Service Date: July 8, 2020

**BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	DOCKETS UE-190529 and UG-190530 (*consolidated*) FINAL ORDER 08
In the Matter of the Petition of PUGET SOUND ENERGY For an Order Authorizing Deferral Accounting and Ratemaking Treatment for Short-life IT/Technology Investment	DOCKETS UE-190274 and UG-190275 (*consolidated*) FINAL ORDER 05
In the Matter of the Petition of PUGET SOUND ENERGY For an Order Authorizing Deferred Accounting associated with Federal Tax Act on Puget Sound Energy's Cost of Service	DOCKETS UE-171225 and UG-171226 (*consolidated)* FINAL ORDER 03
In the Matter of the Petition of PUGET SOUND ENERGY For an Order Authorizing the Accounting treatment of Costs of Liquidated Damages	DOCKETS UE-190991 and UG-190992 (*consolidated)* FINAL ORDER 03 REJECTING TARIFF SHEETS; AUTHORIZING AND REQUIRING COMPLIANCE FILING

***Synopsis**: The Commission rejects the tariff sheets filed by Puget Sound Energy (PSE or Company) on June 20, 2019. The Commission authorizes a revenue increase of approximately $29.5 million, or 1.6 percent, for the Company's electric operations. We, however, extend the amortization of certain regulatory assets and the Company's electric decoupling deferral to mitigate the impact of the rate increase in response to the economic instability created by the COVID-19 pandemic, which reduces the revenue increase to approximately $857,000, or 0.05 percent. With respect to PSE's natural gas operations, the Commission authorizes a revenue increase of approximately $36.5 million, or 4.0 percent. We extend the amortization of certain regulatory assets and extend the PGA deferral from two to three years, which reduces the revenue increase to $1.3 million, or 0.15 percent. The Commission requires PSE to file revised tariff sheets to reflect these decisions.*

The Commission determines that the Company's proposed attrition adjustment of $23.9 million for electric and $16.2 million for natural gas is not in the public interest at this time.

The Commission lowers the Company's return on equity by 10 basis points to 9.40 percent, and accepts PSE's short-term and long-term costs of debt of 2.47 percent and 5.51 percent, respectively. The Commission accepts the Company's uncontested hypothetical capital structure of 48.5 percent equity, 49.20 percent long-term debt, and 2.30 percent short-term debt (51.5 percent). This results in a 7.39 percent rate of return for PSE.

We authorize recovery of the following pro forma capital additions through the period ending December 31, 2019: Advanced Metering Infrastructure, Get to Zero, Public Improvement, HR TOPS, High Molecular Weight Cable Replacement, and the Energy Management System. The Commission also adopts PSE's proposal to value rate base on an End of Period (EOP) basis. Both of these measures address regulatory lag by modifying the test year to reflect actual rate base values and revenue requirement more closely during the rate effective period.

The Commission determines that investor supplied working capital (ISWC) should also be valued on an EOP basis consistent with all components of rate base for the purposes of this proceeding. As such, the Commission authorizes the ISWC amounts as proposed in PSE's rebuttal filing calculated on EOP basis, and declines to adopt Staff's proposal to calculate ISWC using the Average of Monthly Averages method.

The Commission approves three major pro forma capital additions: Advanced Metering Infrastructure, Get to Zero, and Data Center Relocations.

The Commission authorizes PSE to defer costs associated with Upgrades 1 and 3 to PSE's Liquefied Natural Gas facility in Tacoma (Tacoma LNG) until such time as the Tacoma LNG plant is placed in service.

The Commission finds that costs related to PSE's SmartBurn plant investment were not prudently incurred based on the Company's failure to maintain contemporaneous documentation of its decision making, and thus disallows recovery of $7.2 million in plant costs related to SmartBurn.

The Commission approves three smaller pro forma adjustments, HR TOPS, High Molecular Weight Cable replacement, and Public Improvement, on the basis that their costs are known and measurable and each is in service and serving customers.

The Commission sets power costs at $750.6 million, an increase of 5.5 percent, accepting PSE's new wind resource capacity factors and the Company's proposal to shift $1.5 million in common costs from Colstrip Units 1 and 2 to Units 3 and 4. The Commission disallows the inclusion of $13.1 million in Power Purchase Agreement costs related to PSE's Green Direct Program to prevent cross-subsidization by non-participating customers. The Commission also allows PSE to defer certain costs related to the removal of Colstrip Unit 4 major maintenance costs incurred in 2020 due to the Company's pending sale of Unit 4 in Docket UE-200115. Finally, the Commission adopts Staff's proposal to restore 80 separate runs for every year in the water record in the AURORA hydroelectric model.

The Commission approves PSE's proposed annual incentive compensation plan, finding that it is reasonable and provides benefits to ratepayers.

The Commission requires PSE to return unprotected excess deferred income tax totaling $38.9 million before gross-up ($36 million electric and $2.9 million natural gas) over a three- year amortization period, grossed-up, and refunded through a separate schedule to resolve the accounting petition in Dockets UE-171225 and UG-171226 consolidated with this proceeding. We also direct PSE to continue to pass back protected-plus excess deferred income tax (PP EDIT) through Schedule 141X consistent with the Average Rate Assumption Method, and further require the Company to file annual updates to ensure transparency and appropriate accounting treatment. The Commission directs PSE to return 2019 and 2020 PP EDIT over a 12 month period beginning July 20, 2020.

The Commission authorizes PSE's proposal to adjust the annual depreciation expense of Colstrip Units 3 and 4, a portion of which includes decommissioning and remediation (D&R) costs, to ensure those plants are fully depreciated by 2025, as required by the Clean Energy Transformation Act (CETA), and requires the Company to file a proposed *plan for the recovery of the D&R costs for Colstrip Units 3 and 4 that complies with CETA in its next general rate case. The plan must include an assessment of production tax credits available to offset D&R costs for those units. We further require the Company to move all D&R costs associated with Units 3 and 4 to a regulatory asset account for tracking purposes, and allow PSE to continue to recover D&R costs through depreciation rates for Units 3 and 4. Those amounts will be trued up once the units are retired and the actual D&R costs are known, and the prudency of the actual costs will be evaluated for inclusion in rates or refund once they are incurred.*

The Commission resolves the Company's accounting petition related to its Get to Zero program in Dockets UE-190274 and UG-190275, which authorizes PSE to defer the depreciation expense for investments with a book life of 10 years or less that the Company has incurred, or will incur, outside of the test year period of the Company's next GRC.

We also grant the Company's petition for deferred accounting treatment in Dockets UE-190991 and UG-190992 for current and future liquidated damages related to the Power Purchase Agreements for its Green Direct program, subject to the condition that PSE must not discriminate between Green Direct customers when applying liquidated damages to offset program costs. We reserve any decision related to the use of the funds until such time as the Power Purchase Agreements are in service and the final amount of liquidated damages is known.

The Commission adopts the Company's proposed electric cost of service study, with the exception of its proposed change to transmission cost classification for energy and demand, which we maintain at 75 percent and 25 percent, respectively. We adopt the Company's proposed natural gas cost of service study, as well as the Company's rate spread and rate design for both electric and natural gas. The Commission declines to adopt the Federal Executive Agencies' proposal to require PSE to classify its fixed production and transmission costs as 100 percent demand-related and allocated to customer classes using the "4 CP Method," instead maintaining the status quo until PSE is able to conduct a new study under the recently adopted Cost of Service rules. The Commission also rejects Staff's proposal to require PSE to update its economic bypass study as premature.

The Commission approves a low-income funding increase of $1.4 million or twice the percentage increase of residential base rates, whichever is greater.

We decline to adopt Staff's proposed materiality threshold, instead examining each pro forma adjustment individually and allowing or disallowing recovery on the basis of *established standards of prudency, including whether the individual capital additions are used and useful, and whether the costs are known and measurable prior to the rate effective date. We also consider the life of the asset to appropriately capture investments that are at risk of under-recovery.*

The Commission rejects NWEC's proposal to modify the methodology for calculating natural gas line extensions in the context of this proceeding, recognizing that it would have industry-wide impacts that should be addressed in an alternative forum.

The Commission also resolves several contested policy issues. The Commission declines to require PSE to adopt an on-bill repayment program, form a distribution system planning group, or implement pricing pilots. The Commission approves PSE's conjunctive demand service option pilot program as proposed, but requires additional reporting to clarify the purpose and scope of the program and track the program's progress. PSE's proposed sale of its water heater rental program has been removed from this proceeding and will be addressed in Docket UG-200112.

The Commission accepts 49 uncontested adjustments and multiple issues resolved on rebuttal, finding that each is supported by the evidence in the record and consistent with the public interest.

The Commission rejects two of the Company's proposed pro forma adjustments that would remove Directors and Officers Insurance and Excise Tax and Filing Fee restating adjustments to the detriment of ratepayers.

To mitigate the economic impacts of the COVID-19 pandemic on PSE's customers, the Commission extends the amortization period for certain assets, extends the electric decoupling deferral, and extends the PGA deferral to arrive at the reduced revenue requirement increase described in the first paragraph of this synopsis.

The Commission's decisions related to revenue requirement are summarized briefly in the Summary section of this Order at paragraphs 25–36.

Commissioner Balasbas dissents from the Commission's decision related to recovery of SmartBurn costs. Chair Danner dissents from the Commission's decision related to natural gas line extensions.

TABLE OF CONTENTS

I. BACKGROUND

A. PROCEDURAL HISTORY

1 *Tax Cuts and Jobs Act Accounting Petition*. On December 29, 2017, Puget Sound Energy (PSE or Company) filed with the Washington Utilities and Transportation Commission (Commission) a petition for an order authorizing deferred accounting associated with the impacts of the Tax Cuts and Jobs Act (TCJA) on PSE's cost of service in Dockets UE-171225 and UG-171226 (TCJA Petition). The TCJA Petition sought deferral of the costs and savings associated with the difference between the prior tax rate of 35 percent and the new tax rate of 21 percent. On November 26, 2018, PSE filed an amended petition (Amended TCJA Petition), which updated the petition to address (a) the over-collection of taxes for the period of January 1 to April 30, 2018, and (b) the excess deferred income tax (EDIT) balances created by the TCJA.

2 *Get to Zero Accounting Petition*. On April 10, 2019, PSE filed with the Commission a petition in Dockets UE-190274 and UG-190275 for an order authorizing deferral of certain expenses related to the Company's investments in short-lived technology assets as part of its Get to Zero (GTZ) program. PSE requests that the Commission approve the deferred accounting and ratemaking treatment for the depreciation expense associated with GTZ program investments and allow the Company to seek recovery of the deferred costs in future regulatory proceedings (GTZ Accounting Petition).

3 *General Rate Case (GRC)*. On June 20, 2019, PSE filed with the Commission revisions to its currently effective Tariff WN U-60, Tariff G, Electric Service, and Tariff WN U-2, Natural Gas, which were assigned Dockets UE-190529 and UG-190530, respectively. The filing would increase rates and charges for electric and natural gas service provided to PSE's customers in the state of Washington. PSE requested an increase in its annual electric revenue requirement of approximately $140 million (6.9 percent), and an increase to its annual natural gas revenue requirement of approximately $65.5 million (7.9 percent). On July 5, 2019, the Commission suspended the tariff revisions, consolidated Dockets UE-190529 and UG-190530, and initiated PSE's general rate case (GRC Dockets).

4 On July 22, 2019, the Commission entered Order 03, Prehearing Conference Order; Notice of Hearing, in the GRC Dockets. Order 03 granted petitions to intervene filed by The Energy Project (TEP), Alliance of Western Energy Consumers (AWEC), Nucor

Steel Seattle, Inc. (Nucor Steel), The Kroger Co. (Kroger), the NW Energy Coalition (NWEC), and the Federal Executive Agencies (FEA).

5 On October 23, 2019, Commission regulatory staff (Staff)[1] filed an unopposed motion to consolidate the GTZ Accounting Petition with the GRC Dockets. On October 28, 2019, the Commission entered Order 04/01, Granting Motion for Consolidation (Order 04/01), which consolidated for hearing the GRC Dockets with the GTZ Accounting Petition.

6 On November 22, 2019, Staff, the Public Counsel Unit of the Washington State Attorney General's Office (Public Counsel), AWEC, NWEC, TEP, Kroger, and FEA filed response testimony and exhibits in the GRC Dockets opposing the Company's rate and revenue requests.

7 *Green Direct Accounting Petition*. On November 27, 2019, PSE filed with the Commission a petition for an order authorizing deferral accounting for liquidated damages under Schedule 139, Voluntary Long-Term Renewable Energy Purchase Rider (Green Direct Petition) in Dockets UE-190991 and UG-190992. The Green Direct Petition seeks authority for PSE to defer liquidated damages and use them to offset other voluntary long-term renewable energy Green Direct program costs.

8 Also on November 27, 2019, Staff filed a motion for leave to file supplemental testimony in the GRC Dockets on increased fuel costs associated with a new coal contract for Colstrip Generating Station Units 3 and 4. On December 3, 2019, PSE filed a response stating that it did not oppose the motion, provided the Commission required Staff to file supplemental testimony by December 24, 2019. In its response, PSE also argued that "the Commission should allow a full update to power costs, to include all power cost inputs that have changed since PSE filed its direct testimony, in addition to the finalized coal supply contract, in order to allow the power cost baseline rate to be set as close as possible to what is expected to be experienced in the rate year."[2]

---

[1] In formal proceedings such as this, the Commission's regulatory staff participates like any other party, while the Commissioners make the decision. To assure fairness, the Commissioners, the presiding administrative law judge, and the Commissioners' policy and accounting advisors do not discuss the merits of this proceeding with regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. *See* RCW 34.05.455.

[2] PSE's Response to Staff's Motion for Leave to File Supplemental Testimony at 9:6-9.

9 On December 4, 2019, AWEC filed a response opposing Staff's motion and opposing PSE's alternative proposal to allow a full update to power costs, including the costs of the new coal contract in the Company's power cost update. On December 5, 2019, Public Counsel also filed a response opposing Staff's motion and incorporating AWEC's arguments by reference.

10 On December 10, 2019, the Commission denied Staff's motion on the basis that the proposed testimony was offered at a late stage of the proceeding, thereby depriving the parties of any meaningful opportunity to review the prudence of the new coal contract.

11 The Commission held the first of two planned public comment hearings in Lacey, Washington, on January 7, 2020.

12 On January 15, 2020, PSE filed rebuttal testimony revising its position on several issues. Most notably, the Company reduced its requested return on equity from 9.80 percent to 9.50 percent and reduced its electric revenue request by $1.5 million.[3]

13 Also on January 15, 2020, Staff, Public Counsel, AWEC, Kroger, and FEA filed cross-answering testimony and exhibits.

14 The Commission held its second public comment hearing in Bellevue, Washington, on January 22, 2020. Over the course of the proceeding, including the two public comment hearings, the Commission and Public Counsel received 713 comments regarding the proposed rate increases from Washington customers, with 706 comments opposing the increases, 3 comments supporting the increases, and 4 comments neither supporting nor opposing.

15 The vast majority of the consumers who filed comments were critical of the Company's provision and expansion of natural gas service, and expressed concerns that increased rates would be used to cause further environmental damage rather than procuring energy

---

[3] PSE's revenue request on rebuttal does not incorporate the Company's acceptance of Staff's revisions to adjustments 20.01 GR and 20.01 EP (Revenue and Expense) and 20.02 ER/GR and 20.02 EP/GP (Temperature Normalization), nor does it include the Company's uncontested update to its short-term cost of debt provided in response to Bench Request No. 11 (BR-11). In rebuttal testimony, PSE witness Free states that the Company will include these changes in its compliance filing. *See* Free, SEF-17T at 68:1-2 and11-13; 73:4-6. The Commission's decision incorporates the Company's updated revenue requirement, which accounts for these adjustments and the updated cost of short-term debt, as provided in response to BR-11.

from cleaner sources. Many commenters expressed concerns about the proximity of the Tacoma Liquefied Natural Gas facility site to tribal lands, the impact of an explosion in the dense urban area adjacent to the site, and the Company's decision to expand its natural gas infrastructure despite these dangers. Numerous commenters also asserted that public sentiment is shifting away from fossil fuels and fracking, and that PSE is lagging in its responsibility to move toward cleaner energy sources.

16 Other commenters believe the Company's requests for rate increases are excessive and too frequent, and many state that they are on fixed incomes and cannot afford any rate increase.

17 Finally, a significant number of customers complained that the proposed rate increase would benefit only PSE's investors, and specifically criticized PSE's investment in its Energize Eastside, Lake Hills Transmission Line, and Tacoma LNG projects.

18 On February 5, 2020, the Commission entered Order 06/03/01, Consolidation Order, which consolidated for hearing the Amended TCJA and Green Direct Accounting Petitions with the GRC Dockets and the GTZ Accounting Petition.

19 The Commission conducted an evidentiary hearing at its headquarters in Lacey, Washington, on February 6, 2020, on the remaining contested adjustments and policy issues. The Commission admitted into the record all pre-filed testimony and exhibits, as well as all cross-examination exhibits.

20 The parties filed initial post-hearing briefs on March 17, 2020.

21 Also on March 17, 2020, PSE filed with the Commission a Motion to Extend Suspension Date (Motion), requesting and agreeing to extend the statutory deadline associated with the GRC Dockets from May 20, 2020, to July 20, 2020. No party objected to the Motion, and all parties either supported or did not oppose extending the deadline to file reply briefs until April 10, 2020.

22 On March 19, 2020, the Commission entered Order 07/04/02, Granting Motion to Extend Suspension Date and Modifying Procedural Schedule.

23 On April 10, 2020, the parties filed reply briefs.

24 Sheree Strom Carson, Jason Kuzma, Donna Barnett, and Jason S. Steele, Perkins Coie LLP, Bellevue, Washington, represent PSE. Lisa W. Gafken, Nina Suetake, and Ann

Paisner, Assistant Attorneys General, Seattle, Washington, represent Public Counsel. Sally Brown, Senior Assistant Attorney General, and Jennifer Cameron-Rulkowski, Jeff Roberson, Harry Fukano, Joe Dallas, Daniel Teimouri, and Nash Callaghan, Assistant Attorneys General, Lacey, Washington, represent Staff. Tyler Pepple and Brent Coleman, Davison Van Cleve, P.C., Portland, Oregon, represent AWEC. Kurt J. Boehm and Jody Kyler Cohn, Boehm, Kurtz & Lowry, Cincinnati, Ohio, represent Kroger. Damon E. Xenopolous and Shaun Mohler, Stone Mattheis Xenopolous & Brew, PC, Washington, DC, represent Nucor. Simon J. ffitch, attorney, Bainbridge Island, Washington, represents TEP. Irion Sanger and Marie Barlow, Sanger Thompson P.C., Portland, Oregon, represent the NWEC. Rita Liotta, U.S. Navy, San Francisco, California, represents FEA.

B. SUMMARY OF REVENUE REQUIREMENT DETERMINATIONS

25 The Commission and all parties to this proceeding acknowledge the inherent difficulty of setting fair, just, reasonable, and sufficient rates in the midst of a global health crisis that has created significant economic uncertainty. In this Order, the Commission makes determinations concerning all uncontested and contested adjustments to revenue requirements and rates and resolves important policy issues presented by the parties. Based on the decisions we have made in this Order, we authorize an increase in PSE's revenue requirement in the amount of $29.5 million, or 1.6 percent, for the Company's electric operations and an increase in the amount of $36.5 million, or 4.0 percent, for its natural gas operations.

26 With respect to the electric revenue requirement, we extend the amortization of certain regulatory assets and the Company's electric decoupling deferral to mitigate the impact of the rate increase in response to the economic instability created by the COVID-19 pandemic, resulting in an estimated reduced revenue increase of approximately $857,000, or 0.05 percent. With respect to natural gas, we extend the amortization of certain regulatory assets and extend the PGA deferral from two to three years, resulting in an estimated reduced revenue increase of $1.3 million, or 0.15 percent. Summaries of both the electric and natural gas revenue requirements are attached hereto at Appendix A.

27 We determine that the Company's proposed attrition adjustment of $23.9 million for electric and $16.2 million for natural gas is not in the public interest at this time due to the current economic circumstances and the absence of a multi-year rate plan. The Commission employs other tools, including valuing rate base on an End of Period (EOP) rate basis and extending the pro forma period through December 31, 2019, to ensure the rates set by this Order are fair, just reasonable, and sufficient. We also determine that, for the purposes of this case, investor supplied working capital should be valued on an EOP basis consistent with all components of rate base.

28 We also authorize a rate of return (ROR) of 7.39 percent based on a hypothetical capital structure of 48.50 percent equity and 51.50 percent debt. The Commission authorizes return on equity (ROE) of 9.40 percent, which is 10 basis points lower than the Company's current ROE.

29 The Commission authorizes recovery of six pro forma adjustments through December 31, 2019, and denies cost recovery for PSE's SmartBurn investment on the basis that those costs were not prudently incurred.

30 The Commission authorizes PSE to defer costs associated with Upgrades 1 and 3 to PSE's Liquefied Natural Gas Plant in Tacoma, costs associated with GTZ, costs associated with liquidated damages received in connection with Green Direct Program power purchase agreements, and costs related to the removal of Colstrip Unit 4 major maintenance costs incurred in 2020 due to the Company's pending sale of Unit 4 in Docket UE-200115.

31 The Commission sets power costs at $750.6 million, an increase of 5.5 percent, accepting PSE's new wind resource capacity factors and the Company's proposal to shift $1.3 million in common costs from Colstrip Units 1 and 2 to Units 3 and 4. The Commission disallows the inclusion of $13.1 million in Purchase Power Agreement costs related to PSE's Green Direct Program to prevent cross-subsidization by non-participating customers. Finally, the Commission rejects the Company's proposal to average 80 years of hydro data in the AURORA hydroelectric model.

32 The Commission approves PSE's proposed annual incentive compensation plan, finding that it is reasonable and provides benefits to ratepayers.

33 The Commission requires PSE to return unprotected excess deferred income tax (UP EDIT) totaling $38.9 million before gross-up ($36 million electric and $2.9 million natural gas) over a three-year amortization period, grossed-up, and refunded through a separate schedule to resolve the accounting petition in Dockets UE-171225 and UG-171226 consolidated with this proceeding. We also direct PSE to continue to pass back protected-plus excess deferred income tax (PP EDIT) through Schedule 141X consistent with the Average Rate Assumption Method (ARAM), and further require the

Company to file annual updates to ensure transparency and appropriate accounting treatment. The Commission directs PSE to return PP EDIT for 2019 and 2020 over a 12-month period beginning July 20, 2020.

34 The Commission approves a low-income funding increase of $1.4 million or twice the percentage increase of residential base rates, whichever is greater.

35 The Commission accepts 49 uncontested adjustments and multiple issues resolved on rebuttal, but rejects the Company's proposal to remove Directors and Officers (D&O) Insurance and Excise Tax and Filing Fee restating adjustments both in this case and on a going forward basis.

36 To mitigate the economic impacts of the COVID-19 pandemic on PSE's customers, the Commission adopts Staff's recommendation to extend the amortization period for certain regulatory assets. We also extend the electric decoupling deferral and the Purchase Gas Adjustment (PGA) deferral. Together, these mitigation strategies produce the reduced revenue requirement increases described in paragraph 26, above.

II. DISCUSSION AND DECISION

A. CASE OVERVIEW

37 PSE requests an increase in its annual electric revenue requirement of approximately $140 million (6.9 percent), and an increase to its annual natural gas revenue requirement of approximately $65.5 million (7.9 percent), which includes an attrition adjustment of $38.5 million for electric and $11.7 million for natural gas.[4]

38 PSE bases its revenue requirement requests for electric and natural gas operations on a January 1, 2018, through December 31, 2018, modified historical test year, and values rate base on an EOP basis, rather than an AMA basis. PSE proposes numerous restating and pro forma adjustments. PSE requested in its initial filing an overall ROR of 7.62 percent based on a hypothetical capital structure consisting of 48.5 percent equity and

[4] Free, Exh. SEF-1Tr at 2:9-12.

51.5 percent debt,[5] an ROE of 9.80 percent,[6] a long-term debt ratio of 49.20 percent, and a short-term debt ratio of 2.30 percent.[7]

39 Staff calculates its recommended revenue requirement based on a modified historical test year with limited pro forma adjustments through June 30, 2019, and values rate base other than ISWC on an EOP basis. Public Counsel calculates its proposed revenue requirement based on a modified historical test year with limited pro forma adjustments through June 30, 2019, and values rate base on an AMA basis. Like Staff, AWEC calculates its recommended revenue requirement based on a modified historical test year and values rate base on an EOP basis. No other party presented a revenue requirement model.

40 The only cost of capital element in dispute is the Company's authorized ROE. All parties accept PSE's hypothetical capital structure of 48.50 percent equity, 49.20 percent long-term debt, and 2.30 percent short-term debt. Staff recommends an ROE of 9.20 percent, and Public Counsel recommends 8.75 percent. On rebuttal, PSE proposes maintaining the Company's current ROE of 9.50 percent. No other party recommends a specific ROE.

41 Five major pro forma capital investments are contested:

1. **Advanced Metering Infrastructure (AMI).** PSE proposes a three-year amortization of the deferral of the return on AMI plant that was placed in service from October 2016 through June 2018. Public Counsel recommends the Commission disallow cost recovery of and on all expenditures associated with AMI system implementation. Staff supports the Company's proposals for the recovery of deferred depreciation expense and the deferred return on net plant (from prior periods) for AMI investments.

2. **Get to Zero (GTZ).** PSE proposes a pro forma adjustment to amortize the deferred GTZ expenses and rate base amounts for GTZ-related projects placed into service between July 2018 and June 2019 over a three-year period. PSE also seeks to continue to defer depreciation for GTZ assets placed in service from July 2019 forward. Staff and AWEC accept only one GTZ project for a pro forma adjustment. Public Counsel recommends deferring PSE's recovery for 2019 GTZ-

---

[5] McArthur, Exh. MDM-1T at 14:17-15:1.

[6] Doyle, Exh. DAD-1Tr at 2:5.

[7] McArthur, Exh. MDM-1T at 4:8-10.

related costs until the Company's next GRC, and disallowing half of the GTZ-related costs in the test year.

3. **Data Center Relocation.** PSE requests recovery of $79.3 million related the relocation and replacement of two data centers and various technology updates for disaster recovery requirements. AWEC challenges the prudency of those costs, arguing that PSE was aware of the data center deficiencies when the facilities were originally built.

4. **Tacoma Liquefied Natural Gas Plant.** In its initial filing, PSE seeks recovery of $31.5 million for upgrade work performed on its distribution system related to the Tacoma Liquefied Natural Gas Project. Staff recommends that the Commission authorize deferred treatment, while AWEC requests all costs associated with the 16-inch line upgrade project be deducted through a rate spread adjustment and reallocated to sales customers. On rebuttal, PSE accepts Staff's recommendation.

5. **SmartBurn at Colstrip.** PSE is seeking recovery for the costs of installing SmartBurn controls at Colstrip Units 3 and 4. Staff recommends disallowing the costs because PSE failed to provide evidence that SmartBurn is required to comply with federal NOx levels or that it is providing any benefits to ratepayers. In addition, Staff argues that PSE failed to provide documentation supporting its decision to install SmartBurn.

42 The parties also contest several other pro forma adjustments. PSE requests a $71.8 million, or 10.3 percent, increase to its authorized power cost baseline established in the 2017 GRC. Staff's adjustments reduce the Company's power costs by approximately $8 million and reduce the revenue requirement by approximately $10.7 million. Staff raises numerous concerns related to power costs, and Public Counsel argues that PSE's Green Direct Power Purchase Agreements are not yet used and useful.

43 PSE proposes to remove the undepreciated plant balances for Colstrip Units 1 and 2 from test year rate base, and recover through rates all remaining rate base for Colstrip Units 3 and 4 by December 31, 2025. Staff accepts the Company's treatment of Colstrip rate base and the decommissioning and remediation costs, but only until the Company's next GRC. AWEC proposes to remove Units 1 and 2 from the test year rate base entirely, make additional deferred tax adjustments to the plant balances of Units 1 and 2, and create a regulatory asset account for the unrecovered plant balances of Units 1 and 2 that would be offset by production tax credits.

