Exh. CRM-1Tr
Dockets UE-240004,
UG-240005, UE-230810
Witness: Chris McGuire

**BEFORE THE WASHINGTON**
**UTILITIES AND TRANSPORTATION COMMISSION**

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| **WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,**<br><br>**Complainant,**<br><br>**v.**<br><br>**PUGET SOUND ENERGY,**<br><br>**Respondent.** | **DOCKETS UE-240004, UG-240005 and UE-230810 (Consolidated)** |

**REVISED TESTIMONY OF**

**CHRIS McGUIRE**

**STAFF OF**
**WASHINGTON UTILITIES AND**
**TRANSPORTATION COMMISSION**

***Policy; Policy Standards for Trackers; Earning and Deferring a Return on Qualifying PPAs; CWIP in Rate Base; Pro Forma O&M***

**August 6, 2024**

***Revised August 27, 2024***

## TABLE OF CONTENTS

## LIST OF EXHIBITS

# I. INTRODUCTION

**Q. Please state your name and business address.**

A. My name is Chris McGuire, and my business address is 621 Woodland Square Loop SE, Lacey, Washington 98503. My business mailing address is P.O. Box 47250, Olympia, Washington 98504-7250. My email address is chris.mcguire@utc.wa.gov.

**Q. By whom are you employed and in what capacity?**

A. I work in the Energy Regulation Section of the Regulatory Services Division of the Washington Utilities and Transportation Commission (Commission) as a Regulatory Analyst. I have worked at the Commission since May 2012, and in my current position since February 2022.

**Q. Would you please state your educational and professional background?**

A. I graduated from the University of Washington in 2002 with a Bachelor of Science degree in Cell and Molecular Biology. I graduated from the University of Colorado in 2010 with a Master of Business Administration and a Master of Science in Environmental Studies. Prior to my employment with the Commission, I held research positions at various institutions, including the University of Washington, the University of Colorado, and the National Renewable Energy Laboratory. Since joining the Commission in 2012, I have held the positions of Regulatory Analyst (2012-2016, 2022-present), Energy Policy Strategist (2016-2018), Assistant Director of Energy Regulation (2018-2021), and Director of Legislation and Policy (2021-2022).

**Q. Have you previously testified before the Commission?**

A. Yes. With respect to Puget Sound Energy (PSE), I sponsored testimony on behalf of Commission Staff in the following adjudicated proceedings: PSE's 2017 general rate case (GRC), Dockets UE-170033 and UG-170034; PSE's 2018 expedited rate filing, Dockets UE-180899 and UG-180900; PSE's 2019 GRC, Dockets UE-190529 and UG-190530; PSE's proposed sale of its ownership stake in Colstrip Unit 4, Docket UE-200115; and PSE's 2022 GRC, Dockets UE-220066 and UG-220067.

I also sponsored testimony on behalf of Commission Staff in PacifiCorp's 2013 GRC, Docket UE-130043; Avista's 2014 GRC, Dockets UE-140188 and UG-140189; the initial and remand phases of Avista's 2015 GRC, Dockets UE-150204 and UG-150205; Avista's 2017 GRC, Dockets UE-170485 and UG-170486; Avista's 2019 GRC, Dockets UE-190334 and UG-190335; Cascade's 2020 GRC, Docket UG-200568; and PacifiCorp's 2023 GRC, Docket UE-230172.

## II. SCOPE AND SUMMARY OF TESTIMONY

**Q. What is the purpose and scope of your testimony?**

A. My testimony serves three purposes. First, I provide an overview of the policy issues Staff addresses in its responsive case. Second, I outline the policy standards for, and Staff's recommendations on, (1) the threshold for ordering refunds related to plant provisionally included in rates, (2) PSE's request to establish three new trackers, (3) PSE's request to earn and defer a return on CETA-qualifying PPAs, and (4) PSE's request to include CWIP in rate base for its Beaver Creek Wind Project. Third, I present the accounting adjustments related to Staff's recommendations regarding: (1) CETA-qualifying PPA deferrals (Adjustment 6.47), (2) CWIP in rate base for the Beaver Creek Wind Project (Staff Adjustment S-6.49), wildfire-related costs (Staff Adjustment 6.51), and (4) pro forma O&M expense (Adjustments 6.22 and 11.22).

**Q. Please summarize your recommendations.**

A. For the annual retrospective capital reviews, when determining refunds related to plant provisionally included in rates Staff recommends that the Commission apply a threshold that adheres to the requirement in RCW 80.04.250 that only the level of plant used and useful for service during the rate effective period be included in rates, irrespective of whether the Company earns over or under the 0.5 percent above authorized ROR earnings cap under the MYRP statute, RCW 80.28.425(6).

Regarding PSE's request to establish three new trackers, Staff recommends that the Commission apply Staff's proposed criteria for assessing whether authorizing a tracker would be in the public interest and, as a result, find that authorizing PSE's proposed trackers would be inconsistent with the public interest. Accordingly, Staff recommends that the Commission deny PSE's requests to establish Schedule 141CGR, Schedule 141WFP, and Schedule 141DCARB. However, Staff recommends that a balancing account be established for the costs PSE included in its proposed wildfire tracker.

Regarding PSE's request in Docket UE-230810 to defer a return on CETA-qualifying PPAs, and PSE's request to recover the deferral balance through Adjustment 6.47, Staff recommends that the Commission (1) grant PSE's request to defer and recover the return the Company deferred in 2023, but calculated at the Company's authorized cost of debt rather than at its authorized rate of return, and (2) deny PSE's request to defer (and recover) the return the Company projects it will defer in 2024.

Regarding PSE's request to include CWIP in rate base for its Beaver Creek Wind Project, Staff recommends that the Commission find that including CWIP in rate base would lead to inequitable outcomes for low-income customers and, as a result, would be inconsistent with the public interest. Accordingly, Staff recommends that the Commission deny PSE's request to include CWIP in rate base and instead follow the Commission's standard practice of allowing PSE to capitalize AFUDC for the duration of the project's construction period.

Regarding PSE's request with respect to wildfire-related costs, in addition to recommending that those costs be included in base rates, Staff recommends that the Commission exclude from the wildfire-related revenue requirement PSE's requested recovery of the deferral balance associated with the Company's petition for deferred accounting in Docket UE-231048 which is as of yet unresolved.

Regarding pro forma O&M expense (Adjustments 6.22 and 11.22), Staff recommends that the Commission remove amounts PSE includes in O&M for "management reserves" and "reserve contingencies," as those amounts are for "unanticipated" or "unplanned" expenses and, accordingly, cannot meet the Commission's known and measurable or prudence standards.

**Q. Have you prepared any exhibits in support of your testimony?**

A. Yes. I prepared Exhibits CRM-2 through CRM-9. They are described in the List of Exhibits, above.

## III. POLICY

### A. General Discussion of PSE's Framing of this Case

**Q. Does Staff have any broad comments to make about the way in which PSE has framed certain issues in the Company's initial testimony?**

A. Yes, I'll briefly address two matters. The first issue is the way in which PSE describes the changing relationship it has with the UTC and the state generally. The second issue is the way in which PSE characterizes a set of its proposals and their relationship to CETA implementation.

**Q. How does PSE describe the relationship between itself and the UTC?**

A. At various points in initial testimony, PSE describes itself as "partnering" with the state of Washington or the UTC in accomplishing the clean energy transition.[1] PSE witness Doyle expresses the opinion that recent legislation creates a new dynamic between the UTC and PSE.

[1] *See e.g.*, Doyle, Exh. DAD-1CT at 2:1-3 ("The rate relief requested by PSE in this proceeding is critical if PSE is to partner with the state of Washington to make the clean energy transition a reality.").

**Q. Is there anything wrong with characterizing the state and PSE as "partners" in accomplishing the clean energy transition and other state policy goals?**

A. If all that PSE intends to convey by using this type of language is that the Company intends to be cooperative in achieving these goals, then no. In fact, if that is PSE's intention, then Staff applauds that sentiment. However, certain statements in initial testimony indicate that PSE may intend to convey something more when using the "partnership" language.[2] PSE appears to believe that recent legislation has caused some fundamental shift in the relationship between regulated utilities and the Commission; namely, that PSE is now acting as an "extension of the state"[3] in some ways.

**Q. Does Staff agree with that?**

A. No. While the last few years have seen substantial legislative changes to utility regulation in our state, the fundamental character of that regulation remains the same. While it is true that new legislation has expanded the subject matter that the Commission considers when regulating utilities, PSE remains a private company subject to oversight by its regulator, the UTC. When PSE takes steps to accomplish clean energy or equity related goals, it is doing so to comply with statutory and regulatory requirements, not because recent legislation has implicitly authorized it to act as an extension of the state. The Commission should avoid conceptualizing regulated companies as partners implementing state policy because such characterization implies that a lower level of scrutiny and oversight is warranted.

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[2] Doyle, Exh. DAD-1CT at 14:17-18 ("In many ways, jurisdictions are asking utilities to act as an extension of the state to promote the public interest more broadly.").
[3] *See Id*.

**Q. What impact does this have on the current case?**

A. It has no direct impact, but Staff believes that the nature of the relationship between the UTC and the companies it regulates should be clear. While recent legislation has added to the Commission's duties, it remains primarily an economic regulator. Ensuring that utilities achieve new state policies is in addition to – not a replacement of – the UTC's traditional regulatory goals. In other words, the UTC's role is to ensure that those state policy goals are achieved in a cost-effective manner, consistent with the public interest. This brings me to the second general issue I wanted to address.

**Q. Does PSE frame a set of rate increase requests as necessary in order to accomplish the clean energy transition?**

A. Yes. In initial testimony, PSE repeats different flavors of this assertion quite a few times.[4] PSE suggests that without approval of its proposals related to ROR, CWIP, various trackers, etc., that it simply will have no choice but to stall the clean energy transition.[5]

**Q. What is Staff's general reaction to this claim?**

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[4] Doyle, Exh. DAD-1CT at 2:1-3; Peterman, Exh. CGP-1T at 19:3-20:4; Steuerwalt, Exh. MS-1T at 31:18-22 ("To be successful in these endeavors during this multiyear rate plan and to preserve a path to succeed on the 2030 requirements, the financial support requested in this case is critical, as is Commission support for a measured and thoughtful approach to the speed at which PSE decarbonizes the gas system and transportation.").

[5] *See* Doyle, Exh. DAD-1CT at 12:1-9 ("Without sufficient regulatory support in the form of this two-year rate plan, which includes an increased authorized ROE, an increased authorized equity ratio, inclusion of CWIP in rate base for projects constructed by PSE to meet CET goals, and the three proposed tracker mechanisms, PSE would face unsustainable financial pressures that would further impair its credit ratings, erode its financial strength and integrity, and inhibit its ability to access the debt and equity capital markets at a reasonable cost. Ultimately, an inability of PSE to access debt and equity capital markets at reasonable costs would jeopardize its ability to deliver on the state's clean energy objectives.").

A. Staff will address specific proposals and adjustments in more detail elsewhere. But to broadly address the main theme of PSE's initial testimony, the Commission should be skeptical of the claim that all these proposals are necessary. The Commission should always remember that affordability is a key aspect of CETA;[6] the legislature clearly concluded that the clean energy transition could be accomplished on the timeline set by the law *while also* remaining relatively affordable for customers. The Commission has come to the same conclusion.[7] That implicit promise to customers would ultimately mean little if the Commission were to authorize an unreasonably inflated cost of capital or similar proposals in the name of increasing cash flow. Staff does not doubt that PSE must make significant investments over the course of the next few years, but questions whether these numerous cash flow-related adjustments are necessary in order to make those investments, as noted below. PSE presents a false dilemma in which the Commission must approve its requested rate increase or the clean energy transition will inevitably need to be put on hold or slowed. In fact, PSE recently projected that its progress on CETA interim targets would stall over the next three years, even before knowing the

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[6] *See* RCW 19.405.010(2): "In implementing this chapter, the state must ... provide safeguards to ensure that the achievement of this policy does not impair the reliability of the electricity system or impose unreasonable costs on utility customers". *See also* Docket UE-210795, Order 08, 92, ¶ 340 ("Under CETA, the utility must, to the maximum extent possible, achieve its targets at the lowest reasonable cost. The Commission has accordingly found that "[i]n most cases, the actual costs of achieving those targets, not the annual incremental cost threshold amount, will determine the real cost impact of CETA on customer rates."" (citations omitted)).

[7] *In the Matter of Adopting Rules Relating to Clean Energy Implementation Plans and Compliance with the Clean Energy Transformation Act*, Dockets UE-191023 & UE-190698 (Consolidated), General Order 601, 39, ¶ 105 (Dec. 28, 2020) ("We expect utilities to propose reasonable interim targets and meet the statutory standards of -.040(1) and -.050(1) in a cost-effective manner. Like the Legislature, we believe this is achievable without imposing unreasonable costs on customers. In most cases, the actual costs of achieving those targets, not the annual incremental cost threshold amount, will determine the real cost impact of CETA on customer rates. We believe those actual amounts will be less than the incremental cost threshold amount calculated under WAC 480-100-660.")

outcome of this case.[8] In other words, the Commission's decision in this case apparently has no bearing on PSE's projection that its progress on CETA interim targets will stall over the next three years.[9]

### B. MYRP Policy Issues

#### 1. Provisional plant subject to review – threshold for refunds.

**Q. Does Staff contest PSE's delineation between "traditional" pro forma plant additions (not subject to review in the annual capital report filings) and "provisional" pro forma plant additions (which would be subject to review and possible refund in the annual capital report filings)?**

A. Yes~~No~~. Staff does not accept~~s~~ PSE's treatment of all capital additions in~~ prior to January 1,~~ 2024, as traditional pro forma adjustments not subject to future review and refund~~ and capital additions from January 2024 through December 2026 as provisional pro forma adjustments~~.

[8] *In re Petition for an Order Extending Filing and Reporting Requirements under RCW 19.405.060 and 19.280.030, an Exemption from the Requirements of WAC 480-90-238(4), 480-100-640(1) and 480-100-655(2)*, Docket UE-240433, Transition Work Plan Attachment A at 3, Table 1 (projecting 63 percent of retail load served by renewable and non-emitting resources in 2026 and 2027, the same target as currently approved for 2025 in the company's 2021 CEIP. Note that the Commission did not approve these proposed targets as part of approving the petition) (filed June 5, 2024).

[9] While Staff recognizes that PSE ascribes this plateauing to load growth, Staff still finds the disconnect between the message PSE sends about CETA progress in the work plan and the message sent about CETA progress in this case noteworthy.

**Q. Why is Staff contesting PSE's proposal to treat all capital additions in 2024 as traditional pro forma adjustments not subject to future review and refund?**

A. Staff's position is that PSE's 2024 plant additions should be included in rates on a provisional basis, subject to future review and refund, because a full review of the 2024 plant additions cannot be completed within this general rate case. The response testimony of Staff and other intervening parties is due on August 6, 2024, well before many of PSE's 2024 plant additions were placed in service. While in theory it is possible for parties to have performed a "threshold" prudence examination for many of the 2024 plant additions PSE has included in this case, it simply is not possible to complete a full prudence examination for plant additions that are not yet in service. Parties cannot confirm that those projects will be used and useful for service in Washington in the rate year, and parties cannot perform a critical examination of the final project costs because those costs are not yet known and measurable. Parties should be given an opportunity to perform comprehensive prudence examinations on plant additions before the Commission allows those plant additions to be included in rates permanently.

**Q. What does Staff recommend with respect to which plant additions should be included in rates provisionally and subject to future review and refund?**

A. Staff recommends that the Commission treat all 2024 plant additions as provisional and subject to review in the annual retrospective plant reviews.

**Q. Why does Staff recommend that the Commission treat all 2024 plant additions as provisional rather than just the portion of the 2024 plant additions that could not have been reviewed by the parties prior to filing response testimony?**

A. For the retrospective review of plant included in 2025 rates, prior to examining the accuracy of PSE's projected plant transfers in 2025 parties will first need to examine the accuracy of PSE's projected plant-in-service at the end of 2024. While it is possible that parties will have had a reasonable opportunity to examine plant placed in service in early 2024, the fact that parties (and the Commission) must assess the accuracy of PSE's projected plant-in-service at the end of 2024 means that all plant additions in 2024 should be examined in aggregate. As a practical matter, treating all 2024 plant additions as provisional simplifies the analysis of – and correction for – differences between PSE's forecasted transfers to plant in 2024 and PSE's actual transfers to plant in 2024.

**Q. Given that the Commission in this GRC is valuing plant in 2025 for the purpose of setting rates in 2025, why is Staff concerned with preserving parties' ability to examine 2024 plant additions during the first retrospective review?**

A. The property valuation statute, RCW 80.04.250, grants the Commission the authority to "ascertain and determine the fair value for rate making purposes of the property of any public service company used and useful for service in this state by or during the rate effective period," including property "acquired or constructed by or during the rate effective period."[10]

[10] RCW 80.04.250(2).

In short, in setting rates for 2025, the Commission must ascertain and determine the fair value of all of PSE's property used and useful for service in 2025, including the used and useful property the Company acquired prior to 2025. Given that parties have not had an opportunity to perform a full prudence examination of many of the Company's 2024 capital additions, and given that those projected 2024 capital additions are included in the value of utility property in 2025, the 2024 plant additions must be subject to review and refund consistent with any other property included in 2025 rates that became used and useful at a date where parties could not have had a reasonable opportunity to fully examine that property.

**Q. Does Staff agree with PSE that the annual capital reviews should compare actual used and useful plant to the level of plant included in provisional rates on a portfolio basis (rather than on a project-by-project basis)?**

A. Yes. Requiring the Company to stick rigidly to its forecasted capital plan could lead to bad business decisions and the Company should not be penalized for adaptively managing its investment plan and appropriately responding to changing circumstances. Examining the level of plant on a portfolio level allows for adaptive management while still ensuring that, in the aggregate, customers only pay for plant that is used and useful during the rate-effective period.

However, one caveat that the Commission should note is that once provisional rates are set and the Company later discovers that it made a significant forecasting or accounting error for a project it included in its rate request and, as a result, erroneously high amounts were included in provisional rates for that project, then the Commission should order the

Company to refund amounts to ratepayers attributable to that forecasting or accounting error.[11] And during the retrospective review of plant provisionally included in rates, the Commission should exclude amounts attributable to that error from the portfolio-level plant-in-service included in provisional rates when it is comparing the actual, portfolio-level plant-in-service against that included in provisional rates. The Commission should not allow companies to use errors as windfall spending cushions.[12]

For example, in the retrospective review of plant included in PSE's provisional rates for 2023, the Company revealed that its 2022 GRC rate request included an error for AMI plant and, as a result, an incremental $132.6 million was included erroneously in 2023 provisional rates.[13] However, when comparing its actual, portfolio-level plant-in-service against the plant included in provisional rates, PSE does not adjust portfolio-level plant included in provisional rates to account for that error. Rather, PSE asks the Commission to ignore the error in the provisional plant amount when determining whether the Company's actual level of plant additions warrants issuing refunds to customers.

**Q. Does PSE propose a specific timeline within which parties should complete their reviews of the annual capital report filings?**

[11] RCW 80.28.425(3)(b): "...The commission may order refunds to customers if property expected to be used and useful by the rate effective date when the commission approves a multiyear rate plan is in fact not used and useful by such a date."

[12] The purpose of authorizing portfolio basis review of provisional pro forma plant instead of project-by-project review is to allow the utility to engage in adaptive management over the course of the rate plan. Allowing forecasting and accounting errors to remain part of the portfolio basis total does not achieve this goal and encourages overestimation of costs in GRCs.

[13] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UE-220066, Attachment D to The Multi-Year Rate Plan Annual Report, Explanations for Significant Variances Between 2023 Forecasted and Actual Plant Closings at 5 (filed March 29, 2024).

A. Not directly. However, although the testimony of PSE witness Free does not address the timeframe for review, PSE's proposed annual review process is largely the same as the annual review process it proposed in its last GRC which identified an annual filing on March 31 of each year with a three-month review period. The Settlement stipulation in that case modified the review process to four months.[14]

**Q. Does Staff have a recommendation with respect to the timeframe for review of the annual capital reports?**

A. Yes. Through its experience reviewing prior annual capital reports filings of PSE and Avista, Staff has come to realize that three or four months is an insufficient amount of time to complete the reviews. Therefore, to the extent that the Commission requires that the reviews be completed within a specific timeframe, Staff recommends that the Commission allow a full six months for the reviews.

**Q. What does Staff recommend with respect to the threshold for determining refunds during the annual retrospective reviews of plant provisionally included in rates?**

A. Staff recommends that the Commission establish that, to determine ratepayer refunds related to plant provisionally included in rates, the annual retrospective review should compare the actual used and useful plant with the level of plant included in provisional rates, thus applying a refund threshold that is consistent with the property valuation statute, RCW 80.04.250.

[14] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-220066, UG-220067 & UG-210918, Order 24/12, 72, ¶ 237 (Dec. 22, 2022).

