of period participant count multiplied by the average cost as of September 2023. The forecasted O&M for the rate years does not track employee insurance separately. Accordingly, the level of employee insurance expense from this adjustment will be automatically adjusted to the level included in the forecasted O&M included in this filing as indicated on page two of Exh. SEF-13.

10. <u>Adjustment Nos. 6.10 and 11.10 - Injuries and Damages</u>

This restating adjustment restates injuries and damages to the three-year average of accruals and payments. When necessary, amounts are allocated to O&M based on the distribution of wages and then allocated between electric and natural gas based on the average number of customers allocator. Because PSE uses a specific methodology for recovery of injuries and damages, the total amount on a regulated basis from this adjustment replaces the level of injuries and damages expense in the forecasted O&M included in this filing as indicated on page two of Exh. SEF-13.

11. <u>Adjustment Nos. 6.11 and 11.11 - Incentive Pay</u>

Consistent with prior general rate cases, this adjustment, which impacts all periods, uses a four-year average of incentive compensation paid to employees, which is allocated between electric and natural gas operations. Mr. Hunt explains why this expense is appropriate for recovery in rates.

The forecasted O&M in this filing includes a specific level of expense for incentive payments. Because PSE uses a specific methodology for recovery of incentive payments, PSE has replaced the specific amount of incentives in the forecasted O&M with the four-year averaging normalization methodology using the forecasted incentive amounts as indicated on page 2 of Exh. SEF-13. These adjustments are made for all periods after the restating period.

The incentive payment is allocated to O&M based on the distribution of wages. The four-year average of the payouts is allocated between electric and natural gas O&M using the direct labor allocator. For the restating portion of this adjustment, PSE used the payouts that occurred in March for years 2020 through 2023, which related to calendar years 2019 through 2022. For the pro forma period adjustment, the four-year average was updated to include the expected 2024 payout for calendar year 2023 that was discussed above. For each subsequent period, the four-year average was updated to include the forecasted incentive payouts for the 2024 through 2027 periods that relate to calendar years 2023 through 2026.

12. <u>Adjustment Nos. 6.12 and 11.12 - Investment Plan</u>

This restating adjustment adjusts the PSE portion of investment plan expense to reflect the annualized expense associated with the wage increases during the test year and is based on the current employee contribution rates.

The forecasted O&M being included in this filing for the rate years does not track investment plan expense separately. Accordingly, the level of investment plan expense from this adjustment will be automatically adjusted to the level included in the forecasted O&M included in this filing as indicated on page two of Exh. SEF-13.

13. <u>Adjustment Nos. 6.13 and 11.13 – Interest on Customer Deposits</u>

This restating adjustment annualizes and allows recovery for the interest associated with using customer deposits as a reduction to rate base. Since this interest is originally recorded below the line in the test period, this restating adjustment adds to operating expense the cost of interest for this item based on the most currently implemented annual interest rate. Pursuant to WAC 480-100-113(9) and WAC 480-90-113(9), the interest rate paid on customer deposits is determined annually based on the interest rate for a one-year Treasury Constant Maturity as of the fifteenth day of January of that year. This approach is consistent with prior general rate cases. The forecasted O&M being included in this filing for the rate years does not include a level of expense for interest on customer deposits. Accordingly, the level of interest on customer deposits from this adjustment is included in the forecasted O&M included in this filing as indicated on page two of Exh. SEF-13.

14. <u>Adjustment Nos. 6.14 and 11.14 - Property and Liability Insurance</u>

This adjustment is both a restating and pro forma adjustment. The restating adjustment annualizes the most current property and liability insurance premiums, which became effective during the test year. Common property and liability insurance is allocated to electric and natural gas operations based on the non-production plant or number of customers allocation factor.

The pro forma adjustment reflects the known and measurable premium increases for property and liability insurance expense based on premium renewals in April or December 2023. Common property and liability insurance is allocated to electric and natural gas operations based on the non-production plant or number of customers allocation factor.

Insurance premiums related to wildfire coverage are included in these restating and pro forma adjustments. These premiums are then removed from the revenue requirement in Adjustment 6.22 Pro forma O&M so that O&M amounts for 2025 and 2026 do not contain insurance premiums for the development of the base rates revenue requirement. Instead, the premiums for that period are included in the independent revenue requirement calculation for Schedule 141WFP that I discuss further below.

The forecasted O&M being included in this filing for the rate years does not track the remaining non-wildfire property and liability insurance separately. Accordingly, the level of property and liability insurance from this adjustment will be automatically adjusted to the level included in the forecasted O&M included in this filing as indicated on page two of Exh. SEF-13.

15. Adjustment Nos. 6.15 and 11.15 - Deferred Gains and Losses on Property Sales

The amortization of deferred gains and losses adjustment impacts multiple periods. The restating adjustment is necessary to annualize the amortizations granted in Dockets UE-220066/UG-220067 that are not fully reflected in the test year. The rate year two adjustment for natural gas also includes the removal of the amortization of the deferred losses on PSE's water heater and conversion burner rental services that have been discontinued. These deferrals were authorized in Dockets UG-190784 and UG-200112. The gains and losses in this adjustment are also allocated between electric and natural gas based on the use of the property and amortized over three years.

16. <u>Adjustment Nos. 6.16 and 11.16 - Directors and Officers ("D&O") Insurance</u>

The restating adjustment removes the portion of D&O insurance that should be allocated to non-utility activity. This restating adjustment also annualizes the most current premiums, which became effective during the test year for D&O insurance. To allocate the restated insurance expense between utility and non-utility activity, PSE uses an allocation methodology evenly weighted between the 1) allocation of directors' fees and 2) allocation of covered employees' salaries. The total amount is then allocated to O&M expense in the same manner as the test year D&O insurance, which is based on where direct labor is charged. The restated D&O insurance applicable to O&M is then allocated between electric and natural gas operations based on the average number of customers allocator. The forecasted O&M being included in this filing for the rate years does not track D&O insurance separately. Accordingly, the level of D&O insurance from this adjustment will be automatically adjusted to the level included in the forecasted O&M included in this filing as indicated on page two of Exh. SEF-13. The level of insurance included in the forecasted O&M only includes the portion allocable to utility operations.

17. <u>Adjustment Nos. 6.17 and 11.17 - Pension Plan</u>

This restating adjustment calculates pension expense based on a four-year average of cash contributions to PSE's qualified retirement fund.

PSE made tax deductible cash contributions totaling $72 million for the four-year period ending June 30, 2023. For the restating adjustment, the four-year average of $18 million is allocated to O&M based on the distribution of wages, and then allocated between electric and natural gas based on the direct labor allocator.

The forecasted O&M being included in this filing includes pension expense based on a forecast of the expense on a GAAP basis. Because PSE uses a specific methodology for recovery of pension expense, PSE has replaced the specific amount of GAAP basis pension expense in the forecasted O&M with the four-year averaging normalization methodology using the forecasted amount of plan contributions as indicated on page 2 of Exh. SEF-13. The forecasted plan contributions are $18 million per year from 2024 through 2026. The forecasted amounts for each period beyond the restating period are also allocated to O&M based on the distribution of wages and then allocated between electric and natural gas based on the direct labor allocator.

18. <u>Adjustment Nos. 6.18 and 11.18 - Wage Increase</u>

This is a restating adjustment that reflects the impact of wage increases and payroll tax changes, as described by Mr. Hunt. No pro forma adjustment is made as wage expense in the forecasted O&M being included in the rate years is used as the basis of the wage expense for the periods beyond the restating period. Mr. Hunt discusses incremental amounts for union wage increases that have occurred since the test year and are included in the forecasted wages in the board approved O&M used as the basis for this filing. Accordingly, the level of restated wage expense from this adjustment will be automatically adjusted to the level included in the forecasted O&M as indicated on page two of Exh. SEF-13.