44 The parties address multiple low-income issues, including the impact of PSE's proposed electric rate spread on vulnerable populations, funding for low-income bill assistance programs, and disconnections due to non-payments.

45 Other notable issues include PSE's request to treat EDIT in a manner fundamentally different than that approved by the Commission in prior cases since the enactment of the TCJA and Staff's proposed modified materiality threshold. The parties also make various other proposals, including NWEC's recommendation to revert to PSE's previous method for calculating natural gas line extensions, NWEC's proposed on-bill repayment program, Public Counsel's proposal that the Commission require PSE to form a Distribution System Planning Group, and Staff's pricing pilot proposal.

46 On rebuttal, PSE reduced its electric revenue request by $1.5 million, and reduced its requested ROE to 9.50 percent.

47 Several additional issues were resolved on rebuttal, and all parties but FEA recommend resolving contested cost of service issues for the purposes of this case only, reserving formal Commission guidance until parties submit cost of service studies under the Commission's recently adopted cost of service rules in Dockets UE-170002 and UG-170003.[8] This result is consistent with the Commission's recent direction and decisions in other general rate proceedings.[9]

48 **PSE's 2017 GRC.** On December 5, 2017, the Commission entered Order 08, its Final Order in Dockets UE-170033 and UG-170034 (PSE's 2017 GRC).[10] The Commission observed that the 2017 GRC was "one of the major complex litigations before the Commission during the past two decades," and that it resulted in agreement resolving "many challenging issues regarding the Colstrip coal-fired power plants."[11] Ten parties,

---

[8] *See In the Matter of Amending WAC 480-07-510 and Adopting Chapter 480-85 WAC Relating to Cost of Service Studies for Electric and Natural Gas Investor-Owned Utilities,* Dockets UE-170002 and UG-170003, General Order R-599 (July 7, 2020).

[9] *See Wash. Utils. and Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-160228 and UG-160229, Order 06 (Dec. 15, 2016) at ¶¶ 94-100; *Wash. Utils. and Transp. Comm'n v. Puget Sound Energy,* Dockets UE-170033 and UG-170034, Order 08 (Dec. 5, 2017).

[10] *Wash. Utils. and Transp. Comm'n v. Puget Sound Energy,* Dockets UE-170033 and UG-170034, Order 08 (Dec. 5, 2017).

[11] *Id.* ¶ 8.

including PSE and Staff, supported a Settlement Stipulation, which Public Counsel opposed. Order 08 approved several terms of the Settlement Stipulation, including:

- An overall electric revenue increase of $20 million (1.0 percent increase) and an overall natural gas revenue decrease of $35 million (3.9 percent decrease).
- A capital structure for PSE that included 48.5 percent equity and 51.5 percent debt, with an authorized ROE of 9.50 percent.
- Shortened depreciation schedules for PSE's coal-fired production assets in Colstrip, Montana. The parties agreed to depreciation rates for Colstrip Units 1 and 2 based on a projected closure date of no later than July 1, 2022. The Parties also agreed to set deprecation rates for Colstrip Units 3 and 4 to December 31, 2027.
- Permission to file an Expedited Rate Filing (ERF) within one year of the effective date of the tariffs resulting from Order 08.

49 In Order 08, the Commission also resolved contested issues that were not addressed by the Settlement Stipulation. Among other matters, the Commission approved PSE's continued use of a decoupling mechanism and refined the grouping of non-residential electric and natural gas customers taking service under certain rate schedules. The Commission rejected PSE's proposed Electric Cost Recovery Mechanism for capital investments, finding that PSE failed to carry its burden to show the need for such a mechanism.

50 **PSE's 2018 ERF.** On February 21, 2019, the Commission entered Order 05, its Final Order in consolidated Dockets UE-180899 and UG-180900, stylized as PSE's ERF, consistent with the settlement agreement approved in the 2017 GRC.[12] All of the parties supported a Joint Settlement Agreement resolving all issues in that case. Order 05 approved several terms of the Joint Settlement Agreement, including overall rate offsets by passing back 2018 PP EDIT reversals that resulted in (1) no change in overall electric rates to customers and (2) an overall natural gas revenue increase of $21.5 million, or 2.9 percent. However, Order 05 did not approve the settlement term that would allow PSE to

---

[12] *Wash. Utils. and Transp. Comm'n v. Puget Sound Energy*, Dockets UE-180899 and UG-180900, Order 05 (Feb. 21, 2019).

delay returning over-collected tax expenses related to the TCJA collected during the interim period from January 1, 2018, to April 30, 2018, until its next GRC. Order 05 instead required that PSE return the interim period over-collected tax expenses to customers over a 12-month period from May 1, 2019, to April 30, 2020.

51 As part of its compliance filing in those dockets, PSE filed on February 25, 2019, Schedule 141X, Protected-Plus Excess Deferred Income Tax Reversals for both its Electric Tariff G and Natural Gas Tariff.

52 The parties agreed in the Joint Settlement Agreement that Schedule 141X would be reviewed in PSE's next GRC, leaving for resolution in this proceeding a determination of the proper accounting and ratemaking treatment of PP EDIT reversals for the period from January 1, 2018, through February 28, 2019. Accordingly, we resolve in this Order the proper accounting and ratemaking treatment of PP EDIT reversals both for that period and on a going forward basis, reducing the total amount owed to customers as of December 31, 2017, by amounts passed back to customers since March 1, 2019, when Schedule 141X became effective.

B. ISSUES

53 The Commission received pre-filed testimony from 51 witnesses (*i.e.*, direct, supplemental, and two revisions to direct testimony from PSE; response and three revisions to response testimony from Staff; response from Public Counsel and five intervenors; rebuttal and replacement rebuttal testimony from PSE; and cross-answering from Staff, Public Counsel, and three intervenors). The parties filed numerous exhibits supporting their witnesses' testimonies. The Commission thoroughly reviewed the pre-filed testimony and exhibits in preparation for an evidentiary hearing held February 6, 2020.

54 The following test-year adjustments proposed by PSE are uncontested by any party:

20.01 ER/GR Revenue & Expenses
20.02 ER/GR Temperature Normalization
20.04 ER/GR Tax Benefit of Interest
20.05 ER/GR Pass-Through Revenue & Expenses
20.06 ER/GR Injuries & Damages
20.07 ER/GR Bad Debts
20.09 ER/GR Excise Tax & Filing Fee

20.10 ER/GR	Directors & Officers (D&O) Insurance
20.11 ER/GR	Interest on Customer Deposits
20.12 ER/GR	Rate Case Expense
20.13 ER/GR	Pension Plan
20.14 ER/GR	Property & Liability Insurance
20.15 ER/GR	Wage & Payroll Tax
20.16 ER/GR	Investment Plan
20.17 ER/GR	Employee Insurance
20.23 ER/GR	Annualize Rent Expenses
21.02 ER	Montana Tax
21.03 ER	Wild Horse Solar
21.04 ER	ASC 815
21.05 ER	Storm Damage
20.01 EP/GP	Revenue & Expenses
20.02 EP/GP	Temperature Normalization
20.04 EP/GP	Tax Benefit of Interest
20.14 EP/GP	Property & Liability Insurance
21.02 EP	Montana Tax
21.05 EP	Storm Damage
21.08 EP	Remove Energy Imbalance Market[13]
8.01 GP	Remove 2018 Cost Recovery Mechanism[14]
8.02 GP	SCH. 149[15]

55 The following issues were resolved on rebuttal and are uncontested:

- ***Temperature Normalization*: In direct testimony, PSE proposed a two-model reconciliation approach to develop weather normalized sales. However, on rebuttal, PSE accepted each of Staff's recommendations for modifying its approach.

- ***Gain on Sale of Shuffleton:*** On direct, PSE proposed to return to customers the approximately $12 million gain from the sale of the

[13] This adjustment removes Energy Imbalance Market rate base and expense.

[14] This adjustment removes November and December 2018 balances that will be recovered in the 2018-2019 Cost Recovery Mechanism (CRM) in Docket UG-190464.

[15] Schedule 149 is the Company's most recent annual CRM filing for Pipeline Replacement.

Shuffleton Transmission Switching Station property in Renton, Washington. Staff responded that PSE should include the gain on sale proceeds in rates but should remove the sold property from rate base and depreciation. PSE accepted Staff's recommendation on rebuttal.

- ***Natural Gas Pipeline Capacity*:** Staff opposed PSE's proposal to de-rate its fixed transport capacity on the Enbridge Westcoast transmission pipeline, instead proposing that PSE assume 100 percent availability of the Enbridge Westcoast pipeline for the rate year power costs. PSE accepted Staff's recommendation on rebuttal.

- ***Centralia Power Purchase Agreement:*** Staff recommended that the Commission reduce the equity adder to the Centralia Power Purchase Agreement to $1.23/MWh to account for the reduction of the federal income tax rate from 35 percent to 21 percent. PSE accepted Staff's recommendation on rebuttal.

56 We discuss first PSE's proposed attrition adjustment and cost of capital, followed by contested adjustments related to revenue requirement, including five proposed major capital additions, other proposed pro forma adjustments, EOP rate base, investor supplied working capital, power costs, annual incentive pay, Colstrip decommissioning and remediation costs, and EDIT treatment.

57 Next, we address the accounting petitions consolidated with the GRC Dockets related to GTZ and Green Direct, followed by cost of service, rate spread, rate design, and changes to PSE's low-income programs. We then turn to the broader policy issues presented by the parties, including:

- Staff's proposal to adopt a new materiality threshold for pro forma adjustments,
- NWEC's proposal to implement an on-bill repayment program,
- Staff's proposal to require pricing pilots,
- PSE's proposed Conjunctive Demand Service Option Pilot,
- PSE's proposal to discontinue its Water Heater Rental Program,
- NWEC's recommendation to revert to a previous methodology to calculate natural gas line extension allowances, and
- Public Counsel's proposal to require PSE to form a Distribution System Planning Advisory Group.

Finally, we address the Commission's rejection of two proposed pro forma adjustments (20.09 EP/GP – Excise Tax & Filing Fee, and 20.10 EP/GP – D&O Insurance), then turn to uncontested adjustments, issues resolved on rebuttal, and COVID-19 considerations.

1. ATTRITION

58 PSE originally sought an attrition adjustment to address its claimed additional revenue shortfalls of $38.5 million for electric and $11.7 million for natural gas, but revised its requested adjustment to $23.9 million for electric and $16.2 million for natural gas. PSE presented testimony and exhibits from nine witnesses to support its proposed attrition adjustment.

59 Company witness Amen argues that the Company's current circumstances, coupled with recent guidance from the Commission, support the Company's proposed attrition adjustment. Citing the Commission's Final Order in Dockets UE-150204 and UG-150205, the 2015 GRC for Avista Corporation, d/b/a Avista Utilities (Avista), Amen argues that the Commission no longer requires the presence of extraordinary circumstances as a condition precedent to granting attrition adjustments. Rather, Amen asserts, attrition adjustments are just another "tool," and the "new normal" of increased capital investments in an environment of low load growth gives the Commission flexibility to authorize such adjustments.[16] Further, Amen testifies that multiple PSE witnesses, through their own testimony unrelated to the attrition adjustment, demonstrate that the pace of PSE's spending is beyond the Company's control.[17]

60 PSE witness Doyle testifies that the backward-looking nature of traditional ratemaking significantly contributes to the regulatory lag and attrition that PSE is experiencing, as demonstrated by the Company's failure to earn its authorized ROR and ROE from 2013 through 2018.[18] Although the normalized authorized RORs and ROEs in the later years show that the Company marginally over-earned, Doyle argues that this is not a fair representation of traditional ratemaking. Doyle testifies that the 2013 ERF filing increase and the use of a K-factor during the Company's multi-year rate plan from 2013 to 2017 provided a more predictable and gradual increase. Absent the benefit of those cumulative

---

[16] Amen, RJA-1T at 13:1-15.

[17] *Id.* at 18:18-20:8.

[18] Doyle, Exh. DAD-1T at 13:19-21.

effects, Doyle claims that the Company would have requested an additional $160 million revenue requirement increase in its 2017 GRC.[19]

61 Doyle argues that limited pro forma adjustments, which are allowed under traditional ratemaking, do not capture the complete impact of inflation and other expense growth between the test year and the rate year.[20] Specifically, Doyle argues that short-lived information technology (IT) investments and their related software and licensing expenses contribute to attrition. Doyle also testifies that power costs have increased and tax reform has reduced cash flow, both of which further contribute to cost pressures.

62 Staff witness Chris McGuire provides policy arguments opposing the Company's proposal. Specifically, McGuire relies on the Final Order in Avista's 2016 GRC, which reinforces that a utility requesting an attrition allowance must demonstrate: (1) a showing of chronic under-earning; and (2) that circumstances giving rise to the claimed attrition are beyond the utility's ability to control. McGuire emphasizes that both criteria must be satisfied, arguing that neither has been met here.[21]

63 Staff witness Liu provides testimony to support Staff's attrition analysis, but ultimately does not recommend that the Commission approve an attrition adjustment. Instead, Staff recommends a revenue requirement calculation based on its pro forma revenue requirement model.[22]

64 Public Counsel opposes an attrition adjustment and instead proposes limited post-test year adjustments using the traditional modified historical test year approach. Public Counsel witness Garrett testifies that the Company's attrition adjustment is better

---

[19] Doyle, Exh. DAD-1T at 13:22-15:16.

[20] *Id.* at 19:15-22.

[21] McGuire, Exh. CRM-1T at 18:6-11, 18:15-18.

[22] Staff's attrition analysis results in an additional revenue requirement increase of $47.5 million for electric operations, and $50.5 million for gas operations. However, relative to Staff's modified test year with limited pro forma adjustments, Staff's attrition analysis produces a rate year revenue sufficiency of $2.5 million for electric operations, and a rate year deficiency of $12.1 million for natural gas operations. *See* Liu, Exh. JL-1CTr at 73:4-6.

described as a forecasted test year for the rate effective period, and cites several past Commission orders in which the Commission rejected a future test year approach.[23]

65 AWEC recommends the Commission reject the Company's proposed attrition adjustment because it is based on an "unsound and unbalanced" methodology.[24] AWEC witness Gorman argues that PSE ignores other regulatory mechanisms available to address regulatory lag. Specifically, Gorman references expedited rate filings, the cost recovery mechanism for gas operations, accounting deferrals, and the utilization of EOP rate base and pro forma adjustments.[25]

66 NWEC also opposes the Company's proposed attrition adjustment. NWEC witness Gerlitz testifies that PSE's proposal does not conform to common attrition relief mechanism approaches; specifically, it is not part of a multi-year rate plan.[26] Further, Gerlitz argues that the proposed attrition adjustment does not provide the appropriate incentive for the Company to control costs during the rate effective period.[27]

67 TEP opposes an attrition adjustment, arguing that (1) historically, attrition adjustments have been reserved for substantial earnings erosion resulting from cost increases beyond a company's control; (2) PSE's regulatory lag argument does not support an attrition adjustment given the likelihood of a subsequent GRC filing in the near future;[28] and (3) the use of an attrition adjustment is premature in advance of other Commission proceedings that will address alternative ratemaking, such as the exploration of regulatory reform in Docket U-180907, and the Commission's policy statement providing guidance on the used and useful standard.[29]

68 Kroger argues that the Company's attrition adjustment parameters represent an "extreme overreach" because they contain plant additions expected to go into service 26 months

---

[23] Garrett, Exh. MEG-1T at 4:13-15, 6:4-17.

[24] Gorman, Exh. MPG-1T at 1:22-23.

[25] *Id.* at 2:7-10, 6:9-7:4, 6:19-21, 8:1-4.

[26] Gerlitz, Exh. WMG-1T at 5:19-6:19.

[27] *Id.* at 11:5-9.

[28] Collins, Exh. SMT-1T at 27:18-19.

[29] *Id.* at 27:19-28:2.

after the conclusion of the test period and more than 22 months after the initial filing.[30] Kroger witness Higgins recommends that, if the Commission chooses to authorize an attrition adjustment, it exclude plant additions made after December 31, 2019, in the calculation because the resulting rates address regulatory lag and provide a "greater nexus between revenue requirement and plant actually in service."[31]

69 FEA also opposes PSE's attrition adjustment because it is based on projections that may not materialize in the future, which, it argues, creates risks for ratepayers with no corresponding risk for shareholders.[32] Additionally, FEA witness Ali Al-Jabir argues that an attrition adjustment removes the cost-control incentive for the Company and essentially pre-approves the cost increases as proposed for inclusion in base rates.[33] Further, Al-Jabir argues that a utility's shareholders are already compensated for the business risk of cost escalation during the rate year through the rate of return, and that a utility has the ability to manage costs effectively.[34] Finally, Al-Jabir testifies that, based on its response to FEA's data request, PSE has "multiple riders and trackers designed to pass through costs to customers outside of the traditional base rate case."[35]

70 Multiple PSE witnesses respond to the opposing parties' collective position that the Company has not proven it has suffered from chronic under-earning. Doyle argues that it would be inappropriate to suggest historical revenues are indicative of rate year earnings under the current conditions the Company is facing.[36]

Commission Determination

71 In any general rate proceeding, the Commission's ultimate goal is to set rates that are *fair* to customers and to the Company's shareholders; *just* in the sense of being based solely on the record developed in a rate proceeding; *reasonable* in light of the range of possible

---

[30] Higgins, Exh. KCH-1T at 5:17-22.

[31] *Id.* at 6:8-13.

[32] Al-Jabir, Exh. AZA-1T at 23:6-11.

[33] *Id.* at 24:1-9.

[34] *Id.* at 25:18-22.

[35] *Id.* at 26:17-24 referencing PSE's Response to FEA Data Request No. 24(c). The data request is not provided as an exhibit.

[36] Doyle, Exh. DAD-7T at 5:2-7.

outcomes supported by the evidence; and *sufficient* to meet the needs of the Company to cover its expenses and attract necessary capital on reasonable terms.[37]

72 In the instant proceeding, we are faced with unprecedented circumstances that substantially impact each of these considerations. In the throes of the COVID-19 pandemic, it is not fair either to significantly increase customer rates or to deny the Company recovery of the costs it must incur to continue providing safe and reliable service. The evidence in the record reflects the economic uncertainties the Company and its customers are facing, both of which the Commission must consider to arrive at just results. The outcome must also be reasonable in light of the range of possible outcomes supported by the evidence, which includes outcomes that account for the short-term impacts of the COVID-19 pandemic. Finally, the rates we set by this Order must be sufficient to meet the Company's financial needs, including the ability to attract capital in a market that has also been impacted by the global pandemic.

73 Because the Commission is charged with setting rates amidst a public health crisis that rapidly escalated into an economic crisis of unknown length and depth, it is incumbent upon us to keep at the forefront of our decision the Commission's overarching statutory obligation to regulate in the public interest. It is within this context that we evaluate PSE's proposed rate increase, including the Company's proposed attrition adjustment. Our analysis necessarily includes consideration of alternative tools the Commission has at its disposal to address common ratemaking issues such as regulatory lag and rate shock, as well as more novel issues like the economic impacts of a public health crisis. Based on the totality of the circumstances, we determine that an attrition adjustment is not the regulatory tool best suited to achieve a fair, just, reasonable, and sufficient outcome for PSE and its ratepayers at this time.

74 First – and perhaps foremost for our purposes here – the COVID-19 pandemic has created serious economic challenges for many residential and small business customers, which, in turn, will impact PSE's earnings. As Public Counsel observes in response to Bench Request No. 15 (BR-15), residential energy usage is rising as people are required to spend more time at home in response to the pandemic. At the same time, many people cannot afford larger bills created by these circumstances because they are unemployed, under-earning, or working from home, which requires them to incur energy costs

---

[37] *Wash. Utils. and Transp. Comm'n v. Avista Corp., d/b/a Avista Utils.*, Dockets UE-160227 and UG-160228, Order 06 ¶ 79 (Dec. 15, 2016).

normally borne by their employers. Any of these scenarios may result in more missed or late payments, a need for payment arrangements, or increased write-offs for PSE.

75 In addition, the Governor's Proclamation 20-23.3, Ratepayer Assistance and Preservation of Essential Services, prohibits all energy companies from disconnecting any residential customers for nonpayment, refusing to reconnect customers who have been disconnected for nonpayment, and charging late fees for late payment or reconnection of energy service. The Proclamation, however, is currently set to expire on July 28, 2020. Although PSE has laudably worked with the Commission and stakeholders to develop a phased-in approach to disconnections that includes multiple measures to help customers stay connected, the economic recovery from the COVID-19 pandemic will be a long and difficult process for PSE's customers. Bearing all of these considerations in mind, we conclude that allowing an attrition adjustment in this case, which would significantly increase rates for customers, would not be fair to the Company's customers or reasonable in light of the range of possible outcomes supported by the evidence in the record.

76 Second, the Commission has flexible authority to use any standard, formula, method, or theory of valuation reasonably calculated to arrive at fair, just, reasonable, and sufficient rates.[38] As such, other tools at our disposal can help address PSE's concerns about regulatory lag, particularly as it impacts short-term investments, and allow the use of money that must be returned to customers to offset necessary rate increases.

77 The Commission has considerable discretion and authority to select from a wide range of regulatory tools, including:

- ***End of Period Rate Base.*** An adjustment that restates rate base values from the Average of Monthly Averages to the End of Period. The restating adjustment converts rate base (including working capital) and depreciation to balances as of December 31, 2018.

- ***Deferrals.*** Rather than amortizing depreciation expense for certain investments in rates now, the Commission may defer those costs for consideration of recovery in a future rate proceeding.

- ***Post-test year adjustment period.*** Although the Commission has been conservative in its approach to extending the pro forma period more than a

---

[38] *See* RCW 80.04.250.

few months past the end of the test period, new provisions of RCW 80.04.250 grant the Commission broad discretion and flexibility to include pro forma adjustments for up to 48 months past the end of the test year.

- ***Amortization Periods.*** Amortization is the period over which depreciation expense is recovered from rate payers. Typically, amortization periods align with the life (*i.e.*, depreciation schedule) of the underlying asset. The Commission has the discretion to adjust amortization periods to effect a decreased or increased rate impact based on the circumstances presented.

- ***Use of off-setting accounts*.** PSE must return to ratepayers the difference between taxes that were collected at a rate of 35 percent, but will ultimately be paid to the IRS at a rate of 21 percent. Taxes collected on plant assets must be returned using the Average Rate Assumption Method, but the Commission has discretion over the length of the pass back period for other taxes collected.

78 Accordingly, we calculate PSE's revenue requirement based on a modified historical test year with limited pro forma adjustments that include pro forma capital additions through December 31, 2019, and we value rate base on an EOP basis. These tools capture short-term technological investments for inclusion in rate base that would otherwise be excluded by a traditional pro forma period and present a more accurate, end-of-year valuation of rate base that better reflects the rate base value in the rate effective period.

79 We also create deferrals to delay rate increases related to certain projects, and alter amortization periods, including those proposed by Staff, for certain regulatory assets to decrease the rate impact to customers. Rather than authorizing an attrition adjustment that, due to timing, is unable to accommodate the unique situation in which we now find ourselves, we determine that the regulatory tools employed by this Order better fit the present circumstances and reasonably calculate rates that are fair, just, reasonable, and sufficient.

80 Finally, PSE has proposed a one-year rate plan, and reiterated at hearing that the Company is contemplating the need to file another rate case within one year of the conclusion of this case.[39] Rates set in this proceeding thus will likely be effective for a relatively brief period of time, which also weighs against the need for an attrition adjustment. Accordingly, given the totality of these circumstances and options, we determine that an attrition adjustment is unnecessary.[40]

2. COST OF CAPITAL

81 No Parties contest PSE's proposed capital structure, which includes 48.5 percent equity and 51.5 percent debt. The only contested issue related to cost of capital is the appropriate level for PSE's return on equity (ROE). Table 1, below, illustrates the positions of parties that have performed cost of capital analyses.

Table 1 - Cost of Capital Positions

Component	PSE	Staff	Public Counsel and Nucor Steel
Short-Term Debt	2.47%	2.47%	2.38%
Long-Term Debt	5.51%	5.57%	5.51%
ROE	9.50%	9.20%	8.75%
ROR	7.44%	7.29%	7.07%

82 In the Company's initial filing, PSE witness Morin argues the Commission should increase PSE's ROE from 9.50 to 9.80 percent, and that adopting a lower ROE would increase costs for ratepayers because it would lead to an over-reliance on debt, thereby increasing the utility's debt-to-equity ratio, which in turn drives up the cost of equity and the cost of debt.[41]

83 On rebuttal, Morin updates the six models presented in his direct testimony with more recent stock prices and interest rates, showing that the simple average of each model

---

[39] Piliaris, TR 246:5-8

[40] Disallowing the attrition adjustment renders moot multiple adjustments contested by Public Counsel.

[41] Morin, Exh. RAM-1T at 5:13-7:6.

results in an ROE of 9.30 percent. Morin then points out that if the lowest result (from a Discounted Cash Flow, or DCF, model) is removed, the average result is 9.50 percent.[42]

84 Morin relies on three models to support his recommendation: DCF, Capital Asset Pricing Model (CAPM), and Risk Premium methodologies.[43] Morin uses a constant growth DCF model, a CAPM analysis, and an empirical approximation to the CAPM (referred to as the ECAPM).

85 For the proxy group, Morin utilizes a combined group of investment-grade, dividend-paying gas and electric utilities covered in Value Line's Electric Utility Composite.[44] Morin testifies that all the proxy utilities earn the majority of their revenues from regulated utility operations, are investment-grade, and pay dividends.[45]

86 Staff recommends an ROE of 9.2 percent, with a range of 8.9 to 9.5 percent based on the upper end of the result range for the DCF model and the mid-point of the range of results for the Comparable Earnings (CE) model.[46] Staff witness Parcell calculates results for three models: DCF, CAPM, and CE. However, Parcell does not give the CAPM result any weight in his quantitative consideration of ROE because he considers it to be an anomaly. Parcell does, however, use the CAPM results to guide his recommendation.[47]

87 Parcell uses both Staff's and Morin's proxy groups. Parcell used criteria similar to Morin's to select Staff's proxy group, which consists of a combination of electric and gas-electric utilities. [48] Parcell explains that it is Staff's practice to also run the utility witness's proxy group, and that Staff's conclusions and recommendations are based upon the results of both proxy groups.[49]

---

[42] *Id.* at 92:1-3.

[43] *Id.* at 5:1-5, 5:8-10.

[44] *Id.* at 5:1-5. Morin states that all of the Companies in PSE's Proxy are investment-grade and are paying dividends.

[45] *Id.* at 5:5-7.

[46] Parcell, Exh. DCP-1T at 4:12-15.

[47] *Id.* at 4:12-15.

[48] *Id.* at 24:17-25:2.

[49] *Id.* at 25:10-11.

88 Though Parcell's DCF results for Staff's two proxy groups range between 6.3 and 8.9 percent, Parcell recommends a range of 7.8 to 8.9 percent (8.35 percent mid-point) for the current DCF-derived ROE from Staff's proxy groups.[50] Considering the results of Staff's models, Parcell considers the recommendation to be conservative (*i.e.,* high side).[51]

89 Parcell produces, but then dismisses the weight of, the CAPM results used to make Staff's ROE recommendation. Parcell explains:

> [E]ven though the CAPM results have not been given weight in developing my recommended ROE range, they should be considered as one factor in determining where, within the recommended range, the cost of equity for PSE should fall. Therefore, I recommend that PSE's ROE be set at no higher than the mid-point of the ROE range for the proxy companies.[52]

90 Public Counsel recommends an ROE of 8.75 percent with a range of 6.9 to 8.95 percent, noting that Public Counsel's recommendation is in the upper end of the range. Public Counsel witness Woolridge argues that Parcell's ROE recommendation does not accurately reflect the results of his own ROE analysis, and that Parcell overstates Staff's "results of the DCF analysis by reporting DCF results that only include the single, high DCF growth rate."[53] Woolridge further asserts that Parcell ignores the results of his own CAPM study, which show a much lower ROE for PSE.[54] Finally, Woolridge argues that Parcell's analysis relies completely on his CE approach, which suffers from being "a model of his own creation and interpretation."[55]

91 Woolridge applies the DCF model and CAPM methodologies to three proxy groups:[56] a proxy group of publicly-held electric utility companies, Morin's proxy group, and a

---

[50] *Id.* at 29:10-18.