**Q. For the annual retrospective reviews of plant provisionally included in rates, what threshold does PSE propose the Commission apply when determining whether to require PSE to issue refunds?**

A. PSE proposes to apply the 0.5 percent above authorized ROR threshold from the MYRP statute, RCW 80.28.425(6). That is, PSE proposes to issue refunds related to plant provisionally included in rates that was not used and useful during the rate-effective period *only if* the Company's actual rate of return exceeds its authorized rate of return by more than 50 basis points.

**Q. Does Staff agree with PSE's proposed threshold?**

A. No. The 0.5 percent earnings threshold described in the MYRP statute, RCW 80.28.425(6), is not the appropriate threshold to apply during the retrospective capital reviews as it is not an indicator of whether (or the degree to which) the level of plant provisionally included in rates was used and useful for service during the rate effective period, which is a requirement under Washington's property valuation statute, RCW 80.04.250. The purpose of establishing a process for reviewing and approving plant provisionally included in rates is to ensure that provisional rates do not run afoul of used and useful provision of RCW 80.04.250.[15]

To the extent that provisional rates are shown during the retrospective review to include a level of plant above the level of plant that was actually used and useful for service during the rate-effective period, RCW 80.04.250 would necessitate refunding

[15] *See In re Commission Inquiry into the Valuation of Public Service Company Property that Becomes Used and Useful after Rate Effective Date*, Docket U-190531, Policy Statement on Property that becomes Used and Useful after Rate Effective Date, 3-4, ¶¶ 7-8 (Jan. 31, 2020) (Used and Useful Policy Statement).

ratepayers in full the amount the utility collected through rates for the value of plant that was not used and useful.

The 0.5 percent threshold under RCW 80.28.425(6) pertains to a company's overall earnings and is meant to ensure that companies operating under a MYRP do not over-earn by more than 0.5 percent of authorized ROR. A company's overall (over)earnings tell the Commission nothing about whether provisional rates include plant that was not used and useful. Applying the 0.5 percent threshold under RCW 80.28.425(6) would allow the utility to keep amounts collected from customers for plant that was not used and useful as long as the utility didn't over-earn by more than 0.5 percent of authorized ROR.

**Q. Was the 0.5 percent threshold that PSE proposes the threshold that was used for PSE's previous retrospective capital reviews?**

A. Yes. However, the 2022 PSE and Avista GRCs were the first two GRCs adjudicated under the state's new multiyear rate plan statute, and subsequent to the conclusion of those cases – and, in particular, during the initial retrospective reviews of plant included provisionally in rates – Staff realized that the MYRP statute's earnings cap of 0.5 percent over authorized ROR is not the appropriate threshold for determining whether companies should issue refunds related to provisional plant that was not used and useful in the rate effective period. Since the initial PSE and Avista MYRP GRCs, Staff has recommended that the Commission employ a different threshold than what was used for those MYRPs. Most recently, in PacifiCorp's 2023 GRC, Staff recommended that the Commission reject PacifiCorp's proposal to use the MYRP statute's 0.5 percent above authorized ROR threshold to determine whether to order refunds related to plant included in rates and, instead, use a threshold that is consistent with the property valuation statute, RCW 80.04.250.[16]

**Q. What does Staff recommend in this case?**

A. Staff makes the same recommendation here that it made in the PacifiCorp GRC. For determining refunds related to plant provisionally included in rates the annual retrospective capital reviews, Staff recommends that the Commission reject PSE's proposal to use the MYRP statute's 0.5 percent above authorized ROR threshold to determine whether to order refunds related to plant included in rates provisionally. Rather, Staff recommends that the Commission compare the actual level of plant used and useful during the rate effective period to the level of plant included in provisional rates and, consistent with the property valuation statute, RCW 80.04.250, order refunds if the level of plant included in provisional rates exceeds the level of actual plant during the rate-effective period, regardless of whether the Company over- or under-earned over that period.

**Q. Did the Commission order PacifiCorp to implement Staff's recommended threshold for refunds related to plant included in rates provisionally?**

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[16] *Wash. Utils. & Transp. Comm'n v. Pac. Power & Light Co.*, Dockets UE-230172 & UE-210852, McGuire, Exh. CRM-1T at 40:12-19 (filed Sept. 14, 2023).

A. Yes. In that case, the Commission approved the multiparty settlement stipulation which adopted Staff's recommended threshold for refunds related to plant included in rates provisionally.[17]

### 2. Performance metrics and PIMs.

#### a. Performance metrics.

**Q. Does Staff have concerns with any of PSE's proposed modifications to the list of performance measures?**

A. Yes. As explained in the testimony of Staff witness Koenig, Staff recommends the Commission reject the following:

- PSE's proposal to modify the calculation of *Number of customers served by PSE's DER programs* (DER metric) to roll up the number of customers served in each DER program into one total for all.
- PSE's proposal to modify the calculation of *Capacity provided through each of PSE's DER programs* (DER metric) to roll up all DER program capacity performance into one total for all.
- PSE's proposal to modify the calculation of *Successful billing accuracy* (Customer Service metric) to roll up gas and electric reads into one.

[17] *Wash. Utils. & Transp. Comm'n v. Pac. Power & Light Co.*, Dockets UE-230172 & UE-210852, Order 08/06, Appendix A at 11, ¶ 30 (March 19, 2024).

**Q. Does Staff recommend modifications to any of PSE's proposed metrics?**

A. Yes. As explained in the testimony of Staff witness Koenig, Staff recommends that the Commission:

- Modify the DER metric "*The capacity provided through each of PSE's DER programs*" to only report on capacity, and not energy.
- Modify the Customer Satisfaction metric "*Successful billing accuracy*" to replace average monthly actuals for annual cumulative of all reads.
- Modify the DR metric "*Total Electric Peak Load Management Savings*" to shift from annual MW reduction to winter and summer season MW reductions.

**Q. Does Staff propose any additional metrics beyond those proposed by PSE?**

A. Yes. First, Staff recommends that the Commission order PSE to report on the following six additional affordability metrics:

- Total revenue occurring through riders and associated mechanisms not captured in the MYRP;
- Number and percentage of households with a high-energy burden (>6 percent), separately identifying known low-income, vulnerable populations, and highly impacted communities;
- Average excess burden per household;
- Residential arrearages by month, measured by location (zip code) and demographic information (known low-income customers, vulnerable populations, highly impacted communities, and all customers in total);

- Number and percentage of residential electric disconnections for nonpayment by month, measured by location (zip code) and demographic information (for known low-income, vulnerable populations, highly impacted communities, and all customers in total);
- Number and percentage of low-income customers who participate in bill assistance programs.

Second, Staff recommends the Commission require PSE to provide annual reporting on average connection times for new service requests associated with new construction of single family and multi-family housing.

**Q. Why does Staff recommend the Commission order PSE to track the additional six affordability metrics?**

A. In the Commission's final order in PacifiCorp's 2023 GRC, in addition to approving the metrics identified in the Settlement Stipulation, the Commission ordered PacifiCorp to track 14 additional metrics that were not identified in the Settlement Stipulation.[18] Of these 14 metrics, the six affordability metrics listed above were not identified in the list of metrics PSE proposed in this case. Staff interprets the PacifiCorp GRC Order as an indication that the Commission expects these specific metrics to be included in the overall list of metrics that utilities report on. Therefore, consistent with the Commission's Final Order in the 2023 PacifiCorp GRC, Staff recommends that the Commission order

[18] *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.*, Dockets UE-230172 & UE-210852 (consolidated), Order 08/06, 68-70, ¶ 234 (March 19, 2024).

PSE to report on the six affordability metrics identified in the PacifiCorp order that PSE did not include in its list of proposed metrics.

**Q. Why does Staff recommend the Commission order PSE to track average connection times for new service requests associated with new construction of single family and multi-family housing?**

A. Staff believes insight into interconnection timelines is in the public interest for several reasons. First, Washington is currently experiencing a housing crisis which is driven in part by limited housing supply and availability. Washington State Department of Commerce housing needs projections indicate the state will need to add 1.1 million homes over the next 20 years.[19] In the last few years, the Washington State Legislature has passed legislation to encourage greater housing density,[20] allow for more accessory dwelling units,[21] simplified design review processes,[22] as well as provided additional funding in the state budget to support construction of more affordable housing. The public has an interest in knowing how responsive utilities are in providing electric service necessary to make new housing ready for occupancy. Second, recent changes to state building codes require Electric Vehicle (EV) Charging Infrastructure to be included in new construction[23] to support decarbonization of transportation. Understanding how quickly PSE energizes new EV infrastructure will provide valuable data as the Company

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[19] "HB 1220 Update with Final Projections final March 2023.PDF." *Available at*: deptofcommerce.app.box.com/s/6z6bjbnbat83wikpp23yiuktutm0z4zv. Accessed 10 June 2024.
[20] 2023 E2SHB 1110.
[21] 2023 HB 1337.
[22] 2023 ESHB 1293.
[23] WAC 51-50-0429.

plans for the future. Finally, PSE proposes significant expenditures related to new revenue in this rate case. It seems reasonable to provide ratepayers with insight into how quickly those investments result in adding new customers and generating additional income for the Company.

**Q. What information should this annual connection time report include?**

A. Reporting should include, at a minimum, the average connection times for new service requests associated with new housing construction, calculated as the average number of days between requests for new service and (a) the dates temporary service was provided, and (b) the dates permanent service was provided. The metrics should be reported separately for single family and multi-family housing. Reporting should also include supporting documentation identifying the date each request for new service was received, the date the application for new service was approved, the date temporary service was provided if applicable, and the date permanent service was provided.

**b. Demand response PIM.**

**Q. Does PSE include a demand response (DR) PIM proposal in its direct case?**

A. Yes. PSE's proposed DR PIM is effectively the same DR PIM approved in PSE's 2022 GRC which rewarded PSE for the degree to which the Company exceeds its DR target. The only change to PSE's proposed PIM is that the Company updates the DR target to 149 MW (up from the 40 MW target used for PSE's existing DR PIM).

**Q. Does Staff recommend the Commission adopt the DR PIM that PSE has proposed?**

A. No. As described in the testimony of Staff witness Koenig, Staff believes that the DR PIM should properly incentivize PSE to meet its equity goals, which PSE's proposed PIM does not do. Staff also believes that PSE's DR target of 147 MW is too low given that for 2024-206 PSE identified 207 MWs of incremental DR resource additions in its 10-year Annual Incremental Resource Additions Preferred Portfolio.[24]

**Q. Does Staff have an alternative DR PIM proposal that it recommends the Commission adopt?**

A. Yes. Staff has developed an alternative DR PIM proposal that builds DR equity into the mechanism's incentive structure and adjusts the DR target to 207 MW. As described in the testimony of Staff witness Koenig, Staff's proposed PIM incentivizes performance according to the following two metrics: (1) the percent of DR benefits to Named Communities over and above the requirement that 30 percent of energy benefits go to Named Communities,[25] and (2) the percent of DR achieved over and above the DR goal of 207 MW. The performance incentive under Staff's proposal would be PSE's DR program costs multiplied by the average of percentage (1), percentage (2), and (3) PSE's authorized ROR, but would be $0 if *either* percentage (1) or percentage (2) is less that 0 (i.e., if PSE fails to meet the 30 percent DR equity target or the 207 MW DR target).

[24] The 207 MW target is the sum of 71 MWs, 65 MWs, and 71 MWs for years 2024, 2025, and 2026 respectively, as shown in PSE's 2023 Electric Progress Report in Docket UE-200304, Table 2.2 at 2.2 (filed March 31, 2023).

[25] *See In re Puget Sound Energy's 2021 Clean Energy Implementation Plan*, Docket UE-210795, Order 08, Appendix A, 6, ¶ 22 (Condition 20) (June 6, 2023).

### C. Accelerated Depreciation of Gas Assets and Upcoming Legislative Initiatives

**Q. What does PSE propose in this case with respect to the depreciation rates for the Company's natural gas facilities?**

A. As described in the testimony of PSE witness Allis, PSE requests to shorten the service lives of gas plant by as much as 10 years, depending on plant account.[26] PSE's proposal would increase natural gas depreciation expense by approximately $71 million per year (from $169.3 million to $240.2 million).[27] This recommendation is driven by what witness Allis calls "Net Zero by 2050",[28] referring to a variety of state laws and regulations, including the CCA and CETA, aimed at reducing GHG emissions. Allis specifically notes that the CCA sets stringent statewide GHG emission reduction targets, eventually resulting in Net Zero emissions by 2050.[29]

**Q. Has there been recent legislation that could pertain to the depreciation schedules for PSE's natural gas facilities?**

A. Yes. On March 28, 2024, Governor Inslee signed into law Engrossed Substitute House Bill 1589 (ESHB 1589), the Washington Decarbonization Act for Large Combination Utilities.[30] Section 7(1) of ESHB 1589 states that the Commission "shall approve a

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[26] Allis, Exh. NWA-1T at 4:11.
[27] *Id*. at 29-30, Table 1.
[28] *Id*. at 30:12-16.
[29] *Id*. at 20:1-2.
[30] Laws of 2024, Chapter 351 (Codified as Chapter 80.86 RCW).

depreciation schedule that depreciates all gas plants in service as of July 1, 2024, by a date no later than January 1, 2050, in any multiyear rate plan."[31]

**Q. Is the requirement in ESHB 1589 that the Commission approve a depreciation schedule that depreciates all gas plant by a date no later than January 1, 2050, directly applicable to this GRC?**

A. No. Section 7(1) of ESHB 1589[32] pertains to updated depreciation studies that reduce gas rate base consistent with an approved integrated system plan which, pursuant to Section 3(4) of ESHB 1589, large combination utilities must file by January 1, 2027.[33] Given that PSE does not yet have an integrated system plan that the Commission has approved pursuant to ESHB 1589, the requirements of ESHB 1589 with respect to depreciation schedules does not apply to the depreciation schedules at issue in this general rate case.

**Q. Is ESHB 1589 still a relevant consideration for the Commission as it considers PSE's request to accelerate the depreciation of its gas assets?**

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[31] ESHB 1589, Sec. 7(1). "In any multiyear rate plan filed by a large combination utility pursuant to RCW 80.28.425 and in accordance with this chapter, the large combination utility must include an updated depreciation study that reduces the gas rate base consistent with an approved integrated system plan, and the commission may adopt depreciation schedules that accelerate cost recovery and reduce the rate base for any gas plant. The commission shall approve a depreciation schedule that depreciates all gas plants in service as of July 1, 2024, by a date no later than January 1, 2050, in any multiyear rate plan, but the commission may adjust depreciation schedules for gas plants as necessary when considering future multiyear rate plans to address affordability provided all plants in service as of July 1, 2024, are fully depreciated by 2050."

[32] Codified as RCW 80.86.060(1).

[33] ESHB 1589, Sec. 3(4). "By January 1, 2027, and on a timeline set by the commission thereafter, large combination utilities shall file an integrated system plan demonstrating how the large combination utilities' plans are consistent with the requirements of this chapter and any rules and guidance adopted by the commission, …" (Codified as RCW80.86.020(4)).

A. To a limited extent, yes. While ESHB 1589 does not require the Commission to approve a depreciation schedule that depreciates all gas plant by January 1, 2050, in this GRC, the law does require that at some point PSE's depreciation schedules be adjusted such that all gas plant is depreciated by January 1, 2050, and the more time that elapses before depreciation rates are updated the more that costs will be concentrated on future customers. And as explained by Staff witness Franks, concentrating costs on future generations of gas customers generates serious equity concerns. Therefore, the Commission would be justified in taking the requirements of ESHB 1589, as well as the associated equity-related concerns, into account when examining PSE's proposed depreciation schedules in this GRC.

**Q. Did Staff perform a thorough analysis of PSE's proposed depreciation schedules for its gas facilities?**

A. No. Staff did not have the resources to be able to fully analyze the depreciation proposals in PSE's initial filing, and therefore does not have a specific position on the matter at this point.

**Q. Does Staff have a general perspective on PSE's proposal that it would like to offer to the Commission?**

A. Yes. Staff wishes to bring to the Commission's attention the fact that there are multiple competing principles at play when considering whether, or to what extent, to authorize PSE's request to accelerate the depreciation of its gas assets. On the one hand, after giving consideration to the requirements of ESHB 1589, PSE's request may appear to adhere to the principles of reasonableness and gradualism. While ESHB 1589 could be seen as justification for accelerating the depreciation schedules of the Company's gas assets to a terminal date of no later than January 1, 2050, the Company's proposal in this GRC does not go that far immediately. Rather, the Company proposes an annual depreciation expense that is $17.8 million lower than what would be the depreciation expense if the depreciation schedules were all accelerated to 2050.[34] On the other hand, the principle of gradualism is subjective; one could reasonably conclude that PSE's proposal to increase annual natural gas depreciation expense by $71 million – which represents a 42 percent increase relative to current depreciation rates – fails to adhere to the principle of gradualism.

However, as described in further detail in the testimony of Staff witness Franks,[35] whether the Company's proposal is "reasonable" must consider more than just the principle of gradualism. Specifically, if the increase in depreciation rates is *too* gradual, there is risk that costs will be unjustly concentrated on future generations of customers who likely will be composed of a high proportion of low-income customers and vulnerable populations. In other words, to arrive at a conclusion at what level of acceleration is reasonable, the Commission must find a balance between its principles of gradualism and equity.

[34] Allis, Exh. NWA-1T at 29-30, Table 1. The $17.8 million amount is calculated as the difference between the depreciation expense under the "10-year shorter service lives" scenario ($240.2 million) and the "recover by 2050" scenario ($257.8 million).
[35] Franks, Exh. WF-1T at 27-30.

**Q. Is there the potential for pending legislation to impact whether the Company's proposal to accelerate the depreciation of its gas assets is reasonable?**[36]

A. Yes. The Commission should be aware that there are ballot initiatives set for this year that, if passed, would significantly undermine the rationale behind PSE's proposal to shorten the service lives of its gas facilities. Specifically, if passed, Initiative 2066 would repeal provisions of ESHB 1589 relevant to accelerated depreciation of gas assets and Initiative 2117 would repeal the CCA.[37]

**Q. Does Staff have a recommendation regarding how to deal with this issue?**

A. Yes. Commission decisions should be consistent with current law. Therefore, with respect to I-2066, Staff believes that the Commission should keep the administrative record open long enough to take notice of the results of the ballot initiative pursuant to WAC 480-07-495(2). Because the evidentiary hearing in this case is set for November 4-5, parties will not be able to include the results in the record through normal means. A bench request issued after the evidentiary hearing could also accomplish the same result. As for I-2117, it is unlikely that the matter will be decided before the Commission must issue an order in this case. Therefore, if the Commission agrees with Staff, the Commission should include a condition requiring PSE to file a petition to amend the final order in this case if the initiative passes. This would reopen only to the issues of the

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[36] Staff's testimony is not an endorsement or criticism of any ballot initiative or pending legislation and should not be interpreted as such. Staff's discussion of these initiatives is solely for the limited purpose of discussing the ways in which the Commission might efficiently react to the outcome of these initiatives.

[37] Initiatives I-2066 and I-2117, *available at*: https://www.sos.wa.gov/elections/voters/2024-general-election-voters-guide/2024-initiative-information. Initiative 2066 will be decided by the people in November and Initiative 2117 is an indirect initiative that will be presented to the legislature this upcoming session.

appropriate service lives of the gas plant in question and the related rate impacts of any adjustment, as well as removing CCA related costs from rates.

### D. Trackers and the Need for Policy Standards

#### 1. Context: PSE Proposes three new trackers in this case.

**Q. Is PSE requesting to establish any new trackers in this proceeding?**

A. Yes. In its direct case PSE proposed three new trackers with rates and true-up functions effected through the following proposed tariff schedules:

1. Schedule 141CGR – Clean Generation Resource Tracker (Electric)
2. Schedule 141WFP – Wildfire Prevention Plan Adjustment Rider (Electric)
3. Schedule 141DCARB – Decarbonization Rate Adjustment (Electric and Gas)

**Q. What is the purpose of PSE's proposed Schedule 141CGR?**

A. Through the Clean Generation Tracker, Electric Schedule 141CGR, PSE is proposing to recover the costs of its Beaver Creek Wind Project,[38] including depreciation expense, production O&M expense, and return on rate base.[39] PSE calculates annual Schedule 141CGR revenue requirements of $71,656,160 in 2025 and $90,076,101 in 2026.[40]

[38] While PSE states that the purpose of Schedule 141CGR, more generally, is to allow the Company to recover the fixed costs associated with large utility-scale CETA-compliant generation resources, PSE has included only the costs of the Beaver Creek Wind project in its proposed Schedule 141CGR rates. *See* Free, Exh. SEF-1T at 7:21-8:3.
[39] Free, Exh. SEF-21.
[40] *Id*. at 1:27.