For represented (union) employees, the restating adjustment reflects the known annual wage increases that were granted in the approved contracts for the International Brotherhood of Electrical Workers (“IBEW”) and United Association of Plumbers and Pipefitters (“UA”) union employees. A contracted wage increase percentage for IBEW union employees of three percent occurred on January 1, 2023. A contracted wage increases for UA union employees of three and one-half percent occurred on October 1, 2022.

The average wage increase used in the restating adjustment for non-union employees includes the known wage increase of 7.0 percent that was paid in January 2023 and 3.46 percent that was paid effective March 1, 2023. These wage increases are discussed by Mr. Hunt. As in prior rate cases, this increase has been weighted by prior year actual salary increases. This is done to account for “slippage,” as it is sometimes called, that occurs when new non-union employees are hired at lower salary rates than the more senior employees they are replacing.

19. <u>Adjustment Nos. 6.19 and 11.19 – AMA to EOP Rate Base</u>

As discussed earlier in my testimony, PSE’s test year rate base was developed using historical AMA balances for the 13 months ended June 30, 2023. This restating only adjustment moves the average rate base balances to actual EOP balances as of June 30, 2023 as was done in the prior case.

20. <u>Adjustment Nos. 6.20 and 11.20 – Update and Annualize Depreciation Rates</u>

The adjustment restates test year depreciation expense as if the end of period balances were in effect for the entire test period. It also annualizes the impact of the full depreciation study that was approved in the 2022 general rate case. Additionally, this adjustment reduces the annual expense for assets that use the end-of-life convention down to their end of period levels. The amortization of these assets is calculated by spreading the gross cost of the assets over a specified life and automatically retiring the asset, thus stopping amortization once the accumulated amortization equals the asset's gross cost.

This adjustment also reclassifies the depreciation on asset retirement costs ("ARC") and asset retirement obligations ("ARO") to depreciation expense. For financial reporting purposes, PSE follows Accounting Standards Codification ("ASC") 410 which governs accounting for AROs. An ARO is a legal obligation associated with the retirement of an asset, where the company is legally responsible for such things as removing equipment or cleaning up hazardous materials at some future date. ASC 410 requires that the ARO be recorded at its discounted net present value and then accreted over time to equal the future value of the remediation. In addition to the ARO, ASC 410 also requires the recognition of an ARC that is depreciated over the life of the asset to which the ARO relates ("underlying asset"). To accomplish this, PSE reclassifies amounts from the net salvage component[55] included in the depreciation of the underlying asset, which is

[55] Mr. Allis defines net salvage in his Prefiled Direct Testimony, Exh. NWA-1T.

recorded at studied rates in order to recognize its ARO accretion and ARC depreciation. In this adjustment, the reclassification is essentially reversed, which restores the depreciation expense from the ARC depreciation and ARO accretion to the underlying assets. This is necessary to properly compare the depreciation expense on the same basis as the rates as studied in the depreciation study presented in this filing.

Notably, PSE is not presenting a separate gas depreciation study adjustment for the current gas depreciation study presented in this case within the revenue requirement calculation. PSE is rolling forward all of its existing test year plant as well as including all of its forecasted capital additions in its request. The new gas depreciation rates are utilized in calculating the adjustments associated with PSE's proposed treatment of utility plant,[56] and therefore, a separate stand-alone adjustment for the depreciation study is not needed.

In order to transparently provide the impact of the gas depreciation study, I have provided Exh. SEF-16, which calculates the gas depreciation expense for 2025 and 2026 without the use of the new depreciation rates and provides the difference to the amounts that were determined using the new depreciation rates. Exh. SEF-16 shows that gas depreciation expense is $76.9 million higher in total in 2025, with a further increase of roughly $2.8 million for 2026. Mr. Allis

[56] Adjustment 6.28/11.28 Proforma Retirements Depreciation, Adjustment 6.29/11.29 Programmatic Provisional Proforma, Adjustment 6.30/11.30 Customer Driven Programmatic Provisional Proforma, Adjustment 6.31/11.31 Specific Provisional Proforma and 6.32/11.32 Projected Provisional Proforma.

discusses the need for the new gas depreciation rates and underlying reasons for the changes in the rates in his Prefiled Direct Testimony.

Additionally, to recognize the full impact of the increases in depreciation expense on the EOP accumulated depreciation, in this adjustment, PSE increased the balance of accumulated depreciation by the respective increases in depreciation expense. Finally, the change to book depreciation expense necessitates a change to deferred taxes, which are decreased by 21 percent of the change to accumulated depreciation.

21. Adjustment Nos. 6.21 and 11.21 – WUTC Filing Fee

This restating adjustment adjusts the test year WUTC Filing Fee to the level of expense that should have been recorded in the test year for these costs. In order to properly match the level of WUTC Filing Fee to the revenues included in the results of operations for each period, PSE applies the WUTC fee of 0.4 percent to all adjustments made to revenue as appropriate. Accordingly, the level of WUTC Filing Fee included in the forecasted O&M in Adjustments 6.22 and 11.22 is replaced with the WUTC Filing Fee from this and all other adjustments as indicated on page two of Exh. SEF-13.

22. Adjustment Nos. 6.22 and 11.22 – Pro forma O&M

The level of O&M PSE is requesting is based on its approved O&M levels in its board approved plan. These amounts are presented by Mr. Kensok. I have taken the approved O&M levels and adjusted them to reflect the approved O&M levels on a Commission Basis. Table 5, below, provides an overview of how the approved O&M has been adjusted to be reflected on a Commission Basis. Exh. SEF-15 provides additional details for the adjustments that are reflected in Table 5.

Table 5. Overview of Approved O&M Forecast on a Commission Basis

Row	Description	2025	2026
a	Board approved target	**$ 848,000,000**	**$ 876,000,000**
b			
c	Add: Incremental Wildfire Costs	3,329,579	3,819,757
d	Add: Phase 2 Decarb Study Costs	10,600,000	11,700,000
e	Add: Participatory Funding	-	-
f	Add: LTIP	966,856	1,000,696
g	Total Approved Plan as Adjusted	**$ 862,896,435**	**$ 892,520,453**
h	Remove Non-Utility/Non-Rate Case (Puget LNG, Low Income Amort, Green Power)	(72,755,380)	(71,199,304)
i	Remove Items Recovered Elsewhere (Colstrip, Transp Elect, Unselected CETA projects)	(45,340,995)	(29,684,165)
j	Regulatory Adjustments (mainly RSIs on above and GAAP Pension to regulatory)	(24,542,603)	(34,063,463)
k	Total Requested O&M	$ 720,257,457	$ 757,573,521
l	Base Rates	$ 678,539,269	$ 713,787,536
m	Schedule 141CGR - Clean Generation Resources Tracker	13,631,606	13,904,238
n	Schedule 141WFP - Wildfire Prevention Cost Recovery Adjustment	17,486,582	18,181,747
o	Schedule 141DCARB - Decarbonization Rate Adjustment	10,600,000	11,700,000
p	Total Requested O&M	$ 720,257,457	$ 757,573,521

This adjustment, which impacts the rate year periods, adjusts O&M to the level reflected in Table 5. This adjustment also sets the level of payroll taxes to match the wage expense that is included in the approved plan.

Additionally, page two of Exh. SEF-13 provides an overview of how the items within the approved plan were adjusted to be reflected on a Commission Basis.

23. <u>Adjustment Nos. 6.23 and 11.23 – Advanced Meter Reading ("AMR") Regulatory Asset</u>

As a result of its last rate case, PSE is recovering the regulatory asset for the undepreciated AMR assets over twenty years. See the discussion of the Advanced Metering Infrastructure rollout below. Therefore, the test year must be adjusted to remove the rate base and depreciation expense for these items and also to include the regulatory asset and amortization expense, which is done in Adjustment 6.41 and 11.38 Regulatory Assets and Liabilities. This adjustment removes the AMR assets and depreciation expense that are still included in the end of period rate base from Adjustment 6.19/11.19 AMA to EOP Rate Base and Adjustment 6.20/11.20 Update and Annualize Depreciation Rates. Additionally, the target amounts used in Adjustment 6.27/11.27 Test Year Plant Roll Forward do not include AMR plant utility accounts to ensure that the plant assets removed in this adjustment are not reintroduced into the revenue requirement calculation.