[51] *Id.* at 29:17-18.

[52] *Id.* at 39:19-23.

[53] Woolridge, Exh. JRW-13T at 2:16-1.

[54] *Id.* at 3:1-2.

[55] *Id.* at 3:2-8.

[56] Woolridge, Exh. JRW-1T at 4:4-7.

proxy group of nine natural gas distribution companies.[57] Woolridge develops Public Counsel's electric proxy group using criteria similar to that used by Morin and Parcell.[58]

92 Public Counsel's recommended ROE relies primarily on the DCF model.[59] Woolridge performs a CAPM study but gives its results less weight because Public Counsel believes "that risk premium studies, of which the CAPM is one form, provide a less reliable indication of equity cost rates for public utilities."[60]

93 On rebuttal, Morin argues that Woolridge's recommendation is more extreme than Staff's, that it falls outside the reasonable limits of probability, and that it contains numerous flaws and contradictions. First, Morin argues that Woolridge's 8.75 percent ROE recommendation is well below ROEs "authorized by state utility commissions in 2018 and 2019, which average 9.6 percent" and would harm "PSE's credit ratings, financial integrity, and ability to raise capital."[61] Second, Morin argues that Woolridge relies on a single methodology, the DCF, to support Public Counsel's recommendation and uses questionable inputs in the DCF model.[62] Third, Morin argues Woolridge's DCF growth rate is "arbitrary, contradictory, and inconsistent with several statements in his testimony."[63] Morin concludes that Public Counsel's analysis "should be given little, if any, weight in the Commission's considerations."[64]

94 Morin agrees with several, but not all, of Parcell's methodologies. Morin considers one of Parcell's market risk premiums and beta estimates to be reasonable, but nevertheless concludes that the Commission should give little weight to Parcell's CAPM results.[65]

---

[57] *Id.* at 13:8-11. Woolridge's gas proxy group includes Atmos Energy, Chesapeake Utilities, New Jersey Resources, NiSource, Inc., Northwest Natural Gas Company, ONE Gas, Inc., South Jersey Industries, Southwest Gas, and Spire.

[58] *Id.* at 12:1-11. The electric proxy group includes 30 companies.

[59] *Id.* at 25:10-16.

[60] *Id.* at 25:14-16.

[61] Morin, Exh. RAM-12T at 5:1-16.

[62] *Id.* at 5:17-20.

[63] *Id.* at 5:10-7:3.

[64] *Id.* at 8:3-7.

[65] *Id.* at 78:1-5, 79:4-6, 77:1-2.

95 On rebuttal, Doyle argues that this GRC filing is critical to restoring cash flow due to the negative impacts of tax reform,[66] and that Staff's and Public Counsel's recommendations would have a negative impact on PSE's credit metrics.[67] Finally, Doyle argues that "the weighted-average returns on equity proposed by Commission Staff and Public Counsel do not provide an appropriate balance between safety and economy."[68]

96 In its brief, PSE argues that Staff's proposed ROE is understated and based on flawed analyses, and that Public Counsel's proposed ROE is so extreme that it should be disregarded completely.[69]

97 Staff argues in its brief that its recommended ROE is appropriate for current market conditions in which interest rates are extraordinarily low and trending downward. As such, Staff argues that the Commission should decline PSE's request to maintain the same ROE approved in the 2017 GRC in light of the significantly different circumstances presented in this proceeding. Staff also observes that PSE's analysis produces an ROE of 9.25 percent rather than 9.46 percent when Morin's DCF Analyst Growth Methodology results are properly included, and argues that Morin fails to explain why the DCF Analyst Growth Methodology results, 8.2 percent, are excluded as an outlier.

98 Staff recommends the Commission also reject PSE's proposal to update the marginal short-term debt rate in its compliance filing because the Commission would not be able to calculate the ROR or the revenue requirement until after entering its final order. To avoid this outcome, Staff recommends the Commission incorporate the 2.47 percent short-term cost of debt reported in response to BR-11 into PSE's final ROR. In its reply brief, PSE accepts Staff's proposal to use the short-term cost of debt of 2.47 percent.

99 TEP also supports a reduction in PSE's ROE, arguing that "Morin concedes that the overall average of his results is 9.3 percent, just slightly above Staff's recommendation. He only arrives at his 9.5 percent recommendation by excluding the lowest DCF result from his calculation while including both estimates at the high-end of his range. The mid-

---

[66] Doyle, Exh. DAD-7T at 36:14-18.

[67] *Id.* at 37:3-4, 38:2-4.

[68] *Id.* at 38:7-8.

[69] PSE Initial Brief ¶¶ 54-56.

point of his range (8.2 - 10.2 percent) is 9.2 percent, also directionally consistent with Staff and Public Counsel."[70]

100 Public Counsel argues that PSE's requested ROE of 9.5 is excessive because capital markets remain at low levels and PSE's short-term debt and equity cost rates are out of date. Public Counsel contends that its recommended 8.75 percent ROE appropriately reflects the downward trend in utility authorized and earned ROEs. Despite the lower ROEs, Public Counsel asserts, credit profiles for those utilities have not been impaired, they have been able to collectively raise more than $50 billion per year in capital, and utility stock prices have performed right along with the S&P 500.[71]

101 Finally, Nucor Steel supports Public Counsel's analysis and recommendations and requests the Commission approve an ROE of 8.75 percent.[72]

Commission Determination

102 The expert witnesses for each party rely on familiar analytical tools such as DCF and CAPM models, and use a variety of data sources to populate these and other models to calculate and support their respective ROE recommendations. As we have noted in many past proceedings, the results produced by each model vary significantly due to subjective judgments each expert makes with respect to their individual approaches and inputs. For example, all three experts in this proceeding arrive at ROE results ranging widely from 3.8[73] to 10.2[74] percent, a difference of more than 600 basis points. The disparity in outcomes is directly attributable to the experts' selection of proxy groups and their reliance on different sources for growth rates, discount rates, and risk premiums. While the expert witnesses' analyses produce a range of possible returns, the 600-plus basis point disparity suggests that both the lower and higher results are outside the zone of reasonableness, which typically falls within a narrower range. Considering all of the expert witnesses' analytical results and industry trends during recent periods, we

---

[70] TEP Initial Brief ¶ 59.

[71] Public Counsel Initial Brief ¶ 20.

[72] Nucor Steel Reply Brief ¶ 4.

[73] Public Counsel's low-end CAPM result.

[74] PSE's high-end Allowed Risk Premium Result.

determine that Staff most appropriately identifies a reasonable range between 8.9 and 9.5 percent.

103 With respect to the parties' specific ROE recommendations, we share Staff's concern that PSE excludes Morin's DCF Analyst Growth Methodology result, 8.2 percent, as an "outlying result" with no further explanation.[75] Presumably, Morin considers this number an outlier because it is the lowest of the six ROE results used in his calculation. Notably, Morin did not afford similar treatment to the highest of the six ROE results. Such inconsistency is not reasonable.

104 The average of all six of Morin's ROE results produces an ROE of 9.25 percent (which Morin rounds up to 9.3 percent) when Morin's DCF Analyst Growth Methodology results are properly included. When both the highest (10.2 percent) and lowest (8.2 percent) results are excluded, the average of the remaining four ROE results produces an ROE of 9.28 percent. Although PSE recommends we authorize its current ROE of 9.5 percent, PSE offers no analysis to support that result. Absent PSE's unsupported 9.5 percent ROE, the record supports a range of reasonableness set by parties' recommendations between 8.75 percent and 9.28 percent.

105 We rely on both the range of reasonableness and the parties' recommendations to inform our decision. We are also cognizant that the midpoint of the range of reasonableness – 9.2 percent – is 30 basis points below PSE's currently authorized ROE. A reduction of that magnitude, under current conditions, would run afoul of the principle of gradualism. As we noted in Avista's 2017 GRC:

> When considering changes to a regulated utility's authorized ROE, we endeavor to avoid material adjustments, upward or downward, in authorized levels to provide stability and assurance to investors and others regarding the regulatory environment supporting the financial integrity of the utility. Based on the evidence produced by the various expert witnesses, we generally determine whether modest increases or decreases, if any, to

---

[75] Morin, Exh. RAM-12T at 92:2.

> currently authorized levels are appropriate given the evidence produced in the immediate proceeding.[76]

106 Here, the detailed analyses presented in the record suggest that a more modest decrease is appropriate. Giving weight to all of the expert's recommendations but appropriately incorporating the principle of gradualism, we determine that an ROE of 9.4 percent is reasonable and fully supported by record evidence.

107 In addition, the Commission recently approved an ROE of 9.4 percent for three other Washington utilities, which we have found strikes an appropriate balance between the lower risk of utility investment and regulated companies' ability to attract investors in an economic environment where interest rates are low.[77]

108 The Commission, therefore, approves an ROE of 9.4 percent. Based on that ROE, the uncontested hypothetical capital structure, and the uncontested cost of debt, we approve and adopt an overall ROR of 7.39 percent for purposes of establishing electric and natural gas revenue requirements and rates in this proceeding.

3. REVENUE REQUIREMENT – CONTESTED ADJUSTMENTS

i. Pro Forma Capital Additions

109 In its initial filing, PSE proposes numerous pro forma adjustments, including five major projects: Get to Zero Program (GTZ), Advanced Metering Infrastructure (AMI), Data Center and Disaster Recovery Program (DCDR), Tacoma LNG Distribution Upgrade, and SmartBurn. PSE proposes a pro forma capital additions cutoff date of June 30, 2019, and a materiality threshold that includes any adjustment that "impacts the rate of return

---

[76] *See Wash. Utils. and Transp. Comm'n v. Avista Corp., d/b/a Avista Utils.,* Dockets UE-170485 and UG-170486 (*Consolidated*), Final Order 07 ¶ 68 (Apr. 26, 2018).

[77] *See Wash. Utils. and Transp. Comm'n v. Avista Corp., d/b/a Avista Utils.,* Dockets UE-190334, UG-190335, and UE-190222 (*Consolidated*), Final Order 09 (Mar. 25, 2020), approving settlement that set Avista's ROE at 9.4 percent; *Wash. Utils. and Transp. Comm'n v. Cascade Natural Gas Corp.,* Docket UG-190210, Final Order 05 (Feb. 3, 2020), approving settlement that set Cascade's ROE at 9.4 percent; and *Wash. Utils. and Transp. Comm'n v. Northwest Natural Gas, d/b/a NW Natural,* Docket UG-181053, Final Order 06 (Oct. 21, 2019), approving settlement that set NW Natural's ROE at 9.4 percent.

by one basis point."[78] For its electric operations, PSE's proposed net operating income (NOI) threshold is $500,000 and the rate base threshold is $9.5 million. For natural gas, the NOI threshold is $200,000 and the rate base threshold is $3.7 million.[79]

a. *Capital Additions through December 31, 2019*

110 On February 19, 2020, the Commission issued BR-11, which requested that PSE provide updates to six of the Company's pro forma adjustments for AMI, GTZ, Public Improvement, HR TOPS, High Molecular Weight Cable, and Energy Management Systems. The update included only amounts that are used and useful and known and measurable, consistent with Commission past practice, and did not include forecasts or estimates.

111 On March 2, 2020, PSE filed a response to BR-11. PSE's response provides for an increase to certain pro forma capital adjustments based on actual expenses for electric and natural gas through December 31, 2019.

Commission Determination

112 As described throughout this Order, the Commission has considerable discretion and authority to select from a wide range of ratemaking tools, including adjusting the length of the post-test year pro forma period. Prior to the statutory amendments made to RCW 80.04.250, granting pro forma adjustments beyond a few months after the end of the test year was considered "exceptional."[80] The statute's new language, however, provides the Commission may include in rates "property that is used and useful for service in this state *by or during the rate effective period*,"[81] and further that:

> (3) The Commission may provide changes to rates under this section for up to forty-eight months *after* the rate effective date using any standard,

---

[78] Free, Exh. SEF-1Tr at 6:9-10.

[79] *Id.* at 11:7.

[80] *Wash. Utils. and Transp. Comm'n vs. Pacific Power & Light Co.*, Docket UE-140762, Order 08 ¶165, n. 57 (March 25, 2015).

[81] RCW 80.04.250(2) (Emphasis added).

formula, method, or theory of valuation reasonably calculated to arrive at fair, just, reasonable, and sufficient rates.[82]

113 As a result, extending the pro forma period beyond a few months after the end of the test year is no longer "exceptional." To the contrary, it is a method we expect to employ as a tool to address regulatory lag and particularly when a utility proposes a multi-year rate plan. This use of an extended pro forma period is not a one-size fits all solution, and thus will be determined on a case-by-case basis.

114 Here, we need not rely on projections or estimates. Each of the investments we approve meets the used and useful standard because it is currently being used to provide service to customers, and their associated costs are known and measurable. We find that allowing these adjustments through December 31, 2019, is a reasonable means to address regulatory lag by ensuring more timely recovery for investments – some of which are short-lived and particularly vulnerable to regulatory lag – that are already benefitting customers.

115 We address each pro forma adjustment in turn.

b. *Get to Zero*

116 In its initial filing, PSE describes GTZ as "a six year (2016-2021) corporate initiative that focuses on improving the customer service in many different ways and includes multiple projects . . . that ultimately make doing business with PSE easier for PSE's customers."[83]

117 PSE witness Jacobs describes the GTZ initiative as "a focused effort on all digital channels to eliminate problems that drive customers to call us," including replacing technologies that are outdated, no longer supported, or no longer meet PSE's cyber security requirements.[84] According to Jacobs, GTZ will:

- Improve billing and payment capabilities for customers;
- Create new field force automation within many of PSE's operational teams;

[82] RCW 80.04.250(3) (Emphasis added).

[83] Jacobs, Exh. JJJ-1T at 2:15-18.

[84] Jacobs, Exh. JJJ-1T at 2:18-22.

- Create new self-service capabilities for scheduling field work or booking appointments; and
- Improve PSE's approach to governing customer and asset data, and leverage that data to glean further insights into how to better serve customers through the use of enhanced data analytics tools and methods.[85]

118 Jacobs also argues that GTZ creates efficiencies tied to (1) driving operational improvements through automation or call reduction, (2) reducing paper and postage due to digitization and e-bill adoption, and (3) reducing bad debt write-offs through more effective account management practices and, in the future, the implementation of remote disconnect and reconnect features.[86]

119 Jacobs testifies that PSE customers have demonstrated an interest in digital interactions with the Company,[87] with the number of customers signing up for digital accounts growing by 9 percent in the two years ending January 2019.[88]

120 Jacobs describes the three Customer Interface (CI) projects, each over $10 million, that were in service as of December 31, 2018, and benefitting customers: Web Platform Redesign, Communication Gateway,[89] and Microservices.[90]

121 Jacobs also summarizes the GTZ projects that are expected to go into service by June 30, 2019, and are therefore included in PSE's pro forma adjustment:

---

[85] *Id.* at 2:22-3:7.

[86] *Id.* at 1:20-21, 9:24-10:19.

[87] *Id.* at 5:1-3.

[88] *Id.* at 6:5-7.

[89] *Id.* at 23:6-10. Communication Gateway "provides a standard means to plan, send and trigger pro-active, flexible and on-demand communications through the various communication channels (email, SMS, notifications, phone calls) to parties outside of PSE. The Communication Gateway project establishes a communication hub to centrally manage customer preferences for communicating with PSE."

[90] *Id.* at 27:15-28:10. In short, Microservices solution is the IT needed for the exchange of data between customer-facing digital channels and PSE's back-end systems, which PSE wanted to be more modular, scalable, and robust to avoid a system-wide shut down due to one application's failure.

- Visual Integrated Voice Response
- Additional Web / Mobile / Integrated Voice Recognition (IVR) enhancements or functionality
- Billing Performance Phase 3
- Integrated Work Management for Meter Network Services and Automated Time Entry
- Field Payment Strategy
- Data Governance.[91]

122 Jacobs estimates that the total cost of the projects placed in service between January 1, 2019, and June 30, 2019, is $32.5 million.

123 In addition to the pro forma adjustment to include actual costs through June 2019, PSE proposes to amortize deferred GTZ expense and rate base amounts for the GTZ assets placed in service between July 2018 and June 2019, arguing that including the depreciation expense up to the rate year and pro forma plant for the rate year eliminates any double counting. The Company requests a three-year amortization period from the date rates will become effective for this proceeding on July 20, 2020.

124 Applying Staff's proposed materiality threshold, Staff witness Higby accepts only one pro forma adjustment for the projects under the GTZ umbrella.[92] Higby's recommendation decreases PSE's requested revenue requirement by $3.4 million for electric operations and by $1.7 million for gas operations relative to the pro forma adjustments proposed by the Company. Higby makes no adjustment to the GTZ test year amounts.

125 Public Counsel witness Baldwin recommends the Commission: (1) defer PSE's request to recover post-test year GTZ costs until the Company's next rate case to increase

---

[91] *Id.* at 12:14:11-13. "The Customer Interface (CI) program represents a collection of separate but related projects that are focused on all customer-facing digital channels, including but not limited to web, mobile, IVR, email, text and social media platforms."

[92] Staff proposes gross cost thresholds for electric operations, natural gas operations, and electric and natural gas combined. Staff's threshold is approximately $2.7 million for electric, approximately $1.2 million for natural gas, and approximately $3.9 million for combined. *See* Higby, Exh. ANH-1T at 23:14-16. Applying this threshold, Staff recommends allowing only one GTZ project.

accountability, and (2) consider disallowing half of the GTZ test year costs to appropriately shift some of the financial risk to PSE's shareholders.[93] Baldwin also makes several other general recommendations for the GTZ program that would require PSE to monitor customer service, ensure equal access to the program for customers at all income levels, and would require certain reporting to the Commission regarding performance and effectiveness.

126 Baldwin also questions whether PSE's customers are digitally proficient enough to adequately utilize GTZ, speculating that approximately one-third of PSE's customers take advantage of automated interactions with the Company, another third have the potential to do so but are "inactive," and the last third are not yet ready to use the automation that GTZ offers.[94] Baldwin thus concludes that "the majority of PSE's customers continue to prefer non-digital ways of conducting transactions with PSE."[95]

127 In its initial brief, PSE argues that Baldwin's analysis is based on a false premise that PSE customers lack digital fluency. Rather, PSE asserts that over 90 percent of its customers are currently utilizing a digital resource provided by GTZ, consistent with the widespread use of technology in the United States.[96] In addition, PSE argues that numerous GTZ services, such as improved IVR, advanced resources for PSE customer service representatives who assist customers over the phone, more coordinated and efficient customer field service, various improvements to customer billing, and better management and use of customer data will benefit all customers, and none will require digital engagement.[97] In its reply brief, PSE argues that Public Counsel failed to demonstrate that any GTZ investment was imprudent, and requests the Commission reject Public Counsel's "extreme position."[98]

128 In its initial brief, Public Counsel argues that requiring ratepayers to pay costs associated with GTZ capital additions before the benefits are achieved would inappropriately place the risk on ratepayers. Public Counsel requests the Commission require PSE to educate

---

[93] Baldwin, Exh. SMB-1CT at 4:15-20.

[94] *Id.* at 9:6-10.

[95] *Id.* at 10:3-5.

[96] PSE Initial Brief ¶ 40.

[97] *Id.* ¶ 41.

[98] PSE Reply Brief ¶ 23.

its customers on the use of digital platforms, monitor PSE's implementation of GTZ, require PSE to engage its advisory committees, and require PSE to file annual reports documenting GTZ's costs and benefits. Public Counsel acknowledged in its reply brief that GTZ offers some efficiencies and customer benefits.

129 TEP does not oppose GTZ, but argues that PSE should use its Low-income Advisory Committee to work on issues related to customer education, and that the Commission should require PSE to file and present biannual reports detailing GTZ deployment at one of the Commission's regularly scheduled open meetings. TEP supports Staff's and Public Counsel's recommendations, or some combination of the two.

Commission Determination

130 We allow the Company's proposed pro forma adjustments related to GTZ through December 31, 2019. As discussed in Section II(B)(3)(i)(a), above, we determine that extending the pro forma period through the end of 2019 for GTZ and other pro forma adjustments is a regulatory tool that is available and appropriate given the relatively short lives of the assets, which, if not captured, may result in lost recovery due to regulatory lag.

131 We are not persuaded by Public Counsel's assertion that customers are not yet benefitting from GTZ. Rather, the Company's data shows that 90 percent of its customers are currently utilizing one or more GTZ digital resource. We agree with several of the parties, however, that PSE should be required to provide more detail about GTZ's performance and metrics. As such, we require PSE to file with its next GRC a report on GTZ that:

- Itemizes and describes each component of the GTZ program placed in service to date;
- Documents, by itemized component, the program's costs and customer benefits;
- Reports on the program's overall performance and metrics; and
- Describes the GTZ components not yet deployed, with estimated in-service dates for each.

132 We also allow PSE to amortize deferred GTZ expense and rate base amounts for the GTZ assets placed in service between July 2018 and June 2019 over three years beginning July 20, 2020. Although the prudency review for GTZ will necessarily be ongoing because it is a multi-phase project, we determine that the investments made through December 31, 2019, were incurred prudently and should be included in rates. As with any large project, we share Public Counsel's concerns that customer benefits must be demonstrated as part of our prudency review. Here, PSE has shown that, thus far, the GTZ assets placed in service are benefitting customers in a variety of ways through improved customer service experiences. Accordingly, we are satisfied that the costs incurred to date have been prudent, but remind the parties that prudency will be revisited each time PSE seeks to include in rates a portion of the GTZ project.

c. *AMI*

133 In 2016, PSE began replacing its Automatic Meter Reading (AMR) meters with AMI meters. In total, PSE estimates it will invest $473 million in its AMI communication network and metering equipment, and that AMI implementation will be completed between 2022 and 2023.

134 In PSE's 2018 ERF Settlement, the parties agreed to, and the Commission approved, a deferral of the following:

- Depreciation expense of AMI investment in the ERF test year (July 1, 2017, to June 30, 2018) and depreciation expense of AMI investments after the test year on an ongoing basis until all such AMI plant in service is allowed or disallowed for recovery. The deferred depreciation expense was booked to a FERC 182.3 Regulatory Asset Account.
- Cost of capital at PSE's authorized ROR on AMI investment in the ERF test year until the Commission makes a determination on the prudency of the underlying investment. The deferred cost of capital was booked to a FERC 186 Deferred Debit Account.

135 The 2018 ERF Settlement also reserved the issue of prudency and recovery of the AMI deferrals for the subsequent PSE GRC or other future proceeding where costs and benefits can be considered. Accordingly, PSE seeks a determination in this proceeding that the decision to implement AMI was prudent, and also seeks approval to recover in rates the deferral amounts described above.[99]

---

[99] Koch, Exh. CAK-1T at 26:12-14.

136 According to PSE witness Gilbertson, AMI is a foundational technology that supports grid modernization, which is necessary to maintain a safe and reliable grid, meet the objectives of the Clean Energy Transformation Act (CETA),[100] and enable PSE and its customers to manage energy in new ways.[101] PSE argues that one of the benefits of installing AMI is the avoided costs of installing and maintaining an obsolete AMR system.[102]

137 PSE witness Koch presents PSE's business case for AMI, claiming that the total benefits associated with avoided AMR investment, Conservation Voltage Reduction (CVR) to provide energy savings, and distribution automation using the AMI communication network are estimated at $668 million over the 20-year life of the AMI assets.[103] Koch contends that the AMI project's present net value is $258 million.[104]

138 Koch argues that it was necessary to replace PSE's AMR infrastructure due to factors such as network equipment failure, a higher than acceptable rate of meter failure, and system obsolescence.[105] Koch claims that installing AMI will have a "nominal total savings of $230 million including capital and [operations and maintenance] investment from avoiding replacement of AMR through 2037."[106]

139 Staff witness McGuire supports the Company's proposals "for recovery of deferred depreciation expense and deferred return on net plant (from prior periods) for AMI investments" as described in the 2018 ERF Settlement.[107] Although McGuire makes no recommendation related to prudency, Staff argues on brief that PSE reasonably determined it needed to replace its AMR infrastructure, reasonably selected AMI from available alternatives, reasonably involved its board and management, and adequately

---

[100] Chapter 19.405 RCW.

[101] Gilbertson, Exh. BKG-1T at 27:15-21.

[102] *Id.* at 18:1-8.

[103] Koch, Exh. CAK-4 at 1:16-2:1.

[104] *Id.* at 2:1-2.

[105] *Id.* at 4:14-5:4; 5:6-9; *see also* Appendix A, PSE 2016 AMI Business Case, at 18.

[106] *Id.* at 18:1-5.

[107] McGuire, Exh. CRM-1T at 27:17-18.

documented its decision-making process in a manner that allowed for regulatory review.[108]

140 Public Counsel witness Alvarez recommends the Commission find that the AMI system investments made during the test year were imprudent and disallow cost recovery on that basis.[109] Public Counsel's proposed disallowance excludes test year plant of $13.8 million, which reduces the revenue requirement by $4.2 million.[110]

141 Alvarez ultimately argues the AMI investment was imprudent because PSE did not consider the $189 million in costs related to prematurely discontinuing AMR, attributed $416 million in CVR benefits to its full AMI deployment even though PSE's own CVR Pilot indicated it could have secured these benefits through selective smart meter placement at a fraction of the cost, and did not conduct stand-alone cost-benefit analyses on the various metering options available, further biasing its decision to install AMI. Public Counsel argues that, taking these factors into account, customers will pay $641 million for the AMI investment, whereas the alternatives available to PSE's existing AMR system would have cost $230 million.[111]

142 Alternatively, Alvarez recommends the Commission "disallow cost recovery for the $126.8 million in book value of the existing metering system replaced prematurely," because PSE failed to include the book value of the legacy system it abandoned to make way for AMI in its cost estimate.[112] In addition, Alvarez argues that PSE did not include approximately $62.5 million in carrying charges that customers will pay on abandoned legacy meter equipment until that equipment is fully depreciated.

143 On rebuttal, PSE witness Koch argues that Alvarez failed to address the obsolescence of AMR meters, and was silent on the diminishing supply of available AMR equipment.[113] Koch reiterates that AMR obsolescence was the primary reason for PSE's decision to

---

[108] Staff Initial Brief ¶ 66.

[109] Alvarez, Exh. PJA-1T at 24:11-12.

[110] *Id.* at 4:15-17. Public Counsel witness Mark Garrett provides the accounting adjustment.

[111] Alvarez, Exh. PJA-1T at 24:14-25:3.

[112] *Id.* at 25:6-8.

[113] Koch, Exh. CAK-6T at 3:19-4:5:3-5.

transition to AMI.[114] Additionally, Koch argues that Alvarez's analysis of failure rates did not consider the complete failure rate data that PSE provided.[115] Koch also disputes the acceptable meter failure rate used in Alvarez's analysis, instead recommending the Commission give more weight to the results provided by PSE's hired consultant.[116]

144 In response to Public Counsel's calculated book value for the undepreciated value of AMR, Koch asserts it is not an accurate reflection of the undepreciated value at the time all AMR meters will be completely removed from service between 2022 and 2023.[117] Further, Koch argues that excluding the AMR book value from the evaluation process does not bias the analysis because, in any alternative scenario, AMR would need to be replaced.[118]

145 With regard to Public Counsel's claim that CVR benefits were overstated and the benefits could be achieved with fewer AMI meters, Koch argues that Public Counsel's position "only makes sense if the sole purpose of PSE's AMI deployment was to achieve CVR."[119]

146 Koch also responds to Public Counsel's argument that it was premature to replace AMR and its corresponding cost-benefit analysis, arguing that Alvarez's $230 million avoided cost is the mathematical difference between maintaining the failing AMR system, which would cost $378 million, and a new AMI system, which would cost $148 million. Koch argues that, because $230 million does not represent the cost of continuing with AMR, it cannot be compared "apples-to-apples" with the cost of deploying AMI.[120]

147 PSE witness Spanos addresses Public Counsel's recommendation not to allow the return of the unrecovered costs of AMR. Spanos observes that "Public Counsel does not contest that legacy meter costs were prudently incurred," and argues that the AMR meters will continue to be in service and benefiting customers "as AMI installations progress through

---

[114] *Id.* at 3:19.