**Q. What is the purpose of PSE's proposed Schedule 141WFP?**

Through the Wildfire Plan Tracker, Electric Schedule 141WFP, PSE is proposing to recover the costs of implementing its Wildfire Mitigation and Response Plan, including depreciation expense, O&M expense, insurance premiums attributable to wildfire risk, and return on rate base.[41] PSE calculates annual Schedule 141WFP revenue requirements of $27,546,601 in 2025 and $34,392,948 in 2026.[42]

**Q. What is the purpose of PSE's proposed Schedule 141DCARB?**

Through the Decarbonization Tracker, electric and natural gas Schedule 141DCARB, PSE is proposing to recover the costs of implementing Phase 2 of the Company's Targeted Electrification Pilot. For electric operations, PSE calculates annual (2025 and 2026) Schedule 141DCARB revenue requirements of $7,673,452 for electric operations[43] and $4,035,116 for natural gas operations.[44]

**Q. What rationale does PSE provide in support of its request to recover these costs through separate trackers rather than through base rates?**

A. PSE requests to recover these costs through trackers because it would help to improve the Company's credit metrics by reducing the Company's exposure to risk.[45]

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[41] Free, Exh. SEF-22.
[42] *Id*. at 1:29.
[43] Free, Exh. SEF-23 at 1:12.
[44] *Id*.
[45] Doyle, Exh. DAD-1CT, 10:16–11:3.

**Q. Should the Commission be concerned with PSE's request to establish new trackers to pass through to ratepayers more than $230 million in projected costs and the justification the Company provides in support of its request?**

A. Yes. What PSE's explicit objective of reducing the Company's exposure to risk makes clear – and as I explain in further detail in the following section of this testimony – is that establishing these trackers would shift risk from the Company and onto ratepayers. And as I also explain in the section that follows, shifting risk from the Company and onto ratepayers is, as a general matter, inconsistent with the public interest.

**Q. Has the Commission adopted policy standards for assessing whether authorizing a tracker – or whether shifting risk from the utility and onto its ratepayers – is in the public interest?**

A. To Staff's knowledge, no. Given the growing number of utility requests to establish new trackers on top of the already substantial proportion of revenues that utilities recover through trackers, and given that shifting risk onto ratepayers can be harmful to ratepayers and inconsistent with the public interest, there is an urgent need for the Commission to adopt policy standards that can be applied to utility requests to establish new trackers. Below, Staff presents a policy framework as well as recommended policy standards for the Commission's consideration.

### 2. Policy standards for authorizing trackers.

#### a. Policy problem: trackers shift risk onto ratepayers.

**Q. What is a "tracker?"**

A. A tracker (or a "tracking and true-up mechanism") is a cost recovery mechanism for a defined category of costs that enables a utility to track the difference between the level of costs embedded in rates and the actual costs the utility incurs and then pass the difference onto ratepayers in a subsequent rate period, typically in a standalone tariff schedule commonly referred to as a "tariff rider." The baseline rates for a tracker typically are based on forecasted costs, and the difference between the actual (prudently incurred) costs and the baseline typically is passed onto ratepayers in an annual "true-up."

**Q. Can you explain the concept of "risk" within the context of utility cost recovery?**

A. Yes. Normally (i.e., absent a tracker), the utility's costs are recovered through its base rates which, since the passage of the multiyear rate plan legislation in 2021 (codified as RCW 80.28.425), are based on the utility's forecasted costs for the rate-effective period.[46] However, when the rate-effective period unfolds, the actual costs that the utility incurs will be different than the level of costs embedded in rates. The difference between the

[46] RCW 80.28.425(3)(b) requires the Commission to, at a minimum, ascertain and determine the fair value for rate-making purposes of utility property used and useful as of the rate effective date. RCW 80.28.425(3)(c) requires the Commission to ascertain and determine the operating expenses for rate-making purposes for each rate year of a multiyear rate plan.

actual costs and the level of costs embedded in rates is commonly referred to as the "variance."

When rates are set, but before actual costs are incurred, there is uncertainty with respect to the degree to which actual costs will differ from the level of costs embedded in rates. This uncertainty (i.e., the "risk" that actual costs will be different than forecasted costs) is called "variance risk."

**Q. Who bears this variance risk, the utility or its ratepayers?**

A. Variance risk normally is borne by the utility. Under normal circumstances, to the extent that actual costs during the rate year differ from the costs embedded in rates, the utility must absorb the difference. There are exceptions, of course, such as when the utility incurs substantial, unexpected costs that are the result of extraordinary circumstances beyond the utility's ability to control. Under those circumstances, the utility may petition for deferred accounting treatment which would serve to limit the utility's exposure to upside variance risk. Absent extraordinary circumstances, however, the utility bears 100 percent of the variance risk.

**Q. Is it fair to the utility that when costs are embedded in base rates the utility bears the variance risk?**

A. Yes. Utilities are *supposed to* bear this risk; they receive compensation for bearing this risk though the risk-adjusted return on equity that the Commission authorizes (and ratepayers pay through rates).

**Q. How do trackers shift risk from the utility and onto ratepayers?**

With a tracker, when actual costs during the rate year differ from the baseline level of costs embedded in the tracker rates, the difference is captured in the annual "true-up" and passed through to ratepayers over a subsequent rate-effective period. That is, under a tracker variance risk is borne by ratepayers. Given that absent a tracker variance risk is borne by the utility and that with a tracker variance risk is borne by ratepayers, trackers shift variance risk from the utility and onto ratepayers.

**Q. Is shifting risk from the utility and onto ratepayers consistent with the public interest?**

A. As a general matter, no. Shifting risk from the utility and onto ratepayers is generally harmful to ratepayers for two reasons. First, the risk that unexpected cost increases will negatively impact the utility's earnings is a risk that is supposed to be borne by the utility because, after all, the utility is compensated for bearing that risk through the Commission-authorized return on equity. When a cost is recovered through a tracker, the utility no longer bears the very risk that it is being compensated for – i.e., the utility no longer bears the risk that unexpected cost increases will have a negative impact on the utility's earnings. With a tracker, ratepayers are harmed because they absorb some of the utility's risk yet continue to compensate the utility for bearing that risk.

Second, the utility's exposure to the risk is an important element of incentive-based regulation; specifically, the utility's exposure to the risk that cost increases will impact earnings negatively incentivizes the utility to control its costs and pursue cost efficiency. When costs are recovered through a tracker, however, the utility incentive to control its costs in pursuit of profit is effectively eliminated, which in turn exposes ratepayers to the added risk that cost inefficiencies will lead to increased rates.

In short, trackers are harmful to ratepayers because they unfairly shift risk onto ratepayers without compensation, and eliminating the utility cost control incentive increases the magnitude of that risk.

**Q. Are there any other implications of establishing trackers?**

A. Yes. Trackers increase the Commission's administrative burden. Trackers require annual tariff revisions, and the Commission's review of those tariff revisions requires evaluation of the reasonableness of the company's cost forecasts and, in most cases, a retrospective examination of the prudence of the costs the utility incurred over the prior year. Because trackers require annual tariff revisions, trackers are more administratively burdensome than if the costs were embedded in base rates. Generally, embedding costs in base rates requires the review to be performed only as frequently as the company files GRCs.[47]

**Q. Given that trackers shift risk from the utility and onto ratepayers, and given that as a general matter shifting risk from the utility and onto ratepayers is inconsistent with the public interest, is establishing a tracker *ever* in the public interest?**

A. Yes. In rare circumstances establishing a tracker can be in the public interest. However, establishing a tracker is in the public interest *only when* the Commission concludes that, for a defined set of costs, establishing a tracker serves a specific public interest purpose.

[47] This is not necessarily true for prospective capital additions in a multiyear rate plan. Such prospective capital additions are typically included in rates on a provisional basis and subject to a retrospective prudence review and possible refund.

Absent a finding by the Commission that establishing a tracker serves a specific public interest purpose, establishing a tracker would be harmful to ratepayers.

**Q. Has the Commission established standards it applies when determining when authorizing a tracker is in the public interest?**

A. To my knowledge, no it has not. In the following section, I outline policy standards that Staff recommends the Commission apply when assessing whether authorizing a tracker would be in the public interest.

### b. When is authorizing a tracker in the public interest?

**Q. Why does Staff believe that the Commission should apply a public interest lens when considering whether to authorize a tracker?**

A. As I described in the previous section, trackers shift risk from the utility and onto ratepayers, and that risk shift is generally harmful to ratepayers because (1) ratepayers continue to compensate the utility for risk that the utility does not bear, and (2) it disrupts the utility's incentive to control its costs which can exacerbate the risk passed onto ratepayers as well as contribute to upward pressure on rates. Establishing a tracker is appropriate *when and only when* the Commission concludes that doing so would serve a specific public interest purpose. Absent the tracker serving such a purpose, the harmful effects of establishing the tracker cannot be overcome and, consequently, authorizing the tracker would not be in the public interest.

Thus, the Commission's fundamental concern when considering whether to authorize a tracker is whether authorizing the tracker would be in the public interest. And the key question when considering whether authorizing the tracker would be in the public interest is: does authorizing the tracker serve a specific public interest purpose?

**Q. Under what circumstances might creating a tracker serve a specific public interest purpose?**

A. There are three basic circumstances where establishing a tracker for a specific set of costs could serve a specific public interest purpose: (1) when establishing a tracker is necessary to advance a specific public policy goal, (2) when establishing a tracker is necessary to ameliorate potential intergenerational inequities, and (3) when establishing a tracker is necessary to address variance risk that is both outside of the utility's ability to control and so high that normal cost variances could have a substantial impact on the utility's earnings.

**Q. Can you explain the first circumstance – i.e. when establishing a tracker is necessary to advance a specific public policy goal – in more detail?**

A. Yes. Under the standard method of cost recovery – i.e., embedding costs in base rates – the utility is incentivized to control its costs because it is exposed to variance risk and regulatory lag and, therefore, the utility can improve earnings by controlling costs. However, in some cases, the utility cost control incentive works counter to public policy because it can cause the utility to cut costs in an area where continued spending is important for achieving a public policy goal. In those circumstances, the Commission could consider authorizing a tracker *because* it disrupts the utility cost control incentive and, therefore, promotes spending in an area where continued spending is important for achieving a public policy goal.

**Q. Can you provide an example where eliminating the utility cost control incentive was important to advancing a specific public policy?**

A. Yes. The Commission authorized trackers for utility conservation costs in part because embedding conservation costs in base rates utilities doubly incentivizes the utility to cut conservation spending: first because cutting conservation spending increases sales volumes and revenues, and second because cutting costs improves earnings. The Commission determined that these incentives to reduce conservation spending interfered with the public policy of maximizing utility acquisition of cost-effective conservation.[48] The Commission addressed the first incentive – i.e., the throughput incentive – by establishing decoupling mechanisms, and it addressed the second incentive – i.e., the utility cost control/ profit incentive – by establishing conservation trackers.

Another example is the Commission's authorization of cost recovery mechanisms (CRMs) for the replacement of high-risk natural gas pipe. The Commission's policy statement on accelerated replacement of pipeline facilities with elevated risk stated explicitly that one of the Commission's goals was to reduce regulatory lag for recovery of

[48] *In the Matter of the Petition of Puget Sound Energy, Inc. and Northwest Energy Coalition for an Order Authorizing PSE to Implement Electric and Natural Gas Decoupling Mechanisms and to Record Accounting Entries Associated with the Mechanisms*, Dockets UE-121697, UG-121705, UE-130137 & UG-130138 (consolidated), Order 07, ¶¶ 85, 112 (June 25, 2013). *See In re WUTC Investigation into Energy Conservation Incentives*, Docket U-100522, Report and Policy Statement on Regulatory Mechanisms, including Decoupling, to Encourage Utilities to Meet or Exceed Their Conservation Targets (Nov. 4, 2010) (Decoupling Policy Statement).

investment in the replacement of high-risk pipe.[49] The Commission saw eliminating regulatory lag (and providing the utility with dollar-for-dollar recovery of pipeline replacement costs) as a way of promoting accelerated replacement of high-risk pipe that the utility otherwise might be disinclined to do. In that way, establishing pipeline CRMs worked to advance the specific public policy goal of accelerating the replacement of high-risk pipe.

**Q. Other than establishing a tracker to eliminate the utility cost control incentive, does the Commission have any other options at its disposal for incentivizing utility actions that advance public policy?**

A. Yes. The Commission can establish performance measures or performance incentive mechanisms (PIMs) to incentivize utility actions that advance public policy (or disincentivize utility actions that work counter to public policy). In fact, pursuant to RCW 80.28.425(7), "the commission must, in approving a multiyear rate plan, determine a set of performance measures that will be used to assess a gas or electrical company operating under a multiyear rate plan," and one of the key objectives when establishing performance measures or PIMs for a utility operating under a MYRP is to address the risk that in pursuing profit maximization the utility will cut spending in areas where continued or elevated spending is important for meeting public policy objectives.

Given the need to establish performance measures pursuant to RCW 80.28.425(7), the practice of establishing a tracker for the sole purpose of addressing the

[49] *In re Policy of the Washington Utilities and Transportation Commission Related to Replacing Pipeline Facilities with an Elevated Risk of Failure*, Docket UG-120715, Commission Policy on Accelerated Replacement of Pipeline Facilities with Elevated Risk at 9, ¶ 33 (Dec. 31, 2012).

utility incentive to cut costs may be obsolete. Therefore, if for a given set of costs the Commission finds that eliminating the utility cost control incentive is necessary for advancing a specific public policy, rather than establish a tracker to eliminate the utility cost control incentive the Commission should consider whether a more appropriate solution would be to establish a performance measure or PIM that counters the incentive to cut costs by offering a carrot for meeting performance targets (or, alternatively, a stick for failing to meet performance targets).

**Q. Can you explain in more detail the second circumstance you note above where establishing a tracker is necessary to ameliorate potential intergenerational inequities?**

A. Yes. Under the standard method of cost recovery, where the utility's base rates are based the utility's anticipated cost of service in the rate-effective period, the utility could incur unexpected and substantial new costs that are the result of extraordinary circumstances and outside of the utility's ability to control. New costs that are the result of extraordinary circumstances and outside of the utility's ability to control generally qualify for deferred accounting treatment whereby the utility would be authorized to record the costs to a regulatory asset, set aside for future ratemaking treatment. Typically, these deferral balances accumulate until they are addressed in the utility's next GRC.

However, when deferral balances accumulate for multiple years and then are recovered through rates at the conclusion of the utility's next GRC, the ratepayers that end up paying for the deferred cost pay an amount that is far greater than their fair share; not only do they pay for their fair share of the cost as reflected the underlying cost of service used to establish going-forward rates in a GRC, through the amortization of the deferral balance they also pay for amounts that the utility incurred in prior years which, in a perfect world where rates perfectly match the utilities cost of service in real time, would have been paid for by ratepayers in the years in which the deferred costs were actually incurred. In short, deferred accounting creates intergenerational inequity. Ratepayers during the period the deferred costs were actually incurred pay nothing while ratepayers during the period where the deferral balances are amortized through rates pay substantially more than their fair share.

Ordinarily these deferral balances are small enough relative to the utility's overall cost of service that the intergenerational inequities created by allowing the deferral balance to accumulate through the utility's next GRC are relatively minor. However, in some circumstances the new costs resulting from extraordinary circumstances are so large – and the associated deferral balance grows large rapidly – that allowing the deferral balance to continue to accumulate between rate cases and then forcing ratepayers going forward to pay for multiple years of accumulated costs creates extreme intergenerational inequity. In those circumstances, the Commission could consider authorizing a tracker because, rather than let the deferral balance continue to grow until the conclusion of the utility's next GRC, the tracker would allow the utility to begin recovering costs in the interim, thereby stopping the growth of the deferral balance which, in turn, limits the severity of the intergenerational inequity created by the deferral balance.

**Q. Can you provide an example where authorizing a tracker helped to reduce potential intergenerational inequities?**

A. Yes. PSE's Schedule 111 is a case in point. In 2023, PSE (and other Washington utilities) began incurring substantial new costs resulting from the enactment of the CCA. Given that the CCA compliance costs that PSE began to incur were not reflected in PSE's existing rates, and that the costs were the result of extraordinary circumstances beyond the Company's ability to control, the Commission appropriately granted the Company's request for deferred accounting treatment for those costs. However, given the magnitude of the costs at issue, the resulting mismatch between the existing rates and the Company's underlying cost of service, and the potential for severe intergenerational inequities that likely would have resulted from allowing the deferral balance to continue to grow, the Commission first authorized PSE's request to establish tariff Schedule 111 with rates calculated to recover estimated going-forward CCA compliance costs beginning October 1, 2023,[50] and then allowed PSE to revise its Schedule 111 rates, effective November 1, 2023, to begin recovering the deferral balance the Company recorded between January and September 2023.[51] In its order authorizing PSE to establish Schedule 111, the Commission noted specifically that "the tariff revisions are necessary to allow the Company to begin to recover the costs of implementing the CCA, which will mitigate the impact of a ballooning future rate impact to customers."[52]

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[50] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UG-230470, Order 01 (Aug. 3, 2023).
[51] *See In re Tariff Revision Petition*, Docket UG-230756, Staff's Open Meeting Memorandum, 4 (filed on October 26, 2023) (Noting that "it is important to maintain a tracking and true-up mechanism that attempts to align rates in any given year for the estimated cost of service for that same year. Such a mechanism reduces the potential for significant intergenerational inequity.").
[52] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Docket UG-230470, Order 01, 4, ¶ 17 (Aug. 3, 2023).

**Q. Can you explain in more detail the third circumstance you note above where establishing a tracker is necessary to address variance risk that is too high and outside of the utility's ability to control?**

A. Yes. If variance risk is so high for a specific set of costs that there is a reasonable likelihood that cost changes outside of the utility's ability to control will have a substantial impact on the utility's earnings, then exposing the utility to 100 percent of the variance risk might be contrary to the public interest. In those circumstances, the Commission could consider authorizing a tracker as a means of allowing *some* of the variance risk to be shifted from the utility and onto ratepayers.

**Q. How can exposing the utility to 100 percent of the variance risk when that variance risk is extremely high have consequences contrary to the public interest?**

A. When the utility must bear 100 percent of the risk for a set of costs where variance risk is extremely high – i.e., when there is a high risk that cost increases outside of the utility's ability to control will have a substantial impact on the utility's earnings – the utility may appear too risky to investors. Appearing risky to investors could undermine the utility's ability to attract capital on reasonable terms which, in turn, could increase the utility's cost of capital. Ratepayers can be harmed when a utility's cost of capital increases because ratepayers pay for that cost of capital through the rate of return authorized by the Commission in a GRC. Therefore, when variance risk is so high that exposing the utility to 100 percent of the risk is likely to increase the utility's cost of capital, it could be in the public interest to shift some of that risk from the utility and onto its ratepayers.

**Q. Can you provide an example where shifting variance risk from the utility and onto ratepayers was warranted?**

A. Yes. In 2001, utilities in Washington (and especially Avista) suffered severe financial consequences resulting from the western energy crisis which was created by unprecedented prices and price volatility in the western wholesale power combined with serious drought conditions in the Pacific Northwest.[53] In response to this extreme market volatility (which was outside of utilities' ability to control) and the resulting extreme deviations between actual costs and the level of costs embedded in rates, the Commission authorized power cost adjustment mechanisms (PCAMs) for its regulated electric utilities.[54]

**Q. Do power cost adjustment mechanisms allow utilities to shift 100 percent of the variance risk onto ratepayers?**

A. No. The power cost adjustment mechanisms authorized for PSE, Avista, and PacifiCorp all have risk-sharing mechanisms (RSMs) in the form of dead bands and sharing bands. Utilities absorb 100 percent of the variance risk within the dead bands (i.e., utilities absorb 100 percent of the costs that are within $X of the baseline[55]) and utilities and ratepayers share the risk of variances that are beyond the dead bands (i.e., within the sharing bands).

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[53] *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Dockets UE-160228 & UG-160229, Order 06, 7, ¶ 14 (Dec. 15, 2016). *See also In the Matter of Avista Corporation d/b/a Avista Utilities Request Regarding the Recovery of Power Costs Through the Deferral Mechanism*, Docket UE-010395, Sixth Supp. Order ¶¶ 5-7 (Sept. 24, 2001).

[54] *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Docket UE-072300, Order 13, 12-13, ¶ 29 (Jan. 15, 2009). Additionally, as recently as 2006, the Commission reaffirmed that the PCA is intended to deal with extreme events. *See Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-060266 & UG-060267, Order 08, 10-11, ¶ 20 (Jan. 5, 2007).

[55] The sizes of the dead bands and sharing bands vary between utilities.

### c. Staff's proposed criteria for assessing whether authorizing a tracker is in the public interest.

**Q. Why is Staff recommending that the Commission establish policy standards for determining whether a tracker is warranted?**

To Staff's knowledge, the Commission has not established criteria for determining whether establishing a tracker would serve a specific public interest purpose. Absent such criteria, there is risk that the Commission will authorize trackers that are harmful to ratepayers and inconsistent with the public interest.