24. <u>Adjustment Nos. 6.24 and 11.24 – Advanced Metering Infrastructure ("AMI") Plant and Deferral</u>

Installation of PSE's advanced metering infrastructure began in 2016 under a strategy explained in the Prefiled Direct Testimony of Roque B. Bamba, Exh. RBB-1T. AMI provides communication network and metering equipment in PSE's electric and natural gas service territory that has largely replaced its existing AMR system. In past rate cases, PSE was not allowed to include in rates both the debt and equity return on its AMI investment. All told, PSE has had to defer over $40 million of recovery for AMI return – $8.1 million related to debt return before it was allowed to be incorporated into rates and $33.0 million of equity return that is being requested for recovery in this proceeding. This pro forma adjustment is comprised of the following three components:

a. As part of its last rate case, PSE began recovering the debt return on its AMI investment and was allowed to continue to defer its equity investment on AMI as of December 2023. Accordingly, for purposes of conforming with WAC 480-07-510(3)(c)(i) only, the restating adjustment on line 35 removes the equity portion of the AMI investment from rate base as the Commission has not yet allowed the equity portion of the AMI investment to be included in rate base. This adjustment is immediately reversed in the pro forma period as PSE is requesting all AMI investment be included in rate base in this proceeding. The justification for including AMI in rate base in this proceeding is supported by Mr. Bamba.

b. An additional pro forma adjustment is made on line 38, which removes the entries to defer the debt and equity return on AMI plant from the test year.

c. An adjustment in 2025 is made on line 47 to include the rate year amortization of the deferral of the equity return on AMI plant over three years. A three-year amortization period was chosen due to the relative size of the deferrals.

d. Although PSE believes that it has met all requirements to be allowed to include recovery of the equity return on its existing and forecasted AMI investment, should the Commission not allow recovery of the equity return on AMI as requested, PSE respectfully requests that it be allowed to continue to defer its equity return on the forecasted level of investment approved for AMI in this filing until a proceeding in which the equity return on AMI is granted for recovery in rates.

25. <u>Adjustment Nos. 6.25 and 11.25 - Environmental Remediation</u>

The amortization of environmental remediation deferrals impacts multiple time periods. The restating adjustment is necessary to annualize the amortizations granted in the 2022 general rate case that are not fully reflected in the test year. The adjustments to the remaining periods adjust the amortization to approved levels as well as to include additional environmental remediation costs that have not been incorporated into rates as of the end of the test year. This adjustment also amortizes over five years a corresponding amount of the third party and insurance proceeds, either directly assigned or prorated, that are deferred as of June 30, 2023. This adjustment follows the allocation methodology that has been developed in collaboration with Commission Staff and that was utilized in Dockets UE-190529 and UG-190530.

26. <u>Adjustment Nos. 6.26 and 11.26 – Estimated Plant Retirements Rate Base</u>

PSE is forecasting its entire utility plant balance in each of the rate years based on the roll-forward of its test year plant balances and its approved capital additions forecast as presented by Mr. Kensok. This adjustment recognizes the impact on gross plant and accumulated depreciation for the transfer that occurs when assets are retired. The retirements transfer has no impact on overall rate base but is needed to present the appropriate amount of gross plant and accumulated depreciation when those categories are used independently.

This adjustment only includes the adjustment to rate base associated with retirements. Adjustment 6.28/11.28 adjusts for the impact of retirements on depreciation expense and accumulated depreciation. This adjustment and Adjustment 6.28/11.28 are companion adjustments to Adjustment 6.27/11.27 – Test Year Plant Roll Forward. Taken together, the three adjustments provide the benefit of the continued depreciation net of retirements that will occur on test year plant during the multiyear rate plan periods.

The estimated retirements are based on a historical three-year average of retirements. The method for estimating retirements is discussed in more detail in

Adjustment 6.28/11.28. Retirements after 2024 included in this adjustment have been included in this filing subject to refund as discussed above.

27. <u>Adjustment Nos. 6.27 and 11.27 – Test Year Plant Roll Forward</u>

As PSE is forecasting its full utility plant balance in each of the rate years, this adjustment provides the benefit of the additional depreciation that will occur on test year plant. This adjustment is prepared in the same manner as the previous rate case. Mr. Marcelia provides a detailed description of how this adjustment is calculated [57]. As discussed above, it does not include the impact of retirements on rate base or depreciation expense, as those impacts are included in Adjustments 6.26/11.26 and 6.28/11.28.

This adjustment accommodates for two different impacts associated with rolling forward test year plant. Amounts for AMR, Colstrip, and Tacoma LNG are not included in the targeted amounts in this adjustment as they are intended to be removed from this filing as discussed in other areas of my testimony.

a. **<u>Adjustments to Existing Test Year Depreciation</u>** – Absent retirements, as test year depreciation expense is carried forward, the depreciation for depreciable assets will generally remain at the same level as these assets are depreciated on a straight line basis through the application of a depreciation rate. Changes to test year depreciation expense on existing plant that do occur with the passage of time are decreases to depreciation that are the result of a) asset classes that are accounted for using the end of life convention, and b) intangible assets such as software that are on a set amortization schedule[58] so that depreciation expense on the asset ceases and overall depreciation expense is reduced once the intangible asset is fully amortized. This part of the adjustment accounts for the impact on depreciation expense

[57]Mr. Marcelia provides a detailed description of the process used in Exh. MRM-3.
[58] As opposed to through the application of a depreciation rate.

and rate base for the benefit of the reduction to test year depreciation expense for end of life and intangible amortization. The impacts to rate base are the result of the additional accumulated depreciation that occurs as well as the corresponding impact to ADIT.

b. **Incorporation of the Rates from the New Depreciation Study** – As discussed above, PSE is presenting a new gas depreciation study for approval in this filing. This adjustment reflects the use of PSE's existing depreciation rates through 2024 and the incorporation of new rates beginning in 2025, after the study would be approved.

28. Adjustment Nos. 6.28 and 11.28 – Provisional Pro forma Retirements Depreciation

This adjustment is a companion adjustment to Adjustments 6.04, 11.04, 6.26, 11.26, 6.27 and 11.27 discussed above. This adjustment provides for the benefit of the decrease to depreciation expense and the corresponding impact on accumulated depreciation that will occur during the multiyear rate plan periods for the estimated retirements included in Adjustments 6.26 and 11.26. The impact on ADIT (including EDIT) is included in Adjustments 6.27 and 11.27.

PSE used a three-year historical average of retirements after adjustment for nonrecurring activity.

This adjustment also takes into consideration the new depreciation rates discussed above; retirements that occur after 2024 are valued at the proposed new depreciation rates.

29. Adjustment Nos. 6.29, 6.30, 6.31, 6.32, 11.29, 11.30, 11.31, and 11.32 – Provisional Pro forma Plant Adjustments

All four adjustments, 6.29/11.29 through 6.32/11.32 provide for the impact on depreciation expense and rate base for the pro forma and provisional pro forma adjustments related to PSE's forecasted capital additions. The method for calculating these adjustments is the same as utilized in the prior rate case. These adjustments also incorporate the depreciation rates from the new gas depreciation study starting in 2025. Mr. Marcelia provides a detailed description of how these adjustments are calculated.[59]

A detail of the rate base by project or program has been provided in Exh. SEF-17. Exh. SEF-17 also provides the list of witnesses who discuss each of the specific and programmatic adjustments.

Table 6, below, provides a reconciliation between the board approved capital additions as presented by Mr. Kensok and the capital additions included in the rate years in the MYRP. Amounts included in the below table are the basis for these provisional proforma adjustments as well as Exh. SEF-14 and Exh. JAK-5.

[59] *See* Exh. MRM-3.