[115] *Id.* at 5:13-14.

[116] *Id.* at 6:3-9.

[117] *Id.* at 9:11-10:6.

[118] *Id.* at 12:9-13.

[119] *Id.* at 14:9:14.

[120] *Id.* at 19:16-20-6.

2023 and, therefore, PSE is entitled to a return of and on these AMR assets while in service."[121]

148 In cross-answering testimony, Staff witness Panco disagrees with Public Counsel that PSE overstates the benefits of AMI.[122] Panco argues that Public Counsel's analysis of the Company's ability to obtain the CVR benefits with significantly fewer AMI meters "fails to consider the increasing failure rate of PSE's older advanced meter readers (AMR) and PSE's need to continue to collect accurate billing data across all customers as a primary objective."[123] Panco argues that Public Counsel also fails to consider or recognize AMI's ability to enable time of use rates, the benefits of two-way communication across the entire network, including increased outage awareness, and the benefits of AMI enabling integration of distributed generation resources and demand side management.[124]

149 TEP does not oppose AMI deployment, but observes that "AMI investments involve substantial costs for equipment, software, and other items while its benefits are still to be fully evaluated."[125] TEP makes two recommendations: (1) the Commission and its Staff should review these costs in relation to the benefits of the technology and ensure that the investments are prudent before being imposed on ratepayers, and (2) consumer protections should be preserved as AMI is deployed, including the introduction of remote disconnection.[126] In its initial brief, TEP recommends the Commission adopt Public Counsel's recommendation to disallow cost recovery for the $126.8 million in book value of the existing metering system to avoid simultaneous customer payments for two metering systems.[127]

150 On brief, Staff argues that Public Counsel's analysis (1) fails to address the operational challenges related to maintaining the AMR system; (2) significantly miscalculates the cost difference between maintaining the AMR network and installing AMI; (3)

---

[121] Spanos, Exh. JJS-4T at 3:3-4, 3:8-11.

[122] Panco, Exh. DJP-4T at 5:11-13.

[123] *Id.* at 5:16-19.

[124] *Id.* at 6:1-7.

[125] Collins, Exh. SMC-1T at 26:14-17.

[126] *Id.* at 26:16-27:6.

[127] TEP Initial Brief ¶¶ 71-72.

miscalculates CVR savings from a partial AMI deployment; and (4) overlooks the potential benefits of AMI, including enabling dynamic pricing structures, improving grid resiliency, and reliability due to increased outage awareness.

151 In its initial brief, Public Counsel argues that PSE should be held accountable for all available benefits of AMI deployment, including those connected to the GTZ program.[128] Public Counsel recommends the Commission disallow $473 million for costs PSE plans to spend to implement AMI because (1) PSE failed to consider the $189 million cost of abandoned equipment customers must pay; (2) PSE improperly attributed $416 million in CVR benefits to its full AMI deployment despite data from its pilot indicating it could have secured those benefits at a much smaller cost; (3) PSE did not conduct stand-alone benefit-cost analyses on the various metering options available; and (4) customers will pay $641 million for the AMI investment after making adjustments for PSE's artificial inflation of benefits and omission of costs, whereas updates and repairs to PSE's existing AMR system would have only cost $230 million.[129]

152 PSE reiterates in its brief that its investment in AMI is necessary to not only replace its failing meter system but to modernize the grid and facilitate the use of needed technologies. PSE argues that Public Counsel ignores the indisputable fact that the AMR system is failing and focuses almost entirely on the financial costs and benefits of AMI. PSE also argues that its AMI investment is overseen by PSE's planning department and does not duplicate any IT investments.[130]

Commission Determination

153 As a threshold matter, we find unpersuasive Public Counsel's argument that PSE prematurely abandoned its AMR system. PSE provided ample testimony and evidence related to the obsolescence of its AMR system and the Company's inability to obtain technical support or procure replacement parts going forward. In addition, the Company provided testimony and exhibits documenting its business case, including each of the systems it considered before it elected to install AMI. As PSE observes, moving to a smart meter platform has become the industry standard, and the Company is

---

[128] Public Counsel Initial Brief ¶ 103.

[129] *Id.* ¶ 137.

[130] PSE Initial Brief ¶ 29.

appropriately on pace to keep up with this evolving technology. Therefore, we determine based on the record evidence that the operational decision to install AMI was prudent.

154 We also decline Public Counsel's request to address the Company's recovery of its AMR investment at this time. Instead, we conclude it is more appropriate to address regulatory treatment of these assets once the transition to AMI is complete.

155 We share Public Counsel's concern, however, that PSE has not yet satisfactorily demonstrated the benefits of the AMI system as a whole. The Company represented at hearing that it is planning to pursue additional benefits, but it has yet to put forth any formal plan or proposal. Instead, the only benefits the Company has cited are billing functions, voltage management – which cannot yet be adequately demonstrated – and remote disconnection capability. As such, PSE has not yet made a showing that would justify authorizing the Company to recover a *return on* any portion of its AMI investment made thus far. Accordingly, we allow into rates the test year AMI costs, deferral for the return of, and pro forma adjustments through December 31, 2019, but continue to require PSE to defer *recovery of the return on* these investments in a deferral account, FERC Account 186 – Miscellaneous Deferred Debits for both Electric and Natural Gas Operations, per the terms of the Settlement Stipulation in the 2018 ERF.

156 Going forward, the Commission will evaluate the portion of AMI investment for which PSE seeks recovery in rates, but will require the continued deferral of the *recovery of the return on* each portion of the investment until the AMI project is complete. Our decision recognizes that PSE will not be able to demonstrate a significant portion of AMI benefits until the system is fully deployed. In light of these circumstances, we will reserve a final determination of prudency on the project as a whole until the AMI installation is complete and all customer benefits can be presented for evaluation. The final prudency determination thus rests on PSE's ability to live up to its promises of multiple customer benefits.

157 At hearing, the Commission referred PSE to a Utility Dive article entitled "Most utilities aren't getting full value from smart meters, report warns," as well as the report the article referenced, which concluded that "[m]any utilities are underexploiting AMI capabilities and attendant benefits, thus missing a key tool to deliver value to their customers and systems."[131] We expect PSE to take great strides to ensure that both the Company and its customers receive maximum value from its AMI system, and we expect PSE will be able to demonstrate that value to the Commission in the near future. We encourage the Company to carefully review the report referenced in the Utility Dive article, which examined whether utilities are leveraging AMI by capturing data on six use cases: time of use rates, real-time energy use feedback for customers, behavior-based programs, data disaggregation, grid-interactive efficient buildings, and CVR or volt/VAR optimization. The Commission is interested in PSE's analysis of the six use cases and whether or how they are applicable, as well additional information or metrics that demonstrate AMI's benefits to customers. Although we share PSE's optimism about the benefits AMI will ultimately produce, we reiterate our expectation that PSE will maximize those benefits.

d. *Data Center Disaster Recovery and Relocation*

158 By the end of 2019, PSE completed the relocation of its two data centers from Bothell and Bellevue to Snoqualmie and Cle Elum, respectively, and completed its application migration.[132] According to PSE witness Hopkins, the data center relocations were part of PSE's Data Center Disaster Recovery (DCDR), a three phase program that includes: (1) replacement of substandard data centers; (2) implementation of disaster recovery capabilities for information technology (IT) systems; and (3) decommissioning of existing data center facilities.[133]

159 The Company contends that data center replacement focused on mitigating a significant risk related to insufficient disaster recovery capabilities by replacing previous data centers with "geographically diverse, highly redundant modular facilities."[134] The previous data centers were located 12 miles apart on the same seismic fault, and the

---

[131] *See Most utilities aren't getting full value from smart meters, report warns*, Utility Dive, Robert Walton (Jan. 13, 2020), *available at* https://www.utilitydive.com/news/most-utilities-arent-getting-full-value-from-smart-meters-report-warns/570249/.

[132] Hopkins, Exh. MFH-1T at 21:9-11.

[133] *Id.* at 19:19-22, 20:1-2.

[134] *Id.* at 12:11-16.

facility in Bothell was located within a flood plain.[135] PSE is requesting recovery of $79.3 million related the DCDR program and construction of the new data centers.

160 Hopkins argues that previous data centers were located too close together, increasing the risk to business continuity in the event of a localized disaster.[136] In addition, Hopkins claims that both facilities lacked the power, redundancy, and cooling requirements needed to ensure safe IT operations, and that the Bothell facility was located on the second floor of an office building, which created structural concerns due to the weight of the IT equipment.[137]

161 As part of the DCDR program, all of the equipment from the previous facilities will be removed and decommissioned in 2019-2020. According to Hopkins, the replacement data centers were completed by the end of 2017, with all modules and network infrastructure ready for application migration. Decommissioning of the old data centers was anticipated for completion in 2019.[138]

162 Hopkins explains that PSE considered three alternatives to replacing the data centers. These alternatives included: (1) fortifying existing data centers; (2) utilizing leased space by co-locating both data centers in shared facilities; and (3) utilizing a combination of co-located leased facilities along with PSE-owned data centers.[139]

163 AWEC recommends disallowing the entire $79.3 million cost of the new data centers. AWEC witness Mullins argues that the concerns PSE presents to justify replacing the data centers existed when PSE originally decided to locate the data centers at their previous sites in Bothell and Bellevue. Mullins observes that PSE became aware of the flooding risk at the Bothell location in 2007, but nevertheless executed a lease for the space to develop the data center in 2009.[140] AWEC argues that, due to PSE's prior knowledge of the business risks associated with the Bothell location, customers should

---

[135] *Id.* at 20:3-12.

[136] *Id.* at 20:3-17.

[137] *Id.* at 19:21-22, 20:9-12.

[138] *Id.* at 20:5-11.

[139] *Id.* at 23:6-23, 24:1-9.

[140] Mullins, Exh. BGM-1T at 39:1-6.

only pay for the original data center costs at Bothell and Bellevue, which they have already done.

164 On rebuttal, Hopkins argues that Mullins overemphasizes the seismic and flood concerns of the previous data centers, and ignores the fact that the previous data centers did not have adequate disaster recovery protections in place. According to Hopkins, those sites are unable to be adapted to today's data center standards or incorporate technological advancements to ensure reliable and secure IT operations.[141] Hopkins argues that Mullins misjudges the asset life of a data center and fails to recognize that PSE customers have fully benefited from the previous data centers, which had reached the end of their useful lives. Hopkins testifies that the Bothell facility served PSE and its customers for nearly a decade, and the Bellevue data center for even longer. As such, Hopkins contends it is now prudent for PSE to transition to facilities that can safely, securely, and reliably meet PSE's IT needs on going-forward basis.[142] Hopkins also highlights that, of the $79.3 million PSE is seeking to recover, $33.2 was spent to acquire and construct the new data centers. The remaining $46.1 million was spent on redesigning PSE's network, server, telecommunications, and cybersecurity architecture required for disaster recovery ($31.2 million), and the configuration, testing, and migration of the systems to the new facilities (14.9 million).[143]

165 In its brief, PSE argues that its reasons for replacing the former data centers are much broader than to mitigate flood risk. PSE contends that data center standards have evolved substantially over the last 10 to 15 years, and that the prior centers could not support accelerated growth, heavier and denser equipment, increased power, redundancy and cooling requirements, or virtualization, and that they did not meet current cyber security and environmental monitoring standards.

166 While AWEC does not contest that requirements related to data center operations have evolved as the Company's operations have become more technology-dependent, it argues in its brief that the Company's previous decisions related to the locations of the Bothell and Bellevue data centers significantly contributed to the expenses PSE now seeks to

---

[141] Hopkins, Exh. MFH-7T at 20:10-22.

[142] *Id.* at 17:13-17.

[143] *Id.* at 5:8-14.

recover from ratepayers. Accordingly, AWEC argues that the Company should bear some of the expense that it now must incur to cure its prior unreasonable decisions.

167 In its reply brief, AWEC renews its recommendation that the Commission deny recovery, at a minimum, of the $33.2 million expense related to the re-siting and reconstruction of the data centers, as well as a portion of the $31.2 million related to the labor associated with relocation.[144]

Commission Determination

168 We find that PSE prudently incurred the costs to relocate its data centers. PSE amply demonstrated that the data centers needed relocation regardless of any flood or seismic concerns. We find persuasive PSE's testimony and evidence demonstrating that the prior centers could not support accelerated growth, increased power, redundancy requirements, virtualization, and environmental monitoring standards. As PSE witness Hopkins testified at hearing, data centers present challenges because they cannot keep pace with technology. Specifically, "the heating and cooling requirements are outpacing them as well as the density [related to] weight requirements."[145] In addition, each facility had exceeded its useful life – the Bellevue data center was in service for 15 years, and the Bothell data center was in service for 10 years.

169 We thus determine that the record evidence does not support AWEC's assessment that PSE's decision was driven primarily by the need to relocate the disaster centers from their previous locations due to preexisting factors. To the contrary, PSE provided a comprehensive description of its needs assessment and decision making process, which we conclude was prudent. Accordingly, we approve this adjustment.

e. *Tacoma LNG Distribution Upgrade*

170 On November 1, 2016, the Commission entered Order 10, Final Order Approving and Adopting Settlement Stipulation in Docket UG-151663 (Order 10). Order 10 approved a settlement stipulation (Settlement Stipulation) that allocated costs, benefits, and liabilities between PSE's gas customers and the shareholders of PSE and its wholly-owned subsidiaries, thereby authorizing PSE to proceed with its planned Tacoma Liquefied Natural Gas (LNG) facility. The facility will be used to supply fuel to Totem Ocean

---

[144] AWEC Reply Brief ¶ 30.

[145] Hopkins, TR 334:10-16.

Trailer Express, Inc. (TOTE), provide fuel for sales to other marine vessels or other purchasers, and serve as a peaking resource for PSE's core natural gas customers.

171 The terms of the Settlement Stipulation required PSE to form a wholly-owned subsidiary named Puget LNG, and provided for allocation of the capital costs of the Tacoma LNG facility between PSE and Puget LNG so that each entity can properly account for its ownership shares of each component of the Tacoma LNG facility. Additionally, the Settlement Stipulation was clear that it provided only the terms and conditions under which PSE may pursue the LNG facility, but did not approve the prudency of the project itself.

172 Under the terms of the Settlement Stipulation, both Puget LNG and PSE own a share of the Tacoma LNG facility. Puget LNG pays the capital and operating costs allocated to it under the agreement based on the proposed use of the facility to produce and sell liquefied natural gas as transportation fuel to TOTE and other customers without being subject to Commission jurisdiction. PSE pays the capital and operating costs allocated to it based on its proposed use of the facility as a peaking resource for its core natural gas customers. PSE's participation is subject to Commission regulation as a "gas company" and "public service company" as defined in RCW 80.04.010(14) and (23). The Settlement Stipulation contains multiple ring-fencing provisions that protect PSE's ratepayers from the unregulated activities of Puget Energy (PSE's parent company) and Puget LNG. Each entity is individually responsible for the performance of its own obligations. All risk, loss, and damage arising out of the ownership, construction, operation, or maintenance of any portion of the Tacoma LNG facility is borne by each entity in proportion to its capital cost allocation as set forth in an attachment to the Settlement Stipulation.

173 In its initial filing in the GRC Dockets, PSE requested recovery for work performed on its distribution system for its Tacoma LNG Project totaling $31.5 million. The distribution system upgrade costs are for work performed between October 1, 2016, (the end of the test year in PSE's 2017 general rate case) and December 31, 2018, (the end of the test year in this proceeding).[146] The costs include four miles of new 16-inch pipe completed

---

[146] Henderson, Exh. DAH-1T at 1:16-20.

and placed in service in October 2017, as well as upgrades to the Frederickson Gate Station completed and placed in service in September 2017.[147]

174 Staff opposes the Company's request for recovery of the Tacoma LNG Project distribution system upgrades, instead recommending the Commission authorize PSE to defer the two completed Tacoma LNG projects until a commercial operation date for the Tacoma LNG facility is established. Staff agrees that the distribution system upgrades are necessary to connect the Tacoma LNG Project to its gas distribution system, but argues that those costs should not be recovered in this proceeding because the Tacoma LNG Project is not yet in service.

175 AWEC requests all costs associated with the 16-inch line upgrade project be deducted through a rate spread adjustment and reallocated to sales customers. AWEC argues that under the Settlement Stipulation, PSE agreed it would not propose any cost allocations associated with the 16-inch line or Bonney Lake lateral improvements for transportation customers. AWEC also agrees with Staff that the distribution system upgrades are necessary to connect the Tacoma LNG Project, but do not yet meet the used and useful standard.

176 On rebuttal, PSE accepts Staff's recommendation to defer costs until the Tacoma LNG Project is finished.

Commission Determination

177 We agree with Staff's proposal, which the Company accepts, to defer the costs associated with Upgrade 1 and Upgrade 3 for recovery until the Tacoma LNG facility is operational. On rebuttal, PSE stated that the Tacoma LNG Facility may be operational as early as March 2021.[148]

178 At hearing, the Commission issued Bench Request No. 6 (BR-6), which posed the following question related to the Tacoma LNG Project:

> Whether Upgrades 1 and 3 are included in rates or deferred, is the Company intending to apply the Common Cost Allocator that was

---

[147] *Id.* at 7:5-8.

[148] Henderson, Exh. DAH-4T at 4:19-20.

> approved as part of the Settlement Agreement in the Final Order approving the Special Contract in Docket UG-151663? If not, why not?

179 On February 18, 2020, PSE responded to BR-6, as follows:

> [PSE] does not intend to apply the Common Cost Allocator to allocate these Tacoma [LNG] distribution upgrades between its regulated businesses and Puget LNG, LLC, as it is not reflective of the relative need for or use of these facilities. In other words, doing so would not be reflective of cost causation. Instead, PSE anticipates including 100 percent of the cost of these facilities in its regulated rate base and then recovering an equitable share of these costs from users of the Tacoma LNG facility through a Commission-approved rate. That rate, and the methodology for determining it, has not yet been finalized.

180 PSE's response is inconsistent with the terms of the Settlement Agreement in Docket UG-151663, which provides:

> In the general rate case proceeding in which PSE seeks to include PSE's Ownership Shares of the Tacoma LNG Facility in general rates, PSE shall (i) identify the final actual capital costs associated with each component of the Tacoma LNG Facility and (ii) calculate the common cost allocator for each of PSE and Puget LNG. PSE's calculation of the common cost allocator shall be consistent with paragraph 26 and Attachment D to this Settlement Stipulation.[149]

181 Paragraph 26 of the Settlement Stipulation presents a table of component ownership shares and both PSE's and Puget LNG's allocators for each share. Attachment D provides an allocation of the projected capital expenditures associated with component ownership share. Under the terms of the Settlement Stipulation, all phases of the Tacoma LNG Project, with the exception of the 16-inch Line and Bonney Lake Lateral Improvements, are subject to the capital cost allocators set out in the Settlement Stipulation.

---

[149] *In the Matter of the Petition of Puget Sound Energy, Inc., for (i) Approval of a Special Contract for Liquefied Natural Gas Fuel Service with Totem Ocean Trailer Express, Inc., and (ii) a Declaratory Order Approving Methodology for Allocating Costs Between Regulated and Non-regulated Liquefied Natural Gas Services*, Docket UG-151663, Order 10, Appendix A, Settlement Stipulation ¶ 28 (Nov. 1, 2016).

182 With respect to costs related to the 16-inch Line, the Settlement Stipulation requires allocation in accordance with the principle of cost causation and must be separately identified and recorded in a subaccount of FERC Account 376. Accordingly, PSE's proposal to include "100 percent of the cost of these facilities in its regulated rate base and then recover[] an equitable share of these costs from users of the Tacoma LNG facility through a Commission-approved rate" is inconsistent with the terms of the Settlement Stipulation with respect to the Frederickson Gate Station, the costs of which must be allocated according to the cost allocators in the Settlement Stipulation.

183 Although the Commission authorizes PSE to defer these costs in this Order, the Company is advised that it must adhere to the capital cost allocators and all other terms of the Settlement Stipulation when it seeks recovery of these costs in a later proceeding. If the Company wishes to deviate from the terms of the Settlement Stipulation, it must renegotiate the capital cost allocator terms with the other parties to the Settlement Stipulation.

f. *SmartBurn*

184 PSE explains that SmartBurn controls were originally installed at the Colstrip Units 3 and 4 to reduce nitrogen oxides (NOx), a pollutant regulated under the federal Regional Haze Rule, by optimizing the combustion process in coal-fired generation plants.[150]

185 According to PSE witness Roberts, Colstrip's owners (Owners)[151] expected additional NOx regulations based on the Federal Implementation Plan (FIP) finalized for the State of Montana in September 2012, which prompted the Owners to begin installing SmartBurn in 2015 in what PSE describes as "a strategic and cost-effective" effort to manage future regulatory obligations.[152]

186 Roberts claims that the Owners intend to use the NOx emissions data received from the SmartBurn controls to determine the scope of the next expected step in NOx reduction,

[150] Roberts, Exh. RJR-1T at 12:17-22.

[151] PSE owns 25 percent of both Colstrip Units 3 and 4. For Unit 3, other owners are Talen (30 percent), Portland General Electric (20 percent), Avista (15 percent) and PacifiCorp (10 percent). For Unit 4, other owners are NorthWestern Energy (30 percent), Portland General Electric (20 percent), Avista (15 percent), and PacifiCorp (10 percent).

[152] Roberts, Exh. RJR-1T at 14:8-16, 15:3-9.

which is installing selective catalytic reduction (SCR).[153] Although SmartBurn is not a replacement for SCR, Roberts argues that the combination of SmartBurn and the associated measured data results in a smaller and less expensive SCR investment, lower future operating costs, lower operating and maintenance (O&M) expenditures, reduction of future capital expenditures, and earlier realization of environmental benefits.[154]

187 Although the Owners did not expect SmartBurn to satisfy all future NOx emission reduction requirements, Roberts contends the Owners believe it is integral to any future control technology, and that it is the most cost-effective way to reduce the "first increment" of NOx.[155] Roberts argues that the earlier SmartBurn installation provides several years of operational data for the eventual installation of SCR or other technology. Roberts explains that SmartBurn was installed during scheduled outages to reduce implementation costs.[156]

188 Finally, Roberts testifies that SmartBurn has met the guaranteed emission rate reduction specified in the contract and that the controls on Units 3 and 4 improved NOx removal by 8 percent.[157] Roberts testifies that the Owners had considered a wide array of alternatives prior to selecting SmartBurn.

189 Staff witness Gomez argues that the Company failed to demonstrate that SmartBurn is necessary, failed to maintain appropriate documentation of its decision to install SmartBurn, and failed to demonstrate the benefits associated with SmartBurn's installation. Gomez testifies that Staff's assessment is informed by the Commission's final order in Avista's 2017 GRC. In that case, the Commission found that Avista failed to provide sufficient information related to its SmartBurn investment, and expressed skepticism that the investment mitigated future compliance obligations.[158]

---

[153] *Id.* at 13:3-6.

[154] *Id.* at 13:18-14:5.

[155] *Id.* at 15:12-17.

[156] *Id.* at 16:8-9.

[157] *Id.* at 17:3-11.

[158] Gomez, Exh. DCG-1CT at 12:13-13:4.

> In its final Order, the Commission concluded that Avista "…provided insufficient information related to its investments at Colstrip Units 3 and 4. The

190 Gomez testifies that, prior to 2015, the Owners anticipated an obligation to install SCR for each Colstrip unit to address Montana's Regional Haze requirements in the 2017 State of Montana Regional Haze Progress Report.[159] However, Gomez argues that the FIP categorizes Units 3 and 4 separately from Units 1 and 2, resulting in separate regulatory requirements.[160] The FIP placed additional emissions control requirements on Units 1 and 2, but not on Units 3 and 4. Gomez testifies that the 2016 agreement to shut down Units 1 and 2 by 2022 resolved the emission limits for those particular units. Further, Gomez notes that the Owners agreed to other NOx and SO_2 limits after SmartBurn was installed on Unit 2.[161] Gomez highlights that the State of Montana's 2017 Regional Haze Progress Report Update concluded that the state's FIP was adequate and did not require substantive revision, and that the SmartBurn installation on Units 3 and 4 was voluntary.[162]

191 Gomez also argues that PSE failed to maintain appropriate documentation memorializing the Owners' decision to install SmartBurn.[163] Finally, Staff argues that PSE failed to demonstrate the benefit of installing SmartBurn.[164] Gomez asserts that PSE's claim of an 8 percent improvement for NOx removal was an expected, not an actual, improvement.[165] Furthermore, Gomez testifies that PSE's only source of information was a conversation

> Company presents an argument for the SmartBurn investment on rebuttal, but it does not dispel Staff's primary concern: that the investment does not appear to have been required by any state or federal laws. Any future compliance obligations that the SmartBurn investment might have helped mitigate are purely speculative, and it is unclear whether the decision by the Colstrip owners to proactively take on future assumed compliance obligations reflected that retirements of other coal units in the region might reduce any compliance obligations for Colstrip Units 3 and 4."

Wash. Utils. & Transp. Comm'n v. Avista Corp., Dockets UE-170485 & UG-170486, Order 07 ¶ 204 (Apr. 26, 2018). Avista's SmartBurn investment met neither Avista's nor Staff's materiality threshold in Avista's 2017 GRC.

[159] Gomez, Exh. DCG-1CT at 15:9-14.

[160] *Id.* at 15:17-21.

[161] *Id.* at 16:3-7.

[162] *Id.* at 16:11-17.

[163] *Id.* at 17:11-18:3.

[164] *Id.* at 18:6-20:4.

[165] *Id.* at 18:6-16.

with Talen, the units' operator.[166] Although Gomez does not believe that SmartBurn's operating status is relevant to the Company's decision, Gomez found evidence of a decrease of only 0.01 lbs/MMbtu in NOx levels.[167] Gomez also asserts that Roberts provides no evidence to support the claim of lower O&M and capital costs.[168]

192 Roberts counters that the Owners took a gradualist approach, and that installing SmartBurn was the first in a multistep process to address NOx emissions.[169] Roberts argues that installing SmartBurn controls will provide years of operational data to inform future NOx controls and create options for more cost-effective technology to be installed in place of SCR.[170]

193 Roberts disputes Staff's assertion that SmartBurn is not currently providing any benefit to ratepayers.[171] Roberts claims that SmartBurn has met the guaranteed emission rate reduction, improved NOx removal by 8 percent at Units 3 and 4, and demonstrated further emission reductions at Unit 2.[172] Roberts admits that the NOx emissions at Unit 3 are more modest than the reductions at Unit 2 but counters that installing SmartBurn was just the first in a multi-step process to reduce NOx emissions at Units 3 and 4. Roberts also argues that Staff should have relied on the 30-day rolling average for NOx emissions compliance limits rather than using a five-year rolling average because a 30-day rolling average demonstrates that each unit had periods when it achieved 25 percent NOx emission reductions.[173]

---

[166] *Id.* at 18:12-16.

[167] *Id.* at 19:5-14.

[168] *Id.* at 18:20.

[169] Roberts, Exh. RJR-14T at 3:14-4:7.

[170] *Id.* at 4:8-20.

[171] *Id.* at 5:15-16.

[172] *Id.* at 5:15-6:12.

[173] *Id.* at 7:6-8:15.

194 Finally, Roberts argues that it was "fortuitous" that the Owners pursued a gradualist approach to NOx reductions in light of CETA.[174] Roberts concedes, however, that if PSE knew then what it knows now, it would not have invested in SmartBurn.[175]

195 AWEC witness Mullins agrees with Staff's assessment and includes Staff's adjustment in his revenue requirement calculation.[176]

196 In its brief, Staff argues that PSE failed to meet its burden to demonstrate that there was a need to acquire SmartBurn, and failed to identify any contemporaneous documentation of its decision. As such, Staff recommends disallowing recovery of the $7.2 million investment.