**Q. Can you please summarize the foundation for Staff's proposed policy criteria?**

A. Yes. Fundamentally, Staff's position with respect to the need to establish policy standards for authorizing trackers is based on the recognition that trackers shift risk onto ratepayers, disrupt the utility's incentive to control its costs (further exacerbating the risk that is shifted onto ratepayers), and add to the Commission's administrative burden. And because trackers have these negative effects, authorizing a tracker is, as a general matter, inconsistent with the public interest.

While there are circumstances where establishing a tracker could generate public interest benefits, the Commission does not have established policy standards that can be used to assess whether authorizing a tracker would generate such benefits and, accordingly, whether authorizing a tracker is in the public interest.

**Q. Are Staff's proposed criteria based on the notion that establishing a tracker must generate specific public interest benefits for authorizing the tracker to be in the public interest?**

A. Yes. For authorizing a tracker to be in the public interest, establishing the tracker must generate specific public interest benefits that are sufficient to overcome the harmful effects the tracker creates. Absent such benefits, the harmful effects of establishing the tracker would render the tracker inconsistent with the public interest.

Therefore, as a threshold matter, for the Commission to determine that authorizing a tracker is in the public interest, the Commission first must find that establishing the tracker would generate specific public interest benefits that would not exist absent the tracker and that, in the Commission's view, are sufficient to overcome the harmful effects of authorizing the tracker.

**Q. What specific criteria does Staff recommend the Commission adopt when evaluating whether authorizing a tracker serves a specific public interest purpose?**

A. For a tracker to serve a public interest purpose, one of the following three criteria should be met:

**<u>Criterion 1</u>: For a specified set of costs, does the utility cost control incentive interfere with progress toward meeting an important public policy objective?**

If yes, the Commission could consider authorizing a tracker to eliminate the utility's exposure to regulatory lag and variance risk which, in turn, eliminates the utility's incentive to cut costs in pursuit of profit. However, before authorizing a tracker to eliminate the utility's incentive to cut costs, the Commission should consider whether establishing a performance measure or PIM would be a more appropriate solution given the requirements of RCW 80.28.425(7).

**<u>Criterion 2</u>: For a specified set of costs for which the Commission has authorized deferred accounting treatment, is allowing the deferral balance to continue to accumulate through the utility's next GRC likely to create severe intergenerational inequities?**

If yes, the Commission could consider authorizing a tracker to allow the utility to begin recovering the costs in question in advance of the utility's next GRC, thereby staunching further growth of the deferral balance and, in turn, limiting the severity of the intergenerational inequity created by the deferral.

However, authorizing a tracker for this purpose should be viewed only as a temporary stop-gap measure and not a permanent ratemaking solution. While stop-gap trackers can provide a bridge between when the utility begins incurring costs resulting from extraordinary circumstances and when those costs are embedded in base rates, stop-gap trackers should be eliminated at the conclusion of the utility's next GRC, at which point the underlying costs at issue can be embedded in base rates.

However, the Commission should recognize that authorizing a tracker to stop the growth of a deferral balance that, if left unchecked, is likely to create severe intergenerational inequities, is a temporary stopgap measure and not a permanent ratemaking solution. Trackers can provide a bridge between when the utility begins incurring substantial new costs resulting from extraordinary circumstances and when those costs are embedded in base rates through a GRC. Trackers established as temporary stop gaps should be eliminated at the conclusion of the utility's next GRC, at which point the underlying costs at issue should be embedded in base rates.

**<u>Criterion 3</u>: For a specified set of costs, is the variance risk so high that cost increases outside of the utility's ability to control are reasonably likely to have a substantial impact on the utility's earnings?**

If yes, the Commission could consider authorizing a tracker as a means of reducing the utility's exposure to that variance risk by shifting some of the risk onto ratepayers.

**Q. Are there any circumstances where establishing a tracker could be warranted even in the absence of identified public interest benefits?**

A. Yes. In rare circumstances, establishing a tracker could be required by statute. For example, RCW 19.405.030(1)(b) requires the Commission to "allow in electric rates all decommissioning and remediation costs prudently incurred by an investor-owned utility for a coal-fired resource." Without a tracking and true-up mechanism, it likely would not have been possible for the Commission to ensure that all decommissioning and remediation costs – and ultimately no more than the amount it deems prudent and no less than the amount the utility prudently incurs – are recovered through rates, as required by the statutory language.

However, in those circumstances establishing the tracker would be justified because it is necessitated by law and not because the Commission concludes that it is in the public interest. Trackers necessitated by statute fall into a special category of trackers where policy standards for determining whether a tracker is in the public interest are not applicable. Therefore, they can be ignored for the purpose of establishing criteria to apply when deciding whether to authorize a tracker that is *not* required by law, such as the PSE's CCA tracker.

### d. Policy standards for determining what level of risk-shifting is warranted.

**Q. For circumstances where a tracker is justified because it satisfies Criterion 1 (i.e., the Commission determines that the utility cost control incentive works counter to public policy), is it appropriate to shift 100 percent of the variance risk onto ratepayers?**

A. Yes. If the Commission determines that, for a specific set of costs, the utility cost control incentive works counter to public policy, the Commission should eliminate the utility's exposure to variance risk entirely. If the utility continues to be exposed to variance risk – i.e., if the utility's earnings continue to be affected by cost increases – the utility still would be incentivized to cut costs and, thus, the utility cost control incentive would continue to work counter to public policy.

**Q. For circumstances where a tracker is justified because it satisfies Criterion 2 (i.e., the Commission determines that allowing a deferral balance to continue to grow is likely to create severe intergenerational inequities), is it appropriate to shift 100 percent of the variance risk onto ratepayers?**

A. Yes. First, it is important to recognize that when the Commission authorizes the use of deferred accounting treatment, the utility records the applicable costs dollar-for-dollar to a regulatory asset which the utility would seek to recover (also dollar-for-dollar) in its next GRC. In circumstances where the Commission has authorized the utility to establish a tracker to begin recovering those costs in advance of a GRC on the grounds that doing so ameliorates potential intergenerational inequities, the Commission has, in effect, decided to address proactively what otherwise could have become problematic deferral balance in the future.

In short, at its core a tracker established to avoid intergenerational inequity is a tracker established to address a deferral balance, and the concept of variance risk is not applicable to deferral balances.

**Q. For circumstances where a tracker is justified because it satisfies Criterion 3 (i.e., when the Commission determines that variance risk is so high that cost increases outside of the utility's ability to control are reasonably likely to have a substantial impact on the utility's earnings), is it appropriate to shift 100 percent of the variance risk onto ratepayers?**

A. No. If transferring variance risk from the utility and onto ratepayers is justified on the grounds that variance risk is too high for the utility to bear alone, it would be illogical to then say that same risk should be borne in full by ratepayers. In circumstances where high variance risk warrants establishing a tracker, that variance risk always should be shared in a rational and equitable manner and never passed from the utility onto ratepayers in full.

**Q. In circumstances where high variance risk warrants establishing a tracker, how should the Commission ensure that that variance risk is shared in a rational and equitable manner?**

A. In those circumstances, the Commission should require the utility to establish an RSM. However, the proper design of such a mechanism – i.e., ensuring that risk is shared in a rational and equitable manner – should be determined on a case-by-case basis and dependent on the degree to which variance risk threatens the utility's earnings and its ability to attract capital on reasonable terms.

**Q. Does Staff recommend that the Commission adopt a general formula for determining how much variance risk is appropriate to transfer to ratepayers?**

A. Not at this time. There is not enough information on the record in this proceeding for the Commission to develop a formula for determining the level of risk sharing that is fair and equitable at a given level of variance risk.

However, Staff does recommend that the Commission formally recognize that there is a relationship between the magnitude of variance risk the utility is exposed to and the degree to which shifting risk onto ratepayers is warranted. That is, circumstances where variance risk is extreme may warrant more risk being shifted onto ratepayers than circumstances where variance risk is moderately high. The degree to which variance risk should be shifted onto ratepayers should be directly related to the magnitude of impact the risk in question could have on the utility's earnings.

**Q. Should the Commission always require the utility to establish a RSM when the Commission authorizes a tracker on the grounds that variance risk is too high for the utility to bear alone?**

A. Yes. The Commission should require an RSM when it authorizes all such trackers (and CRMs). Unless the Commission is authorizing a tracker for the explicit purpose of eliminating the utility cost control incentive to advance a specific public policy, the Commission should never allow 100 percent of the variance risk to be transferred to ratepayers. As long as utility cost control and efficiency remain important regulatory objectives, and as long as utilities continue to be compensated for variance risk through the authorized rate of return, an RSM should be a default component of a tracker.

### 3. Application of Staff's proposed policy standards.

#### a. Applying Staff's proposed policy standards to the three new trackers PSE proposes.

**<u>PSE's Proposed Clean Generation Resources Tracker, Schedule 141CGR</u>**

**Q. For the costs PSE includes in its proposed Clean Generation Resource Tracker (Electric Schedule 141CGR), does PSE's incentive to control its costs interfere with progress toward meeting an important public policy objective?**

A. No. For the costs PSE includes in its proposed Schedule 141GCR – namely, the costs associated with PSE's investment in the Beaver Creek facility – there is no discernible public policy benefit of eliminating PSE's incentive to control its costs. It remains in the public interest for PSE to minimize the cost of developing the facility. Therefore, PSE's proposed Schedule 141CGR fails Criterion 1.

**Q. Is establishing Schedule 141CGR in any way necessary to advance a specific public policy?**

A. No. While PSE's investment in the Beaver Creek facility may be characterized as investment made for the purpose of complying with CETA, whether the company recovers the cost of the Beaver Creek facility through a tracker or through base rates has no bearing on whether the Company invests in the facility or makes progress on meeting the requirements of CETA. The Commission should be careful to differentiate between trackers *related to* a specific public policy and trackers that *advance* that public policy. PSE's proposed Schedule 141CGR falls firmly into the former category.

Furthermore, the law itself requires that PSE take actions that transition the Company toward providing retail customers with renewable and nonemitting energy; removing the incentive to control costs is unnecessary because CETA provides the incentive to achieve public policy. Therefore, establishing a tracker would have no impact on advancing the policy goals of CETA. The same would be true of any other investments that PSE sought to include in the tracker.

**Q. Is establishing Schedule 141CGR necessary to address potential intergenerational inequity?**

A. No. Staff's proposed Criterion 2 is only relevant only to costs for which the Commission has authorized deferred accounting treatment and is only applicable between rate cases. Therefore, Staff's proposed Criterion 2 is not applicable to the costs PSE included in its proposed Schedule 141CGR.

**Q. For the costs PSE includes in its proposed Electric Schedule 141CGR, is variance risk so high that cost increases outside of the utility's ability to control are reasonably likely to have a substantial impact on the utility's earnings?**

A. No. Absent a tracker, the variance risk associated with PSE's investment in the Beaver Creek facility is extremely low. Not only does PSE exert a such a substantial degree of control over its investment decisions that it is able to manage its aggregate level of plant additions according to the forecasted plant-in-service the Commission allowed into prospective rates, but even if the cost of one project in particular (such as the Beaver Creek project) ended up being substantially greater than the forecasted cost embedded in provisional rates, the Company would be able to include the updated, higher cost of the facility in rates in its next GRC and, from that point forward, the variance risk effectively would be zero (because rates would reflect the actual, relatively constant, plant-related costs associated with the facility).

In short, no, for the Beaver Creek Project variance risk is not so high that cost increases outside of the utility's ability to control are reasonably likely to have a substantial impact on the utility's earnings. Therefore, PSE's proposed Schedule 141CGR fails Criterion 3.

**Q. What does Staff conclude with respect to PSE's proposed Clean Generation Resources Tracker (Electric Schedule 141CGR)?**

A. Staff concludes that Schedule 141CGR would not generate benefits supporting a finding that establishing the tracker would be in the public interest. Without generating such benefits, the harm caused by shifting risk from the utility and onto its ratepayers requires that the Commission find that authorizing Schedule 141CGR would be inconsistent with the public interest. Therefore, Staff recommends that the Commission deny PSE's request to establish Schedule 141CGR and, instead, include the revenue requirement associated with the Beaver Creek project in the calculation of PSE's base rates.

## PSE's Proposed Wildfire Tracker, Schedule 141WFP

**Q. Please summarize the costs PSE includes in its proposed wildfire tracker.**

A. PSE calculates annual Schedule 141WFP revenue requirements of $27,546,601 in 2025 and $34,392,948 in 2026.[56] As shown in Free Exh. SEF-22, the costs PSE includes in its proposed Schedule 141WFP are as follows:

**Table 1. Wildfire-related Costs, per Free Exh. SEF-22.**[57]

| | **2025** | **2026** |
|---|---|---|
| WILDFIRE NON-INSURANCE O&M | 5,628,712 | 6,425,884 |
| WILDFIRE INSURANCE LIABILITY EXPENSE | 14,460,817 | 14,336,418 |
| WILDFIRE INSURANCE LIABILITY CONSTRUCTION SUPPORT | (2,602,947) | (2,580,555) |
| DEPRECIATION EXPENSE | 1,178,635 | 3,282,561 |

[56] Free, Exh. SEF-22 at 1:29.
[57] These amounts are prior to grossing up for taxes and revenue sensitive items.

| | | |
|---|---|---|
| AMORTIZATION OF WILDFIRE LIABILITY INSURANCE DEFERRAL | 5,386,070 | 5,386,070 |
| TOTAL OPERATING EXPENSE | 24,051,287 | 26,850,378 |
| RETURN ON RATE BASE | 1,829,710 | 4,971,736 |
| TOTAL COSTS | **25,880,996** | **31,822,114** |

**Q. In assessing whether authorizing the proposed Wildfire Prevention Tracker would be in the public interest, did you apply Staff's proposed criteria that you describe above?**

A. Yes.

**Q. Do the costs PSE includes in its proposed Wildfire Tracker meet Staff's proposed Criterion 1 (i.e., does PSE's incentive to control its costs interfere with progress toward meeting an important public policy objective)?**

A. Possibly, yes. The Commission has previously communicated that addressing wildfire risk is an important public policy goal,[58] and it is entirely possible that if wildfire prevention costs were included in base rates without a true-up mechanism that PSE would cut costs in pursuit of improved earnings.[59] Staff is therefore concerned that including wildfire costs in base rates without some form of a true-up mechanism could undermine utility progress toward meeting the Commission's expressed policy goals with respect to wildfire prevention.

[58] *See, e.g., Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Dockets UE-200900, UG-200901 & UE-200894 (consolidated), Order 08/05, 81-84, ¶¶ 231-238 (Sept. 27, 2021).

[59] Please note that Staff is not saying here that PSE *will* cut costs in pursuit of improved earnings, Staff is only saying that, absent a true-up mechanism, there is an incentive for the utility to cut costs because doing so could improve the Company's earnings.

**Q. Is establishing Schedule 141WFP necessary to address potential intergenerational inequity?**

A. No. Staff's proposed Criterion 2 is only relevant only to costs for which the Commission has authorized deferred accounting treatment and is only applicable between rate cases. Therefore, Staff's proposed Criterion 2 is not applicable to the costs PSE included in its proposed Schedule 141WFP.

**Q. For the costs PSE includes in its proposed Electric Schedule 141WFP, is variance risk so high that cost increases outside of the utility's ability to control are reasonably likely to have a substantial impact on the utility's earnings?**

A. Probably not. It's important to recognize, however, that PSE's proposed Schedule 141WFP contains two broad categories of costs, one of which is not exposed to market volatility and one of which is exposed to market volatility.

The first category of costs relates to wildfire prevention activities. For those costs, variance risk is likely to be extremely low to nonexistent. Not only are the costs largely predictable as they reflect specific actions identified in the Company's wildfire plan, but the costs are squarely within the Company's ability to control and are not a function of highly volatile market prices. Therefore, PSE's wildfire prevention costs do not meet Staff's proposed Criterion 3.

The second category of costs relates to wildfire-related insurance premiums (which represents approximately 46 percent of the wildfire costs in 2025 and 37 percent of the wildfire costs in 2026).[60] For those costs, variance risk is uncertain. While PSE notes that in recent years there has been increasing volatility in premiums for general liability insurance[61] and asserts that insurance markets continue to be volatile with premium increases difficult to forecast,[62] whether variance risk is high enough to warrant special ratemaking treatment is unclear and, in any event, unlikely. Given that the wildfire-related insurance premiums PSE included in Sch. 141WFP represent less than 0.5 percent of the Company's overall cost of service,[63] it is not likely that cost increases will have a material impact on the utility's earnings.

While it is possible that PSE will be able to produce an analysis showing that the uncertainty in future wildfire-related insurance premiums is so high that cost increases outside of the utility's ability to control are reasonably likely to have a material impact on the utility's earnings, the Company has yet to produce such an analysis. Therefore, with the evidence currently on the record, Staff cannot conclude that the insurance premiums-portion of the Company's forecasted wildfire costs meets Staff's Criterion 3.

**Q. What does Staff conclude with respect to the costs PSE includes in its proposed Wildfire Tracker?**

A. Given the Commission's expressed opinion that addressing wildfire risk is an important public policy goal, and given Staff's concern that including wildfire costs in base rates without some form of a true-up mechanism could incentivize the utility to cut wildfire

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60 *See* Table 1, above. These percentages are calculated by dividing the sum of "Wildfire Insurance Liability Expense" and "Wildfire Insurance Liability Construction Support" by the Total Costs.
61 Doyle, Exh. DAD-1CT at 109, Table 3.
62 *Id*. at 107:9-10.
63 Insurance premiums compared against PSE's overall cost of service of approximately $3 billion annually.

prevention costs, Staff is inclined to conclude that PSE's wildfire prevention-related costs satisfy Staff's proposed Criterion 1 and, therefore, would be appropriate for PSE to recover through some form of a cost recovery mechanism.

**Q. Does Staff recommend that the Commission allow PSE to recover its wildfire-related costs in some form of a cost recovery mechanism?**

A. Yes. However, Staff does <u>not</u> recommend that the Commission grant PSE's request to establish its proposed wildfire tracker, Schedule 141WFP. Rather, Staff believes that it would be more appropriate in this case to include PSE's wildfire costs in base rates but authorize PSE to establish a balancing account to track the difference between the amounts included in rates and the amounts PSE actually incurs.

**Q. What is the difference between a balancing account and a tracker?**

A. Balancing accounts and trackers are effectively the same thing; they both include a baseline level of costs in prospective rates and allow the utility to track the difference between the amounts included in rates and the amounts the utility actually incurs, and they both allow for future ratemaking treatment of the difference (i.e., the deferral balance). The main difference between a balancing account and a tracker relates to the timing of when the utility would seek recovery of the deferral balance; with a tracker the utility would seek recovery of the deferral balance in an annual true up of the tracker rates, and with a balancing account the utility would seek recovery of the deferral balance in its next general rate case.

**Q. Are Staff's proposed policy criteria applicable to both trackers and balancing accounts?**

A. Yes. Trackers and balancing accounts are cost recovery mechanisms that allow the utility to track the difference between the amounts included in rates and the amounts the utility actually incurs and pass those differences onto ratepayers. As such, both shift risk from the utility and onto ratepayers which would be inconsistent with the public interest unless one or more of Staff's proposed criteria are met.

**Q. Why is Staff recommending that the Commission order PSE to establish a balancing account rather than just allowing PSE to establish its proposed wildfire tracker?**

A. The primary reason Staff is recommending that the Commission order PSE to establish a balancing account is to promote consistency between utilities. The Commission authorized a wildfire balancing account for Avista in its 2020 and 2022 GRCs,[64] and in Avista's current GRC, Staff has recommended that the Commission allow Avista to continue tracking wildfire expenses through a balancing account.[65]

Additionally, Staff believes that consistency between utilities is particularly important here because in each of the utilities' next GRC the Commission should reexamine the need for wildfire cost recovery mechanisms, and it will be more efficient to undertake that examination if all the Commission's electric utilities are operating under the same cost recovery framework.

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[64] *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Dockets UE-200900, UG-200901 & UE-200894 (consolidated), Order 08/05, 91, ¶ 258 (Sept. 27, 2021); *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Dockets UE-220053, UG-220054 & UE-210854 (consolidated), Order 10/04, 52, ¶ 146 (Dec. 12, 2022).

[65] *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Dockets UE-240006 & UG-240007 (consolidated), Erdahl, Exh. BAE-1T at 26:5-10 (filed July 3, 2024).

**Q. Why does Staff believe the Commission should reexamine the need for wildfire cost recovery mechanisms in the companies' next GRCs?**

A. As I explain in Section III.D.2, above, before authorizing a tracker (or another form of a cost recovery mechanism) for the purpose of eliminating the utility's incentive to cut costs, the Commission should consider whether establishing a performance measure or PIM would be a more appropriate solution given the requirements of RCW 80.28.425(7). Therefore, in the next GRCs for each of the Commission's regulated electric utilities, the Commission should consider whether establishing a wildfire-related PIM would be a more appropriate way to incentivize utilities to continue making progress toward wildfire resiliency.