Table 6. Reconciliation of Requested Capital Additions

Row	Reconciliation of Gross Capital Additions Description	2025	2026
(a)	(b)	(c)	(d)
		(in millions)	
9	Capital Additions Originally Approved	$ 2,975.7	$ 1,244.7
10	Move the closing date for Marine Crossing beyond 2026	(1.0)	(19.8)
11	Adjust project categories and in service dates for Distributed Energy Resource projects	26.6	(28.4)
12	Adjust in-service assumptions on Infrastructure Program Management projects	21.6	20.7
13	Adjust in-service assumptions from December to August 2025 for Beaver Creek	(35.6)	
14	Add incremental wildfire projects	15.4	23.4
15	Basis for Capital Additions for the multiyear rate plan supported by Mr. Kensok	$ 3,002.7	$ 1,240.5
16	Remove items not included:		
17	Clean Energy Resources not yet selected	(726.7)	(2.1)
18	Items recovered outside of rate cases:		
19	Transportation Electrification Plan (Schedule 141TEP)	(12.8)	(13.3)
20	Colstrip (Schedule 141COL)	(15.3)	-
21	Tacoma LNG Facility (Schedule 141LNG)	(0.1)	(0.1)
22	Total Capital Additions for General Rate Case before CWIP in Rate Base Treatment	$ 2,247.6	$ 1,225.1
23	Remove Beaver Creek AFUDC from January through August 2025	(24.1)	-
24	Total Capital Additions for General Rate Case with CWIP in Rate Base Treatment	$ 2,223.5	$ 1,225.1
25			
26	Base Rates	$ 1,646.1	$ 1,157.8
27	Schedule 141CGR - Clean Generation Resources Tracker	528.3	-
28	Schedule 141WFP - Wildfire Prevention Cost Recovery Adjustment	49.1	67.3
29	Total Capital Additions for General Rate Case	$ 2,223.5	$ 1,225.1

30. <u>Adjustment Nos. 6.33 and 11.33 – Remove Test Year Deferrals</u>

This adjustment removes various deferral entries from the test year that have not been removed in other adjustments. For electric, lines 17 and 28 removes the deferral of revenues and expenses related to amounts recovered in Schedule 141TEP – Transportation Electrification Plan Adjustment Rider. For natural gas, line 27 removes the deferrals related to the regulatory asset related to the distribution upgrades for the Tacoma LNG project. For both electric and gas, line 30 (electric) and line 29 (gas), the adjustment removes the deferrals related to the GTZ depreciation expense deferral that was approved for recovery part way through the test year. Also for electric and gas, line 29 (electric) and lines 32 and

33 (gas), the adjustment removes the emissions expense accrual (gas only) and deferral of the emissions expense (both electric and gas) that are allowed under Dockets UE-220974 and UG-230471 associated with the CCA as discussed in Section VII of my testimony. On the electric side, there is no removal of the emissions expense as that adjustment is inherently included in Adjustment 6.38 Power Costs.

31. <u>Adjustment Nos. 6.34 and 11.34 – Regulatory Filing Fee Deferral</u>

Effective June 9, 2022, RCW 80.24.010 was amended to increase the Commission regulatory fee from 0.2 percent of revenues to the newly approved level of 0.4 percent. The Commission granted PSE's accounting petition as amended in Dockets UE-220407 and UG-220408 to defer the increased cost of the regulatory fee. PSE is now requesting recovery over two years of the deferral of costs, including interest at its actual cost of debt updated semi-annually for December and July. This increased cost is related to a mandatory fee, and as such, should be allowed for recovery.

This is both a restating and pro forma adjustment. The restating adjustment removes the deferral recorded during the test year and the pro forma adjustment includes the amortization over two years of the deferral for calendar year 2025 and 2026. PSE has not requested rate base treatment for this regulatory asset as the petition allows PSE to accrue interest while the regulatory asset is amortizing.

32. <u>Adjustment Nos. 6.35 and 11.35 – Participatory Funding Grant</u>

This adjustment provides for the revenue requirement associated with participatory funding agreements for grants that are governed by the Revised Extended Interim Funding Agreement approved in Docket U-210595. The restating adjustment removes funding payment expenses incurred during the test year as PSE will seek to recover those amounts in Schedule 141PFG Participatory Funding Agreement Rate Adjustment to be filed in 2024. The adjustment also pro forms in the funding levels for PSE established in Order 02 of Docket U-210595, which have been allocated between gas and electric based on payments made in 2023. Please refer to Mr. Mickelson for PSE's proposal for rate recovery related to participatory funding and schedule 141PFG.

33. <u>Adjustment Nos. 6.36 and 11.36 – Amortization of the Targeted Electrification Activities Deferral</u>

This adjustment includes the rate base and amortization for the deferral associated with targeted electrification activities allowed in the 2022 Revenue Requirement Settlement. The requested rate base treatment for the deferral follows prior allowed treatment related to AMI deferrals as approved in Dockets UE-190529 and UG-190530, et al., specifically, paragraph 6 of Order No. 10 Granting Motion for Clarification. Mr. Mannetti provides testimony about the costs that are forecasted in the deferral balance. A two-year amortization period for recovery of the deferral is proposed. My adjustments were originally set up assuming this adjustment would be common to both electric and gas. However, per the 2022 Revenue Requirement Settlement, it appears these costs are intended to be recovered from electric only customers.[60] Therefore, although there is an Adjustment 11.36 for gas, no actual adjustment is made on the exhibit page. The revenue requirement associated with this adjustment is separately stated in column k row 74 on page one of Exh. SEF-4 (the revenue requirement summary page) to allow Mr. Mickelson to apply the rate spread methodology included in the settlement agreement.

34. Adjustment Nos. 6.37 and 11.37 – Long Term Incentive Plan ("LTIP") Payments

In Docket UE-090704, the Commission determined that PSE could no longer recover the costs of its Long Term Incentive Plan ("LTIP") in rates,[61] and PSE has not included LTIP since that time. However, as discussed by Mr. Hunt in his Prefiled Direct Testimony, PSE's LTIP program has recently changed and in recognition of Washington laws such as CETA, it now measures and incentivizes executives to achieve Environmental, Social and Governance ("ESG") goals in order to receive a payout. Ten percent of LTIP funding in the 2023-2025 cycle is based on achievement of reduction in carbon intensity. Accordingly, PSE is requesting ten percent of the costs of the program be recovered in rates. Mr. Hunt provides the details for how the program works. This adjustment assumes an initial funding level of $12 million that increases three percent per year. Ten percent of the payout that is estimated for 2025 and 2026 is used for the adjustment. This amount was then allocated to O&M using the O&M allocator

[60] *WUTC v. PSE*, Dockets UE-220066 *et al.*, Revenue Requirement Settlement ¶ 67g (Dec. 22, 2022).

[61] *WUTC v. PSE*, Dockets UE-090704 and UG 090705, Order 11, ¶ 81 (April 2, 2010). Previously referred to as the Supplemental Excess Benefit Retirement Plan, or SERP.

and then between electric and gas based on the number of customers allocator. Because PSE uses a specific methodology for recovery of these costs, PSE has added these amounts to the forecasted O&M, which included no estimate of LTIP expenses as indicated on page 2 of Exh. SEF-13.

B. Electric Only Adjustments

Q. Please explain the electric only adjustments.

A. Explanations of the electric only adjustments are as follows:

1. Adjustment No. 6.38 - Power Costs

This adjustment impacts multiple periods. The restating adjustment is applied in the same manner as in a Commission Basis Report and is intended to depict power costs under normal temperature and power supply conditions. Test year power costs are adjusted to recognize the changes in load and generation from test year levels summarized below. The following changes in load and generation are priced at the Mid-Columbia flat dollar per MWh embedded in rates that were in effect for the month being repriced:

a. the change in load used in the weather normalization adjustment (Adjustment No. 6.03), and

b. the adjustment to reflect hydro and wind volumes at normal levels based on levels assumed in the most recent rate case as they are also impacted by weather.

Additionally, an adjustment is required for the equity component of the TransAlta Centralia Coal Transition Power Purchase Agreement ("PPA") approved by the Commission in Docket UE-121373. This adjustment is necessary to make actual booked expenses, which do not include regulatory adjustments, match the recovery built into rates. Further adjustments are required to this item in the rate years as the contracted volumes used to determine the equity adjustment decline and eventually are eliminated in 2026 with the end of the contract.