Commission Determination

197 We agree with Staff and AWEC that PSE failed to demonstrate that the costs related to PSE's SmartBurn investment were prudently incurred.[177] When Avista sought recovery of its investment in SmartBurn in its 2017 GRC, we held that it had provided insufficient information to dispel the concern that the investment was not required by any state or federal laws. PSE concedes as much in this proceeding. Accordingly, we agree with Staff that the Company (1) failed to demonstrate that SmartBurn is necessary and (2) failed to maintain appropriate documentation of its decision to install SmartBurn.

198 First, the Company did not demonstrate, nor does it claim, that installing SmartBurn was necessary. On rebuttal, Roberts concedes that no federal law requires SmartBurn. Roberts explains that the Owners decided to install SmartBurn in response to ongoing litigation against Colstrip, the fact that plants in other states were required to install SCR, and based on their belief that the entire plant would run for the next two decades.[178] We determine that ratepayers should not be required to compensate the Company for the costs of its litigation strategy or for its erroneous speculation.

---

[174] *Id.* at 10:3-11:5.

[175] *Id.* at 11:1-5.

[176] Mullins, Exh. BGM-8T at 12:13-15.

[177] Commissioner Balasbas dissents on this decision.

[178] Roberts, Exh. RJR-14T at 2:25-3:6.

199 Second, according to Staff, PSE did not produce any contemporaneous documents or evidence identifying which future regulatory obligations were contemplated when PSE's management decided to install SmartBurn. PSE failed to rebut this allegation. Gomez further testifies that the Company should have documentation of its decision as required by the Colstrip Ownership and Operation Agreement.[179] We agree. We note, however, that no such documentation exists. For these reasons, we disallow the SmartBurn pro forma adjustment, which reduces the electric revenue requirement by approximately $1.1 million.

ii. Other Pro Forma Additions

a. *HR TOPS*

200 PSE describes its human resources technology transformation project, HR TOPS, as a three-year project to replace PSE's legacy human resources systems in an effort to improve the Company's ability to hire qualified candidates, create and automate reports to improve efficiency, implement self-service and mobile capabilities, integrate disparate systems, and modernize underlying modules scheduled to become obsolete within the next few years.[180]

201 Although HR TOPS did not meet PSE's materiality threshold, PSE included it as part of a larger decision to include adjustments that were close to the threshold for short-lived assets that it claims warrant inclusion as pro forma adjustments. HR TOPS is a pro forma adjustment for software with an estimated total cost of $10.3 million that was placed in service in June 2019.

202 PSE witness Hopkins provides a Corporate Spending Authorization (CSA) for this project, and describes the alternatives that were evaluated prior to selecting the replacement for PSE's legacy human resources systems.[181] PSE prioritized its decision based on whether the system (1) allowed all services to be performed on a single platform; (2) was easy to use (including mobile functionality); (3) improved analytics; (4)

---

[179] Gomez, Exh. DCG-1CT at 17:11–18:3.

[180] Hopkins, Exh. MFH-1T at 32:8-20.

[181] *See* Hopkins, Exh. MFH-6.

aligned with IT technology principles and low total cost of ownership; and (5) had potential to support future functionality in a single product suite.[182]

203 Staff and AWEC oppose this adjustment on the basis that it does not meet Staff's proposed materiality threshold. Public Counsel opposes this adjustment without specifying the basis for its objection.[183]

Commission Determination

204 We determine that allowing this pro forma adjustment is reasonable because the actual costs of the asset are known and measurable, and the HR TOPS software, which was placed in service in January 2019, is used and useful. Additionally, PSE provided reasonable testimony and evidence, including contemporaneous documentation that describes and supports its decision making process. Accordingly, we find that the costs of the HR TOPS investment were prudently incurred. Like other short-lived investments, we recognize that the Company is at risk of losing the ability to recover its costs absent deferred accounting treatment or inclusion in rates on a pro forma basis. Allowing the pro forma adjustment through to December 31, 2019, appropriately remedies this issue.

205 Staff and AWEC oppose this adjustment because it fails to meet Staff's proposed materiality threshold, which we decline to adopt here. As we explain in Section II(B)(7)(i), below, we evaluate pro forma adjustments on an individual basis using several criteria, including the length of the life of the asset, whether the actual costs are known and measurable, and whether the asset is used and useful. Based on our analysis of these criteria, we approve the pro forma adjustment for HR TOPS.

---

[182] Hopkins, Exh. MFH-1T at 33:24-13.

[183] Public Counsel recommends that "post-test year adjustments be limited to the stated pro forma period on an AMA basis." *Id.* at 16:17-18. Public Counsel opposes 19 electric pro forma adjustments (*see* Garrett, Exh. MEG-3r) and 21 natural gas pro forma adjustments (*see* Garrett, Exh. MEG-4r) without specifying the basis therefor. Accordingly, the Commission must infer whether Public Counsel contests those adjustments on the basis that they extend beyond the pro forma period ending June 30, 2019, or because they are valued on an EOP, rather than an AMA, basis. Garret explains that Public Counsel's adjustment to Tax Benefit of Interest (6.04 EP and GP) is based on adjustments Public Counsel recommends to rate base. "Those adjustments reduce rate base, which in turn reduces the proportion of long-term debt interest allocable to the electric and gas utilities, effectively increasing income tax expense and reducing net operating income." Garrett, Exh. MEG-1T at 19:18-20:3.

b. *High Molecular Weight Cable Replacement*

206 PSE explains in its direct case that it invested $340 million in electric reliability and resiliency work between October 1, 2016, and December 31, 2018, which included investments in replacing High Molecular Weight (HMW) cable.[184] According to PSE witness Koch, PSE invested $113 million to replace approximately 315 miles through 883 projects of HMW direct-bury cable that were prone to failure.[185]

207 HMW cable was first installed prior to 1965, at which time it had an expected life of 40-60 years. However, cable installed prior to 1982 began failing much earlier than expected, which led PSE to implement a remediation program in the early 1990s to address the failing cable. In 2016, PSE began proactively replacing failing cables to prevent outages.[186] According to PSE, it has seen a 38 percent reduction in the number of cable-caused outages since 2015, and PSE's system-level SAIDI has decreased by over four minutes from 2015 to 2018 due to replaced HMW cable.[187]

208 Staff and AWEC oppose this adjustment on the basis that it does not meet Staff's proposed materiality threshold. Public Counsel opposes this adjustment without specifying the basis for its objection.

Commission Determination

209 We find that including this pro forma adjustment through to December 31, 2019, is reasonable. The actual costs of the project are known and measurable, and the HWM cable, which was placed in service between January 1 and December 31, 2019, is used and useful. Additionally, we find that the costs were prudently incurred. PSE presented contemporaneous documentation that describes and supports its decision making process, which was reasonable and thorough. Staff and AWEC oppose this adjustment because it fails to meet Staff's proposed materiality threshold, which we decline to adopt. As we explain in Section II(B)(7)(i), below, we evaluate pro forma adjustments on an individual basis using a number of criteria, including whether the actual costs are known and

---

[184] Koch, Exh. CAK-1Tr at 17:7-9.

[185] *Id.* at 26:17-19.

[186] *Id.* at 26:21-27:4.

[187] *Id.* at 27:6-9.

measurable and the asset is used and useful. Based on our analysis of these criteria, we approve the pro forma adjustment for PSE's HMW cable replacement.

c. *Public Improvement*

210 PSE explains in its direct filing that it will incur $13.6 million in electric and $6.3 million in natural gas expenditures through June 30, 2019, in response to requests by municipalities to relocate facilities as specified in jurisdictional franchise agreements and other public improvement projects.[188]

211 PSE witness Koch testifies that franchise agreements allow PSE to locate facilities on public rights of way. When road or other transportation projects change rights of way, PSE is required to relocate those facilities, generally at its own cost.[189]

212 PSE's proposed Public Improvement pro forma adjustment increases both electric and natural gas rate base for post-test year additions to plant placed in service between January and March 2019, and for additions forecasted to be placed in service between April and June 2019.[190]

213 Staff and AWEC oppose this adjustment on the basis that it does not meet Staff's proposed materiality threshold. Public Counsel opposes this adjustment without specifying the basis for its objection.

Commission Determination

214 We accept PSE's proposed pro forma adjustment for its Public Improvement projects. Although we decline to adopt any of the parties' proposed materiality thresholds in this case, PSE correctly observes that our decision here is consistent with the Commission's decision in Avista's 2017 GRC. In that case, we allowed a pro forma adjustment for public improvement projects, recognizing that projects requiring the Company to relocate its facilities should be included as a pro forma adjustment regardless of whether they fall below an established threshold because they "provide tangible value to ratepayers."[191]

---

[188] *Id.* at 56:15-19.

[189] *Id.* at 12:6-10.

[190] Free, Exh. SEF-1Tr at 58:8-15.

[191] *Wash. Utils. and Transp. Comm'n v. Avista Corp. d/b/a Avista Utils.*, Dockets UE-170485, *et al. (Consolidated)*, Order 07 ¶ 201 (Apr. 26, 2018).

215 Accordingly, we allow PSE to recover the costs associated with these projects, which we conclude were prudently incurred. PSE presented contemporaneous documentation demonstrating that these projects were required by municipalities, and thus were outside the Company's control. In addition, the actual costs of the public improvement projects are known and measurable. Finally, the post-test year additions to plant were placed in service between January and December 2019, and are therefore used and useful.

iii. End of Period Rate Base Valuation

216 PSE proposes an adjustment to restate rate base from an Average of Monthly Averages (AMA) basis to an End of Period (EOP) basis.[192] PSE also proposes to restate depreciation from an AMA to EOP basis, which includes related adjustments to accumulated depreciation and deferred taxes.[193]

217 PSE argues that the use of AMA balances for rate base requires that plant be in service prior to the start of the test year in order for the investment to be fully reflected in rates.[194] By contrast, reflecting rate base on an EOP basis provides a "more representative picture of the plant and associated depreciation expense in place during the rate effective period" because it is based on the actual plant values in service and providing benefits to customers at the end of the test year.[195]

218 PSE witness Free testifies that PSE's test year rate base was developed using 13-month historical AMA balances that ended December 31, 2018. The restating adjustments convert rate base and depreciation to EOP balances as of December 31, 2018.[196]

219 PSE argues that EOP rate base is appropriate for this GRC because the Commission recognizes it as a tool to address regulatory lag.[197] PSE further contends that the

---

[192] AMA to EOP Rate Base Adjustment 6.18 ER (electric restating) and 6.18 GR (natural gas restating).

[193] AMA to EOP Depreciation Adjustment 6.19 ER (electric restating) and 6.19 GR (natural gas restating).

[194] Free, Exh. SEF-1Tr at 40:20-22.

[195] *Id.* at 40:16-20.

[196] *Id.* at 40:10-13.

[197] *Id.* at 40:15-16.

Commission has supported the use of EOP rate base in previous GRCs, and allowed EOP treatment in PSE's 2013 expedited rate filing.[198]

220 PSE claims it is experiencing regulatory lag related to its "traditional pipes and wires business" and an increased need for IT infrastructure investments.[199] Free argues that using EOP rate base will partially address the Company's claimed earnings erosion because "it shortens the time frame between when the investment has been placed in service and when the investment is included in rates."[200]

221 Free also argues that spending on IT investments contributes to the Company's earnings erosion due to their shorter useful lives because short-lived assets have a greater impact on earnings erosions than typical transmission and distribution investments with longer lives.[201]

222 Staff agrees with PSE's recommendation to value rate base on an EOP basis with the exception of investor-supplied working capital, discussed in more detail in Section II(B)(3)(iv), below.[202]

223 Public Counsel opposes PSE's EOP adjustment, arguing instead that post-test year additions to rate base should be limited to the pro forma period on an AMA basis.[203] Thus, Public Counsel's recommendations adjust plant in service, accumulated depreciation, accumulated deferred income taxes, and depreciation expense to an AMA basis for the pro forma period ending June 30, 2019.[204]

---

[198] *Id.* at 41:1-12. *See Wash. Utils. and Transp. Comm'n v. Puget Sound Energy*, Dockets UE-170033 & UG-170034, Order 08 ¶ 326 (Dec. 5, 2017).

[199] Free, Exh. SEF-1Tr at 41:13-14.

[200] *Id.* at 42:14-16.

[201] *Id.* at 43:1-16. Free also refers to PSE witness Hopkins's testimony for a broader discussion on utilities' claims that they must continue to rely on technology solutions that they say are now a fundamental part of utility services. *See also* Free, Exh. SEF-1Tr at 44, Table 7.

[202] Steward, Exh. CSS-1T at 3:6-8.

[203] Garrett, Exh. MEG-1T at 16:17-18.

[204] *Id.* at 17:6-10.

224 Public Counsel witness Garrett testifies that Public Counsel's adjustments increase rate base by $121.4 million for electric and $117.6 million for natural gas. According to Garrett, these adjustments also impact related depreciation and income tax expenses.[205] Public Counsel explains that its recommendation replaces several of PSE's proposed adjustments including "restating end of period adjustments to plant and depreciation expense . . . as well as the rate base components of the attrition adjustment."[206]

225 In its initial brief, PSE argues that Public Counsel provides no rationale or support for its recommendation, and notes that no other party opposes the use of EOP rate base.[207] In its reply brief, PSE argues that AMA would result in PSE experiencing a 45 percent delay or loss of recovery for its IT assets.

226 In its brief, Public Counsel argues that PSE has not established that this "preferential rate base treatment" is needed.[208]

Commission Determination

227 We exercise our discretion to value rate base on an EOP basis, recognizing that it is both an important and appropriate tool to use in this case to address PSE's concerns regarding regulatory lag and the nexus between earnings erosion and short-lived assets. RCW 80.04.250 unequivocally authorizes the Commission to provide for changes to rates using any "standard, formula, method, or theory of valuation reasonably calculated to arrive at fair, just, reasonable, and sufficient rates." We do not accept Public Counsel's arguments to the contrary.

228 The Commission continues to view EOP rate base as one of many tools available to address regulatory lag when a sufficient showing has been made that, absent the use of EOP rate base, a utility will experience losses. Here, the record evidence supports such a finding and we determine that it is appropriate under the circumstances presented by this case. PSE has provided ample documentation of its IT investments, which typically have much shorter lives and are thus at risk of under recovery. Accordingly, valuing rate base

---

[205] *Id.* at 17:14-18.

[206] *Id.* at 18:1-9.

[207] PSE Initial Brief ¶ 97.

[208] Public Counsel Initial Brief ¶ 55.

on an EOP basis is an appropriate tool to address this issue and provide PSE with an adequate opportunity to earn its authorized rate of return.[209]

iv. Investor Supplied Working Capital

229 Staff recommends the Commission require PSE to value ISWC on an AMA basis despite its recommendation to value the remainder of rate base on an EOP basis.[210] Staff witness Steward testifies that balance sheet and income statement accounts are cumulative totals for a given time frame, and ISWC calculates the lag between revenue and expenses. Therefore, according to Steward, each month has a different lag.[211] As such, Steward contends that EOP valuation creates a misleading picture of PSE's ISWC needs because it provides only a one-month snapshot that does not necessarily represent an otherwise fluctuating test period.[212] In addition, Steward argues that AMA valuation is more appropriate in this context because ISWC is a calculation, not an account, and "consistency within the financial statements is not violated by using one convention for ISWC and a different convention for financial statement accounts."[213] Steward agrees with the use of EOP for valuing the remainder of rate base even if ISCW is valued using AMA.[214]

230 On rebuttal, PSE accepts Staff's recommendation to include ISWC on an AMA basis.[215]

Commission Determination

231 We decline to adopt Staff's recommendation and instead accept PSE's original proposal to value all components of rate base on an EOP basis. In addition to the reasons discussed in Section II(B)(3)(iii), above, EOP provides the most balanced and accurate representation of rate base value during the rate effective period in this case. We are also not persuaded that Staff's characterization of ISWC as a "calculation" presents a

---

[209] Our decision resolves any and all adjustments that Public Counsel opposes on the basis that the adjustment was valued on an EOP, rather than an AMA, basis.

[210] Steward, Exh. CSS-1T at 3:6-8.

[211] *Id.* at 9:13-18.

[212] *Id.* at 10:1-5.

[213] *Id.* at 10:6-10.

[214] *Id.* at 9:20-21.

[215] Free, Exh. SEF-1Tr at 70:3-4.

compelling reason to value portions of rate base differently because that "calculation" provides for all other balance sheet accounts not already accounted for in rate base and cost of capital. Rather, our preference for the purposes of this proceeding, and the proposal we adopt, is to value all components of rate base consistently and using a method that most accurately reflects rate base values in the rate effective period. By way of guidance, the parties should focus their efforts in future proceedings on demonstrating how their proposed valuation best reflects ISWC during the rate effective period.

v. Power Costs

232 The Company's currently authorized power cost rates were established in PSE's 2017 GRC as part of a multiparty settlement. In its initial filing, the Company estimates $743.5 million in power costs for the rate year, which is 4.5 percent higher than rates set in 2017.[216]

233 PSE witness Wetherbee testifies that the primary drivers of the power cost increase are (1) two new power purchase agreements (PPAs) to serve Green Direct customers; (2) a scheduled increase in the contract rate for the Coal Transition Power Purchase and Sale Agreement with the TransAlta Centralia Generation plant; (3) an increase in gas transportation costs on Northwest Pipeline and Westcoast Energy pipeline; (4) Bonneville Power Administration transmission contracts; and (5) increases to other power supply expenses.[217] According to Wetherbee, those cost increases are partially offset by lower fuel costs for PSE's gas-fired generation resources.[218]

234 Staff's adjustments reduce the Company's power costs by approximately $8 million and reduce the revenue requirement by approximately $10.7 million.[219] In addition to this downward revision of the authorized baseline, Staff requests that the Commission exclude major maintenance expenses at Colstrip that will occur in the rate year, but allow PSE to defer those costs as they are incurred for consideration in a future rate case filing.

---

[216] Wetherbee, Exh. PKW-1CT at 3:20-4:1.

[217] *Id.* at 4:2-15.

[218] *Id.* at 4:16-19.

[219] Liu, Exh. JL-1CT at 30:15-17.

Among other proposals, Staff recommends the following power cost adjustments, which remain contested by the Company:[220]

- Restoration of wind resource capacity factors in the Aurora model rate year simulation;
- Removal of common costs allocated to Colstrip Units 3 and 4 due to the closure of Units 1 and 2; and
- Restoring 80 separate runs for every year in the water record in the Aurora model.

Public Counsel contests the inclusion of the two new PPAs to serve Green Direct customers on that basis that neither is in service and participating customers are not currently receiving benefits.

235 On rebuttal, PSE included a power cost update that projects rate year costs of $771 million, a $27.5 million increase (3.7 percent) from its initial filing and an increase of $71.8 million (10.3 percent) from current rates.[221] The proposed rates include both adjustments on rebuttal and updates to power costs according to the process to which the parties agreed at the prehearing conference.[222]

236 PSE also requests that the Commission adopt Staff's proposed deferral in the event that it does not allow PSE to continue to amortize major maintenance events in rates.[223]

237 Finally, PSE requests that the Commission include replacement power costs if it adopts Public Counsel's proposal to remove the Green Direct PPAs from the rate-year power

---

[220] *Id.* at 29:17. The removal of SmartBurn is addressed in Section II(B)(3)(i)(f), *supra*; the removal of replacement power costs associated with the 2018 Colstrip Outage in the amount of $11.7 million is required by the Commission's final order in Docket UE-190882, and was addressed in Final Order 05 in Docket UE-190324 related to PSE's Power Cost Adjustment mechanism.

[221] Wetherbee, Exh. PKW-34CT at 2:13-20. The proposed rates include both adjustments on rebuttal and updates to power costs, as agreed to by the parties at the pre-hearing conference and memorialized in Order 02.

[222] *Id.* at 24:3-25:35:6-9.

[223] Roberts, Exh. RJR-14T at 14:14-17.

costs. Based on PSE's proposed power costs on rebuttal, PSE estimates the net power cost reduction would be $13.1 million.[224]

238 We address each of the contested issues related to power costs in turn.

a. *Capacity Factors of Wind Resources in AURORA*

239 In its 2011 GRC, PSE used updated wind forecasts developed in 2010 by DNV Global Energy Concepts, Inc., for two of its facilities (2010 Forecasts). The 2010 Forecasts were incorporated into rates approved in PSE's 2011 GRC, PSE's 2013 Power Cost Only Rate Case, PSE's 2016 Power Costs Update, and PSE's 2017 GRC. PSE subsequently retained Vaisala Corporation (Vaisala) to develop 2016 wind forecasts based on several years of actual data for PSE-owned resources,[225] and acquired a 2016 wind forecast for the Klondike III wind power project from Avangrid Renewables, LLC, the facility owner. Based on its analysis of the actual generation data for all years the resources have been in place relative to the 2010 Forecasts, PSE argues that actual generation was consistently below forecasted generation for all wind resources. PSE also argues that the 2010 Forecasts did not reflect historical data currently available or employ current forecasting methodologies.[226] PSE contends that the new forecasts provide the best, most current estimate of the long-term expected energy production for each resource.[227]

240 PSE explained that it shaped the wind generation for calculating rate year power costs using the 2016 monthly wind forecasts based on default hourly shapes in the AURORA model. This process is distinguishable from past proceedings in which PSE used average hourly wind volumes provided with forecasts, which PSE claims do not reflect the variability of wind generation ranging from zero to full output.

241 Staff argues that PSE is inappropriately attempting to de-rate its wind facilities, and recommends the existing wind resource capacity factors be maintained for two reasons. First, Staff is skeptical of PSE's claim that its lower-than-expected wind resource

---

[224] Wetherbee, Exh. PKW-34CT at 22:9-23:10.

[225] The Hopkins Ridge Wind Facility, the Wild Horse Wind Facility, the Wild Horse Wind Facility Expansion, and the Lower Snake River Wind Facility.

[226] Wetherbee, Exh. PKW-1CT at 71:13-72:8.

[227] *Id.* at 72:8-12.

performance is entirely attributable to bad forecasting.[228] Staff cites the U.S. Department of Energy's 2018 Wind Technologies Report (DOE Report), which stated that average wind resource capacity factors in the western region of the U.S. was 36.6 percent in 2018. Staff notes that all of PSE's wind projects' capacity factors fall below the western region average benchmark.[229] Second, Staff disputes the accuracy of Vaisala's forecasts. According to Staff, Vaisala did not actually use 10 years of data as PSE claims, instead using only 80 months of observed, normalized production data without explaining which months were used and why. Staff further criticizes the Vaisala data as "stale."[230]

242 Staff ultimately recommends that the Commission impose a moratorium on capacity factor changes in the AURORA model until PSE explains why its existing wind resources "consistently over-promise, yet under-deliver."[231] Specifically, Staff requests that the Commission require PSE to explain its wind resource performance in the context of its annual wind resource O&M expenditures in its next Integrated Resource Plan.[232]

243 On rebuttal, PSE disputes Staff's claim that the Company is proposing to de-rate its wind resources, instead claiming the Company is updating its forecasts based on historical production.[233] Wetherbee argues that PSE's 2016 Vaisala wind forecasts are more current than Staff's, which rely on PSE's older analysis, and that they utilize data from actual operations rather than projected production.[234] Further, Wetherbee argues that Staff incorrectly stated that Vaisala excluded 48 months of production. Although Vaisala excluded some historical data when developing forecasts for Hopkins Ridge, Wetherbee claims it excluded only 30 months of production.[235] According to Wetherbee, Staff relied

---

[228] Gomez, Exh. DCG-1CT at 39:15-16.

[229] *Id.* at 40:7-19.

[230] *Id.* at 39:18.

[231] *Id.* at 40:4.

[232] *Id.* at 40:16-41:12.

[233] Wetherbee, Exh. PKW-34CT at 15:2-3.

[234] *Id.* at 13:14-14:5, at 17:3-10.

[235] *Id.* at 15:6-15.

on an old version of the Vaisala forecast from the 2017 GRC, which contained errors that the Company later corrected.[236]

244 Wetherbee testifies that the first eight months of operation were excluded because the plant was "breaking-in," that 15 months were excluded due to low wind availability, and that seven months were not analyzed. Wetherbee notes that some data for each of the PSE-owned wind facilities was also excluded from the forecasts.[237]

245 PSE next argues that Staff inappropriately relies on the DOE Report to support its assertion that PSE's facilities underperform. According to Wetherbee, the Company's facilities, built between 2005 and 2012, are not comparable to facilities built between 2014 and 2017 because newer facilities operate at higher capacity factors due to technological advances. [238] PSE argues that the DOE Report offers a more reasonable comparison point of 29.4 percent for average capacity factors for projects built in Washington between 1998 and 2017, which is only slightly higher than PSE's 28.8 percent average.[239]

246 In its brief, Staff argues that PSE used flawed, outdated forecasts, and failed to include with its proposal to de-rate its wind fleet in AURORA any evidence ruling out maintenance practices, turbine degradation, or other possible factors that may contribute to declining wind output.[240] Staff notes that PSE's proposal increases power costs by $1 million, and requests the Commission require PSE to engage with Staff in a collaborative exercise "to deliver one, principled solution and methodology to the Commission to address this common problem among the electric utilities."[241]

---

[236] *Id.* at 16:6-9.

[237] *Id.* at 15:6-15.

[238] *Id.* at 18:3-9.

[239] *Id.* at 19:3-11.

[240] Staff Initial Brief ¶ 77.

[241] *Id.* ¶ 82. Staff explains that it is examining this same issue in the Avista Power Supply Modeling Workshop, and suggests that existing work in that matter could be leveraged to arrive at "a statistically reliable, principled solution that is broadly applicable to all companies and recognizes the reality of long-range variability in wind generation, while fairly allocating renewable generation risk between the companies and ratepayers." *Id.*

247 PSE argues that it appropriately updated the wind forecasts for its owned wind plants and for its Klondike III PPA based on more up-to-date information. PSE criticizes Staff's reliance on "stale wind forecasts" from 2007 and 2010 that are not based on data from project operations,[242] but were instead prepared before the plants were built. PSE argues it has successfully rebutted Staff's objections to its updated wind forecasts, and requests that the Commission accept them.

Commission Determination

248 We accept PSE's updated wind resource capacity factors because they are based on the most recent information available and more accurately represent the facilities' lower-than-expected output than have previous forecasts. Our decision to accept the Company's updates, however, does not excuse the Company's failure to investigate other possible causes of declining output at these facilities. Rather, we accept the Company's updates as the most recent and most reliable information available to the Commission for power cost setting purposes.

249 Although we agree with Staff that the Company should investigate the root cause of its declining output with the dual goal of generating more accurate forecasts and producing more wind power, we decline to adopt Staff's recommendation to impose a moratorium on capacity factor changes in the AURORA model. We do, however, expect PSE to work collaboratively with Staff prior to its next GRC to examine whether other issues may be contributing to declining output at its facilities, including maintenance practices and turbine degradation.

b. *Removal of Colstrip Unit 4 Major Maintenance Costs for 2020*

250 In its initial filing, PSE explains that the rate year includes a planned overhaul of Colstrip Unit 4 in 2020, as projected in the plant operator's budget.[243] PSE proposes to amortize this cost over 36 months. PSE includes an annual amortization expense for Colstrip Unit 4 major maintenance, as described in Staff witness Liu's confidential response testimony, which is scheduled for June 2020.[244]

---

[242] PSE Initial Brief ¶ 84.

[243] Roberts, Exh. RJR-1T at 26:1-9.

[244] Liu, Exh. JL-1CT at 31:11-15.