**Q. Above you note that there is evidence of volatility for wildfire-related insurance premiums. Would establishing a PIM address that market volatility?**

A. No. In the event a utility can demonstrate that variance risk for wildfire insurance premiums is so high that cost increases outside of the utility's ability to control are reasonably likely to have a substantial impact on the utility's earnings, Staff would recommend that some form of cost recovery mechanism (with an RSM) be established to address the potential impact on utility earnings. However, the burden should be on the utilities to demonstrate that such risk exists and warrants establishing a cost recovery mechanism.

**Q. Given the different nature of PSE's wildfire prevention costs and its wildfire insurance costs, does Staff recommend bifurcating the ratemaking treatment of those costs?**

A. Not at this time. Although the different nature of those costs suggests that each category should receive separate ratemaking consideration, and although Staff recognizes that the argument in support of establishing a wildfire balancing account pertains more to wildfire prevention costs than wildfire insurance costs, Staff also recognizes that there is significant uncertainty with respect to forward-looking insurance premiums that, in the future, PSE might be able to argue warrants a cost recovery mechanism. Because of the uncertainty in the insurance markets, and because a significant portion of the wildfire-related costs pertain to wildfire prevention, Staff does not see an urgent need at this point to bifurcate the two categories of costs. However, in the future, Staff does believe that these two categories merit separate, independent consideration.

**Q. Are there any costs PSE includes in its wildfire tracker that the Commission should <u>not</u> include in revenue requirement?**

A. Yes. As shown in Table 1, above, in its proposed Schedule 141WFP, PSE includes a $5,386,070 amount in both rate years 1 and 2 for "amortization of wildfire liability insurance deferral." This amount represents the annual amortization expense to recover a $10,772,139 deferral balance related to PSE's petition for deferred accounting in Docket UE-231048. However, the Commission has not yet ruled on PSE's petition, so PSE has not been authorized to defer the amounts the Company seeks to recover in this case. Furthermore, Docket UE-231048 has not been consolidated with this GRC, so the

Commission must rule on PSE's petition in that docket and not as an adjudicated matter within this GRC. Accordingly, Staff has removed the $5,386,070 amortization expense from its revenue requirement calculations for rate years 1 and 2.

**Q. What does Staff recommend with respect to PSE's wildfire-related costs?**

A. Staff recommends that the Commission (1) reject PSE's request to establish Schedule 141WFP, and (2) reject PSE's request in this GRC to recover the deferral balance related to the unresolved petition for deferred accounting treatment the Company filed in Docket UE-231048.

Instead, Staff recommends that the Commission order PSE to: (1) embed in base rates the costs PSE included in its proposed wildfire tracker, less the amortization expense related to the deferred accounting petition the Company filed in Docket UE-231048, and (2) establish a wildfire balancing account. As part of its next GRC, PSE should: (a) request ratemaking treatment for the balancing account regulatory asset/liability, and (b) request ratemaking treatment for amounts the Commission authorizes PSE to defer in its decision regarding Docket UE-231048, and (c) provide adequate justification for any request to continue the balancing account going forward, including justification for why a balancing account is a more appropriate mechanism than a PIM.

Furthermore, Staff recommends that for any utility seeking to extend the balancing account past the utility's next GRC, the Commission require that utility to either justify that request on a showing that the costs at issue meet Criterion 3 (i.e., variance risk is so high that cost increases outside of the utility's control is likely to materially impact the utility's earnings) or propose a wildfire-related PIM.

**Q. What is the dollar impact of Staff's recommendation to remove the deferral from PSE's forecasted wildfire-related costs?**

A. As described in Section IV.C, below, Staff recommends the Commission remove the $5,386,070 amortization expense from PSE's forecasted wildfire-related costs for rate years 1 and 2. The removal of the $5,386,070 amortization expense is reflected in Staff's revenue requirement calculation via Staff electric Adjustment S-6.51.[66]

**PSE's Proposed Decarbonization Tracker, Schedule 141DCARB**

**Q. For the costs PSE includes in its proposed Decarbonization Tracker (Electric and Natural Gas Schedules 141DCARB), does PSE's incentive to control its costs interfere with progress toward meeting an important public policy objective?**

A. No. As described by Staff witness Franks,[67] for the costs PSE includes in its proposed Schedule 141DCARB – namely, the costs associated with TEP Phase 2 – there is no discernible public policy benefit of eliminating PSE's incentive to control its costs. While decarbonization certainly is a public policy objective in the State of Washington, there is little to no risk that PSE will cut the decarbonization-related costs the Company has included in Schedule 141DCARB in a manner that interferes with progress toward

[66] Kermode, Exh. DPK-6 at 4-5.
[67] Franks, Exh. WF-1T at 31-32.

meeting decarbonization policy goals. The decarbonization-related costs the Company has included in Schedule 141DCARB largely pertain to electrification projects which PSE is naturally incentivized to pursue given their contributions to increases in the Company's electric revenues.[68]

In short, PSE's incentive to control its costs does not interfere with progress toward meeting decarbonization policy goals. Therefore, PSE's proposed Schedule 141DCARB fails Criterion 1.

**Q. Is establishing Schedule 141DCARB necessary to address potential intergenerational inequity?**

A. No. Staff's proposed Criterion 2 is only relevant to costs for which the Commission has authorized deferred accounting treatment and is only applicable between rate cases. Therefore, Staff's proposed Criterion 2 is not applicable to the costs PSE included in its proposed Schedule 141DCARB.

**Q. For the costs PSE includes in its proposed Electric Schedule 141DCARB, is variance risk so high that cost increases outside of the utility's ability to control are reasonably likely to have a substantial impact on the utility's earnings?**

A. No. As described in the testimony of Staff witness Franks, the costs PSE includes in its proposed decarbonization tracker are squarely within the Company's ability to control and, accordingly, any amount of variance risk that PSE may be exposed to is entirely

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[68] This is not universally true, as PSE's electric and gas service territories do not perfectly overlap. However, Staff believes that the Commission can address any incentive to treat customers in gas-only PSE service territory differently in the context of the HB 1589 rulemaking, Docket U-240281.

within the Company's ability to manage. Furthermore, not only are the costs squarely within the Company's ability to control, but they are largely predictable; the costs reflect specific actions identified in the Company's decarbonization plan and are not a function of highly volatile market prices. In short, there is no risk that a decarbonization tracker would seek to shield PSE from. Therefore, PSE's proposed Schedule 141DCARB fails Criterion 3.

**Q. What does Staff conclude with respect to PSE's proposed Decarbonization (Electric and Natural Gas Schedule 141DCARB)?**

A. Staff concludes that Schedule 141DCARB would not generate benefits supporting a finding that establishing the tracker would be in the public interest. Without generating such benefits, the harm caused by shifting risk from the utility and onto its ratepayers requires that the Commission find that authorizing Schedule 141DCARB would be inconsistent with the public interest. Therefore, Staff recommends that the Commission deny PSE's request to establish Schedule 141DCARB and, instead, include the revenue requirement associated with the Company's wildfire plan in the calculation of PSE's base rates.

**b. Applying Staff's proposed policy standards to PSE's existing natural gas Schedule 111 (CCA Tracker).**

**Q. Does Staff recommend that the Commission apply Staff's proposed policy standards to PSE's existing CCA tracker (Natural Gas Schedule 111)?**

A. Yes. However, because PSE's CCA tracker and an associated risk-sharing mechanism is being addressed in adjudicated Docket UG-230968, and because the Commission denied Staff's motion to consolidate Docket UG-230968 with this general rate case,[69] the Commission will need to consider Staff's proposed policy standards and their applicability to PSE's CCA tracker in Docket UG-230968.

### c. Applying Staff's proposed policy standards to other existing trackers.

**Q. Please summarize PSE's existing trackers.**

A. Table 2 below contains a breakdown of the amounts that passed through tariff riders outside of base rate in 2023.[70] Those amounts totaled $302,924,387 and $720,872,650 for electric and natural gas operations, respectively.

**Table 2. PSE Revenues in 2023 Collected Outside of Base Rates, by Schedule**

| | Electric | Gas |
|---|---|---|
| Sch 129D-Bill Discount Rate Rider | $ 3,203,741 | $ 8,782,629 |
| Sch 140 Property Tax Tracker | 49,536,672 | 22,392,594 |
| SCH 141 (ERF) | 5,929 | 134,657 |
| SCH 141A (Energy Chg Cr Rec Adj) | 35,102,690 | - |
| SCH 141X (Protected EDIT CR) | (100,103) | 210,475 |
| SCH 141Y - (Fed Inc. Tax Cr Adj) | (6,853) | (434) |
| SCH 141Z (UNPRT EDIT CR) | (11,909,056) | (839,656) |
| SCH 141D (Distr Pipe Prov Rec Adj) | - | 2,714,905 |
| SCH 141TEP (Transp Elec Plan) | 5,031,042 | - |
| SCH 141CEI (Clean Energy Tracker) | 7,997,053 | - |
| Sch 142: Decoupling Adjustment | (17,624,787) | 7,879,875 |
| Sch 149 CRM Pipeline | - | 976,065 |

[69] Dockets UE-240004, UG-240005 & UE-230810 (consolidated) and Docket UG-230968, Order 08/06/04 Denying Motion for Consolidation (June 11, 2024).
[70] *See* McGuire, Exh. CRM-2 (PSE response to Staff Data Request 102).

| | | |
|---|---|---|
| Sch 120 Conservation Rider | 103,115,152 | 24,529,112 |
| Sch 129 Low Income | 49,402,343 | 3,319,790 |
| Sch 132 Merger Rate Credit | (384) | (123) |
| Sch 137 Temporary Credit/Charge | 2,685 | 1,908,047 |
| Sch 139 Voluntary Renewable Rider | (3,534,792) | - |
| Sch 194 ResEx Benefit | (81,204,605) | - |
| Sch 111 CCA Tracker | - | 44,391,904 |
| Sch 81 Taxe Adjustment (Muni) | 107,275,172 | - |
| Sch 1 Taxe Adjustment (Muni) | - | 61,884,620 |
| Sch 101 Gas Cost Rate (PGA) | - | 560,130,537 |
| Sch 106 PGA Deferral Adj | - | (17,542,346) |
| Sch 95 Power Cost Adjustment | 55,395,917 | - |
| Sch 95A Federal Incentive Tracker | 1,236,571 | - |
| | $ 302,924,387 | $ 720,872,650 |

**Q. What proportion of PSE's regulated revenues does PSE recover through trackers or other cost recovery mechanisms?**

A. Per PSE's 2023 electric Commission Basis Report (CBR), PSE total sales to customers was approximately $2.74 billion.[71] Therefore, PSE received approximately 11 percent of electric revenues through trackers.

Per PSE's 2023 natural gas CBR, PSE total sales to customers was approximately $1.30 billion.[72] Therefore, PSE received approximately 56 percent of its natural gas revenues through trackers.

[71] Docket UE-240219, Puget Sound Energy's 2023 Electric Commission Basis Report, EL Dec 2023CBR.xlsx, Summaries tab, Row 15, Column EC (March 29, 2024).
[72] Docket UE-240220, Puget Sound Energy's 2023 Natural Gas Commission Basis Report, GS Dec 2023CBR.xlsx, model tab, Row 14, Column DC (March 29, 2024).

**Q. Should the Commission be concerned by the proportion of revenues PSE recovers through trackers or other cost recovery mechanisms?**

A. To an extent, yes. The percent of PSE's revenues it collects through trackers reflects the percent of PSE's costs that it recovers dollar-for-dollar (i.e., risk free). That is, no amount of variance in the underlying costs the tracker rates are based on will impact the Company's earnings. So, 11 percent of PSE's electric business and 56 percent of its gas business – or 25 percent of its combined electric and natural gas businesses) is not exposed to variance risk. The Commission should take this into account when it sets the Company's return on equity because, as I explain in Section III.D.2, above, the Company's authorized ROE should reflect the risk shareholders actually bear which decreases as the proportion of revenues passing through trackers increases.

**Q. Did Staff apply its proposed policy standards to PSE's existing trackers?**

A. With the exception of PSE's existing Schedule 111 (CCA tracker) discussed above, no, Staff did not apply its proposed policy standards to PSE's other existing trackers or cost recovery mechanisms. In this case Staff primarily was focused on developing policy standards and then applying those standards to the three new trackers PSE proposed in its direct case.

However, if the Commission adopts the policy standards for trackers described in this testimony, Staff intends to apply those same standards to PSE's existing trackers in the Company's next general rate case and recommend that any existing trackers whose continued existence is inconsistent with the public interest be eliminated and the associated revenue requirement be moved into the base rate revenue requirement calculation.

### E. Earning (and Deferring) a Return on PPAs

**Q. What is at issue in this proceeding with respect to PSE's petition in Docket UE-230810 to defer the costs of certain demand response PPAs (given that the petition has been consolidated with this general rate case)?**

A. In this proceeding, the Commission must rule on: (1) PSE's petition for deferred accounting treatment filed in Docket UE-230810, and (2) PSE's requests in this general rate case to recover the associated deferral balances in rates.

I address each of these two areas in turn below.

#### 1. Summary of PSE's Petition to Defer the Costs of Three Demand Response PPAs (Docket UE-230810).

**Q. Please summarize PSE's petition for deferred accounting treatment filed in Docket UE-230810.**

A. On September 29, 2023, PSE filed a petition seeking an Accounting Order authorizing the Company to defer the costs associated with three DR PPAs pursuant to RCW 80.28.410, to track and preserve them for later ratemaking treatment.[73] On March 8,

[73] Between March 10, 2023, and September 27, 2023, PSE executed PPAs with three separate demand response aggregators: Oracle America, Inc. (Opower), AutoGrid Systems, Inc., and Enel X North America, Inc. Each of the

2024, PSE filed a revised petition adding the benefits of the PPAs to its request for deferred accounting and modifying the requested start date of the deferral period from July 2023 to September 2023.[74]

In its petition, PSE seeks authorization to defer: (1) The expenses and offsetting benefits of the PPAs for the period September 2023 through December 2023, and (2) A return on the PPAs at the Company's authorized rate of return (ROR), beginning September 2023 and continuing indefinitely until the ongoing return on the PPAs is included in rates.

**Q. Please summarize how RCW 80.28.410 pertains to utility deferral of costs associated with demand response PPAs.**

A. On May 7, 2019, the Washington State Legislature enacted Engrossed Second Substitute Senate Bill 5116 (ESSSB 5116), which included various provisions intended to support electric utilities' transition to clean energy.[75] Sec. 21 of ESSSB 5116 added a new section to RCW 80.28 – codified as RCW 80.28.410 – for the primary purpose of allowing electric companies to account for and defer for later consideration by the Commission costs incurred in connection with major projects in companies' clean energy action plans (CEAPs).[76]

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PPAs are for a term of five years and are for capacity and the associated conservation attributes of the aggregator's services.

[74] PSE's revised petition (filed March 8, 2024 in Docket UE-230810) also removed the Company's earlier request that it be allowed to file a Notice of Intent to Defer – rather than a petition for deferred accounting treatment – for all future resources qualifying under RCW 80.28.410(1).

[75] Chapter 288, Laws of 2019.

[76] Pursuant to RCW 19.280.030.

RCW 80.28.410(2) provides that the costs that an electric company may account for and defer pursuant to RCW 80.28.410(1) include the costs – including the costs of capital – associated with the execution of an applicable PPA. If the deferral is granted, the cost of capital that a company may account for and defer for a qualifying PPA is calculated as a rate of return that is no less than the utility's authorized cost of debt and no greater than the utility's authorized rate of return.[77]

**Q. With respect to PSE's petition for deferred accounting filed in Docket UE-230810, what are the issues the Commission must decide?**

A. PSE's petition tees up four separate questions:

a. Should PSE be authorized to defer the PPA expenses and offsetting benefits prior to the PPAs being embedded in rates (i.e., for the period September 2023 through December 2023),

b. Should PSE be authorized to defer a return on the PPAs prior to the PPA expenses being embedded in rates (i.e., for the period September 2023 through December 2023),

c. Should PSE be authorized to continue deferring a return on the PPAs after the PPA expenses were embedded in rates (i.e., for the period January 2024 through the effective date of this general rate case), and

[77] RCW 80.28.410(2)(b).

d. If the Commission authorizes PSE to defer a return on the PPAs, should the Commission authorize PSE to calculate that return at the Company's authorized ROR, or at another rate within the parameters of RCW 80.28.410?

I address each of these four questions in turn below.

### 2. Staff's Response to PSE's Accounting Petition.

#### a. Re: PSE's request to defer the PPA expenses between September and December 2023.

**Q. Please summarize PSE's petition as it pertains to the PPA expenses the Company incurred between September and December 2023.**

A. In its petition, PSE seeks to defer the PPA expenses (as well as the offsetting benefits[78]) that the Company incurred between September and December 2023.

**Q. If PSE executed the PPAs prior to September 2023, why should the deferral not begin prior to September 2023?**

A. In its revised petition, PSE does not request authorization to defer amounts prior to September 2023. Therefore, deferral of a return on the PPAs prior to September 2023 is not within the scope of petition.

[78] PSE added the offsetting benefits to its revised petition, filed March 8, 2024, in response to the Commission taking formal note of the offsetting benefits of DR PPAs in Docket UE-230805, Order 01 at 5, ¶ 16 (Dec. 22, 2023) ("the value of the DR contracts carries an offsetting benefit amounting to $880,000, which will accrue to the benefit of customers").

Furthermore, PSE's initial petition was filed September 29, 2023. Commission policy is to limit the petition's applicability to only amounts incurred from the date the petition is filed forward.[79]

**Q. Does Staff contest PSE's request to defer the PPA expenses that the Company incurred between September and December 2023?**

A. No. RCW 80.28.410 allows utilities to account for and defer the costs of a new resource, including a PPA, provided that the resource was identified in the utility's CEAP. Furthermore, the question of whether a DR PPA, specifically, qualifies for deferred accounting under RCW 80.28.410 was answered for PSE in the Settlement Stipulation in PSE's 2022 general rate case.[80] In the Final Order approving the settlement, the Commission affirmed that, whether they are PPAs or not, to the extent that DR costs relate to projects identified in the company's CEAP, the costs qualify under the statute.[81]

**Q. Were the Demand Response resources in question identified in PSE's CEAP?**

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[79] *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.*, Dockets UE-061546 & UE-060817 (consolidated), Order 08, 43, ¶ 171 (June 21, 2007) ("Staff argues correctly that the Commission's consistent position in this regard is to allow deferral and recovery only for costs incurred during periods that post-date an accounting petition except in extraordinary circumstances beyond the utility's control"). *See also In Re: Petition of Pacific Power & Light Co. for an Accounting Order Authorizing Deferral of Excess Net Power Cost*, Docket UE-020417, 3rd Supp. Order, 2, ¶ 6 (Sept. 27, 2002) ("[A]uthorizing deferral accounting, in appropriate circumstances, for costs incurred during periods that post-date an application to establish such accounting does not violate the general prohibition against retroactive ratemaking").

[80] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-220066, UG-220067 & UE-210918 (consolidated), Appendix A, Settlement Stipulation and Agreement, to Final Order 24/10, 19, ¶ 32 ("The cost of any DER PPA for distributed generation, battery resources and demand response costs are eligible for recovery through PSE's PCORC, PCA Mechanism and/or annual power cost update and are eligible for potential earning on PPAs pursuant to RCW 80.28.410").

[81] *See* 2022 PSE GRC Order at 77, ¶ 258.

A. Yes. In PSE's 2021 CEAP the Company identified 29 MW of incremental DR capacity to be installed by 2025,[82] and in the PSE's 2023 Biennial CEIP Update the Company identified a DR target of 86 MW for the 2025 winter cumulative peak.[83] As explained in further detail in the testimony of Staff witness Koenig, PSE selected the three DR PPAs in question through its 2022 RFP process for DERs, and subsequently contracted with the three DR aggregators to achieve the 86 MW target identified in the Company's 2023 Biennial CEIP update.

Given that these three DR PPAs were selected through the 2022 RFP process for DERs, and that process focused on obtaining DERs identified in the Company's 2021 CEAP, and given that ultimately the Company contracted with these three DR aggregators to obtain the DR capacity identified in the Company's 2023 CEIP update, Staff believes that the expenses for these three DR PPAs qualify for deferral under the law.

**Q. Did PSE incur expenses related to these PPAs prior to those expenses being embedded in rates?**

A. Yes. PSE began incurring expenses related to these three PPAs in July 2023, but the PPAs were not embedded in rates until January 1, 2024, which was the rate-effective date of PSE's 2024 Power Cost Update.[84] Therefore, PSE's requested deferral period for these expenses of September 2023 through December 2023 is appropriate as it corresponds to

[82] Puget Sound Energy's 2021 Clean Energy Action Plan, Docket UE-200304 (2021 IRP docket), pages 2-16, Figure 2-9: Cost-effective Demand Response Incremental Nameplate Capacity (filed April 1, 2021).
[83] *See* Archuleta, Exh. GA-7 at 2.17.
[84] *See* PSE's 2024 Power Cost Update, Docket UE-230805, Order 01 (Dec. 22, 2023). In Order 01 (at 5, ¶ 16), the Commission authorized PSE to include the expenses for the three DR PPAs in the 2024 PCA baseline.

the period spanning the date PSE initially filed its accounting petition up to the date PSE began recovering the going-forward PPA expenses in rates.