On line 33, PSE has included a return on CETA PPAs, which is allowed under RCW 80.28.410(2)(b). The PPAs on which the return is calculated are discussed in more detail in Adjustment No. 6.47. To determine the return on the PPAs, PSE has utilized its authorized rate of return as allowed under the statute. The amount of return included in this adjustment was determined by multiplying PSE's authorized rate of return by the annual PPA costs included in power costs by Mr. Mueller. Use of PSE's authorized rate of return is discussed by Mr. Doyle.

The rate year adjustments represent the power costs that are projected to be incurred during the rate years. The calculation of the projected power costs for the rate years is explained by Mr. Mueller. The change in power costs between the 2024 power cost update approved in Docket UE-230805, and the current proceeding, are shown in Exh. BDM-3C. The change in power costs between rate years one and two, is also included in Exh. BDM-3C.

Line 30 represents the production O&M that is forecasted for each of the rate years that is presented in the Prefiled Direct Testimony of Mark A. Carlson, Exh. MAC-1CT.

Line 31 presents the transmission expenses that are related to the Third AC, Northern Intertie and Colstrip transmission lines. This category of costs is left at its historical test year level and requires no adjustment.

Line 32 presents a forecast of revenues associated with variable transmission revenue earned under PSE's Open Access Transmission Tariff ("OATT") for retail wheeling, network, and ancillary services.

The increase in Other Operating Revenue from the test year to the first rate year in 2025 was discussed above.

Q. Will you update the PCA mechanism's baseline rate in this proceeding?

A. Yes. I have provided the corresponding fixed and variable power cost baseline rates in Exh. SEF-12. PSE will update these baseline rates at the compliance filing in this proceeding as these baseline rates will need to be approved for use in the accounting for PSE's PCA and electric fixed production decoupling mechanisms.

Q. Please continue with your discussion of the electric only adjustments.

A. The following are additional electric only adjustments.

2. <u>Adjustment No. 6.39 - Wild Horse Solar</u>

This adjustment impacts multiple periods. The restating adjustment removes the effects of the solar project at PSE's Wild Horse wind facility. This solar power project is a demonstration project, and PSE is not requesting recovery of the costs associated with it at this time.

The adjustments beyond the restating period are made to counteract the results of moving test year rate base forward to the rate years in Adjustment 6.27. As discussed above, Adjustment 6.27 adds the additional depreciation expense and accumulated depreciation for test year utility plant that will occur through the rate years. Adjustment 6.27 starts with all test year plant and does not isolate projects such as Wild Horse Solar. Therefore, any inherent incremental changes to Wild Horse Solar that are occurring within Adjustment 6.27, such as the additional accumulated depreciation, are removed through this adjustment.

3. <u>Adjustment No. 6.40 – Storm Expense Normalization</u>

This adjustment impacts the restating period and the first rate year. The restating adjustment adjusts the test year expense level of storm damage expense of $8 million to the normalized level of storm damage expense, based on the average of the most recent six years as has been done in prior general rate cases.

The adjustment for the first rate year adjusts the normalized storm expense in the restated results of operations to the current $10 million threshold level of storm expenses included in rates.

Because PSE uses a specific methodology for recovery of normalized storm expenses, PSE has replaced the specific amount of storm expense in the forecasted O&M with the $10 million threshold of normalized storm expense as indicated on page 2 of Exh. SEF-13.

4. Adjustment No. 6.41 - Regulatory Assets and Liabilities

This adjustment includes regulatory assets and liabilities that have been approved for recovery in a previous rate case and impacts all periods beyond the restating period to adjust certain regulatory assets and liabilities to the proper amounts in the rate years. The amortization of power cost-related regulatory assets and liabilities on lines 43 and 44 are considered variable costs in PSE's PCA mechanism and have been adjusted in the power cost adjustment, Adjustment 6.38. As a result, although the rate base section of this adjustment reflects the AMA of the rate year for both power cost and non-power cost regulatory assets and liabilities, only the non-power cost regulatory asset and liability amortizations for the rate years are reflected in this adjustment. The regulatory assets and liabilities for which amortization expires part way through the rate years only include amortization for the applicable months during the rate years.

Q. Are there any regulatory assets or liabilities on this adjustment that require changes since previously approved in the last general rate case?

A. Yes. The AMR regulatory asset (line 30 and 61) was included in the prior rate case as an estimate. Now that the AMI rollout is substantially complete, the AMR regulatory asset balance has been updated to reflect actual amounts where known. Information for this adjustment is provided by Mr. Smith who discusses the change in the regulatory asset balances from $74.6 million in the prior case to $80.8 million in the current case. The amortization period has been maintained at the original 20-year period approved in the prior rate case.

Q. Please continue discussing the electric only adjustments.

A. The next adjustment is:

5. <u>Adjustment No. 6.42 – Green Direct</u>

This adjustment removes the rate base and operating expenses associated with PSE's Green Direct program as Washington law and prior Commission orders require that there be no cross-subsidization resulting from this voluntary program. The revenues for this program were removed in electric Adjustments 6.01 and 6.02. Additionally, the PPAs used to serve this program are not included in power costs as prepared by Mr. Mueller.

6. <u>Adjustment No. 6.43 – Storm Deferral Amortization</u>

This adjustment relates to PSE's storm deferral mechanism.[62] PSE provides regular reporting on qualifying events in Docket UE-040641.

The restating adjustment is made to annualize the level of test year storm deferral amortizations to the level approved in PSE's 2019 and 2022 general rate cases.

The adjustment for the first rate year (2025) calculates the impact on amortization of new storm deferral balances that have not been previously approved. PSE's 2022 general rate case provided recovery of storm deferrals as of November 2021. This adjustment includes amortization for qualifying storms that have been deferred since that time for events that occurred in December 2021, in 2022, and

[62] *WUTC v. PSE*, Dockets UE-040641 *et al.*, Final Order No. 6 ¶ 246; *WUTC v. PSE*, Dockets UE-072300/UG-072301, Final Order No. 12 ¶ 10; *WUTC v. PSE*, Dockets UE-111048/UG-111049, Order 08 ¶¶ 206, 299.

in 2023 through November 2023. There were two qualifying events in December 2021, six qualifying events in 2022, and three qualifying events in 2023. The three qualifying events in 2023 did not meet the threshold for deferral. This adjustment updates the amortization through the December 23, 2022 qualifying event, which was the sixth event for 2022 and the most recent event for which deferred costs have been included in PSE's November 2023 close. Please see the Prefiled Direct Testimony of David J. Landers, Exh. DJL-1T for a discussion of PSE's qualifying storm events.

An adjustment for the first rate year (2025) is also made to recognize that the storm amortization for the events that were approved for recovery in PSE's 2019 general rate case will finish amortizing in June 2025.

7. Adjustment No. 6.44 – Colstrip Removal

This adjustment removes the revenues, depreciation, and operating expenses as well as the production related rate base for all Colstrip units as these amounts are now recovered in a separate tariff, Schedule 141COL – Colstrip Adjustment Rider.

8. Adjustment No. 6.45 – Acquisition Adjustments

PSE has a number of acquisition adjustments recognized in FERC account 114 related to past purchases of generating facilities, one of which will fully amortize by the end of the multiyear rate plan. This adjustment adjusts rate base for the additional accumulated amortization that will occur through the multiyear rate plan periods and reduces amortization expense to recognize that the acquisition adjustment associated with the Encogen Generating Station was fully amortized in 2023.

9. <u>Adjustment No. 6.46 – Transportation Electrification Plan Tracker</u>

This restating adjustment removes the rate base, depreciation, and operating and maintenance expenses associated with PSE's Transportation Electrification Plan ("TEP") from the test year, as TEP investments are recovered in a separate tracker tariff, Schedule 141TEP– Transportation Electrification Plan Adjustment Rider.