251 The all-party settlement in PSE's 2014 Power Cost Only Rate Case (PCORC) required that major maintenance for Colstrip would be amortized over three years and included in rates based on budgeted expenditures and the estimated timing of the event.[245] Staff, however, recommends departing from 2014 PCORC method because of the special circumstances surrounding the aging Colstrip units. Staff is concerned that Talen, the Colstrip operator, and the Company are over-estimating the projected costs, and cites two examples from the 2017 GRC where projected major maintenance costs at Colstrip were more than twice the amount of the actual costs.[246]

252 Although Staff does not challenge the prudency of the previous maintenance investments, Staff witness Liu contends that the "the magnitude of variance between the budget and actual cost is alarming."[247] Liu hypothesizes that, due to the age and uncertain economics of Units 3 and 4, the scope of future planned major maintenance may be scaled back. Liu notes that the 2020 budget for Colstrip was not finalized at the time Staff filed its testimony.[248] Liu acknowledges that PSE is likely to incur some level of major maintenance for Unit 4 in 2020, and thus proposes to allow the Company to defer the costs for recovery in the Company's next GRC.[249]

253 On rebuttal, PSE disagrees with Staff's recommendation to defer inclusion of the amortization of the major maintenance events scheduled for Unit 4.[250] According to PSE witness Roberts, the deviation cited by Staff from budgeted to actual costs for major maintenance at Units 1 and 2 is wholly unrelated to Units 3 and 4.[251] Roberts argues that Units 1 and 2 are separate facilities subject to different ownership structures, operations agreements, and expected lives. Furthermore, Roberts contends that the consent decree for Units 1 and 2 entered into in the second half of 2016 modified the 2017 and 2018 budget.[252] According to Roberts, the average variance between budget and actuals for

---

[245] *Id.* at 31:5-8.

[246] *Id.* at 32:11-33:2.

[247] *Id.* at 33:3-5.

[248] *Id.* at 33:13-34:2.

[249] *Id.* at 34:6-10.

[250] Roberts, Exh. RJR-14T at 12:4.

[251] *Id.* at 12:7-13:2.

[252] *Id.* at 12:7-13:2.

planned outages to Units 3 and 4 in 2014 and 2016 were only 2.45 and 1.7 percent, respectively.[253]

254 Roberts asserts that the budgeting process for Units 3 and 4 is more complicated than Units 1 and 2 because it has six owners, and PSE will continue to rely on the power from Units 3 and 4 through 2025. Additionally, Roberts argues that major maintenance is routine and necessary to ensure the safety and reliability of the units. However, if the Commission does not allow PSE to continue to amortize major maintenance events in rates, it requests the Commission adopt Staff's proposed deferral.[254]

255 In its brief, PSE argues that, because the sale of Colstrip Unit 4 is unlikely to occur prior to June 2020, PSE remains responsible for its share of major maintenance prior to the closing and should therefore be permitted to recover the major maintenance expenses in rates.[255]

Commission Determination

256 We agree with Staff that PSE is likely to incur some level of major maintenance for Unit 4 in 2020, and thus authorize the Company to defer those costs for recovery in its next GRC. First, like Staff, we are not comfortable allowing the Company to begin collecting these projected costs in rates in light of both the Company's and the operator's history of overestimating maintenance costs. Second, this issue presents unique circumstances due to PSE's pending sale of Unit 4 in Docket UE-200115. Those factors weigh in favor of deferring the recovery of any major maintenance costs to ensure that only actual costs incurred by PSE are recovered from ratepayers. Accordingly, we adopt Staff's recommendation and authorize PSE to defer costs associated with major maintenance for Colstrip Unit 4 until the Company's next GRC.

---

[253] *Id.* at 13:6-8.

[254] *Id.* at 14:14-17.

[255] On February 19, 2020, PSE filed with the Commission an Application for an Order Authorizing the Sale of Interest in Colstrip Unit 4 and the Colstrip Transmission System in Docket UE-200115. The Commission has scheduled an evidentiary hearing in that docket for October 14, 2020.

c. *Shifting Common Costs from Colstrip Units 1 & 2 to Units 3 & 4*

257 PSE proposes a single pro forma adjustment of $1.5 million for the production operation and maintenance (O&M) cost for the outages at Colstrip Unit 1 in 2017 and at Unit 2 in 2018.[256] PSE witness Roberts explains that there are no Colstrip common costs included in the adjustment for Units 1 and 2 because PSE is proposing to shift those costs to the rate year production O&M costs for Units 3 and 4.[257] Roberts claims that PSE's share of production and operating budget for Units 3 and 4 is projected to be just under $19 million, including the pro formed rate year amortization of the Unit 3 outage in 2017 and the Unit 4 outage in 2020.[258]

258 Staff opposes PSE's proposal to shift common costs from Units 1 and 2 into the pro forma O&M expense for Units 3 and 4.[259] Instead, Staff recommends using the test year O&M expense for Units 3 and 4, adjusted by the amortization of major maintenance cost but excluding any increase based on a hypothetical change in cost allocation among units.[260]

259 Staff also argues that PSE's proposed O&M costs do not meet the Commission's pro forma standards because the costs are neither known nor measurable, and that the proposed increase is likely to be offset by other factors for which PSE neglected to account.[261] Staff witness Liu explains that, at the time Staff filed testimony, PSE did not have a firm estimate for O&M expense for Units 3 and 4, as acknowledged in its direct testimony.[262] Based on a review of the Company's workpapers, Liu argues that many of the costs carried from Units 1 and 2 would be reduced or completely eliminated, such as general maintenance costs for Units 1 and 2.[263] Because PSE and Talen, the facility operator, remain uncertain about the budget for all Colstrip units, Staff argues that the

---

256 Roberts, Exh. RJR-1T at 22:3-16.

257 *Id.* at 22:3-16.

258 *Id.* at 22:12-16.

259 Liu, Exh. JL-1CT at 35:23-36:4.

260 *Id.* at 35:23-36:4.

261 *Id.* at 36:7-10.

262 *Id.* at 37:1-9.

263 *Id.* at 37:10-15.

common cost reallocation remains unknown. Moreover, since the Colstrip owners still do not know the specific actions required to bring Units 1 and 2 to a cold, dark, dry, and safe condition, Staff contends that the O&M costs for Units 3 and 4 are not measurable.[264]

260 Even if Talen finalizes the budget for inclusion at a later date, Liu maintains that the budget does not meet Commission rules for pro forma adjustments.[265] A budget is not measurable, and, according to Liu, PSE's budgeted expenses have been higher than actuals since 2013 with few exceptions, resulting in ratepayers overpaying by millions.

261 On rebuttal, Roberts testifies that PSE is including a representative amount of common costs that will continue during the rate year and are necessary for the continuation of the plant.[266] Roberts argues that PSE based the amount on test year results, contrary to Staff's claim, and that the budget is a reasonable estimate. According to Roberts, the actual variance between budgeted and actual expenses for Units 3 and 4, excluding major maintenance, has been minimal.

262 In its brief, Staff argues that "PSE simply took one half of those [common] costs and transferred them, dollar for dollar, to Units 3 and 4. This cost transfer apparently does not consider that many costs currently allocated to Units 1 and 2 may be reduced or eliminated now that the units have closed, or that they should continue to be allocated to Units 1 and 2 due to decommissioning and remediation activities."[267]

263 PSE counters that the $1.3 million included in its power cost proposal reflects common costs for shared expenses, such as maintenance of the general plant site, water treatment and handling equipment, the river pumping station, labor relations work, postage, employee safety equipment and training, information technology services, engineering services, communications equipment, and more.

Commission Determination

264 We authorize the Company to shift common costs from Colstrip Units 1 and 2 into the pro forma O&M expense for Units 3 and 4 because PSE's estimate is reasonably based on test year costs. We agree with Staff that PSE's estimate lacks precision, but we

[264] *Id.* at 38:3-17.

[265] *Id.* at 38:21-39:13.

[266] Roberts, Exh. RJR-14T at 15:9-16.

[267] Staff Initial Brief ¶ 89.

nonetheless acknowledge that the Colstrip Units invariably incur common costs. An imperfect estimate is not a reasonable basis to deny the Company recovery of those costs entirely. Going forward, however, we expect that PSE will no longer rely on estimates because the Company will have more than six months of experience operating Units 3 and 4 without Units 1 and 2. As such, we require all common cost expenditures included in future GRCs to be actual rather than estimated. To be clear, we expect those costs to be properly categorized and included in setting the power cost baseline in the Company's next GRC.

d. *Hydroelectric Modeling in AURORA*

265 In its direct case, PSE made several changes to its approach for estimating power costs in the AURORA model, including modifying its long-standing method for modeling 80 years of hydroelectric data. Historically, the Company ran Aurora 80 times, one for each year of hydro, and then averaged the resulting power costs from the 80 runs. The Company proposes instead to use the average of 80 years of hydro data to perform a single AURORA run. PSE argues this change is necessary because performing 80 separate runs is a time-consuming process that takes 14 hours of computational time plus manual labor to process the output data. This modeling change results in a 1.3 percent increase to power costs.[268]

266 Staff opposes PSE's proposal and recommends that the Commission require the Company to restore its existing practice of separately modeling 80 hydro years in AURORA and then averaging the power costs rather than using a single model run as proposed.[269] Staff witness Liu argues that PSE's proposed approach distorts the results and re-litigates a hydro normalization controversy from the Company's 2009 GRC.[270] In the final order in that docket, the Commission rejected arguments from Staff and another party that advocated for a hydro normalization approach.[271] According to Liu, PSE also

[268] Wetherbee, Exh. PKW-1CT at 60:15-16, 61:8-10.

[269] Liu, Exh. JL-1CT at 47:6.

[270] *Id.* at 47:7-10.

[271] *Id.* at 52:16-53:16. In 2009, ICNU and Staff proposed to exclude water years that fell outside one standard deviation above and below the mean water year in the Company's 50-year record. PSE objected from a statistical and analytical perspective and the Commission agreed. The Commission stated that while hydrological data may be normally distributed, the associated power costs were not normally distributed, and that removing the high and low values biased the

fails to explain how the probability distributions affect the sharing of risks and benefits accomplished in the Company's Power Cost Adjustment (PCA) sharing bands.[272]

267 Staff also rejects the Company's argument that the computational simplicity of a single run should take priority over the accuracy of an 80-run model.[273] According to Liu, a single run does not respond to hydro conditions in a symmetrically proportionate manner because the magnitude of the downward impact from good hydro conditions on power costs outweighs the magnitude of the upward impact from poor hydro conditions.[274] Liu argues that the current design of the PCA sharing bands recognizes the asymmetrical relationship between hydro conditions and power costs, and any proposal to modify the modeling approach must be supported by an analysis that accounts for this reality.[275]

268 In response to a Staff data request, PSE stated that high hydro generation leads to an inaccurate reduction to PSE's resource costs because AURORA imposes an artificial price floor to prevent dispatch at negative prices. The Company also claims that AURORA violates hydro resource capacity constraints by modeling greater generation than the maximum capacity of a resource.[276] Staff argues that the Company did not quantify the impact from the capacity constraint violation, and that it is doubtful that the violation is the sole and major source of the difference between single run and 80 run results.[277] Liu argues that PSE's analysis suffers the same analytical flaws as Staff's argument in the 2009 GRC that the Commission rejected.[278]

269 On rebuttal, Wetherbee explains PSE's proposed modified modeling approach. First, PSE's data set has 80 estimates of energy production for each month based on the 80

---

average power costs. *See Wash. Utils. and Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-090704 and UG-090705, Order 11 ¶ 115 (Apr. 2, 2010).

[272] Liu, Exh. JL-1CT at 47:11-13. PSE's PCA mechanism accounts for differences in the Company's modified actual power costs relative to a power cost baseline and provides for a sharing of power costs between the Company and its ratepayers.

[273] *Id.* at 48:5-50:2.

[274] *Id.* at 49:6-50:2.

[275] *Id.* at 49:18-50:2.

[276] *Id.* at 50:6-51:3.

[277] *Id.* at 51:7-52:8.

[278] *Id.* at 54:1-14.

historic years of streamflow.[279] PSE calculates normal hydro production by averaging the 80 estimates. Wetherbee explains that PSE then runs AURORA twice: once to get the projected power prices across the Western Electric Coordinating Council,[280] and then again to dispatch PSE resources to reflect the market prices from the first AURORA run.[281] Wetherbee argues that Staff's proposal is only partially consistent with the Company's previous approach because Staff proposes 160 runs rather than 80.[282]

270 Although PSE's initial proposal focused on computational efficiency, Wetherbee argues on rebuttal that inputting long-term average hydro results in more realistic hydro output.[283] Wetherbee argues that AURORA's logic allows it to unrealistically shift hydro from off-peak to on-peak hours. In reality, Wetherbee argues, the hydro would spill excess water, thus rendering it unable to operate above maximum capacity.[284] PSE argues that this unrealistic shift creates artificially high off-peak prices when PSE generally sells to the market, and artificially low on-peak hours when PSE generally purchases. PSE contends that it identified capacity constraint violations in 1.7 percent of the total hours, on average, in 69 of 80 years.[285] PSE argues that its use of an 80-year average hydro as an input eliminates the occurrence of "impossibly high" levels of AURORA dispatch, resulting in a more realistic power cost estimate.[286]

271 PSE also disagrees that the PCA sharing band asymmetry reflects an asymmetry between hydro conditions and power costs.[287] Wetherbee argues that neither of the documents Staff provided support its asymmetry argument, and that the testimony Staff cites

---

[279] Wetherbee, Exh. PKW-34CT at 3:10-17.

[280] The Western Electricity Coordinating Council is a nonprofit organization that focuses on mitigating risks to the reliability and security of the Western Interconnection's Bulk Power System. The Western Interconnection is comprised of all or part of 14 Western states, two Canadian provinces, and Northern Baja Mexico.

[281] Wetherbee, Exh. PKW-34CT at 3:19-4:3.

[282] *Id.* at 5:3-11.

[283] *Id.* at 6:5-12.

[284] *Id.* at 6:15-7:6.

[285] *Id.* at 7:7-12.

[286] *Id.* at 7:16-18.

[287] *Id.* at 9:8-15.

included analysis stating asymmetry was not significantly affected when hydro variability was removed.[288]

272 PSE also disagrees with Staff's argument that the Company's proposed average hydro approach is similar to the hydro filtering approach the Commission rejected in 2009.[289] Wetherbee argues that the hydro filtering approach at issue in 2009 excluded water years that fell outside of one standard deviation, but PSE's current approach includes all years.

273 In its brief, Staff argues that using only an average of hydro generation instead of the average of the 80 model runs distorts the results of the rate year simulation, and that mere computational simplification does not justify this method. Staff further contends that PSE fails to support its claim that incorporating hydro generation into its estimation of variable power costs improves accuracy. Rather, "by averaging the hydro generation input into the AURORA model, PSE 'exclude[s] the power cost variance from extremely high or extremely low hydro conditions.' This method of normalization can cause distortions in the distribution of power costs, necessarily introducing bias into the power cost outputs."[290]

274 Staff further argues that PSE has not demonstrated that the capacity constraint violations are significant in terms of occurrence or in terms of an actual effect on resource cost. As such, Staff rejects the capacity violations as a credible basis for replacing PSE's traditional methodology. Staff contends that PSE was unable to demonstrate that its new method improves forecast accuracy. As such, Staff concludes that any improved computational efficiency is irrelevant.[291]

275 PSE argues that using the average of 80 years of hydro data as an input results in more realistic hydro output for the model and a better estimate of power costs. PSE alleges that Staff's proposed methodology would involve running AURORA 160 times – with 80 runs to model the Western Interconnection and 80 more runs using the two-zone AURORA model, after which PSE would need to average the results in a spreadsheet.

---

[288] *Id.* at 10:1-10.

[289] *Id.* at 11:11.

[290] Staff Initial Brief ¶ 92.

[291] *Id.* ¶ 95.

PSE contends that such a time-consuming approach is not justified, nor does it produce more accurate results.[292]

276 In its reply brief, Staff argues that PSE should continue to run the model 80 times using all possible hydro assumptions instead of one single average hydro scenario to produce an accurate estimate of power costs in the rate year. According to Staff, an "increase in power costs of $6.3 million that results from a data distortion is not a good deal for ratepayers and should be rejected."[293] As such, Staff recommends that the Commission should require PSE to return to its standard method of running AURORA for each year of hydro data (currently 80 years / 80 times) and averaging the output because "PSE has not demonstrated that its new methodology is worth $6.3 million in terms of accuracy."[294]

277 PSE argues that when the AURORA model is run separately for each hydro year, as Staff proposes, the model results for 69 of the 80 years "are untenable because they include hydro generation in excess of plant capacities."[295] Accordingly, PSE recommends the Commission approve its modified approach.

Commission Determination

278 We agree with Staff and require PSE to continue to run the AURORA model 80 times using all possible hydro assumptions to produce an accurate estimate of power costs in the rate year. We concur with Staff's assessment that "a single run does not respond to hydro conditions in a symmetrically proportionate fashion,"[296] and would thus create a major deviation – as evidenced by the $6.3 million variance in power costs – merely for the sake of efficiency.

279 We acknowledge that AURORA violates hydro resources' capacity constraints by modeling greater generation than the maximum capacity of a resource, but we agree with Staff that PSE needs to quantify the impact of these violations if this problem persists in the future. PSE conceded at hearing, however, that this issue will soon be moot because

---

[292] PSE Initial Brief ¶ 81.

[293] Staff Reply Brief ¶ 28.

[294] *Id.* ¶ 29.

[295] PSE Reply Brief ¶ 31.

[296] Liu, Exh. JL-1CT at 49:6-50:2.

AURORA's next release will include workarounds for resource capacity constraints.[297] In light of these factors, PSE's proposal is not necessary to address the concern over resource capacity constraints. Accordingly, we require the Company to restore its practice of separately modeling 80 hydro years in AURORA and then averaging the power costs rather than using a single model run as proposed.

e. *Green Direct Power Purchase Agreements*

280 Green Direct Power Purchase Agreements is the marketing brand for PSE's Voluntary Long-Term Renewable Energy Purchase Rider, which was approved as Schedule 139 by the Commission in Docket UE-160977. Schedule 139 (Green Direct) is available to PSE's governmental and large corporate customers who consume at least 10,000 MWh annually. The program is fully subscribed, and customers have signed agreements ranging from 10 to 20 years.

281 Green Direct participants are charged a fixed annual rate that covers the full cost of the power purchase agreements (PPAs) executed for dedicated resources, as well as any administrative costs associated with Schedule 139. Participants receive an Energy Charge Credit for the energy-related production costs in their rates, which is based on PSE's Power Cost Adjustment (PCA) baseline rate and the participant's share of PSE's production costs related to the supply of energy.

282 PSE signed PPAs with Skookumchuck Wind Energy Program and Lund Hill Solar Project to serve Schedule 139.[298]

283 In Docket UE-190991, PSE filed an accounting petition for deferred accounting treatment of liquidated damages (LDs) received due to delays in the Skookumchuck project.[299] The accounting petition is consolidated with these dockets and is addressed in more detail in Section II(B)(4)(ii), below.

284 The Company requests the Commission determine that the Company's Skookumchuck and Lund Hill PPAs sourced for Green Direct are prudent. PSE witness Einstein observes that the Commission and stakeholders have already reviewed information related to these

---

[297] Wetherbee, TR 410:24-25.

[298] Einstein, Exh. WTE-1T at 10:4-12:16.

[299] Free, Exh. SEF-17T at 86:2-9.

costs and the need for these PPAs in the Green Direct tariff filing.[300] Einstein further posits that PSE's request for a prudency determination is consistent with the Company's commitment at the time the Commission approved the Green Direct tariff to seek such a determination in a GRC.[301]

285 Staff witness Scanlan testifies that PSE committed to track separately all costs and benefits of Schedule 139 in its PCA mechanism when the Green Direct program was approved. According to Scanlan, however, the PCA will track only variable power costs, which excludes fixed costs, such as administrative and plant costs, and benefits, such as revenues associated with LDs.[302]

286 Staff argues that all fixed non-energy costs and benefits related to the PPAs should be excluded from GRCs and ERFs, and that the tracking mechanism should align with PSE's filing of its PCA, include variable costs such as renewable energy credit (REC) and energy purchases related to PPA shortages in the PCA, and appropriately account for and track excess energy and RECs transferred to non-participating customers.[303]

287 Staff identified $340,639 of billing software improvements related to Schedule 139 that were included for all customers.[304] According to PSE witness Free, these costs were inadvertently included and were removed on rebuttal.[305]

288 Staff recommends that the Commission direct PSE to work with Staff and other stakeholders to establish a more transparent, complete, and timely tracking and reporting mechanism(s) for all costs and benefits related to service under Schedule 139.[306]

289 Staff does not contest the inclusion of the new wind and solar contracts in this proceeding. Staff witness Liu explains that Green Direct subscribers remain PSE customers, and that the new wind and solar contracts are part of PSE's power supply

---

[300] Einstein, Exh. WTE-1T at 14:4-10.

[301] *Id.* at 19:14-17.

[302] Scanlan, Exh. KBS-1CT at 13:4-22.

[303] *Id.* at 14:8-19.

[304] *Id.* at 7:19-22.

[305] Free, Exh. SEF-17T at 85:6-14.

[306] Scanlan, Exh. KBS-1CT at 15:13-16.

portfolio. Furthermore, Staff argues that the costs and benefits of the Green Direct resources are intertwined with the rest of the system resources.[307]

290 Public Counsel opposes the inclusion of the PPAs or any other costs associated with the Green Direct program in this power cost update because neither of the PPAs are in service, nor are any participating customers currently receiving benefits.[308]

291 On rebuttal, PSE argues that both PPA contracts will be placed in service during the rate effective period, and that no party to this case has challenged the prudency of the program.[309] In response to Public Counsel, PSE witness Wetherbee recommends that, if the Commission were to determine that Green Direct PPA costs should be removed from rate-year power costs, the Commission should also account for replacement power costs. Based on PSE's proposed power costs on rebuttal, PSE estimates the net power cost reduction would be $13.1 million.[310]

292 In its brief, PSE requests the Commission determine that PSE's Schedule 139 Green Direct PPAs are a prudent power resource for all PSE customers. PSE again notes that no party challenges the underlying prudency of the PPAs.[311]

293 In its reply brief, AWEC argues that PSE's request to incorporate the costs of two PPAs that will supply alternative energy to its Green Direct program customers into its power cost baseline will result in recovery of costs associated with the Green Direct program from all ratepayers, not just those who elect to participate in the voluntary program. Given this inherent conflict with RCW 19.29A.090(5), which requires that "[a]ll costs and benefits associated with [an optional program such as Green Direct] must be allocated to the customers who voluntarily choose that option and may not be shifted to any customers who have not chosen such option," AWEC supports Staff's request for additional process and collaboration to track Green Direct program costs and benefits to

---

[307] Liu, Exh. JL-1CTr at 56:9-21.

[308] Colamonici, Exh. CAC-1CT at 14:3-11.

[309] Einstein, Exh. WTE-9T at 9:2-11.

[310] Wetherbee, Exh. PKW-34CT at 22:9-23:10.

[311] PSE Initial Brief ¶ 141.

ensure their lawful allocation. Overall, AWEC agrees with Staff that issues related to these costs "require further process" to ensure statutory compliance.[312]

Commission Determination

294 Neither of the facilities associated with the Green Direct PPAs is in service, and both facilities have been subject to multiple delays. Accordingly, we require PSE to remove the Green Direct PPA costs from rate-year power costs, net of replacement power costs. This reduces the power cost baseline by $13.1 million based on PSE's estimated replacement power costs on rebuttal.

295 Additionally, we decline to make a prudency determination at this time. We will revisit the question of prudency, including whether the Skookumchuck and Lund Hill PPAs are prudent for all customers once the PPAs are in service and providing power for Green Direct program participants.

296 Voluntary programs such as the Green Direct program are subject to the requirements of RCW 19.29A.090(5), which prohibits cost-shifting to non-participants. As such, we direct PSE to work collaboratively with Staff and other stakeholders to ensure that the costs and benefits of the Green Direct program are tracked and maintained separately pursuant to statute. In addition to concerns raised by parties in this case, the tracking system for Green Direct costs and benefits should address over- and under-generation of PPAs relative to Green Direct customer demand in a manner that ensures Green Direct program participants benefit exclusively from the sale of over-generation and prohibits non-participants from subsidizing costs of additional power to serve Green Direct customers, respectively, for any costs determined prudent only for Green Direct customers.

297 Finally, the costs of providing power to Green Direct program participants until the PPAs are in service should be separately tracked using Schedule 139 to ensure only program participants bear those costs.

[312] AWEC Reply Brief ¶ 32.

vi. Annual Incentive Compensation

298 PSE's Goals and Incentive Plan (GIP) is a formal annual incentive compensation plan for all employees that the Company's senior management approves.[313] PSE seeks to include in its revenue requirement $9.1 million for electric annual incentive compensation expenses, and $4.4 million for gas annual incentive compensation expenses.[314] These expenses are based on a four-year average of incentive paid to employees, which is allocated between electric and natural gas operations between calendar years 2015 and 2018.[315] PSE describes GIP as a key component of its compensation policy, which includes competitive pay both within the Company and across the industry, as well as pay for performance. GIP is a variable incentive plan, which means that employees are eligible to receive incentive pay if PSE achieves its goals, but are not eligible if it does not.[316]

299 PSE argues that GIP benefits customers in three ways.[317] First, PSE witness Hunt contends that GIP focuses employees on key PSE objectives that directly benefit customers, including safety, reliability, service quality, and customer service. Hunt further argues that GIP focuses on operational efficiency, which results in reduced rates for customers.[318]

300 Second, PSE argues that GIP slows the base wage growth that would occur in a compensation system comprised of only base salaries, in which benefits and wage increases would compound annually.[319] Under PSE's current plan, significant pay is at risk for all employees if GIP goals and objectives are not met. Hunt argues that customers benefit from the Company's decision to limit overall wage growth; instead, wage growth

---

[313] Garrett, Exh. MEG-1T at 20:14-16.

[314] *Id.* at 20:16, 20:1-2.

[315] Free, Exh. SEF-1T at 29:10-6.

[316] Hunt, Exh. TMH-1T at 24: 13-20, 25:1-3.

[317] *Id.* at 25:7.

[318] *Id.* at 25:7-12.

[319] *Id.* at 25:13-17.

occurs only for a given year, and only in the event that the Company meets its strategic objectives.[320]

301 Third, Hunt argues that GIP is part of a comprehensive compensation and benefits package that makes PSE an attractive employer to well-qualified individuals,[321] and that customers benefit from the contributions of a workforce that provides high-quality and efficient service.

302 Hunt testifies that most companies, including investor-owned utilities, follow a pay for performance approach like that of PSE.[322] Hunt explains that two thresholds must be met for employees to receive annual incentive payments. First, PSE must meet or exceed six of its Service Quality Index (SQI) and Safety Goals. Second, PSE's "Earnings before Interest, Taxes, Depreciation, and Amortization" (EBITDA) must exceed the trigger level set by GIP. [323] According to Hunt, the SQI threshold ensures that PSE is providing good customer service and the EBITDA threshold ensures PSE is controlling costs, staying within budget, and operating efficiently.[324]

303 Public Counsel proposes an adjustment to the annual incentive compensation plan expense to remove the costs associated with the financial measures (EBITDA threshold) within the compensation plan.[325] Public Counsel witness Garrett argues that a significant portion of the incentive compensation is dependent on financial performance.[326] While incentive award levels are based on a combination of operational and earnings goals, Garett argues that the funding for annual incentive compensation is based on PSE's EBITDA, and GIP includes a funding trigger, also based on PSE's EBITDA, that requires 90 percent of the EBITDA goal to be achieved for incentive payment to issue in a given year.[327] Further, GIP also provides for increasing levels of funding for incentive

---

[320] *Id.* at 25:13-18.

[321] *Id.* at 25:20-21, 26:1-2.

[322] *Id.* at 26:14-17.

[323] *Id.* at 27:15-18.

[324] *Id.* at 27:3-7.

[325] Garrett, Exh. MEG-1T at 22:6-9.

[326] *Id.* at 20:14-16.