**b. Re: PSE's request to defer a return on the demand response PPAs between September 2023 and December 2023.**

**Q. Please summarize again PSE's request to defer a return on the three demand response PPAs.**

A. PSE seeks to defer a return on the PPAs for the period prior to the PPAs being embedded in rates (i.e., between September 2023 and December 2023) *AND* for the period between the date the PPAs are first embedded in rates and the date the going-forward return would be embedded in rates (i.e., between January 2024 and the rate effective date of this GRC).

**Q. Does Staff support PSE's request to defer a return on these PPAs between September and December 2023?**

A. Yes. RCW 80.28.410 is clear that companies may defer a return on qualifying PPAs between the execution date of the PPAs and the date the PPAs are included in rates.[85] As I described above, PSE executed these PPAs in July 2023 but the PPAs were not included in rates until January 1, 2024. Therefore, deferring a return on the PPAs between

[85] RCW 80.28.410(1) states that: "The deferral in this subsection begins with the date on which the resource begins commercial operation or the effective date of the power purchase agreement and continues for a period not to exceed thirty-six months. However, if during such a period the electrical company files a general rate case or other proceeding for the recovery of such costs, deferral ends on the effective date of the final decision by the commission in such a proceeding."

September and December 2023 ~~2024~~ – i.e., the period spanning the date PSE initially filed its accounting petition up to the date the PPAs were included in rates – is appropriate under the statute. However, as I explain in subsection (d), below, the return should be calculated at the Company's authorized cost of debt and not at its full, authorized rate of return.

### c. Re: PSE's request to defer a return on the demand response PPAs beyond December 2023.

**Q. Does Staff support PSE's request to defer a return on these PPAs from January 2024 forward?**

A. No. Beginning January 1, 2024, at the conclusion of PSE's power cost update, the three PPAs at issue in this case were included in rates. While PSE did not request to include a return on the PPAs in rates effective January 1, 2024 – and therefore the return itself was not included in rates between January 1, 2024, and the effective date of this GRC – under Staff's reading of the law, RCW 80.28.410 does not permit utilities to continue deferring a return on the PPAs beyond the date the underlying PPAs themselves were included in rates.

**Q. Please explain why RCW 80.28.410 does not permit utilities to continue deferring a return on the PPAs beyond the date the underlying PPAs themselves are included in rates.**

A. Per RCW 80.28.410(1) and (2), deferral must end when the PPAs are included in rates.

RCW 80.28.410(1) states:

> "if the company files a general rate case or other proceeding for the recovery of such costs, <u>deferral ends on the effective date</u> of the final decision by the commission in such a proceeding." (Emphasis added).

PSE filed a power cost update on September 29, 2023, wherein the Company included the costs for the DR PPAs described above. The Commission allowed PSE to include the PPA costs in the 2024 PCA baseline rates effective January 1. 2024. Therefore, under the plain language of RCW 80.28.410(1), the deferral ends on January 1, 2024.

**Q. Does Staff contest PSE's ability to earn a return on these PPAs for the duration of the PPAs?**

A. No. RCW 80.28.410(2)(b) indicates that the legislature intended to allow utilities to earn a return on a qualifying PPA "(f)or the duration of a power purchase agreement". Staff is not contesting PSE's ability to earn a return on qualifying PPAs pursuant to this section of the statute. Indeed, Staff is not contesting PSE's request in this GRC to include a return on these PPAs in rates going forward (although Staff does contest the rate of return PSE uses to calculate the return).

Again, Staff is only contesting PSE's request to <u>*defer*</u> a return on the PPAs between January 1, 2024, and the rate-effective date of this GRC as *deferring* a return after the PPAs are embedded in rates is prohibited by RCW 80.28.410(1).

**d. Re: PSE's request to calculate the return on the three PPAs at the company's authorized ROR.**

**Q. What rate does PSE use to calculate the returns on the three DR PPAs?**

A. PSE requests to calculate the return at the Company's full authorized rate of return, which is the maximum return allowed under the law. RCW 80.28.410(2)(b) allows for a return on qualifying PPAs that is no less than the company's authorized cost of debt and no greater than the company's authorized rate of return.

**Q. Does Staff support PSE's use of its full authorized ROR to calculate the returns on these PPAs?**

A. No. In Staff's view, where statute provides a range of possible rates that the Commission may consider for calculating the return on qualifying PPAs, the Commission should authorize a rate at the upper end of that range only when the utility has adequately justified using the upper end of the range. Neither PSE's petition nor its testimony in the present GRC provided such justification.

In its petition, PSE states only that a full rate of return is appropriate "because these are long-term PPAs and as such, will be financed using PSE's full capital structure." However, it is not clear to Staff how the term of a PPA has any bearing on the Company's capital costs. PSE does not pay for the full term of its PPAs up front. These PPAs are paid monthly, so PSE's suggestion that they require long-term financing is an inaccurate representation and, to the matter at hand, not a valid reason for calculating a return at the top end of what is allowed under the law.

**Q. What does Staff recommend?**

A. Staff recommends that the Commission deny PSE's request to defer a return on the PPAs calculated at the Company's full authorized ROR, and instead order the Company to calculate the return using the Company's authorized cost of debt.

**Q. Does PSE indicate that allowing the Company to earn a return on qualifying PPAs at the Company's authorized cost of debt would be an acceptable outcome?**

A. Yes. As explained by PSE witness Doyle, PSE allows that the policy benefits of allowing the Company to earn a return on qualifying PPAs would still be achieved if the return were calculated at PSE's authorized cost of debt.[86] Witness Doyle further states that the "potential policy benefits are more important than the ultimate rate of return the Commission approves,"[87] and that "PSE would be supportive of any rate of return the Commission orders equal to either PSE's authorized cost of debt or its authorized rate of return, or anywhere in between."[88]

**Q. Does Staff recommend that the return be calculated using the Company's authorized cost of debt for all qualifying PPAs going forward?**

A. Not necessarily. Staff's recommendation in this case that the return be calculated using the Company's authorized cost of debt is specific to the record evidence in this case, which is devoid of any adequate justification for using a rate of return that is at the highest end of the range allowed under RCW 80.28.410(2)(b). The record in this case

[86] Doyle, Exh. DAD-1CT at 96:1-10.
[87] *Id*. at 96:10-12.
[88] *Id*. at 96:12-14.

simply does not support calculating a return on these PPAs using a rate that is higher than the bottom end of the range specified in statute, which is the utility's authorized cost of debt.

In future cases, Staff expects that utilities seeking to earn a return on qualifying PPAs at their authorized rates of return will offer justification for that request.[89] The Commission then can determine on a case-by-case basis whether the provided justification is sufficient to warrant using a rate of return that is greater than the utility's authorized cost of debt.

**Q. Do Staff's recommendations to (1) deny PSE's request to defer a return on the PPAs between January 1, 2024, and the effective date of this GRC, and (2) require that the return on the three qualifying PPAs at issue in this case be calculated at the Company's authorized cost of debt (rather than at its authorized rate of return) impact revenue requirement in this GRC?**

A. Yes. In this GRC, PSE seeks to recover the deferral balances associated with these three PPAs through electric pro forma Adjustment 6.47. Therefore, Staff's recommendations impact electric revenue requirement through that adjustment. As discussed in more detail in Section IV.A, below, reflecting the recommendations described herein in Staff's

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[89] RCW 80.28.410 does not outline a standard that the Commission must use when determining the range between the cost of debt and authorized rate of return, Staff therefore assumes that the Commission would decide this issue under the public interest standard unless and until the Commission provides guidance on a more specific standard. While Staff does not have a recommended standard, one consideration that would certainly be relevant is whether the PPA in question would still have been cost effective (or within the lowest reasonable cost portfolio) if a full authorized rate of return was included in estimated costs.

modified Adjustment 6.47 reduces electric revenue requirement by $0.4 million for both 2025 and 2026.

Additionally, given that PSE includes a going-forward return on these three PPAs calculated at the Company's authorized rate of return in its pro forma power cost Adjustment 6.38, Staff's recommendation that the return on these PPAs be calculated at the Company's authorized cost of debt also impacts Adjustment 6.38 but reduces revenue requirement for RY1 and RY2 only trivially (i.e., by less than $0.1 million).

### F. CWIP in Rate Base

#### 1. PSE's request to include CWIP in rate base for the Beaver Creek Project.

**Q. Please summarize PSE's request in this case with respect to including CWIP in rate base.**

A. PSE requests to include CWIP in rate base for its Beaver Creek project, which the Company seeks to recover through its proposed Clean Generation Resources tracker (electric Schedule 141CGR). PSE anticipates that the Beaver Creek project will be placed in service by August 2025, so for its 2025 revenue requirement calculation the Company has included in rate base the projected CWIP balances for January through July 2025 and the projected net plant-in-service balances for August through December 2025.

PSE projects total capital expenditures for the Beaver Creek project to be $501 million, and over the two-year rate plan PSE calculates incremental revenues associated with including CWIP in rate base would be $23.9 million.[90]

**Q. Does PSE propose to recover the costs of the Beaver Creek project (including a return on CWIP) in base rates or in one of its proposed new trackers?**

A. PSE proposes to recover the costs of the Beaver Creek project (including a return on CWIP) through its proposed Clean Generation Resources tracker (electric Schedule 141CGR). The costs of the Beaver Creek Project are the only costs PSE includes in its proposed tracker Schedule 141CGR.

However, as I explain in Section III.D.3, above, Staff is recommending that the Commission deny PSE's request to establish Schedule 141CGR. Therefore, under Staff's recommendation, the costs of the Beaver Creek project would be recovered in PSE's base rates and not through a separate tracker.

**Q. Under PSE's proposal, if the Commission were to allow PSE to include CWIP in rate base for Beaver Creek, would the Company continue to accrue AFUDC on the project's construction costs?**

A. No. For the period where CWIP is included in rate base, the Company is not allowed accrue AFUDC.[91]

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[90] Free, Exh. SEF-25 at 1. The incremental revenues of $23.9 million is the difference between the $132.6 million revenue requirement using PSE's proposed (hybrid) approach in column (d) and the $108.7 million revenue requirement using the conventional (AFUDC) approach in column (c).
[91] Free, Exh. SEF-1T at 10:8-9.

However, PSE would accrue AFUDC on the project during the pendency of this proceeding (i.e., prior to when rates would reflect the inclusion of CWIP in rate base). If the Commission accepts PSE proposal, the Company would recover a return on CWIP beginning on the rate-effective date of this case and continuing until the project is placed in service.

### 2. Relevant background on including CWIP in rate base.

**Q. What is CWIP?**

A. CWIP, or "Construction Work In Progress," reflects a project's total capital costs at the end of each month of construction and accumulated up to the date the project is placed in service. CWIP is composed of the cumulative capital expenditures plus the cost of contributed capital which is calculated as the utility's authorized cost of capital multiplied by the total CWIP balance at the end of each month. The cost of contributed capital that accrues at the end of each month is usually referred to as the "allowance for funds used during construction" (or "AFUDC").

**Q. What is the Commission's standard practice with respect to compensating utilities for invested capital committed to projects during the project's construction phase (i.e., prior to the project being completed and transferred to utility plant-in-service)?**

A. The Commission's standard practice is to allow utilities to accrue AFUDC on CWIP balances for the duration of a project's construction period, up to the date the project is placed in service. AFUDC accrues at the end of each month of construction and is capitalized into the project's total construction costs. Therefore, under the Commission's standard practice, when a project is transferred to service, the resulting gross plant-in-service includes the total capital expenditures plus capitalized AFUDC. And because capitalized AFUDC is part of gross plant-in-service, it depreciates over the life of the facility and is recovered through depreciation expense.

**Q. What is the key distinction between capitalizing AFUDC versus including CWIP in rate base?**

A. Capitalizing AFUDC and including CWIP in rate base both serve the purpose of compensating the utility for capital committed to a project prior to the project being placed in service, and both are calculated at the utility's authorized rate of return. The key distinction between capitalizing AFUDC and including CWIP in rate base is one of timing; capitalized AFUDC is recovered over the life of the underlying facility and including CWIP in rate base allows the utility to recover the return on committed capital (that otherwise would have been capitalized as AFUDC) immediately.

**Q. Why is the Commission's standard practice to allow utilities to capitalize AFUDC rather than to include CWIP in rate base?**

A. While in years past the Commission allowed utilities to include CWIP balances in rate base, that practice ended with a 1984 ruling by the Washington Supreme Court that the Commission's inclusion of CWIP in rate base was unlawful because the plant in question was not yet used and useful for service in Washington which was a requirement of, and within the meaning of, the state's property valuation statute, RCW 80.04.250.[92]

Given the Court's ruling in the *POWER* case, the Commission discontinued allowing CWIP in rate base and began compensating utilities for the cost of committed capital solely through the capitalization of AFUDC. That practice has, to date, remained unchanged.

**Q. Have there been any relevant amendments to RCW 80.28.250 since the Court's ruling in the 1984 POWER case?**

A. Yes. In 1991, the Washington legislature passed Engrossed Substitute Senate Bill 5770, which amended RCW 80.04.250 to provide the Commission with explicit authority to include CWIP in rate base. The statute now reads, "[i]n determining what property is used and useful for providing electric, gas, or water service, <u>the commission may include the reasonable costs of construction work in progress</u> to the extent that the commission finds that inclusion is in the public interest." (Emphasis added.)

**Q. Since RCW 80.04.250 was amended to provide the Commission with explicit authority to include CWIP in rate base, has any of the Commission's regulated utilities requested to include CWIP in rate base?**

[92] *People's Org. for Wash. Energy Res. v. WUTC*, 101 Wn.2d 434 (1984) ("POWER").

A. Not to Staff's knowledge. Aside from PSE's request in this case to include CWIP in rate base, Staff is not aware of any other such requests that have been made since the statute was amended.

**Q. Have there been any additional laws passed that pertain to CWIP amounts PSE may include in rate base?**

A. Yes. During the 2024 legislative session, the Washington State legislature passed Engrossed Substitute House Bill (ESHB) 1589.[93] Section 5(2) of ESHB 1589 provides that a large combination utility submitting an application under Section 5(1) of ESHB 1589 – i.e., a utility submitting an application to the Commission seeking a certificate of necessity for the construction, investment, or purchase of a renewable or nonemitting electric energy or capacity resource costing $100,000 or more and for which the utility must begin incurring significant portions of those costs more than five years before the facility is estimated to be in service – may submit a request to recover financing interest costs in base rates on construction work in progress for capital improvements approved under the law prior to the assets being considered used and useful.

**Q. Is ESSB 1589 applicable to PSE's request to include Beaver Creek CWIP in rate base in this GRC?**

A. No. ESSB 1589 pertains only to facilities for which a utility has applied for a certificate of necessity. Staff does not believe PSE has filed an application to the Commission

[93] Codified as Chapter 80.86 RCW.

seeking a certificate of necessity for the construction of the Beaver Creek Wind facility. Moreover, even if PSE had filed an application for such a certificate of necessity, PSE did not begin incurring significant portions of the costs for Beaver Creek more than five years before the facility is estimated to be in service, so the facility does not qualify for CWIP in rate base treatment under ESSB 1589 regardless. PSE began incurring capital expenditures on Beaver Creek in October 2023, less than two years before PSE's anticipated in-service date of August 2025.

### 3. Staff response and recommendation.

**Q. What is the legal standard for determining whether to grant PSE's request to include CWIP in rate base for the Beaver Creek project?**

A. RCW 80.04.250, as amended in 1991 to provide the Commission with explicit authority to include CWIP in rate base, provides that in valuing utility property for ratemaking purposes, the Commission may include CWIP in rate base "to the extent that the commission finds that inclusion is in the public interest." (Emphasis added.)

Thus, the legal standard for determining whether to grant PSE's request to include CWIP in rate base for the Beaver Creek project is the public interest standard. That is, pursuant to RCW 80.04.250, before the Commission may include CWIP in rate base, it must first find that including CWIP in rate base is in the public interest.

**Q. What rationale does PSE provide to justify its request to include CWIP in rate base for its Beaver Creek Project?**

A. PSE bases its request on the notion that including CWIP in rate base allows for more immediate recovery of the financing costs of a project.[94] PSE argues that this more immediate recovery of the financing costs of the project would increase the Company's near-term cash flows and lead to an improved quality of actual cash earnings which, in turn, could enable financing at a relatively lower cost.[95]

**Q. Does PSE offer any other arguments in support of including CWIP in rate base?**

A. Yes. PSE argues that including CWIP in rate base leads to lower capitalized costs and, as a result, in comparison to the standard AFUDC approach ratepayers pay less over the life of the plant.[96]

**Q. Do the benefits of including CWIP in rate base that PSE cites promote the public interest?**

A. Possibly. The benefits PSE asserts – i.e., lower capital costs and the prospect of ratepayers paying less over the life of the plant – indeed sound beneficial. However, closer scrutiny reveals that these are not particularly persuasive arguments.

**Q. Why is Staff not persuaded by PSE's argument that including CWIP in rate base would increase the Company's near-term cash flows and lead to an improved quality of actual cash earnings which, in turn, could enable financing at a relatively lower cost?**

[94] Free, Exh. SEF-1T at 10:6-8.
[95] Doyle, Exh. DAD-1T at 65:7-12 (citing Accounting for Public Utilities, § 4.04[4], at 4-15).
[96] *Id*. at 64:21 –65:2 (citing Accounting for Public Utilities, § 4.04[4], at 4-15).

A. While in a circuitous way including CWIP in rate base *could* ultimately contribute to reduced capital costs, that outcome is far from certain and, in any event, cannot be proven to be true. There are countless reasons why a utility's financing costs may increase or decrease, and PSE will never know the specific impact of any one factor on the terms of the Company's financing arrangements.[97] In short, PSE's purported benefit of potentially lower capital costs is not measurable or verifiable, so it would be a stretch to conclude that, on the grounds that including CWIP in rate base reduces capital costs, including CWIP in rate base is in the public interest.

Moreover, PSE's argument that including CWIP in rate base could reduce the Company's capital costs is undermined by the fact that, compared to the standard approach of capitalizing AFUDC, PSE's proposal to include CWIP in rate base increases rates over the two-year rate plan by $23.9 million. Staff cannot support the notion that ratepayers paying an extra $23.9 million over the next two years in exchange for the uncertain prospect of a lower cost of capital at some point in the future supports a finding that including CWIP in rate base is in the public interest.

**Q. Why is Staff not persuaded by PSE's argument that if CWIP were included in rate base, ratepayers would pay less over the life of the plant than they would pay using the standard AFUDC approach?**

A. While this argument does have curb appeal, the argument suffers from a serious – and in Staff's view insurmountable – flaw. In short, including CWIP in rate base would

[97] *See* Parcell, Exh. DCP-1T at 60:7 – 65:4, for further discussion of credit ratings and financing costs.

disproportionately impact PSE's low-income customers and, as a result, would lead to inequitable outcomes for those customers.

**Q. Before you detail the inequities that you assert would be created if CWIP were included in rate base, are there any preliminary issues Staff wishes to address regarding PSE claim that if CWIP were included in rate base ratepayers would pay less over the life of the plant?**

A. Yes. As PSE accurately observes, given that the different cost impacts of the AFUDC and CWIP approaches propagate over the life of the underlying plant, it is essential that the revenue requirements under these two scenarios be examined on a discounted, net-present-value (NPV) basis that specifically takes into account the time value of money from the perspective of customers.[98] Thus, calculating the NPV revenue requirement under these two scenarios that accounts for the time value of money from perspective of customers requires using a discount rate that reflects customers' opportunity cost of capital.

**Q. Did PSE compare costs to ratepayers over the life of the plant on net-present-value basis?**

A. Yes. PSE produced an analysis comparing the NPV revenue requirements for the Beaver Creek project under the standard AFUDC approach and under the proposed approach of including CWIP in rate base. The results of that analysis indicated that over the life of the

[98] Doyle, Exh. DAD-1CT at 80:9-14.

plant, on a net-present-value basis, ratepayers would pay $663,969,973 under the standard approach of capitalizing AFUDC and $660,192,269 under PSE's proposal to include CWIP in rate base.[99] That is, PSE's analysis indicates that, on an NPV-basis, including CWIP in rate base would save ratepayers approximately $3.8 million (about 0.5 percent) over the life of the facility.