10. <u>Adjustment No. 6.47 – CETA DR PPA Deferrals</u>

In 2023, PSE began incurring costs under contracts that were selected in its Clean Energy Action Plan ("CEAP") which are eligible for deferral under RCW 80.28.410. The three, five-year demand response ("DR") PPAs that PSE has entered into include: Oracle America, Inc. (Opower) on March 10, 2023; AutoGrid Systems, Inc. on July 14, 2023; and Enel X North America, Inc. on September 27, 2023. In his Prefiled Direct Testimony, Exh. GA-1T, PSE witness Gilbert Archuleta provides testimony in support of these PPAs. The PPAs are for capacity and the associated conservation attributes of the demand response aggregators' services and are qualified resources under RCW 19.280.030. Therefore, the cost of these PPAs, in addition to a return on the PPA costs, are eligible for deferral under RCW 80.28.410. PSE requested this deferral in Docket UE-230810.

In its deferral petition, PSE requested that it be allowed to defer a return at its authorized rate of return as allowed under the statute.

PSE's 2024 power cost update filing made as part of its current MYRP in Docket UE-230805, has a rate effective date of January 1, 2024. That rate request includes the PPA costs associated with these PPAs, but does not include the return on the PPAs.

Therefore, this adjustment includes a pro forma adjustment to include the deferral of $0.9 million PPA costs incurred from the start of the deferral through when rates from Docket UE-230805 became effective. Although PSE's accounting petition requested the deferral begin in July 2023, PSE has modified the deferral to begin when the petition was filed in September 2023. Additionally, PSE has included in the deferral an offset for the benefit of the PPAs as directed in the final order in Docket UE-230805. The rate base treatment requested for this deferral is similar to that requested on other new regulatory assets requested in this case as previously discussed.

Finally, as the 2024 power cost update did not include a return on 2023 and 2024 CETA PPA costs, the adjustments to the first rate year recognize the inclusion of amortization expense for the deferral of the return on PPA costs estimated as of when rates will start, as well as amortization expense for the 2023 PPA cost deferral. PSE seeks recovery of the deferral of 2023 PPA costs and the 2023 and 2024 deferred return over a two-year amortization period.

11. <u>Adjustment No. 6.48 – CEIP Deferral</u>

This adjustment relates to PSE's Clean Energy Implementation Plan ("CEIP") costs that were approved for deferral in Order 01 in Docket UE-230131. The deferrals were stopped at the end of August 2023 as Schedule 141CEI – Clean Energy Implementation Tracker ("CEI Tracker") rates went into effect September 1, 2023 as authorized in Docket UE-230591. These deferred CEIP costs are supported by Mr. Jacobs.

This adjustment impacts the restating period and the two rate year periods. The restating adjustment removes the deferral entries for CEIP that were recorded in the test year. Rate base treatment for this deferral is not requested as the accounting petition provides that interest will be accrued as the deferred balances are amortized.

PSE seeks recovery of the deferral, including the deferred return over a two-year amortization period. The adjustments to rate year one recognize the inclusion of amortization expense for the CEIP deferral balance that is being requested for recovery.

Q. Can you please explain PSE's Proposal to True-up Costs Being Recovered in the CEI Tracker?

A. On September 1, 2023, PSE implemented rates for the CEI Tracker under Schedule 141CEI,[63] which are based on estimated costs associated with implementing the Company's 2021 CEIP,[64] as well as forecasted billing determinants over the period these rates are in effect. As part of the settlement

[63] Docket UE-230591, allowed to go into effect at the August 24, 2023 Open Meeting of the Commission.

[64] *WUTC v. PSE*, Docket UE-210795, Final Order 08 (Approving CEIP Subject to Conditions).

agreement in the 2022 GRC, parties agreed that Schedule 141CEI would expire and costs would be transferred to base rates upon implementation of rates in this general rate case.[65] Accordingly, tariff language was approved in the September 1, 2023 filing that provides for a true up of the estimated costs and also provides that forecasted revenues will be provided for in this GRC.[66] The tariff language further states that reports of the actual amounts for operating expenses and rate base that are included in the true up calculation will be provided for a prudency review.

Q. What challenges have since been identified with the tariff language associated with the true up in Schedule 141CEI?

A. As PSE was preparing for this filing, it became clear that it is not possible to adhere to the approved tariff language. It is not possible to conduct the true up and prudence review in this general rate case as actuals for the costs being recovered in Schedule 141CEI are not known at the time PSE files this general rate case. This timing conflict, although obvious in retrospect, was not foreseen at the time the language was written or approved.

Q. What is PSE's proposal to address the challenges with the tariff language?

A. PSE proposes that the Commission allow the true-up and prudence review of costs and investments recovered through Schedule 141CEI to be conducted in its

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[65] *WUTC v. PSE*, Dockets UE-220066 *et al*., Revenue Requirement Settlement ¶ 23k (Dec. 22, 2022).

[66] Docket UE-230591, Initial Filing Schedule 141CEI (July 17, 2023), at 2 ("Initial rates in this tariff schedule are based on estimated costs associated with implementing the Company's 2021 CEIP, as well as forecasted billing determinants over the period these rates are in effect. A true-up of the estimated costs and forecasted revenues will be provided for in the Company's next general rate case . . . .").

next general rate case. PSE also requests that it be allowed to include the true-up in Schedule 141CEI, or another appropriate rate schedule so that it is not embedded in base rates for a full MYRP period and can provide for flexibility to set the rate to zero at the appropriate time.

Q. Would it be appropriate for the Commission to change the timing of the CEI Tracker true-up and prudence review given the settlement agreement between parties?

A. Yes. PSE believes that this request does not substantively change the spirit of the settlement; it would allow for the process to occur as intended (using actuals to conduct the true up calculations and prudence review); and the request will be approved in this general rate case allowing all interested parties to participate.

C. Natural Gas Only Adjustments

Q. Please explain the natural gas only adjustments.

A. Explanations of the natural gas only adjustments are as follows:

1. Adjustment No. 11.38 – Tacoma LNG Upgrades Plant and Deferral

This adjustment removes the rate base for plant and regulatory assets, depreciation, and operating expenses as well as the test year deferral entries for the Tacoma LNG project. This adjustment is necessary as PSE has requested recovery of these items in Schedule 141LNG – Liquefied Natural Gas Rate Adjustment which is under suspension pending a final order in Docket UG-

230393. The test year entries to defer the O&M for the facility were booked to the originating FERC accounts (FERC 842, etc.). Therefore, no removal of the O&M deferrals is necessary as they net to zero with the originating entries recognized within the same FERC accounts and are further adjusted to zero in Adjustment 11.22, Proforma O&M.

2. <u>Adjustment No. 11.39 – Regulatory Assets and Liabilities</u>

This adjustment is the gas equivalent to Adjustment 6.41 for electric. Please see the discussion for that adjustment for information related to the AMR regulatory asset on lines 21 and 44, which is the only new regulatory asset added to this adjustment since the last rate case.

3. <u>Adjustment 11.40 – Removal of Tacoma LNG Project 4 mile 16 Inch Pipeline</u>

This adjustment relates to the four-mile, 16 inch pipeline related to the Tacoma LNG project, which is currently being recovered in Schedule 141D – Distribution Pipeline Provisional Recovery Adjustment. This adjustment is similar in nature to Adjustment 11.38 in that it removes the rate base and depreciation expense associated with these assets, which are currently before the Commission in Docket UG-230393. The revenue and offsetting reserve were both removed in Adjustment 11.01, Revenue and Expenses.

X. PRESENTATION OF REVENUE REQUIREMENT FOR THE NEW TARIFF SCHEDULES

A. Schedule 141CGR - Clean Generation Resources Rate Adjustment

Q. Please provide an explanation for how the revenue requirement is calculated for the CGR Tracker.

A. Exh. SEF-21 provides the calculation of the revenue requirement for the CGR Tracker. Line 17 shows the rate base balances for the rate years on an AMA basis. These balances are determined by utilizing the estimated capital spending for the project supported by Mr. Crowley with accrual of AFUDC through 2024 when rates are presumed to go into effect. Table 7, below, provides the assumptions for the construction spending and AFUDC.