[327] *Id.* at 22:9-14.

compensation based on the Company's earnings. According to Garrett, this demonstrates that the Company's earnings are the most significant factor in determining whether and to what extent employees will receive incentive compensation.[328]

304 Garrett argues that plans like GIP, which are skewed toward company earnings, prioritize the goal of maximizing shareholder wealth. Garrett contends that incentive plans with a financial trigger are particularly disturbing from a ratemaking perspective; if the earnings threshold is not achieved, money collected from ratepayers for the purpose of compensating employees is diverted to bolster shareholder returns.[329]

305 Garrett discusses an incentive compensation survey of 24 states conducted in 2007 and updated in 2009, 2011, 2015, and 2018 that found a majority of states surveyed disallow incentive payments associated with financial performance from rate recovery.[330] Garrett observes that while some jurisdictions disallow incentive pay using other criteria, and some jurisdictions apply a 50 percent sharing mechanism, no jurisdiction surveyed allows full rate recovery of incentive compensation.[331]

306 Garrett also challenges PSE's argument that incentive pay should be included in rates because it is a necessary component of the overall compensation package needed to attract and retain a qualified workforce.[332] Garrett asserts that the Company is free to offer its employees whatever compensation package it deems appropriate, but most regulatory commissions have agreed that ratepayers should not bear the cost of plans designed to increase corporate earnings.[333] Garrett further argues that when incentive pay is based on financial performance and financial goals are achieved, the financial benefit should provide enough additional funds to make the incentive payments.[334]

---

[328] *Id.* at 23:3-7.

[329] *Id.* at 24:3-10.

[330] *Id.* at 28:12-17.

[331] *Id.* at 28:17-20.

[332] Hunt, Exh. TMH-1T at 25:20-21, 26:1-2.

[333] Garrett, Exh. MEG-1T at 44:18-28.

[334] *Id.* at 45:12-16.

307 Public Counsel recommends that the Commission adopt a 50/50 sharing approach that allocates the annual incentive plan costs evenly between shareholders and ratepayers.[335] Garrett believes this approach is reasonable because it recognizes the Company's plan is based both on financial and operational performance, and that it benefits both shareholders and ratepayers. This adjustment would remove 50 percent of the annual incentive plan costs included in the pro forma operating expense.[336]

308 On rebuttal, PSE argues that Public Counsel incorrectly characterized GIP, focusing on solely the financial goal, which is only one of eleven plan goals.[337] Hunt describes GIP's 10 safety and SQI goals, including the three employee safety measures, all of which must be met for the overall employee safety goal to be achieved.[338] Hunt further argues that the safety and SQI goals are significant to the program, and can have a dramatic impact on funding. For example, if only 5 of 10 of the safety and SQI goals are met, the plan will not fund incentives regardless of financial performance.[339]

309 Hunt addresses the incentive compensation survey that Garrett introduces in Public Counsel's response testimony, arguing that it has two consistent themes: (1) commissions look at the metrics of incentive plans on a case-by-case basis, including prior commission findings; and (2) commissions allow incentives that benefit customers to be included in rates.[340]

310 Hunt points out that the GIP in this case is largely the same as the one approved by the Commission in PSE's 2004 GRC.[341] In sum, Hunt argues that PSE has carefully and thoughtfully crafted GIP to align with the Commission's previous guidance related to appropriate structuring of an incentive plan. The GIP's one financial goal and 10 non-financial goals are inextricably related for the purpose of focusing employee efforts on

---

[335] *Id.* at 47:19-21.

[336] *Id.* at 47:21-26.

[337] Hunt, Exh. TMH-8T at 1:20-21.

[338] *Id.* at 2:10-15.

[339] *Id.* at 3:15-20.

[340] *Id.* at 5:17-22, 6:1-13.

[341] *Id.* at 9:7-11.

goals that best benefit customers. For these reasons, Hunt contends that the Commission should continue to allow full recovery of PSE's incentive plan in rates.[342]

311 In its brief, Public Counsel argues that Company earnings are "by far the most important factor in determining whether incentive compensation will be paid and to what extent."[343] To illustrate its point, Public Counsel explains that if 90 percent of EBITDA is achieved and 100 percent of SQI results are met, incentive payment is reduced to 50 percent. However, if PSE meets 60 percent of its SQI results and achieves 100 percent of its EBITDA target, the incentive payment is reduced only to 60 percent.

312 PSE argues that Public Counsel's position has previously been rejected by the Commission, and that GIP comports with prior Commission orders. PSE cites its 2011 GRC where the Commission rejected an argument that 50 percent of its incentive pay should be removed because it was tied to the Company's financial performance.[344] Overall, PSE contends that Public Counsel failed to provide evidence demonstrating that GIP provides compensation in excess of market average, or that compensation under GIP is unreasonable.[345]

Commission Determination

313 We authorize PSE's adjustment related to incentive pay consistent with our prior decisions on this issue. When the Commission authorized the Company to recover incentive compensation expenses in its 2004 GRC, we recognized that a portion of the program required the Company to achieve certain earnings goals, but nevertheless approved it based on the second threshold that measured service quality, safety, and reliability, noting that "these are the criteria we look for in authorizing, or not, the recovery of incentive payment costs."[346]

---

[342] *Id.* at 12:17-22.

[343] Public Counsel Initial Brief ¶ 50.

[344] PSE Initial Brief ¶ 99.

[345] *Id.* ¶ 104.

[346] *Wash. Utils. and Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-040641 and UG-040640, Order 06 ¶ 144 (Feb. 18, 2005).

314 Several years later, the Commission established a standard for evaluating the reasonableness of employee compensation, including incentive plans, in PacifiCorp, d/b/a Pacific Power & Light Company's (PacifiCorp), 2010 GRC.[347] In that case, the Commission explained that it does not "wish to delve too deeply into the Company's management of its human resources and the manner in which it determines overall compensation policy," and concluded that it inquires "only whether the compensation exceeds the market average, is unreasonable, and offers benefits to ratepayers."[348] Accordingly, we examine only those factors.

315 First, with respect to PSE's GIP, no party disputes PSE's testimony and evidence that its overall compensation is reasonable and consistent with the market average. We conclude that the record evidence supports a finding that it meets both of these criteria. Second, Public Counsel does not dispute that, at least to some extent, PSE's incentive pay program benefits ratepayers. PSE offers extensive testimony and evidence demonstrating that it does.

316 Public Counsel dedicates a significant portion of testimony to discussing incentive compensation in other jurisdictions, which we find informative but not wholly relevant or dispositive. The Commission's standard has been the same for many years, and because the overall compensation is reasonable we decline to modify it now.

vii. Tax Cut and Jobs Act

317 On December 29, 2017, PSE filed with the Commission a petition for an order authorizing deferred accounting associated with the impacts of the TCJA on PSE's cost of service, which was assigned Dockets UE-171225 and UG-171226 (TCJA Petition). The TCJA Petition sought deferral of the costs and savings associated with the difference between the prior tax law amounts embedded in rates and the impacts of the new tax law going forward. On November 26, 2018, PSE filed an amended petition, which provided updates to address (a) the over-collection of taxes for the period of January 1 to April 30, 2018, and (b) the Excess Deferred Income Tax (EDIT) balances created by the TCJA. On

---

[347] On December 5, 2020, Pacific Power & Light Company filed a petition with the Commission changing its name to PacifiCorp, d/b/a Pacific Power & Light Company.

[348] *Wash. Utils. and Transp. Comm'n v. Pacific Power & Light Co.*, Docket UE-100749, Order 06 ¶ 250 (Mar. 25, 2011).

February 5, 2020, the Commission consolidated the TCJA Petition with the GRC Dockets.

318 In the final order in PSE's 2018 ERF, the Commission approved a settlement agreement that resolved all of the issues in that proceeding, which included "black-box" revenue requirement calculations. As part of the settlement, the parties agreed that the issues in the TCJA Petition related to the ratemaking treatment of unprotected EDIT (UP EDIT) and of the over-collection of tax expense from January 1, 2018, to April 30, 2018, would be addressed in the Company's next GRC. The Commission rejected the latter provision, requiring instead that PSE return to customers the over-collected tax expense collected from January 1, 2018, to April 30, 2018, beginning May 1, 2019, concurrent with any rate adjustment made as a result of the Company's annual decoupling filing. Accordingly, the only remaining issue in the TCJA Petition dockets is the ratemaking treatment for UP EDIT.

319 The ERF settlement agreement also included the return of amounts based on the 2018 protected-plus EDIT (PP EDIT) reversals through a separate schedule, Schedule 141X. The parties agreed to the grossed-up, annualized PP EDIT amounts of $25.9 million for electric and $6.1 million for natural gas. The parties further agreed that Schedule 141X rates would be reviewed in PSE's next GRC. The settlement agreement expressly provides, however, that the parties do not agree on the proper accounting and ratemaking treatment of PP EDIT reversals "for the period of January 1, 2018, through February 28, 2019."[349] The parties thus agreed that the disposition of those reversals and the proper ratemaking treatment thereof would be addressed in the Company's next GRC.

320 According to the terms of the settlement agreement, the parties request that in this proceeding we (1) review Schedule 141X rates, and (2) establish the proper accounting and ratemaking treatment both for the PP EDIT reversals made for the January 1, 2018, through February 28, 2019, period covered by the ERF settlement agreement (ERF Period) and the PP EDIT reversals on a going-forward basis.

321 In its initial filing, PSE proposes ratemaking treatment for UP EDIT to resolve the TCJA Accounting Petition. PSE also proposes accounting and ratemaking treatment for PP EDIT reversals.[350] No party disputes that PP EDIT must be reversed using the Average

---

[349] The rates established in the ERF proceeding became effective March 1, 2019.

[350] Marcelia, Exh. MRM-1T at 1:12-20.

Rate Assumption Method (ARAM). All non-company parties propose that PSE maintain Schedule 141X to track PP EDIT reversals. PSE, however, proposes to eliminate Schedule 141X and embed PP EDIT ARAM reversals in base rates on a going-forward basis. Table 2, below, summarizes PSE's EDIT balances as of December 31, 2017.

Table 2 – PSE's EDIT balances as of Dec. 31, 2017

	UP EDIT[351]	PP EDIT[352]
Electric	$36 million	$575.7 million
Natural Gas	$2.9 million	$239.7 million
Total	$38.9 million	$815.4 million

a. *Unprotected EDIT*

322 The Company proposes to pass back to ratepayers a total of $38.9 million of UP EDIT, which is not subject to IRS normalization requirements, over a four-year period,[353] and proposes to book the annual amortization of UP EDIT to FERC account 411.1 – *Provisions for deferred income taxes, Utility Operating Income*.[354] PSE argues that it will need to "gather" all of the EDIT from FERC accounts 190 and 283 and transfer it to a separate deferred tax liability account for EDIT only, which will simplify the process of amortizing the full balance from one account for each electric and natural gas.[355] While no party contests PSE's UP EDIT calculations, Public Counsel and AWEC make different recommendations regarding the amortization period.

---

[351] *Id.* at 8:3-7.

[352] *Id.* at 10:9-12. PSE notes that a small portion of the balances in this category are considered non-plant. However, because these amounts are related to repairs to the underlying asset and the Company's software does not differentiate these balances between plant and non-plant, PSE proposes to treat the entire balance as protected. Further, PSE argues this treatment is consistent with prior Commission orders in Docket UG-170929 for Cascade, and Dockets UE-170485 and UG-170486 for Avista. *See id.* at 15:2-10, 16:9-16.

[353] Marcelia, Exh. MRM-1T at 8:5-15.

[354] *Id.* at 9:17-21.

[355] *Id.* at 10:1-6.

323 Public Counsel recommends a two-year amortization period for UP EDIT.[356] AWEC does not oppose PSE's proposal to amortize UP EDIT over four years for electric operations, but recommends returning UP EDIT to natural gas customers over one year. AWEC argues this treatment is appropriate because of the magnitude of the proposed rate increase compared to the relatively small amount that will be passed back.[357]

324 On rebuttal, PSE argues that Public Counsel provides no rationale for its proposal to return UP EDIT over a two-year period, and that no other party supports its recommendation to amortize over two-years for electric operations.[358] PSE also opposes AWEC's recommendation to return UP EDIT to natural gas customers over one year. PSE argues that, because the Company is "unlikely" to reset base rates within the next 12 months, it would end up passing back more than one year of amortization to natural gas customers.[359] PSE maintains its recommendation for a four-year amortization period for both electric and natural gas.[360]

Commission Determination

325 As the parties acknowledge, the Commission has the authority to set the amortization period for returning UP EDIT to ratepayers. In the context of this proceeding, when PSE's customers are currently experiencing the economic impacts of the COVID-19 pandemic, we conclude that requiring PSE to amortize UP EDIT for both electric and natural gas over a three-year period is in the public interest and will result in rates that are fair, just, reasonable, and sufficient. We require PSE to defer grossed-up UP EDIT amounts of $47.9 million and $3.8 million to separate FERC Accounts 254 – Other Regulatory Liabilities, for electric and natural gas, respectively.[361] Because the Commission's final revenue requirement removes the UP EDIT adjustment in its entirety, we further require PSE to pass back grossed-up UP EDIT using a new separate Schedule 141Z over a three-year period for both electric and natural gas. The grossed-up annual amortization amounts are approximately $16 million for electric and $1.3 million for

---

[356] Garrett, Exh. MEG-1T at 3:11-12.

[357] Mullins, Exh. BGM-1T at 36:9-16.

[358] Marcelia, Exh. MRM-11T at 68:16-69:3.

[359] *Id.* at 51:18-52:4.

[360] *Id.* at 69:3-4

[361] Prior to gross-up, electric and natural gas UP EDIT amounts were $36 million and $2.9 million, respectively.

natural gas. The allocation of UP EDIT will be based on class usage and returned consistent with Schedule 141X.

b. *Protected-Plus EDIT*

326 PSE argues that two components of the IRS regulations apply to the PP EDIT reversal. First, PSE argues that the IRS requires PP EDIT to be returned to customers over a period equal to or greater than the remaining book life of the underlying asset. This reversal method, known as the Average Rate Assumption Method or ARAM, has been proposed by several of the Company's peer utilities and approved by the Commission in multiple proceedings since the TCJA took effect.

327 Second, PSE advances a novel argument that PP EDIT amounts are subject to a component of the IRS rules known as the "consistency rule."[362] The Company interprets the "consistency rule" as prohibiting the deferral of PP EDIT amounts separately from other ratemaking components in a test year; *i.e.* depreciation expense, tax expense, accumulated deferred taxes on the balance sheet, and rate base.

328 Subsection 9 of 26 U.S.C. § 168(i) defines the IRS Normalization Rules for public utility property. Subsection 9(A) provides that a taxpayer must use the same method and period for calculating tax expense as used for depreciation in the taxpayer's cost of service for ratemaking and in its regulated books of account. This subsection also states that taxpayers will use a reserve deferred tax account (*i.e.*, accumulated deferred taxes) to track the difference between depreciation allowed as a deduction for tax purposes and depreciation used to calculate regulated tax expense.

329 Subsection 9(B), which PSE refers to as the "consistency rule," provides in pertinent part:

> (B) Use of inconsistent estimates and projections, etc. –
> (i) In general. – One way in which the requirements of subparagraph (A) are not met is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with the requirements of subparagraph (A).
> (ii) Use of inconsistent estimates and projections. – The procedures and

---

[362] PSE uses the term "consistency rule" to describe a subsection of the IRS normalization rules that addresses the "use of inconsistent estimates and projections." *See* 26 U.S.C. § 168(i)(9)(B)(i) and (ii).

> adjustments which are to be treated as inconsistent for purposes of clause (i) shall include any procedure or adjustment for ratemaking purposes which uses an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under subparagraph (A)(ii) unless such estimate or projection is also used, for ratemaking purposes, with respect to the other 2 such items and with respect to the rate base.

330 In this proceeding, PSE proposes to use PP EDIT values recorded in the 12-month historical test year as the basis for its deferred tax calculation.[363] PSE witness Marcelia explains that the Company has been recording the PP EDIT amortization as a component of deferred tax expense on a monthly basis because "[d]eferring only the reversing [PP] EDIT component of deferred tax expense" would violate IRS normalization rules.[364]

331 To illustrate the Company's argument, Marcelia explains that PSE took multiple steps to "avoid consistency issues" when it calculated the impact of a full 12 months of ARAM using projections based on six months of actual results of operations for purposes of the 2018 ERF settlement agreement.[365] Ultimately, PSE argues that the key to applying "IRS consistency" is to apply the same approach to the same population using the same assumptions.[366] According to PSE, its approach complied with both the normalization rule and the "consistency rule." PSE acknowledges, however, that the settlement agreement was a "black box," and that no party agreed with PSE's accounting or ratemaking treatment. Instead, the parties agreed to an end result and reserved the resolution of accounting and ratemaking treatment issues for this proceeding.

332 To achieve "consistency," PSE proposes to eliminate Schedule 141X for PP EDIT reversals, instead proposing to embed those reversals in base rates.[367] To support the Company's position, Marcelia cites several IRS Private Letter Rulings (PLRs) that

---

[363] Marcelia, Exh. MRM-1T at 29:6-9.

[364] *Id.* at 30:12-15.

[365] *Id.* at 26:14-27:15.

[366] *Id.* at 27:16-17

[367] *Id.* at 54:3-8.

address EDIT, conceding that none refer explicitly to PP EDIT deferrals resulting from tax rate changes.[368]

333 Staff disagrees with PSE's interpretation of the IRS rules, arguing that the Company's position is inconsistent with Commission practice. Specifically, Staff notes that the Commission's January 8, 2018, press release "directed regulated companies to track federal tax savings resulting from the federal Tax Cuts and Jobs Act to ensure those savings will benefit utility customers."[369] Staff argues that PP EDIT represents monies paid by ratepayers for taxes that PSE deferred due to the timing difference between when tax is collected from the Company's customers and when the Company pays those taxes to the IRS. As such, Staff argues that PP EDIT is that portion of accumulated deferred income taxes no longer owed to the IRS. [370] Although federal income tax is a pass-through cost to ratepayers, Staff argues that the "intrinsic" nature and complexity of calculating taxes requires that refunds match the amount collected in order for rates to be fair, just, reasonable, and sufficient.[371]

334 Staff further argues that PSE's proposal to embed PP EDIT reversals in rates will make it challenging for the Commission and other parties to determine whether these benefits are appropriately returned to ratepayers because it will be difficult to distinguish PP EDIT amounts from other components of the Company's federal income tax restating adjustment to its revenue requirement. To increase transparency, Staff recommends that the Commission require PSE to: (1) create a separate EDIT balance sheet account; (2) separate the EDIT reversal amortization from PSE's proposed federal income tax revenue requirement adjustment; (3) require PSE to continue to return PP EDIT to customers through Schedule 141X; and (4) require PSE to annually update Schedule 141X for the following year's PP EDIT amortization consistent with ARAM.[372]

335 Staff witness Steward testifies that the IRS has "detailed and specific requirements" for returning PP EDIT, and that the Commission has reviewed those requirements over the

---

[368] *Id.* at 21:7-10.

[369] *Wash. Utils. & Transp. Comm'n v Puget Sound Energy*, Dockets UE-180899 and UG-180900, Order 05 ¶ 34 (Feb. 21, 2019) (citing Commission Press Release, Jan. 8, 2018).

[370] Steward, Exh. CSS-1T at 4:6-20.

[371] *Id.* at 7:1-3.

[372] *Id.* at 6:1-12.

last two years. Staff contends that PSE's argument that returning PP EDIT through a separate tariff schedule violates the IRS consistency rule relies on outdated, irrelevant materials related to the Tax Reform Act of 1986 that were published well before the TCJA was enacted. Staff also observes that the IRS has yet to weigh in on consistency issues related to the TCJA.[373]

336 Finally, citing IRS Procedure "Safe Harbor for Inadvertent Normalization Violations,"[374] Staff argues PSE could avoid penalties for any normalization violations if it took swift corrective action.[375] In the event the Commission unintentionally ordered PSE to violate IRS requirements, PSE would be protected by the safe harbor provision.[376]

337 Public Counsel argues that PP EDIT represents monies collected from ratepayers that must be returned to ratepayers because those monies are no longer payable to the IRS. Public Counsel witness Garrett argues that PSE is inappropriately transferring "interim period" PP EDIT to shareholders by including it in the Company's current income.[377] Public Counsel argues that if the utility is no longer required to pay these funds to the federal government, they should be returned to customers, and that there is no legal or ratemaking theory that allows PSE to redirect PP EDIT away from ratepayers to shareholders.[378] Accordingly, Public Counsel recommends the Commission order that these funds be deferred in a regulatory liability account and returned to ratepayers.[379]

338 Public Counsel cites the Commission's final orders in Avista's and Cascade Natural Gas Corporation's (Cascade) 2017 GRCs, which required those utilities to return TCJA tax benefits to ratepayers.[380] Garrett argues that both the Avista and Cascade decisions are important because they completely undermine PSE's argument that deferring PP EDIT

---

[373] *Id.* at 7:7-14.

[374] *Id.* at 3:16-17.

[375] *Id.* at 7:15-18.

[376] *See* Steward, Exh. CSS-2 (including copy of Rev Proc 2017-47).

[377] Garrett, Exh. MEG-1T at 50:9-20. Garrett refers to Prefiled Direct Testimony of Matthew R. Marcelia, Exh. MRM-1T at 30:4-11. The "interim period" is January 1, 2018, to February 28, 2019.

[378] Garrett, Exh. MEG-1T at 51:1-11.

[379] *Id.* at 50:17-19.

[380] *Id.* at 51:12-52:3.

results in an IRS normalization violation. Further, Public Counsel argues that the Cascade final order uses strong language, stating that "utilities are on notice that we expect customers will reap the benefits."[381] Finally, Public Counsel argues that utilities across the country have been deferring PP EDIT to a regulatory liability account without incurring normalization violations.[382]

339 Responding to PSE's reliance on prior IRS PLRs to support its position, Garrett argues that PLRs generally are issued in response to an individual taxpayer's inquiry based on specific facts and laws in effect at the time, are directed to the specific taxpayer, and are not precedential.[383] In any event, Public Counsel argues that none of the PLRs to which PSE cites actually address the treatment of protected EDIT under the tax laws created by the TCJA.[384]

340 Garrett recommends that the Commission require PSE to defer amortized PP EDIT collected between January 1, 2018, and February 28, 2019, to a regulatory liability account and return the balance to ratepayers over a two-year period. Public Counsel argues that because the ARAM reversal period has passed, these funds can be treated as unprotected at the Commission's discretion.[385] Public Counsel testifies that the amount of PP EDIT amortized was $27 million for electric and $7 million for natural gas.[386] Finally, Garrett argues that a rider should be used to refund ratepayers, which should include a true-up to ensure the entire liability is credited to customers.[387]

341 AWEC also disagrees with PSE's interpretation of IRS normalization requirements, arguing that other major utilities in Washington and other states have deferred and

---

[381] *Id.* at 52:4-12 and 53:1-14. *See Wash. Utils. and Transp. Comm'n v. Cascade Natural Gas Corp.*, Docket UG-170929, Order 06 ¶ 39 (July 20, 2018).

[382] Garrett, Exh. MEG-1T at 53:15-54:2.

[383] *Id.* at 54:16-19.

[384] *Id.* at 54:20-55:8.

[385] *Id.* at 55:16-21. The reversal period refers to the time period that the over-collection occurred, January 2018 through February 2019, or 14 months. Because more than 14 months will have passed from the rate effective period in this proceeding, Public Counsel argues that the required ARAM normalization period has expired.

[386] *Id.* at 56:1-4.

[387] *Id.* at 56:9-11.

returned PP EDIT to customers without arguing that a deferral violates IRS normalization rules.[388] For Washington utilities, AWEC points to Dockets UG-170929 (Cascade's 2018 GRC) and UG-181053 (Northwest Natural Gas, d/b/a NW Natural's (NW Natural) 2019 GRC) where the Commission ordered the deferral and return of PP EDIT to customers. AWEC also points to an Oregon Public Utility Commission order requiring Portland General and Electric to return protected EDIT to customers.[389] Further, Mullins argues that if PSE's normalization theories were accurate, all of the above-referenced utilities would be in violation of IRS normalization rules.[390]

342 AWEC witness Mullins explains that the IRS is in the process of drafting guidance on the application of the TCJA normalization requirements. As part of that process, the IRS solicited comments from interested persons.[391] Mullins notes that PSE did not submit comments in response to the IRS Notice, but the Commission filed comments addressing the normalization issues that PSE now raises. While resolution of Notice 2019-33 may be uncertain, AWEC rejects PSE's normalization theory as inconsistent with that of its industry peers, including the Edison Electric Institute and the American Gas Association.[392]

343 AWEC recommends that PSE maintain Schedule 141X for both electric and gas customers and reverse the ERF PP EDIT over four years and perform an annual check similar to the treatment the Commission required in Docket UG-170929.[393] AWEC also recommends increasing rate base to offset the amount of the pass back to ratepayers through Schedule 141X.[394] AWEC argues that this recommendation will not result in an IRS normalization violation based on the tax law enacted by the TCJA.[395]

---

[388] Mullins, Exh. BGM-1T at 25:18-20.

[389] *Id.* at 26:1-19.

[390] *Id.* at 27:1-3.

[391] *Id.* at 27:5-11.

[392] *Id.* at 28:1-9.

[393] *Id.* at 30:1-31:2. Mullins refers to the ERF PP EDIT for the period from January 1, 2018, through February 29, 2019, as the "interim period EDIT."

[394] *Id.* at 31:11-16.

[395] *Id.* at 31:19-32:5; *see also* Mullins, Exh. BGM-6 (including copy of TCJA, 26 U.S.C. § 1561).

344 Mullins separately identifies an additional reduction to rate base for the amounts of PP EDIT currently being returned to customers through Schedule 141X that PSE did not include in its revenue requirement adjustment. AWEC states the amounts are $29 million for electric and $7.5 million for natural gas.[396] Applying the totality of AWEC's recommendation regarding PP EDIT reversals results in revenue requirement decreases of $5.7 million and $1.5 million to electric and natural gas operations, respectively.[397]

345 On rebuttal, PSE acknowledges that PSE's approach is not the only correct one, but argues that it complies with all normalization rules.[398] PSE disagrees with Public Counsel's position that PP EDIT amounts become unprotected once EDIT reverses, arguing that this demonstrates Public Counsel's misunderstanding of the ARAM requirement. PSE argues that the "ARAM rule" only controls the speed limit, and does not replace IRS normalization rules; as such, ARAM amortizations never become unprotected.[399]

346 Additionally, PSE witness Marcelia argues that Garrett mischaracterizes the ERF Settlement of PP EDIT issues. PSE argues that the ERF Settlement matched PP EDIT reversal with depreciation expense and rate base (including accumulated deferred income taxes, or ADIT) for the ERF's rate effective period. Further, Marcelia asserts that Schedule 141X did not return to customers "prospective refunds" of EDIT, it simply provided EDIT reversals in rates to match booked depreciation that was also in rates.[400]

347 PSE next argues it is not advocating to transfer PP EDIT reversals to shareholders as Public Counsel claims. Rather, PSE contends that it applied the PP EDIT reversals as a benefit to offset costs in the GRC historical test year to lower rates for ratepayers. PSE assumes that Public Counsel has confused the issue of PP EDIT with the over-collection

---

[396] Mullins, Exh. BGM-1T at 34:16-23.

[397] *Id.* at 35:1-5.

[398] Marcelia, Exh. MRM-11T at 30:1-8.

[399] *Id.* at 30:9-19.

[400] *Id.* at 57:1-12.

of tax expense that PSE is passing back.[401] PSE argues that its approach complies with IRS normalization rules and achieves the lowest rates possible.[402]

348 In response to both Public Counsel and AWEC, PSE argues that comparing this case to other Washington utility filings that have addressed the TCJA is not appropriate. First, Marcelia argues that Cascade and Avista filed their rate cases prior to the TCJA, and therefore did not have any PP EDIT reversals to include in their respective test years. With respect to NW Natural, Marcelia argues that the company had a deferred PP EDIT account that was not part of the tax expense included in the revenue requirement.[403] Finally, Marcelia argues that none of the other utility filings addressed the IRS consistency rule.[404]

349 Turning to Public Counsel's examples of other national utilities, Marcelia argues that none of the six examples have historical test years that include all of 2018. Further, PSE asserts that it is unclear that the deferral mechanism examples provided by Public Counsel will not violate IRS normalization rules.[405] Finally, Marcelia argues that Garrett provides no evidence from other states that have considered the IRS consistency rule in the same manner as PSE.[406]

350 PSE also responds to Mullins's reference to IRS Notice 2019-33 regarding normalization guidance, arguing that neither the Commission nor PSE can wait for guidance, but instead must rely on existing IRS rules.[407] Although PSE concedes that the Commission has the ultimate authority to determine PSE's PP EDIT reversal methods and mechanisms, the Company argues that the Commission's determination must not conflict with IRS normalization rules.[408]

---

[401] *Id.* at 58:5-15.