**Q. What discount rate did PSE use in its NPV analysis to reflect the opportunity cost of capital of its customers?**

A. PSE's NPV analysis used a discount rate of 4.82 percent.[100]

**Q. Did PSE's net present value calculations use a discount rate that reflects ratepayers' opportunity cost of capital?**

A. Yes and no. It appears that PSE put a substantial amount of effort into identifying a discount rate that appropriately reflects the opportunity cost of capital from the perspective of the Company's ratepayers. And, as a general matter, Staff does not contest that the discount rate PSE used to reasonably represent the opportunity cost of capital of the average person. So, from that perspective, yes, PSE did perform its net present value calculations using a discount rate that reflects ratepayers' opportunity cost of capital.

However, using a discount rate that represents the opportunity cost of capital for the average person does not allow for an examination of how customers experiencing financial circumstances that are different from those of the average person would

[99] Free, Exh. SEF-25, line g, columns (c) and (d).
[100] Doyle, Exh. DAD-1CT, 84:12.

experience the cost implications of using the CWIP in rate base approach as opposed to the standard AFUDC approach. Although PSE acknowledges that customers have differing financial circumstances that affect their opportunity cost of capital, PSE states that its analysis makes use of simplifying assumptions because is impossible to know each customer's individual and unique opportunity cost of capital.[101] But in simplifying the analysis, PSE uses a discount rate that represents the opportunity cost of capital of a person who, with increased disposable income associated with lower utility bills, would invest that disposable income in an asset allocation of 40 percent equity and 60 percent debt, and at a debt rate of 4.85 percent.[102]

Therefore, in simplifying the analysis to evaluate costs only from the perspective of someone with a typical opportunity cost of capital, PSE's analysis does not examine the cost implications from the perspective of PSE's lower-income customers – who tend have a higher opportunity cost of capital than the average person – and whether those customers would be made worse off if CWIP were included in rate base. From that perspective, no, PSE did not perform a net present value calculation using a discount rate that equitably accounts for lower income customers' opportunity cost of capital.

**Q. Why is Staff applying an equity lens to the question of whether including CWIP in rate base is consistent with the public interest?**

A. The Commission has made it abundantly clear that to "ensure the Commission's decisions do not continue to contribute to the ongoing systemic harms, we must apply an

[101] Doyle, Exh. DAD-1CT at 82:16-19.
[102] *Id*. at 83:5-6.

equity lens in all public interest considerations going forward."[103] State law defines "equity lens" as providing consideration to those characteristics for which groups of people have been historically, and are currently, marginalized to evaluate the equitable impacts of an agency's policy.[104]

**Q. How would the results of PSE's analysis change if PSE were to use a higher discount rate?**

A. Given that including CWIP in rate base increases costs to ratepayers in the near term and decreases costs to ratepayers in the out years, using a higher discount rate – i.e., weighing near-term costs more heavily than future costs – has the effect of making the CWIP in rate base approach relatively more costly and the standard AFUDC approach relatively less costly.

To examine whether a higher discount rate would cause the CWIP in rate base approach to be more costly than the AFUDC approach, in addition to analyzing the NPV of revenue requirements using a discount rate of 4.82 percent PSE also performed the analysis using a discount rate of 6.25 percent.[105] The results of that analysis indicated that using a discount rate of 6.25 percent still results in a lower NPV revenue requirement if CWIP were included in rate base (relative to the standard AFUDC approach).[106]

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[103] *Wash. Utils. & Transp. Comm'n v. Cascade Nat. Gas Corp.*, Docket UG-210755, Order 9, 17-18, ¶ 55 (Aug. 23, 2022).
[104] *See* RCW 43.06D.010(4); *see also* RCW 49.60.030.
[105] Doyle, Exh. DAD-1CT, 86:13.
[106] *Id*. at 87:18–21. Using a discount rate of 6.25 percent, PSE calculates a NPV revenue requirement of $593.6 million for the conventional AFUDC approach and $592.6 million for the hybrid CWIP approach.

**Q. Do these results persuade Staff that including CWIP in rate base is beneficial to customers with a higher opportunity cost of capital?**

A. No. A discount rate of 6.25 percent still represents an opportunity cost of capital of someone who would invest an increase in disposable income in equity and who would pay down (or avoid) debt that they managed to access at 4.85 percent, just at an asset allocation of 60 percent equity and 40 percent debt[107] rather than 40 percent equity and 60 percent debt. In other words, while 6.25 percent certainly is higher than 4.85 percent, 6.25 percent is not a reasonable representation of the opportunity cost of capital for lower-income consumers.

**Q. What is a reasonable representation of the opportunity cost of capital for low-income customers?**

A. While I do not have a specific discount rate that I would recommend the Commission adopt here, I would note that what the relevant academic literature makes clear is that individuals' time-preferences are negatively correlated with income; that is, lower-income consumers generally have a higher opportunity cost of capital than higher-income consumers.[108]

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[107] *Id*. at 85:13–14.

[108] *See, e.g.*, Lawrence, E.C. (1991) "Poverty and the Rate of Time Preference." *Journal of Political Economy*, 99(1):54-77 (Lawrence 1991); Newell, Richard G., and Juha V. Siikamäki. 2015. "Individual Time Preferences and Energy Efficiency." *American Economic Review*, 105(5):196-200 (Newell & Siikamäki 2015); Carvalho LS, Meier S, Wang SW (2016). "Poverty and economic decision making: Evidence from changes in financial resources at payday." *American Economic Review*, 106(2):260–84.

**Q. In general, how much higher is the opportunity cost of capital for low-income customers than for high-income customers?**

A. One highly cited paper estimates that the time preference for higher-income households is three to five percentage points lower than the time preference for lower-income households.[109] Furthermore, controlling for race and education widens this difference; one paper found the time preference for white, college-educated families to be approximately seven percentage points lower than that for nonwhite families without a college education,[110] while another paper found that individuals with a college degree have discount rates approximately 13–14 percentage points lower than individuals with no college education.[111]

**Q. At what discount rate would PSE's analysis show that including CWIP in rate base would be more costly than adhering to the Commission's standard practice of allowing the utility to capitalize AFUDC?**

A. At a discount rate of seven percent, the CWIP in rate base approach becomes more costly than the standard AFUDC approach which means that any of PSE's customers that have an opportunity cost of capital of greater than seven percent would be harmed if CWIP were included in rate base.

**Q. Are lower income customers likely to have an opportunity cost of capital of lower than seven percent?**

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[109] Lawrence 1991, n.103 supra.
[110] *Id.*
[111] Newell & Siikamäki 2015, n.103 supra.

A. No. Given that the academic literature indicates that, conservatively, controlling for race and education, lower income customers have an opportunity cost of capital that is seven percent higher than that of higher income customers, it is highly unlikely – if not impossible – that lower income customers would have an opportunity cost of capital that is less than seven percent. It is more likely that lower income customers have an opportunity cost of capital that is seven to 13 percentage points higher than the discount rate PSE used in its NPV analysis, which would be between approximately 12 percent and 18 percent.[112] And these numbers pass the smell test; for many low-income customers, the best (lowest risk and highest reward) investment is paying down (or avoiding) high-interest debt, such as credit card debt or payday loans.

It is highly likely that including CWIP in rate base would be harmful to lower-income customers and virtually certain when controlling for race and education.

**Q. What conclusion should the Commission draw from this?**

A. PSE's customers with a relatively high opportunity cost of capital – namely, PSE's lower-income customers – would be disproportionately affected, and very likely harmed, if CWIP were included in rate base. Consistent with the Commission's expressed intention to apply an equity lens in all public interest considerations going forward, the Commission should apply an equity lens here. If the Commission applies an equity lens to PSE's request to include CWIP in rate base, the Commission will find that including CWIP in rate base is inconsistent with the public interest. And given that RCW 80.04.250

[112] These numbers are calculated by adding the percentages from Lawrence 1991 (approximately seven percent) and from Newell & Siikamäki 2015 (approximately 13 percent) to the discount rate of 4.85 percent that PSE used in its NPV analysis.

provides that the Commission may include CWIP in rate base only if the Commission first finds that including CWIP in rate base is in the public interest, the Commission should deny PSE's request to include CWIP in rate base for the Beaver Creek project.

**Q. Does Staff have any other concerns with including CWIP in rate base?**

A. Yes. Staff is concerned that, in addition to potentially leading to inequitable outcomes for low-income customers, including CWIP in rate base creates intergenerational inequities. In comparison to the standard AFUDC approach, including CWIP in rate base requires ratepayers to pay higher costs up front and lower costs in the out years. However, the question of whether paying a return on CWIP now is a beneficial "investment" from the perspective of ratepayers today depends on whether the returns on the investment accrue to the ratepayers that made the investment. And because customers come and customers go, many of today's customers would not receive the promised returns on their investment while many of tomorrow's customers would receive returns on an investment that they did not make. Thus, including CWIP in rate base has the effect of benefiting future customers at the expense of current customers, thereby creating intergenerational inequity.

**Q. What does Staff recommend?**

A. Staff recommends that the Commission find that the record does not support a finding that including CWIP in rate base for the Beaver Creek project is in the public interest and, accordingly, deny PSE's request in this case to include CWIP in rate base for that project. Staff recommends that, instead, the Commission follow its standard practice of allowing the Company to capitalize AFUDC during the project's construction and include gross plant-in-service in rate base as of the date PSE anticipates the Beaver Creek project will be placed in service (i.e., August 2025).

**Q. What is the revenue requirement impact of Staff's recommendation to deny PSE's request to include CWIP in rate base for the Beaver Creek project?**

A. As I describe in Section IV.B below, Staff's recommendation to deny PSE's request to include CWIP in rate base for the Beaver Creek project results in a $28.4 ~~23.5~~ million reduction to electric revenue requirement for RY1 and a $0.7 million ~~increase~~ decrease for RY2.

However, as I discuss in further detail in Section III.D.3, above, the Commission should note that while PSE includes the cost of Beaver Creek in its proposed Clean Generation Resources tracker (Schedule 141CGR), Staff recommends that the Commission deny PSE's request to establish Schedule 141CGR and instead include the costs of the Beaver Creek project in PSE's base rate revenue requirement calculation. Therefore, depending on the Commission's decision on Staff's recommendation to reject the tracker, the revenue requirement impact of denying PSE's request to include CWIP in rate base will either show up in the base rate revenue requirement or the revenue requirement for "other schedules."

### G. Equity

**Q. What are Staff's recommendations regarding advancing equity?**

A. As described in the testimony of Staff witness Harmon, while Staff acknowledges and commends PSE's general progress and efforts to advancing equity, Staff has several recommendations designed to address notable gaps in PSE's implementation of equity programs. Staff witness Harmon makes recommendations spanning recognition justice, procedural justice, distributive justice, restorative justice, and equity investment zones.

In addition to these formal recommendations to the Commission, Staff witness Harmon also provides suggestions directly to PSE that the Company may find instructive as it seeks to make progress on procedural equity, its internal equity work, and with its work with Native nations.

**Q. Does Staff address equity-related issues in any of its other recommendations?**

A. Yes. As discussed in Section III.B.2.b, above, Staff witness Koenig recommends that the Commission adopt Staff's alternative DR PIM proposal which builds DR equity into the mechanism's incentive structure. Witness Koenig also recommends that the Commission require PSE develop an action plan to achieve 30 percent of energy benefits to Named Communities within its DR programs.

Staff witness Franks recommends that the Commission order PSE to conduct a distributional equity analysis on the entirety of PSE's distributed solar portfolio as well as on its proposed targeted electrification pilot Phase 2. Also, as part of PSE's first ISP, Staff recommends that the Commission order PSE to conduct a cost burden analysis on the effect of a range of future inputs and scenarios, including changing customer counts, CCA compliance costs, and other relevant factors on forecasted rates for remaining natural gas customers, with consideration given to energy burden on named communities.

And as discussed in Section III.F.3, above, I recommend that the Commission find that including CWIP in rate base for PSE's Beaver Creek project would disproportionately harm low-income customers, leading to inequitable results for those customers. On that basis, I recommend that the Commission reject PSE's request to include CWIP in rate base.

## IV. CONTESTED ADJUSTMENTS

**Q. Which of PSE's accounting adjustments do you contest?**

A. I contest PSE's electric Adjustment 6.47 – which pertains to amounts PSE is seeking to defer (and recover) via consolidated Docket UE-230810 – as well as electric Adjustment 6.22 and natural gas Adjustment 11.22 – which pertains to PSE's forecasted, pro forma O&M expense.

I also contest amounts PSE included in its proposed tracker Schedules 141CGR and 141WFP, which Staff moves into its base rate revenue requirement calculation via Adjustments S-6.49 and S-6.51, respectively.

I discuss each of these adjustments individually below.

### A. PPA Deferrals (Adj. 6.47)

**Q. Please describe the PPA deferrals for which PSE seeks recovery through electric pro forma Adjustment 6.47.**

A. The deferral balances PSE seeks to include in electric revenue requirement through Adjustment 6.47 are the deferral balances associated with PSE's petition in Docket UE-230810 to defer the costs associated with three DR PPAs pursuant to RCW 80.28.410. I describe those deferrals in detail in Section III.E, above.

**Q. Does Staff contest any portion of the deferral balances PSE seeks to recover through Adjustment 6.47?**

A. Yes. As I describe in further detail in Section III.E.2, above, Staff recommends that the Commission (1) deny PSE's request to defer a return on the PPAs between January 1, 2024, and the effective date of this GRC, and (2) deny PSE's request to calculate the return on the PPAs using the Company's authorized ROR and instead require that the return be calculated at the Company's authorized cost of debt.

Staff does not contest amounts PSE includes in Adjustment 6.47 related to the PPA expenses deferred between September and December 2023.

**Q. Can you please briefly summarize the rationale behind why Staff is contesting these components of Adjustment 6.47?**

A. Yes. Regarding PSE's request to defer a return on the PPAs between January 1, 2024, and the effective date of this GRC, as I describe in further detail in Section III.E.2.c, above, Staff contests PSE's request to defer a return on the PPAs between these dates because RCW 80.28.410 prohibits continued deferral beyond the date the PPAs are included in rates (which was January 1, 2024). Regarding PSE's request to calculate the return on the PPAs using the Company's authorized ROR, Staff contests that request because the Company simply has not justified why it should earn a return on the PPAs at the highest rate allowed by statute.

**Q. Setting aside the statutory prohibition against continuing to record deferrals beyond the date the PPAs are included in rates (i.e., beyond January 1, 2024), are there any other reasons why the Commission should be hesitant to allow PSE to recover the post-2023 return deferral PSE includes in Adjustment 6.47?**

A. Yes. Through its Adjustment 6.47, PSE seeks recovery of a deferred return on the PPAs in 2024 of $815,613 that the Company projects for 2024. The workpapers PSE provided in support of Adj. 6.47 show that the projected deferred return on the PPAs of $815,613 in 2024 is calculated as the Company's authorized rate of return multiplied by the forecasted annual 2024 expense of $11,391,237. However, PSE's first supplemental response to Staff Data Request 103 (which provides PPA expenses through May 2024) indicates that the PPA expenses for 2024 could fall significantly below the $11,391,237 annual expense that PSE had forecasted for 2024.[113]

At this juncture, PSE's forecasted annual expense of $11,391,237 for 2024 cannot be considered a known and measurable amount. And given that the 2024 return deferral of $815,613 that PSE seeks to recover through Adjustment 6.47 is calculated off this $11,391,237 projection, it follows that the forecasted 2024 return deferral of $815,613 also is not a known and measurable amount. Therefore, even if the Commission rejects Staff's argument that deferral of a return in 2024 is prohibited by statute, the Commission

[113] McGuire, Exh. CRM-3C. (PSE's first confidential, supplemental response to Staff Data Request 103, provided June 27, 2024).

should not include the full $815,613 return deferral forecast for 2024 in revenue requirement.

**Q. If Staff is recommending that the Commission deny PSE's request to defer a return on the PPAs between January 1, 2024, and the effective date of this GRC, what is the relevance of Staff's recommendation to calculate the return on the PPAs using the Company's authorized cost of debt (rather than its authorized ROR)?**

A. Two reasons. First, while Staff is recommending that the Commission deny PSE's request to defer a return on the PPAs between January 1, 2024, and this case's effective date, Staff is not contesting PSE's request to defer a return on the PPA for the period prior to the PPAs being included in rates (i.e., between September 2023 and December 2023). Therefore, Staff's recommendation that the return be calculated at the Company's authorized cost of debt impacts the magnitude of the return deferral that accumulated between September and December 2023 (which is included in Adjustment 6.47).

Second, in the event that the Commission disagrees with Staff's interpretation that RCW 80.28.410 prohibits companies from deferring a return on qualifying PPAs beyond the date those PPAs are included in rates (i.e., from January 1, 2024, forward) and, accordingly, rejects Staff's recommendation to deny PSE's request to defer a return between January 1, 2024, and the effective date of this GRC, the Commission still would need to decide if that return should be calculated at the Company's authorized cost of debt or its authorized rate of return (or somewhere in between). In the event the Commission allows PSE to defer (and recover) a return on the PPAs for the period

January 1, 2024, through the effective date of this GRC, Staff recommends that the Commission require that return to be calculated at the Company's authorized cost of debt.

**Q. How does Staff's recommendation to deny PSE's request to defer a return on the PPAs beyond December 2023 impact the level of expense included in Adjustment 6.47?**

A. In its Adjustment 6.47, PSE includes a projected balance of $815,613 for a deferred return on the PPAs in 2024. Given that PSE proposes to amortize the deferral over two years, Staff's recommendation to deny PSE's request to defer a return on the PPAs beyond December 2023 reduces the annual amortization expense included in Adjustment 6.47 for both 2025 and 2026 by $407,807.

**Q. What is the impact of Staff's recommendation to calculate the return on the PPAs between September and December 2023 using the Company's authorized cost of debt?**

A. Calculating the return on the PPAs for the period September 2023 through December 2023 using the Company's authorized cost of debt (rather than its authorized rate of return) reduces the deferral balance that accumulated over that period from $61,803 to $43,158, resulting in a $18,644 reduction to the deferral balance and a de minimus $9,322 reduction to annual amortization expense.

**Q. What is the overall revenue requirement impact of Staff's recommendations regarding Adjustment 6.47?**

A. Staff's modified Adjustment 6.47 includes revenue requirements of $0.46 million for both 2025 and 2026.[114] Relative to PSE's as-filed request, Staff's Adjustment 6.47 represents a $0.4 million reduction to electric revenue requirement for both 2025 and 2026.

## B. CWIP in Rate Base for the Beaver Creek Facility (Staff Adj. S-6.49)

**Q. Please summarize PSE's request in this case with respect to including CWIP in rate base.**

A. PSE requests to include CWIP in rate base for its Beaver Creek project, which the Company seeks to recover through its proposed Clean Generation Resources tracker (electric Schedule 141CGR). PSE anticipates that the Beaver Creek project will be placed in service by August 2025, so for its 2025 revenue requirement calculation the Company has included in rate base the projected CWIP balances for January through July 2025 and the projected net plant-in-service balances for August through December 2025.

Over the two-year rate plan, PSE calculates incremental revenues associated with including CWIP in rate base would be $23.9 million.[115]

**Q. Does PSE propose to recover the costs of the Beaver Creek project (including a return on CWIP) in base rates or in one of its proposed new trackers?**

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[114] Kermode, Exh. DPK-6 at 4-5.

[115] Free, Exh. SEF-25 at 1. The incremental revenues of $23.9 million is the difference between the $132.6 million revenue requirement using PSE's proposed (hybrid) approach and the $108.7 million revenue requirement using the conventional (AFUDC) approach.

A. PSE proposes to recover the costs of the Beaver Creek project (including a return on CWIP) through its proposed Clean Generation Resources tracker (electric Schedule 141CGR). The costs of the Beaver Creek Project are the only costs PSE includes in its proposed tracker Schedule 141CGR.

However, as I explain in Section III.D.3.a above, Staff is recommending that the Commission deny PSE's request to establish Schedule 141CGR. Therefore, under Staff's recommendation, the costs of the Beaver Creek project would be recovered in PSE's base rates and not through a separate tracker.

**Q. Does Staff contest PSE's request to include CWIP in rate base?**

A. Yes. As I describe in further detail in Section III.F.3, above, Staff recommends that the Commission apply an equity lens to PSE's request and find that the record does not support a finding that including CWIP in rate base for the Beaver Creek project is in the public interest. Accordingly, Staff recommends that the Commission deny PSE's request to include CWIP in rate base for that project. Staff recommends that, instead, the Commission follow its standard practice of allowing the Company to capitalize AFUDC during the project's construction and include gross plant-in-service in rate base as of the date PSE anticipates the Beaver Creek project will be placed in service (i.e., August 2025).

**Q. What is the revenue requirement impact of Staff's recommendation to deny PSE's request to include CWIP in rate base for the Beaver Creek project?**

A. Staff includes revenue requirements for Beaver Creek of $43.2 million in 2025 and $89.4 million in 2026.[116] Relative to PSE's request of $71.6 million in 2026 and $90.1 million in 2026,[117] Staff's recommendation to deny PSE's request to include CWIP in rate base for the Beaver Creek project reduces electric revenue requirement in RY1 by $28.4 million and ~~*increases*~~ decreases electric revenue requirement in RY2 by $0.7 million.