Table 7. CWIP Roll Forward for Beaver Creek

Beaver Creek CWIP Roll

Mo/Yr	Beg CWIP	Capex	AFUDC	Closings	End CWIP
Oct - 2023	$ -	$ 79,312,667	$ 237,938		$ 79,550,605
Nov - 2023	$ 79,550,605	$ 79,312,667	$ 715,242		$ 159,578,513
Dec - 2023	$ 159,578,513	$ 79,312,667	$ 1,195,409		$ 240,086,589
Jan - 2024	$ 240,086,589	$ 16,018,655	$ 1,488,575		$ 257,593,819
Feb - 2024	$ 257,593,819	$ 16,018,655	$ 1,593,619		$ 275,206,092
Mar - 2024	$ 275,206,092	$ 16,018,655	$ 1,699,293		$ 292,924,039
Apr - 2024	$ 292,924,039	$ 16,018,655	$ 1,805,600		$ 310,748,294
May - 2024	$ 310,748,294	$ 16,018,655	$ 1,912,546		$ 328,679,494
Jun - 2024	$ 328,679,494	$ 16,018,655	$ 2,020,133		$ 346,718,282
Jul - 2024	$ 346,718,282	$ 16,018,655	$ 2,128,366		$ 364,865,302
Aug - 2024	$ 364,865,302	$ 16,018,655	$ 2,237,248		$ 383,121,204
Sep - 2024	$ 383,121,204	$ 16,018,655	$ 2,346,783		$ 401,486,642
Oct - 2024	$ 401,486,642	$ 16,018,655	$ 2,456,976		$ 419,962,272
Nov - 2024	$ 419,962,272	$ 16,018,655	$ 2,567,830		$ 438,548,757
Dec - 2024	$ 438,548,757	$ 16,018,655	$ 2,679,349		$ 457,246,760
Jan - 2025	$ 457,246,760	$ 8,884,095	$ 2,770,133		$ 468,900,987
Feb - 2025	$ 468,900,987	$ 8,884,095	$ 2,840,058		$ 480,625,140
Mar - 2025	$ 480,625,140	$ 8,884,095	$ 2,910,403		$ 492,419,638
Apr - 2025	$ 492,419,638	$ 8,884,095	$ 2,981,170		$ 504,284,903
May - 2025	$ 504,284,903	$ 8,884,095	$ 3,052,362		$ 516,221,359
Jun - 2025	$ 516,221,359	$ 8,884,095	$ 3,123,980		$ 528,229,434
Jul - 2025	$ 528,229,434	$ 8,884,095	$ 3,196,029		$ 540,309,558
Aug - 2025	$ 540,309,558	$ 8,884,095	$ 3,268,510	$ (552,462,162)	$ -
		AFUDC only through 12/2024		$ 528,319,517	

Q. How was the gross plant calculated for the Beaver Creek project in the CGR Tracker?

A. The Gross Plant for Beaver Creek was determined by including CWIP balances in rate base from January 2025 through the in-service date of August 2025, which is demonstrated in Table 8, below.

Table 8. CWIP and Gross Plant In Service Balances for Revenue Requirement

Month	Cumulative Capex	Capex	AFUDC Balance	CWIP Balance	CWIP in Rate Base	Total Rate Base
Dec - 2024	430,161,855		27,084,905.0	457,246,760	457,246,760	457,246,760
Jan - 2025		8,884,095		466,130,854	466,130,854	466,130,854
Feb - 2025		8,884,095		475,014,949	475,014,949	475,014,949
Mar - 2025		8,884,095		483,899,044	483,899,044	483,899,044
Apr - 2025		8,884,095		492,783,139	492,783,139	492,783,139
May - 2025		8,884,095		501,667,233	501,667,233	501,667,233
Jun - 2025		8,884,095		510,551,328	510,551,328	510,551,328
Jul - 2025		8,884,095		519,435,423	519,435,423	519,435,423
Aug - 2025		8,884,095		528,319,517	528,319,517	528,319,517
Sep - 2025						528,319,517
Oct - 2025						528,319,517
Nov - 2025						528,319,517
Dec - 2025						528,319,517
2025						
				AMA of Total RB	306,508,779	504,628,598

Once the asset reaches its assumed in service date in August 2025, it begins depreciating, which has been incorporated into the rate base balances for 2025 and 2026. The combined CWIP and in-service balances yield the AMA gross plant balances for 2025 and 2026 reflected on row 14 of Exh. SEF-21. Accumulated depreciation and ADIT are included on lines 15 and 16 to derive the overall rate base balances that are used in the revenue requirement calculation for the CGR Tracker.

Q. What other costs are included in the revenue requirement calculation for the CGR Tracker?

A. Depreciation and O&M expenses are also included in the revenue requirement calculation. Depreciation expense was calculated using similar allocations to depreciation groups as other PSE wind facilities. O&M expenses were obtained from the board approved plan and are supported by Mr. Carlson. These amounts, $10.3 million and $13.6 million for 2025 and $27.5 million and $13.9 million for 2026, respectively, are reflected on lines 19 and 20 of the exhibit.

Q. What is the final revenue requirement calculation for the CGR Tracker?

A. After application of the tax benefit of interest and the gross up for federal income taxes and revenue sensitive items, the revenue requirement for the CGR Tracker is $71.7 million in 2025 and $90.1 million in 2026, which reflects an incremental increase of $18.4 million in 2026 as shown on lines 27 and 29. Of the $71.7 million in the first rate year, $28.9 million is associated with earning on the CWIP balances during the rate year and $42.7 million is associated with the revenue requirement once the plant is in service.

B. Schedule 141WFP, Wildfire Prevention Tracker schedule

Q. Please describe the calculation of the revenue requirement for the Wildfire Tracker.

A. Exh. SEF-22 provides the revenue requirement calculation for the Wildfire Tracker. The calculation of the revenue requirement is very similar to that just discussed for the CGR Tracker except that there is no CWIP in rate base treatment for the plant assets in this tracker. Additionally, PSE is requesting the recovery of the estimated balance of the regulatory asset requested in Docket UE-231048 over two years (lines 9 and 16).

Rate base and O&M costs presented on Lines 8 and 12 are supported in the Prefiled Direct Testimony of Ryan Murphy, Exh. RM-1T. The insurance premium costs presented on lines 13 and 14 are supported by Mr. Doyle. The depreciation expense on line 15 was determined using expected depreciation rates and amortizable lives for the assets that are expected to be placed in service, in lines 8 and 9.

Q. What is the revenue requirement for the Wildfire Tracker?

A. After application of the tax benefit of interest and the gross up for federal income taxes and revenue sensitive items, the revenue requirement for the Wildfire Tracker is $27.5 million in 2025 and $34.4 million in 2026, which reflects an incremental increase of $6.8 million in 2026 as shown on lines 29 and 30 of the exhibit.

C. Schedule 141DCARB, Decarbonization Rate Adjustment

Q. Please describe the calculation of the revenue requirement for Schedule 141DCARB.

A. Exh. SEF-23 provides the revenue requirement calculation for Schedule 141DCARB. The calculation of the revenue requirement is simpler than for the other two rate schedules as it only includes O&M expenses.

The expenses for the program are supported by Mr. Mannetti. They are allocated evenly between the rate years for simplicity. As they are for the benefit of customers in PSE's dual fuel service territories, they are allocated between electric and gas based on the four factor allocator.

Q. What is the revenue requirement for Schedule 141DCARB?

A. After the gross up for revenue sensitive items, the revenue requirement for Schedule 141DCARB is $7.7 million for electric and $4.0 million for gas in 2025 as well as in 2026. There is no incremental increase in 2026 as shown on lines 12 and 13 of the exhibit.