### C. Wildfire Costs (Staff Adj. S-6.51)

**Q. Please summarize the costs PSE includes in its proposed wildfire tracker.**

A. Through the Wildfire Plan Tracker, Electric Schedule 141WFP, PSE is proposing to recover the costs of implementing its Wildfire Mitigation and Response Plan, including depreciation expense, O&M expense, insurance premiums attributable to wildfire risk, and return on rate base.[118] PSE calculates annual Schedule 141WFP revenue requirements of $27,546,601 in 2025 and $34,392,948 in 2026.[119]

**Q. Does Staff contest any of the costs PSE included in its proposed Schedule 141WFP?**

A. Yes. Staff contests the $5,386,070 amortization expense PSE includes in rate years 1 and 2 to recover a deferral balance related to PSE's petition for deferred accounting in Docket UE-231048. As discussed in Section III.D.3, above, the deferral balance in question relates to PSE's petition for deferred accounting filed in Docket UE-231048 which the

[116] Kermode, Exh. DPK-6 at 4-5.
[117] Free, Exh. SEF-3 at 1, line 34.
[118] Free, Exh. SEF-22.
[119] *Id*. at 1:29.

Commission has not yet ruled on. Given that PSE has not been authorized to defer the amounts the Company seeks to recover in this case and, furthermore, that Docket UE-231048 has not been consolidated with this GRC, the Commission must rule on PSE's petition in that docket and not as an adjudicated matter within this GRC. The issue of the deferral balance is not ripe for consideration in this case.

**Q. What does Staff recommend?**

A. Staff recommends that the Commission remove the $5,386,070 amortization expense from its revenue requirement calculations for rate years 1 and 2. The removal of the $5,386,070 amortization expense is reflected in Staff's revenue requirement calculation via Staff Adjustment S-6.51.

**Q. What is the revenue requirement impact of Staff's recommendation to remove the deferral from the electric revenue requirement calculation?**

A. Staff recommends wildfire-related revenue requirements of $21.2 ~~19.6~~ million in 2025 and $28.0 ~~28.6~~ million in 2026.[120] Relative to PSE's request, Staff's recommendation represents revenue requirement reductions of $8.0 million in 2025 and $5.8 million in 2026.[121]

As a reminder (and as I explain in Section III.D.3 above), Staff is recommending that the Commission deny PSE's request to establish Schedule 141WFP. Consequently, the revenue requirement impact of Staff's recommendation to remove the wildfire

[120] Kermode, Exh. DPK-6 at 4-5.
[121] These revenue requirement impacts also include the effect of recalculating the return on rate base at Staff's recommended rate of return.

deferral shows up in the base rate revenue requirement calculation in Staff's revenue requirement model.

**D. Pro Forma O&M (Adj. 6.22 and Adj. 11.22)**

**Q. What are the elements of PSE's pro forma O&M adjustments that Staff contests?**

A. Staff recommends the Commission remove from Adjustments 6.22 and 11.22 forecasted amounts related to (1) "management reserves," and (2) a "reserve contingency."

**Q. Can you please explain each of the two components of PSE's pro forma O&M adjustment that you are contesting?**

A. Yes. I explain Staff's concerns with the amounts PSE includes in pro form O&M expense related to (1) "management reserves," and (2) a "reserve contingency," in turn below.

**1. "Management Reserves."**

**Q. What is a "management reserve?"**

A. As PSE explains, management reserves are funds approved by the board and allocated to PSE's senior executives to "potentially offset any unforeseen or unplanned expenses."[122]

[122] McGuire, Exh. CRM-4 (PSE response to Staff Data Request 110).

**Q. Is it appropriate to include "unforeseen" or "unplanned" expenses in PSE's revenue requirement calculations?**

A. No. "Unforeseen" and "unplanned" expenses do not represent specific expenses that the Company identifies in its O&M forecast and, as a result, amounts that the Company includes in its revenue requirement calculations related to "management reserves" fall substantially short of the Commission's "known and measurable" ratemaking standard. As the Commission reaffirmed in its Used & Useful Policy Statement,

> "The known and measurable standard continues to require that an event that causes a change to revenue, expenses, or rate base must be "known" to have occurred during or after the historical 12-months of actual results of operations. It must also be demonstrated (i.e., known) that the effect of the event will be in place during the rate year."[123]

**Q. What dollar amount does PSE include in its pro forma O&M expense for "management reserves?"**

A. The answer to that question is elusive as not only does the management reserve amount vary wildly between different Company workpapers and data request responses, the management reserves included in the revenue requirement workpapers of PSE witness Free – which Staff views as most representative of the costs PSE includes in its formal revenue requirement request in this case – are composed of an indecipherable menagerie of positive and negative amounts (some of which are quite large) assigned to various cost centers.

[123] *In re the Comm'n's Proceeding to Develop a Policy Statement Addressing Alternatives to Traditional Cost of Serv. Ratemaking*, Docket U-190531, Policy Statement on Property that Becomes Used and Useful After Rate Effective Date, 8, ¶ 22 (January 31, 2020) (citing *Wash. Utils. & Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-090134 & UG-090135, Order 10, 21, ¶ 45 (Dec. 22, 2009)).

Table 3 below shows the various management reserve amounts the Company reports across different exhibits and data request responses.

**Table 3. Management Reserves included in Various PSE Workpapers and Data Request Responses.**

| 2025 | | | | |
|---|---|---|---|---|
| WP-SEF-OM | WP-JAK-OpEx | PC DR 150 | **WBS Element** | **Cost Element (BPC)** |
| (37,110,452) | (28,821,540) | | Management Reserve & Corporate Contingen | A_63300140 - Planning - Outside Services Legal |
| 15,803,904 | 15,803,904 | 64,854,881 | Management Reserve & Corporate Contingen | A_63300150 - Planning - Outside Services Other |
| - | | | Management Reserve & Corporate Contingen | A_63300070 - Planning - Miscellaneous Expense |
| 5,308,725 | 25,308,725 | | Enterprise Risk Tracking OM | A_63300152 - Planning - Outside Services-Service Prov |
| (17,704,296) | (17,704,296) | | Enterprise Risk Tracking OM | A_63300150 - Planning - Outside Services Other |
| (278,388) | (278,388) | | Enterprise Risk Tracking OM | A_63300100 - Planning - Payroll Taxes OH |
| 2,178,780 | 2,178,780 | | Enterprise Risk Tracking OM | A_63300080 - Planning - Benefits OH |
| | | | | |
| 2026 | | | | |
| WP-SEF-OM | WP-JAK-OpEx | PC DR 150 | **WBS Element** | **Cost Element (BPC)** |
| 21,080,922 | (4,403,704) | | Management Reserve & Corporate Contingen | A_63300140 - Planning - Outside Services Legal |
| 17,275,488 | 17,275,488 | 64,956,930 | Management Reserve & Corporate Contingen | A_63300150 - Planning - Outside Services Other |
| - | | | Management Reserve & Corporate Contingen | A_63300070 - Planning - Miscellaneous Expense |
| 15,173,490 | 41,173,490 | | Enterprise Risk Tracking OM | A_63300152 - Planning - Outside Services-Service Prov |
| (19,267,608) | (19,267,608) | | Enterprise Risk Tracking OM | A_63300150 - Planning - Outside Services Other |
| (282,192) | (282,192) | | Enterprise Risk Tracking OM | A_63300100 - Planning - Payroll Taxes OH |
| 2,274,312 | 2,274,312 | | Enterprise Risk Tracking OM | A_63300080 - Planning - Benefits OH |

**Q. Which of the management reserve amounts in Table 3, above, represent the amounts included in the projected spend information approved by the Board of Directors for 2025 and 2026.**

A. The management reserve amounts reported in the Company's response to Public Counsel Data Request 150 are the amounts approved by the Board of Directors for 2025 and 2026. In its response, the Company states that Attachment A to PSE's Response Public Counsel Data Request 150 "includes the projected spend information as approved by the Board of Directors for years 2024-2028".[124] Attachment A to PSE's Response Public Counsel Data Request 150 includes management reserves in the amounts of $64,854,881 for 2025 and $64,956,930 for 2026.[125]

[124] McGuire, Exh. CRM-5 (PSE response to Public Counsel Data Request 150).
[125] McGuire, Exh. CRM-5 (PSE response to Public Counsel Data Request 150, Attachment A, excerpt).

**Q. Do the management reserves identified in PSE's workpapers – including the workpapers used as the basis for the O&M expense included in the Company's revenue requirement calculations – identify the management reserve amounts, as approved by the Board of Directors?**

A. No. PSE has indicated that Attachment A to PSE's Response Public Counsel Data Request 150 includes the projected spend information as approved by the Board of Directors. As shown in Table 3, above, the management reserve amounts identified in the O&M workpapers of PSE witnesses Free and Kensok are substantially different than the management reserves included in the projected spend approved by the board.

**Q. Why do the management reserves identified in PSE's workpapers differ from the amounts included in the O&M budget approved by the board?**

A. PSE's response to Staff Data Request 110 indicates that after the board approves the projected spend (including the amounts identified as management reserves), PSE allocates the board-approved management reserves across the Company's various cost centers.[126] Given that explanation, Staff assumes that the management reserves identified in PSE's workpapers do not match the $65 million in management reserves approved by the board because PSE's workpapers capture the management reserve amounts part way through the process of allocating those amounts down to the various cost centers.

[126] McGuire, Exh. CRM-4 (PSE response to Staff DR 110).

**Q. Why do the management reserve amounts identified in the workpapers of PSE witnesses Free and Kensok differ so significantly from one another?**

A. I do not know. I suspect that PSE witness Free's and Kensok's workpapers capture management reserve amounts at different stages of the process of allocating those amounts down to the various cost centers, but I have not yet been able to confirm that suspicion.

**Q. Why are some of the management reserve amounts identified in the workpapers of witnesses Free and Kensok negative amounts while others are positive amounts?**

A. Again, I do not know. I specifically asked that question through a discovery request and did not receive a responsive answer.[127] PSE did not address the negative numbers in its workpapers and instead responded to my discovery request in essence that the Company has been continuing to revise these numbers since it filed this GRC and those negative numbers aren't negative anymore.

However, Staff checked and there are still negative numbers in the O&M workpapers PSE provided to parties and the O&M workpapers PSE used as the basis for its formal revenue request on the record in this case. Whatever PSE is doing outside of the GRC does not change that fact. With respect to the management reserve amounts specifically, the Company's workpapers remain completely indecipherable. And the fact that PSE has provided two separate sets of workpapers in support of its O&M adjustment that contain wildly different amounts across various cost items, and another document it

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[127] McGuire, Exh. CRM-4 (PSE response to Staff DR 110, part (c)).

provided in response to Public Counsel Data Request 150 that contains amounts that are wildly different from the amounts in the Company's formal workpapers, makes it exceedingly difficult for Staff to understand which of the versions capture the specific expenses PSE is asking the Commission to include in rates and, accordingly, which specific expenses Staff should be critically examining in this proceeding.

**Q. What conclusions can we draw from the various versions of workpapers and DR responses that contain inconsistent O&M expense items?**

A. What is interesting to Staff is that, even though the various versions of workpapers and DR responses contain wildly inconsistent O&M expense items (and inconsistent costs across the same O&M expense items), the total O&M expense – i.e., the sum of all the expense items that are substantially inconsistent between each document – is *identical* across all the cacophonous versions. Staff does not believe that it is a coincidence that the total O&M expense in each iteration is equal to the Company's board-approved O&M budget.

From this, it's evident that, while the Company's O&M forecast began as a bottom-up exercise composed of the forecasted O&M expenses across PSE's various business units, in the end the Company is just forcing its forecasted O&M expense to match the board-approved budget. And what the "management reserve" appears to represent is the amount in the total, board-approved budget over and above the amount in the bottom-up O&M forecast.

In other words, the $65 million management reserve included in the board-approved budget for both 2025 and 2026 does not represent specific O&M expenses that the Company forecasted for 2025 and 2026. In the Company's own words, those management reserves represent "funds approved by the board…to potentially offset any unforeseen or unplanned expenses."[128]

**Q. Your Exh. CRM-4 (PSE's response to Staff Data Request 110), indicates that, subsequent filing this GRC, the Company has completed the process of allocating the management reserves down to the various business units. Did you review PSE's modified O&M forecast after allocation of the management reserves across the various business units?**

A. Yes. PSE provided that information in response to Staff Data Request 149 and, not surprisingly, the management reserves were effectively zero.[129]

**Q. Does PSE's response to Staff Data Request 149 (which no longer identifies material management reserves in the O&M forecast) alleviate Staff's concerns with the management reserves PSE identified in the workpapers of witnesses Free and Kensok and in PSE's response to Public Counsel Data Request 150?**

A. No. All that PSE's response to Staff Data Request 149 indicates is that the Company has completed its allocation of a $65 million amount for "unforeseen or unplanned expenses" down to the various business units. Allocating management reserves across business units and then relabeling those costs as something other than management reserves does not change the fact that the now-allocated management reserves continue to represent

[128] McGuire, Exh. CRM-4 (PSE Response to Staff DR 110).
[129] McGuire, Exh. CRM-7 (PSE Response to Staff Data Request 149, Attachment A excerpt).

"unforeseen or unplanned expenses," and does not change the fact that the O&M workpapers PSE provided in support of its formal revenue request in this case does in fact include amounts for management reserves.

**Q. Would it be appropriate to include the amounts PSE identifies in management reserves in rates?**

A No. Again, by PSE's own admission, management reserves represent "unforeseen or unplanned expenses," and, consequently, the effects of said unforeseen or unplanned expenses on the Company's overall cost of service cannot be identified or measured for ratemaking purposes. Thus, "unforeseen" and "unplanned" expenses fall far short of the Commission's "known and measurable" ratemaking standard.[130]

In addition to falling short of the Commission's known and measurable standard, amounts in revenue requirement for "unforeseen events" cannot possibly meet the Commission's prudency standard. Without a specific, identified expense, there is nothing for the Commission to examine to determine whether that expense was (or likely will be) prudently incurred or whether it is appropriate to recover from ratepayers.[131]

**Q. Does Staff recommend that the Commission remove from PSE's pro forma O&M expense the full $65 million amount identified as management reserves in the board-approved budget?**

[130] *See Wash. Utils. & Transp. Comm'n v. Cascade Nat. Gas Corp.*, Docket UG-200568, Order 05, 95, ¶ 315 (May 18,2021) (Finding that Cascade's "blanket funding" request did not meet the known and measurable standard).
[131] *Id.*

A. No. However, I will note at the outset that the Commission would be justified in removing the full $65 million from both 2025 and 2026 given that the only document PSE has produced to date that presents the management reserve(s) in an intelligible manner is the document PSE provided in response to Public Counsel DR 150, which shows unambiguously that the Company's board-approved O&M forecast includes a management reserve of $65 million for both 2025 and 2026.

While Staff seriously considered recommending that the Commission remove the full $65 million, Staff ultimately concluded that removing the full $65 million would not lead to reasonable end results. Staff was concerned that if the full $65 million were removed from pro forma O&M expense combined with the $8 million Staff is recommending be removed for a reserve contingency (discussed below), the resulting O&M expense that the Commission would use to set rates for 2025 would be only marginally (approximately $5 million) higher than the Company's projected O&M expense for 2024. And given that the average annual growth for PSE's O&M expense has been approximately $20 million over the past 10 years and approximately $43 million over the past three years, Staff sought to arrive at an end result in line with the historical growth in O&M expense.

Therefore, in developing its O&M recommendation in this case, Staff attempted to strike a balance between two ratemaking standards that were in conflict with one another; namely, the Commission's known and measurable standard and the end-results test. To be clear though, Staff does believe that the Commission would be fully justified in removing the entire amount based on the record in this case.

**Q. What amount of management reserves does Staff recommend that the Commission remove from PSE's pro forma O&M expense?**

A. Staff recommends that the Commission remove from PSE's pro forma O&M expense management reserves in the amounts of $15,803,904 for 2025 and $17,275,488 for 2026.

**Q. How did Staff choose those management reserve numbers to remove from PSE's pro forma O&M expense?**

A. In comparing the various management reserves across the workpapers of PSE witnesses Free and Kensok and PSE's response to Public Counsel DR 150, the $15.8 million and $17.3 million amounts not only were identical between the workpapers of Free and Kensok, but the specific line item reflecting those amounts is the same line item that contains the original, board-approved management reserve of $65 million that PSE reports in its response to Public Counsel DR 150. Staff determined that this was the management reserve line item most likely to represent the management reserves unallocated as of the date PSE generated the workpapers it provided to parties in support of its case. So, in Staff's assessment, the pro forma O&M amount PSE includes in its as-filed case includes amounts of $15.8 million (for 2025) and $17.3 million (for 2026) relate to amounts that continue to be "unforeseen or unplanned."

### 2. "Reserve Contingency."

**Q. What is a "reserve contingency?"**

A. PSE explains that reserve contingencies are established to offset unforeseen expenses.[132] PSE further explains that the reserve contingency captures "unallocated funds," and does not represent specific costs that are identified at the project or program level in the Company's budget.[133]

**Q. Is it appropriate to include "unforeseen" expenses in PSE's revenue requirement calculations?**

A. No. Much like the "unforeseen" and "unplanned" expenses associated with the "management reserves" discussed above, the "unforeseen" expenses associated with the "reserve contingency" PSE includes in its O&M forecast does not represent a specific expense that the Company identifies in its O&M forecast and, as a result, amounts that the Company includes in its revenue requirement calculations related to a "reserve contingency" fall substantially short of the Commission's "known and measurable" ratemaking standard.

**Q. What dollar amount does PSE include in its pro forma O&M expense for a "reserve contingency?"**

A. The workpapers PSE provided in support of the Company's pro forma O&M adjustment show that PSE's forecasted levels of O&M expense include "reserve contingency" amounts of $7,706,551 in 2025 and $6,890,560 in 2026.

[132] McGuire, Exh. CRM-8 (PSE response to Staff Data Request 106).
[133] *Id.*

**Q. What does Staff conclude with respect to the "reserve contingency" that PSE includes in its O&M forecast?**

A. Staff concludes that, for the same reasons management reserves are inappropriate to include in rates – namely, they represent "unforeseen" costs and, therefore, cannot meet the Commission's known and measurable standard or prudence standard – reserve contingencies are inappropriate to include in rates. Therefore, Staff recommends that the Commission remove from PSE's pro forma O&M expense the reserve contingencies of $7,706,551 in 2025 and $6,890,560 in 2026.

### 3. Staff's overall recommendation on pro forma O&M.

**Q. What is Staff's overall recommendation on PSE's pro forma O&M expense adjustments, reflecting the effects of Staff's recommendations to remove management reserves and reserve contingencies?**

A. Staff recommends that, overall, on a total company basis, the Commission remove from PSE's pro forma O&M expense $23.5 million for 2025 and $24.2 million for 2026.

**Q. How does the removal of these amounts impact pro forma O&M expense for PSE's electric and natural gas operations separately?**

For electric operations, Staff's recommendation reduces PSE's pro forma O&M expense by $17.8 million in 2025 and by $17.9 million in 2026. For natural gas operations, Staff's recommendation would reduce PSE's pro forma O&M expense by $5.7 million in 2025 and by $6.2 million in 2026.

The revenue requirement impacts of Staff's recommendations with respect to pro forma O&M expense (Adjustments 6.22 and 11.22), are presented by Staff witness Kermode.[134]

**Q. How did Staff assess the reasonableness of its overall recommendation to remove $23.5 million and $24.2 million from pro forma O&M expense for 2025 and 2026, respectively?**

A. Recognizing that the pro forma O&M amount that PSE includes in revenue requirement is just the board-approved O&M budget, to assess the reasonableness of Staff's recommendation to remove $23.5 million and $24.2 million from pro forma O&M expense for 2025 and 2026, Staff examined whether recent history indicates that those amounts are within PSE's demonstrated capacity to controlling its O&M expenses such that its actual O&M expenses come in substantially under budget. And comparing Staff's recommendation against PSE most recently completed calendar year, Staff's recommendation seems entirely reasonable. For 2023, on a total company basis, PSE reports an actual O&M expense of $727 million,[135] which was $67 million below the board-authorized budget of $794 million.[136] What the results from 2023 show, clearly, is that (1) the Company can control its costs such that its actual O&M expenses come in far below the board-approved budget, and (2) Staff's recommendation to remove approximately $24 million from PSE's pro forma O&M forecasts for 2025 and 2026 (which are really just the board-approved budgets for those years) is more than

[134] Kermode, Exh. DPK-6 at 4-5.
[135] Kensok, Exh. JAK-3, 1 ("Opex Actuals").
[136] McGuire, Exh. CRM-9 (PSE Response to Staff Data Request 104).

reasonable given that the Company has shown that it is capable of beating the board-approved budget by far more than embedded in Staff's recommended level of pro forma O&M expense.

**Q. Does this conclude your testimony?**

A. Yes.