XI. PASS BACK OF TAX INCENTIVES AND OTHER BENEFITS

Q. What tax incentives and other benefits[67] are potentially available for PSE customers?

A. Mr. Mannetti and Mr. Marcelia discuss the various benefits for which PSE is eligible and is actively pursuing. My testimony discusses how these various benefits, if and when they are realized, could be passed back to customers.

Q. Please summarize the methods by which any realized benefits could be passed back to customers.

A. As discussed by Mr. Mannetti and Mr. Marcelia, other than Production Tax Credits ("PTC") for the Beaver Creek facility, at this time, PSE is not expecting to receive grants or credits during the MYRP requested in this proceeding. Additionally, under Docket U-240013 ("IRA/IIJA workshop"), the Commission

[67] *See WUTC v. PSE*, Dockets UE-220066 *et al*., Final Order 24/10 ¶ 47(3)-(4) (Dec. 22, 2022).

has initiated a proceeding to discuss the treatment of IIJA and IRA benefits. Given there are no specific grants or credits to address in this proceeding, and the fact that policy guidance is likely forthcoming in the IRA/IIJA workshop, PSE is not presenting a formal proposal regarding the treatment of such funds. However, I will provide an overview of PSE's current thoughts regarding how to pass back these benefits to customers.

Q. Please continue explaining methods that could be used to pass back IRA/IIJA benefits to customers.

A. For the majority of IIJA funding opportunities discussed by Mr. Mannetti, because of the competitive nature of the opportunities, whether or not an award will be received and at what level cannot be accurately forecasted in advance of such grants being awarded. Additionally, for benefits such as PTCs discussed by Mr. Marcelia, the level of PTCs that will be generated and how they will be monetized – either through use on PSE's tax return or through a sale to a third party – will be difficult to predict. Therefore, a flexible means of providing any benefits that may eventually become realized during the MYRP to customers will be required. The IRA/IIJA workshop is expected to provide a forum for all parties to clarify this future process. Table 9, below, provides an overview of the types of benefits for which PSE is currently eligible and is actively pursuing and the method by which they can be passed back to customers

Table 9. Potential Ratemaking Treatment for Tax Incentives and Other Customer Benefits

Benefit	Witness	Approach
IIJA - Direct Funding Opportunity Grants	John Mannetti	Same as Underlying Asset
IRA - Production Tax Credits	Matthew Marcelia	Schedule 95A
IRA - Investment Tax Credits	Matthew Marcelia	Same as Underlying Asset
Local - Sales Tax Credits	Matthew Marcelia	Same as Underlying Asset or Schedule 140

Q. Please further describe the best approach for how PTCs in Schedule 95A could be administered.

A. PSE has passed back PTCs in Schedule 95A in the past. As such, PSE believes it would be most efficient to continue to follow this precedent. PSE can file Schedule 95A after its final tax returns are filed in October each year for rates effective January 1st. Additionally, there would need to be accrual of interest on any PTCs that have been monetized but not yet incorporated into Schedule 95A. Interest would then stop accruing once PTCs are included in Schedule 95A, which includes a return on the PTC balances within the tariff.

Q. Are there other costs related to PTCs that should also be set in Schedule 95A?

A. Yes. As discussed by Mr. Marcelia, PSE will incur transaction costs if it sells its PTCs to a third party. Therefore, the transaction costs will also be netted against the PTCs both for purposes of the interest accrual and when setting rates in Schedule 95A.

Q. Is PSE filing any tariff changes to incorporate a proposal for Schedule 95A in this proceeding?

A. No. As Beaver Creek will be eligible for PTCs, PSE's initial filing of Schedule 95A would not need to occur until sometime in 2026 when the PTCs from Beaver Creek are monetized either on a tax return or through a sale to third parties. PSE would propose wording changes to the tariff at the time it files the rates for Schedule 95A.

Q. How might IIJA grants and other benefits, incentives, and grants from federal and state opportunities be passed back to customers?

A. As noted above, these types of grants are difficult to predict with certainty. Therefore, also including these types of benefits in Schedule 95A would allow for contemporaneous pass back to customers once they are received. And, to address the varied timing of grant receipt and the annual Schedule 95A filings, interest could be applied to grant balances until they are incorporated in rates. These types of grants may have different time periods over which the benefit applies depending on the life characteristics of the underlying assets for which the grants are received, and these periods would be the best way to determine the length of time over which to pass back the different types of grants within Schedule 95A.

Q. Please describe how the pass back of Investment Tax Credits ("ITC") could be administered.

A. As discussed by Mr. Marcelia, ITCs may be either subject to or not subject to normalization rules. As these credits are tied to the value of the asset, PSE believes the best approach to pass them back would be in the same manner as the underlying asset. In the case of ITCs that are subject to IRS normalization provisions, this would occur through a reduction to tax expense when setting rates. However, these types of ITCs cannot be used as a rate base offset due to the IRS normalization provisions. Mr. Marcelia explains other considerations that must be followed for normalization rules. For ITCs that are not subject to IRS normalization provisions, PSE can include them as a rate base offset as well as provide the benefit of a reduction to tax expense.

Q. Please explain what is meant by the phrase "in the same manner as the underlying asset."

A. If PSE is recovering the underlying asset on a forecast basis, as I discuss above for the CGR Tracker, any ITCs that are governed by the normalization provisions would also need to be forecasted and set in rates and trued-up in the same manner as the underlying asset. To that end, PSE has included language in its proposed Schedule 141CGR to allow the inclusion of ITCs in the rate schedule if it is eventually deemed appropriate to do so. Likewise, if the asset is recovered in base rates, so too should the ITC. This holds true for ITCs that are not subject to the normalization provisions as it would be most efficient to follow the same approach for this second type of ITCs. These benefits should be included in the same regulatory mechanism that is used to recover the underlying plant investment. For example, if the underlying plant is recovered via the new Clean Generation Tracker, then the impacts of either type of ITC would be included in the tracker as well. Or, if the asset is recovered in base rates, then the ITC would be reflected in base rates as well. Effectively, customers will receive the benefit as a reduction in the cost of the project.

XII. EDIT PASSED BACK TO CUSTOMERS

Q. Please provide a brief background of excess deferred income taxes and how they are passed back to customers.

A. On December 22, 2017, the Tax Cuts and Jobs Act ("TCJA" or "Tax Reform") was signed into law; as a result, the federal income tax structure was significantly modified effective January 1, 2018. Among the most notable changes was a reduction in the federal corporate income tax rate from 35 percent to 21 percent. PSE has a net deferred tax liability ("DTL") that was established using a 35 percent tax rate, but it will pay the liability to the IRS at a 21 percent tax rate; thus, its net DTL is too large due to the change in the corporate tax rate resulting in EDIT. In PSE's 2019 general rate case, the method for passing back EDIT to customers was established[68] whereby PSE passes back EDIT in the same manner as the related gross plant, accumulated depreciation and depreciation expense of

[68] *WUTC v. PSE*, Dockets UE-190529 *et al.*, Final Order 08 (as amended) ¶ 700.

the underlying assets which created the EDIT—namely , in base rates over the life of the plant.

Q. Please explain the requirements PSE has for reporting related to the EDIT passed back to customers.

A. Paragraph 700 of Final Order 08 (as amended by Order 14 – paragraph 46 item 8) in Dockets UE-190529, et al. requires that PSE report in future rate cases cumulative amounts of Protected-Plus[69] EDIT that have been returned to rate payers.

Q. How much Protected-Plus EDIT has PSE passed back to customers?

A. The total amount of Protected-Plus EDIT that PSE originally had available to return to customers was $575.7 million for electric and $239.7 million for natural gas.[70] As of June 30, 2023, PSE has passed back $59.3 million for electric and $15.9 million for gas.

XIII. CONCLUSION

Q. Does that conclude your prefiled direct testimony?

A. Yes, it does.

[69] Includes EDIT amounts recorded to FERC 282 that are not protected by IRS normalization rules but that are not easily separated from protected amounts within the same FERC account.

[70] *WUTC v. PSE*, Dockets UE-190529/UG-190530 ("2019 GRC"), Exh. MRM-1T (Sept. 24, 2019), at 10.