[402] *Id.* at 58:16-17.

[403] *Id.* at 38:8-19, 39:13-22, 40:1-15.

[404] *Id.* at 60:8-9, 61:10-11.

[405] *Id.* at 62:1-63:3.

[406] *Id.* at 66:16-19.

[407] *Id.* at 44:9-13.

[408] *Id.* at 45:17-46:2.

351 Finally, responding to Mullins, PSE argues that it did not retain the ERF PP EDIT reversals. PSE claims that this tax reform benefit was used to eliminate or reduce the ERF revenue increase for electric and natural gas, respectively.[409] PSE argues that not only does Mullins's recommendation challenge IRS consistency rules, it also requires that PSE provide the same benefit to ratepayers twice.[410] PSE contends that, for these reasons, the Commission should not adopt the recommendation to refund customers the ERF PP EDIT reversals.[411] Additionally, PSE supports using Schedule 141X to "capture the cleanup of the EDIT associated with the [ERF] period."[412]

352 In response to Staff, PSE opposes Steward's recommendation to defer PP EDIT to a regulatory liability account because it would impair the Company's ability to effectively use its PowerTax software.[413] PSE does not support Staff's proposal to separate PP EDIT reversals from PSE's rate base and pass them back through Schedule 141X because the Company believes it would create complexity and confusion rather than clarity. PSE also opposes Staff's recommendation to update Schedule 141X annually for the prior year's PP EDIT reversal because that recommendation violates IRS consistency rules.[414]

353 Finally, Marcelia argues that PSE would not receive protections under the IRS safe harbor provision,[415] as Staff suggests, because PSE specifically addresses IRS normalization in this GRC. By doing so, the Commission is now required to consider and address normalization in establishing or approving rates. According to PSE, the Commission's consideration of the issue means that the violation would not qualify as "inadvertent nor unintentional."[416]

---

[409] *Id.* at 46:3-19.

[410] *Id.* at 47:7-10.

[411] *Id.* at 49:15-50:6.

[412] *Id.* at 50:7-18.

[413] *Id.* at 52:18-53:3.

[414] *Id.* at 53:4-55:2.

[415] IRS Rev. Proc. 2017-47.

[416] Marcelia, Exh. MRM-11T at 55:14-56:15.

354 PSE acknowledges that its approach to tax reform is an outlier, and notes that the Company has historically been an outlier as it relates to IRS normalization rules.[417] PSE claims that in 2007, it was the only utility in Washington, and perhaps the country, that understood the importance of IRS normalization rules.[418] PSE states, in no uncertain terms, that it will challenge the Commission's decision if its proposal is rejected. If the Commission still refuses to concede, PSE states that it will seek a PLR from the IRS. PSE notes that this approach is less desirable due to the length of time it takes to obtain a PLR.[419]

355 In its brief, Staff argues that PSE should continue to reverse PP EDIT using Schedule 141X, which should be updated annually to set the PP EDIT reversal amount for each subsequent rate year. Absent the separate schedule, Staff argues, it will be impossible to tell how much PP EDIT has been returned to ratepayers and how much PSE has simply absorbed.

356 Staff further argues that PSE proposes to incorporate PP EDIT into the revenue requirement so that it becomes one of the many inputs into the ratemaking formula used to calculate rates. Under this proposal, Staff contends, PP EDIT amortizations may offset other elements in the ratemaking formula, but the amount PSE has returned to ratepayers in any given year will never be clear. Staff also argues that its proposal for an annual update to Schedule 141X alleviates concerns about violating IRS Normalization rules.

357 Staff notes that at hearing, PSE witness Doyle conceded that the annual update to Schedule 141X "could work,"[420] and expresses concern that PSE witnesses Doyle and Marcelia are unable to agree on whether every dollar of PP EDIT would be returned to customers.[421] Staff argues that transparency can be achieved by requiring PSE to continue to return PP EDIT to customers through Schedule 141X, which will allow the Commission to track the amount of PP EDIT that has been returned to customers, receive annual updates on PP EDIT amortizations, and evaluate whether PSE is meeting the Commission's expectations with respect to the return of PP EDIT to ratepayers.

---

[417] *Id.* at 71:17-20.

[418] *Id.* at 71:21-72:4.

[419] *Id.* at 73:5-11.

[420] Staff Initial Brief ¶ 121 (citing Doyle, TR 370:19-22; 373:25-374:9).

[421] *Id.* ¶ 122 (citing Doyle, TR 377:3-10; Marcelia, TR 388:18-398:11).

358 In its initial brief, Public Counsel argues that it disagrees with PSE's proposal regarding PP EDIT for the period January 1, 2018, through February 28, 2019, because PSE treats that amount as current income, thereby improperly transferring the TCJA benefit from ratepayers to PSE's shareholders.

359 Like Staff, Public Counsel is not persuaded that returning PP EDIT through a separate schedule would violate IRS Normalization rules. Public Counsel observes that IRS normalization rules did not prevent Avista or Cascade from returning PP EDIT to its customers.

360 PSE argues in its brief that opposing parties are ignoring the general ratemaking principle of single-issue ratemaking by attempting to treat PP EDIT differently than the underlying rate base, book depreciation, tax expense, and ADIT to which it is tied. According to PSE, singling out PP EDIT for reversal in a manner that differs from the ratemaking treatment for these other items is single-issue ratemaking that excludes offsetting factors that may otherwise need to be considered in the broader ratemaking context. PSE argues that a previous PLR it received from the IRS demonstrates that consistent treatment is required in ratemaking as well as accounting.

361 PSE criticizes AWEC's proposal for reversing PP EDIT both for violating "consistency rules" and reversing the same deferred benefits back to customers twice. PSE contends that AWEC's proposal would provide customers the benefit of PP EDIT reversals in the test year as PSE has done, and would defer and amortize over four years those same PP EDIT reversals.

362 PSE argues that Public Counsel's proposal suffers from the same flaws as AWEC's proposal, and both misapply standard ratemaking protocols, which are constructed to ensure that components of revenue requirement are not double counted.

363 PSE further argues that the TCJA includes an additional penalty for violations of IRS Normalization rules because it "requires that the utility's tax be increased by the amount that the utility has passed back to customers beyond what is allowed under normalization and consistency rules."[422] In addition, existing penalties for a normalization violation

---

[422] PSE Initial Brief ¶ 68.

would prohibit PSE from using accelerated tax depreciation, which, the Company argues, "would have a dire impact on PSE and its customers."[423]

364 In its reply brief, PSE argues that Staff mischaracterizes Doyle's testimony that Schedule 141X could work. Rather, PSE argues that any PP EDIT tracker must also track the other items that are components of the "consistency rule": rate base, book depreciation, tax expense, and ADIT. PSE offers that it could update the Commission and parties on the amortization of the PP EDIT on the accounting books and the reversal of PP EDIT through rates without creating a tracker. According to PSE, the book amortization of PP EDIT and the reversal in rates of PP EDIT will follow different pathways due to the ratemaking process, but customers will ultimately receive the full credit—and likely more—from the reversal of PP EDIT.

Commission Determination

365 We require PSE to continue to utilize Schedule 141X to return PP EDIT to customers consistent with ARAM. Specifically, we direct PSE to: (1) defer all PP EDIT balances in FERC Accounts 282, grossed-up, to separate FERC Accounts 254 – Other Regulatory Liabilities, for both electric and natural gas; (2) separate the PP EDIT ARAM reversal from PSE's proposed federal income tax revenue requirement adjustment (20.03 ER and 20.03 GR);[424] (3) separate the PP EDIT ARAM reversal adjustments from PSE's proposed Colstrip depreciation adjustment (21.07 ER); (4) return grossed-up PP EDIT reversals (unadjusted for "flow-through reversal") to customers through Schedule 141X on a going-forward basis; (5) annually update Schedule 141X for the current year's PP EDIT reversals consistent with ARAM; and (6) annually true-up each previous year's return of PP EDIT reversal amounts with actual amounts returned through volumetric rates.

366 PSE must submit its annual filing no later than June 20 of each year going forward to update Schedule 141X for that year's ARAM reversal and to true-up the prior period

---

[423] *Id.*

[424] We note that PSE's proposed restating FIT adjustments, 20.03, included PP EDIT impact on NOI by a corresponding impact on rate base. It appears that PSE's own base rate treatment of PP EDIT is inconsistent because it does not adjust rate base upward to match its inclusion in tax expense. Removing adjustments to EDIT from base rates avoids overly-burdensome complexity and provides greater transparency.

reversals with amounts actually refunded through volumetric rates. Allocation of ARAM will be based on class usage and refunded on a volumetric basis.

367 We address the Company's arguments related to the IRS "consistency rule" and the Company's reliance on IRS PLRs, as well as single-issue ratemaking, in turn, below. Finally, we resolve Public Counsel's and AWEC's issues related to PP EDIT amounts captured by the ERF Settlement.

368 **IRS Rules and PLRs.** First, PSE asserts that continuing to return PP EDIT using Schedule 141X would violate the IRS "consistency rule," which is a section of the IRS Normalization rules that addresses "use of inconsistent estimates and projections." We disagree. PSE's argument that reversing PP EDIT using a separate schedule would somehow result in the use of inconsistent estimates and projections is without merit.

369 As each of the other parties observes, PP EDIT amounts PSE owes to customers are neither estimated nor projected. Rather, they are actual amounts that PSE collected from customers through December 31, 2017, that PSE must return to customers, dollar for dollar. As illustrated in Table 2, above, PSE owes ratepayers a combined total of $815.4 million in PP EDIT (before gross-up) for both electric and natural gas, less any amount reversed through Schedule 141X as a result of the ERF Settlement. This reflects the *actual amount* PSE collected from and owes to customers and is not subject to adjustment or modification (excluding the deregulation or sale of the underlying asset). As such, the so-called "consistency rule" has no application to the means and mechanisms by which the Commission may require PSE to return these monies.

370 We thus agree that PSE should continue to reverse PP EDIT using Schedule 141X, which should be updated annually to set the PP EDIT reversals for each subsequent rate year. Staff correctly observes that, absent the separate schedule, it will be impossible to determine how much PP EDIT has been returned to ratepayers and how much PSE has simply absorbed. Again, PP EDIT represents monies paid by ratepayers for taxes that PSE deferred due to the timing difference between when tax is collected from the Company's customers and when the Company pays those taxes to the IRS. As such, we agree with Staff and Public Counsel that amounts over-collected from customers must be returned on a dollar-for-dollar basis in order for rates to be fair, just, reasonable, and sufficient.

371 Moreover, we are concerned that PSE has included PP EDIT reversals the Company owes to customers in its adjusted revenue requirement calculation. The Commission's direction to all regulated utilities was to "track federal tax savings resulting from the [TCJA] to ensure those savings will benefit utility customers."[425] The Commission's expectation was that regulated companies would place those over-collected funds owed to ratepayers in a separate account for tracking purposes, not commingle those amounts with base rates going forward from the effective date of the TCJA. Although the Commission did not formally resolve that issue until it entered this Order, we note that PSE failed to follow the Commission's general direction and appears to be attempting to benefit from money that does not belong to it.

372 Second, PSE's reliance on PLRs to support its position is misplaced. Specifically, PSE provides examples in the context of assets that are sold or deregulated, neither of which has relevant application here. Moreover, PLRs are issued in response to specific taxpayer questions, apply only to the matter at hand, and are non-precedential. The PLRs on which PSE relies are not instructive as to whether the Company may defer and use a separate schedule to return PP EDIT in the context of this general rate proceeding. As AWEC correctly observes, the IRS has yet to weigh in on inconsistency issues related to the TCJA. Until the IRS provides such guidance, we decline to give any weight to irrelevant PLRs and PSE's use of inconsistent estimates and projections under its interpretation of the IRS Normalization rules. If PSE seeks a PLR from the IRS on this subject, the Company should include the Commission in that process.

373 **Single Issue Ratemaking.** PSE next argues that singling out PP EDIT for reversal in a manner that differs from the ratemaking treatment for related items is single-issue ratemaking that excludes offsetting factors that may otherwise need to be considered in the broader ratemaking context. We disagree. The amount of PP EDIT PSE owes to customers is an actual and known quantity, and has no "offsetting factors." Nor does it need to be "considered in a broader ratemaking context." The money will never have to be paid to the IRS and simply needs to be returned to ratepayers, dollar for dollar, in a transparent way that ensures the public interest is protected and that rates collected by the Company are fair, just, reasonable, and sufficient. We note that no other utility in Washington has taken PSE's position. More importantly, the Commission has not allowed regulated utilities to retain *any* tax benefits related to TCJA. We decline to do so now.

---

[425] *See* Commission Press Release dated Jan. 8, 2018.

374 **ERF PP EDIT Amounts.** The ERF Settlement provided that: (1) PSE would create a separate tariff Schedule 141X for the pass back of PP EDIT consistent with ARAM; (2) the grossed-up, annualized PP EDIT reversals consistent with ARAM were $25.9 million for electric and $6.1 million for gas based on PP EDIT reversals in the 2018 period; (3) Schedule 141X rates would be reviewed in PSE's next GRC; (4) the Settling Parties did not agree on the proper accounting and ratemaking treatment of the PP EDIT reversals for the period January 1, 2018, through February 28, 2019; and (5) the disposition and proper ratemaking treatment of those reversals would be addressed in the Company's next GRC.[426]

375 On behalf of AWEC, Mullins testifies that the parties to the ERF settlement agreed that PSE would amortize and track annual amounts of PP EDIT through the newly created Schedule 141X for both electric and natural gas. According to Mullins, PSE began amortizing $25.9 million in PP EDIT for electric services and $6.1 million of PP EDIT for gas services on March 1, 2019.[427] Mullins explains that the parties agreed that PSE would return the PP EDIT on a going-forward basis, but were unable to agree on the accounting and proper ratemaking treatment of PP EDIT reversals for the period between January 1, 2018, and February 28, 2019. As such, Mullins asserts that the resolution of the ratemaking treatment of ARAM reversals over the 14-month period from January 1, 2018, through February 28, 2019, should be addressed in this proceeding.[428]

376 Similarly, Public Counsel recommends that PSE defer amortized PP EDIT collected between January 1, 2018, and February 28, 2019, to a regulatory liability account and return the balance to ratepayers over a two-year period. Public Counsel argues that because the ARAM reversal period has passed, these funds can be treated as unprotected at the Commission's discretion.

377 AWEC's and Public Counsel's proposals expose a fundamental misunderstanding by some ERF settling parties. Both Public Counsel and AWEC appear to believe that the amounts returned through Schedule 141X beginning on March 1, 2019, do not include

---

[426] PSE lacks any basis for its claim that its EDIT treatment in its ERF litigated position is foundational and applies to the Settlement. We note that the ERF revenue requirement Settlement was a "black-box," and the parties did not agree to any specific adjustment or treatment. The Settlement provides for no overall electric rate change and a natural gas revenue increase, which includes the effect of refunded PP EDIT.

[427] Mullins, Exh. BGM-1T at 21:7-12.

[428] *Id.* at 21:22-22:5.

amounts that represent the ARAM period of January through December 2018. This is incorrect. PSE is currently returning PP EDIT to customers for the 2018 ARAM period through Schedule 141X.

378 The "interim period" PP EDIT reversal to which Public Counsel and AWEC refer represents the PP EDIT reversals that occurred from January 1, 2018, to February 28, 2019, which was one day prior to the Company's new rates taking effect on March 1, 2019, pursuant to the Commission's approval of PSE's ERF. The ERF Settlement established Schedule 141X to pass back grossed-up 2018 annualized PP EDIT reversals of $25.9 million for electric and $6.1 million for gas. Schedule 141X continues to return grossed-up 2018 annualized PP EDIT to ratepayers.

379 Public Counsel and AWEC are correct, however, that the Commission did not resolve the issue of proper accounting and ratemaking treatment for January and February 2019 PP EDIT. The ERF settlement neither resolved the proper accounting treatment of the "interim" PP EDIT nor contemplated resolving EDIT in its entirety. As described above, we resolve those issues here by requiring PSE to defer PP EDIT and UP EDIT into separate regulatory liability accounts for both electric and natural gas operations, less the amounts that have already been passed pack to ratepayers through Schedule 141X.

380 PSE must defer PP EDIT balances in FERC Accounts 282 to separate FERC Accounts 254 – Other Regulatory Liabilities, for both electric and natural gas. The amounts deferred for both electric and natural gas operations must be grossed-up and reduced by amounts already refunded through Schedule 141X.

381 The grossed-up annualized amounts of PP EDIT returned through Schedule 141X from March 1, 2019, to February 29, 2020, and from March 1, 2019, to May 19, 2020, reflect the ERF settlement's intent to offset the annual revenue requirement increases with 2018 ARAM reversals totaling $25.9 million for electric and $6.1 million for natural gas.

382 Based on PSE's response to Bench Request No. 13 (BR-13), from March 1, 2019, to February 29, 2020, PSE did not return approximately $3.7 million to electric customers and $0.4 million to natural gas customers. Additionally, from March 1, 2020, to May 19, 2020, PSE continued to pass back approximately $5.7 million and $1.4 million to electric and natural gas customers. Our decision in this Order requires PSE to net these amounts against amounts returned going forward through Schedule 141X, beginning July 20, 2020.

383 We require PSE to return to customers 2019 and 2020 ARAM reversals as reflected in the Company's response to BR-13 through Schedule 141X for both electric and natural gas operations. The 2019 and 2020 ARAM reversals for electric customers are approximately $22 million ($29.3 million grossed-up) and $20.4 million ($27.3 million grossed-up), respectively. For natural gas customers, the 2019 and 2020 ARAM reversals are approximately $5.6 million ($7.5 million grossed-up) and $5.2 million ($6.9 million grossed-up), respectively. We require PSE to return these amounts over a 12-month period beginning July 20, 2020.

viii. Colstrip Issues

384 In its initial filing, PSE removes undepreciated plant for Colstrip Units 1 and 2 from test year rate base and accelerates the depreciation rate on the remaining plant balances for Colstrip Units 3 and 4 through December 31, 2025, consistent with the requirements of the Clean Energy Transformation Act (CETA).[429]

385 In its 2017 GRC, PSE hired an engineering firm to complete a depreciation study.[430] For the purposes of this proceeding, the same firm performed limited updates to the study to evaluate PSE's depreciation rates for Colstrip Units 3 and 4 in light of CETA.[431]

386 Based on the Company's new depreciation study, PSE witness Free adjusts Colstrip Units 3 and 4 depreciation to ensure the plant will be "fully depreciated by December 31, 2025, as required by [CETA]."[432] Free also removes the restated level of depreciation expense for Colstrip Units 1 and 2.[433]

387 For this case only, Staff witness McGuire recommends the Commission approve PSE's proposal to recover decommissioning and remediation (D&R) costs for Colstrip Units 3 and 4 through depreciation accelerated to 2025.[434] McGuire observes that PSE's proposed

---

[429] Free, Exh. SEF-1T at 67:19-68:2.

[430] *Id.* at 67:14-18.

[431] *Id.* at 67:14-18.

[432] *Id.* at 67:19-22. PSE witness Spanos provides the depreciation schedule. *See* Spanos, Exh. JJS-3.

[433] Free, Exh. SEF-1T at 67:22-68:2.

[434] McGuire, Exh. CRM-1T at 31:7-10.

rates include recovery of $73.2 million in D&R costs over the remaining book life of Colstrip Units 3 and 4, adding $10.8 million to annual depreciation expense.[435]

388 McGuire opines that this method of recovery may not comply with CETA unless additional measures are put in place to ensure that only actual D&R costs are recovered from customers. CETA requires that coal-fired generation costs be removed from rates by the end of 2025, but expressly provides that this does not include the costs associated with decommissioning and remediation.[436] Based on the statutory language, McGuire argues, PSE was not required to propose accelerated recovery of projected D&R costs to 2025, but did so anyway. McGuire observes that the proposed accelerated recovery would be standard under the traditional method of recovering D&R costs, which is over the useful life of an asset. According to McGuire, the acceleration that CETA requires could aggravate intergenerational inequity, and thus presents new policy considerations.[437] Finally, because the D&R costs are estimated and, under CETA, only "prudently incurred" costs can be recovered from ratepayers, McGuire contends that a tracking and true-up mechanism is needed for D&R costs.

389 McGuire recommends that the Commission order PSE to file a proposed plan for the recovery of D&R costs for Colstrip Units 3 and 4 that complies with the D&R provisions of CETA in its next GRC, and to include in that plan an assessment of production tax credits (PTCs) available to offset D&R costs for Colstrip Units 3 and 4.[438] McGuire argues that PSE should create a tracking and true-up mechanism for those costs in case the available PTCs do not cover the ultimate D&R costs for Units 3 and 4. Alternatively, McGuire suggests that the Commission could order PSE to remove D&R costs for Units 3 and 4 from rates now in light of the fact that PTCs will likely be available to offset those costs. Staff emphasizes that the latter proposal is not its primary recommendation due to the "substantial uncertainty with respect to when Units 3 and 4 will actually close."[439]

---

[435] *Id.* at 34:16-18.

[436] *Id.* at 35:5-36:5.

[437] *Id.* at 35:5-36:5.

[438] *Id.* at 31:11-14.

[439] *Id.* at 39:5-8.

390 Finally, Staff recommends the Commission provide notice in this proceeding that it will address the recovery of D&R costs, and Microsoft's fair share thereof, in PSE's next GRC.[440]

391 AWEC argues that PSE did not properly apply the PTC regulatory liability balance against the unrecovered plant balances associated with Colstrip Units 1 and 2 according to the terms of the 2017 GRC settlement. AWEC further argues that PSE did not transfer the remaining unrecovered investment balances associated with Colstrip Units 1 and 2 to a regulatory asset, instead including the plant balances for those units in rate base at 2018 levels.[441]

392 With respect to the unrecovered plant balances associated with Colstrip Units 1 and 2, AWEC witness Mullins criticizes PSE's failure to include an additional three months of accumulated depreciation and reversal of ADIT. Mullins argues that the reversal of ADIT will also trigger PP EDIT reversals, which he recommends handling in the unrecovered investment balance rather than through rate base amortization. Based on Mullins's calculations, the unrecovered investment in Units 1 and 2 as of December 31, 2019, will be approximately $30 million less than the amounts PSE included in rate base.[442]

393 Mullins also disagrees with the Company's decision to not apply the monetized PTCs against the regulatory asset balance for Units 1 and 2. According to Mullins, PSE stated in response to an AWEC data request that it did not apply the PTCs because PSE monetized the full balance of PTCs applicable to the unrecovered plant in PSE's 2018 tax return filed in September 2019, beyond the June 30, 2019, pro forma cut off. Mullins disagrees with the Company's decision because he believes PTCs are properly monetized at the time PSE makes estimated quarterly tax payments over the course of the tax year.[443] Mullins also takes issue with PSE's timing of interest accruals on the PTCs, arguing that interest should accrue quarterly rather than annually.[444]

---

[440] *Id.* at 39:20-40:3.

[441] Mullins, Exh BGM-1T at 6:14-19.

[442] *Id.* at 10:1-2.

[443] *Id.* at 12:14-19.

[444] *Id.* at 14:1-7.

394 According to Mullins, the revenue requirement impact of applying the ratemaking treatment required by the 2017 GRC settlement is an approximate $1.6 million reduction to rate base, which leaves a regulatory asset of approximately $16.2 million in rate base. Mullins argues that this amount should be fully offset by future PTC monetization, and that the impact of the rate base reduction is an approximately $16.2 million reduction to revenue requirement for electric services.[445]

395 AWEC recommends the Commission require PSE to (1) transfer the unrecovered plant balances for Colstrip Units 1 and 2 into a regulatory asset account and reduce the balance for the PTCs monetized by PSE as of September 30, 2019, including monetization in 2019; and (2) reduce the annual depreciation expense for Colstrip Units 3 and 4 for the residual PTC regulatory liability amounts.[446]

396 On rebuttal, PSE opposes AWEC's proposal to reduce the Colstrip Units 1 and 2 unrecovered plant asset balance by the ADIT and PP EDIT amounts.[447] PSE witness Marcelia argues that the ADIT should be included in rate base,[448] and that the PP EDIT will reverse itself over time regardless of whether the net plant value of Colstrip Units 1 and 2 is in rate base or in a regulatory asset account. As such, the unrecovered rate base should not be netted against the PP EDIT.[449]

397 PSE also disagrees with AWEC's position that PTCs become monetized on a quarterly basis, instead arguing that the realized benefits are not known until the Company's annual tax return filing date.[450] Marcelia thus opposes AWEC's use of PTCs to immediately lower the depreciation expense for Colstrip Units 3 and 4,[451] arguing that the 2017 GRC settlement agreement requires the PTCs to be applied to unrecovered plant balances once Colstrip Units 3 and 4 are retired, and does not permit PTCs to be used to lower the depreciation expense for those units. Second, Marcelia argues that Mullins fails to

---

[445] *Id.* at 17:1-5

[446] *Id.* at 2:21-3:2.

[447] Marcelia, Exh. MRM-11T at 2:11-16.

[448] *Id.* at 6:21-7:2.

[449] *Id.* at 8:5-7.

[450] *Id.* at 10:18-19.

[451] *Id.* at 15:12-16.

acknowledge that monetization, according to PSE's definition, is required before a benefit is created.

398 In cross-answering testimony, Mullins disagrees with Staff's decision to accept the Company's position to keep the unrecovered plant balances associated with Units 1 and 2 in rate base.[452] According to Mullins, the 2017 GRC settlement agreement provided that if Units 1 and 2 closed prior to the monetization of sufficient PTCs to offset additional unrecovered plant balances for these units, PSE would hold remaining unrecovered plant balances in a regulatory asset in rate base until all plant balances had been recovered through monetized PTC offsets. Because Units 1 and 2 have closed, Mullins argues that there is no need to hold the unrecovered plant balances in rate base because, according to his interpretation, there are sufficient monetized PTCs to offset the entire plant balance for those units.[453]

399 Mullins also provides updates to the unrecovered plant balances for Units 1 and 2 following receipt of additional data request responses from the Company. First, Mullins testifies that the D&R expenditures he speculated were included in the unrecovered investment balances were, in fact, present, and have subsequently been removed by the Company.[454]

400 Finally, Mullins testifies that PSE has agreed to include ADIT in the interest calculation associated with the regulatory liability for monetized PTCs. Mullins nevertheless continues to take issue with the Company's position that it is necessary to consider any additional deferred taxes associated with the regulatory liability in the interest calculation.[455]

401 In its brief, Staff recommends the Commission accept PSE's proposal to collect D&R costs for Units 3 and 4 through accelerated depreciation to 2025. Staff further recommends the Commission order PSE to propose a plan in its next GRC to recover D&R costs at Colstrip Units 3 and 4 so that parties can reach a full resolution of these issues based on a fully developed record.

---

[452] Mullins, Exh. BGM-8T at 4:8-9, 4:13-15.

[453] *Id.* at 5:12-20.

[454] *Id.* at 7:13-17.

[455] *Id.* at 8:2-6.

402 Staff also suggests the Commission interpret RCW 19.405.030 to restrict recovery of D&R costs to the actual, prudently incurred costs rather than restricting the timing of when those costs are recovered. Staff argues that a tracking and true-up mechanism would (1) allow the rates to be based on projected D&R costs; (2) allow cost recovery to continue beyond the facility's service life; (3) enable regular adjustments to capture updated cost estimates, actual expenditures, and prudency disallowances; and (4) ensure that PSE recovers only prudently incurred D&R costs.

403 Staff further argues that both AWEC and PSE ignore CETA's policy implications related to recovering D&R costs. According to Staff, both parties characterize CETA as having little to no impact on the recovery of D&R costs from Colstrip Units 3 & 4, which, Staff asserts, overlooks the new options CETA provides the Commission to address intergenerational equity and the potential restrictions on recovery noted in Staff's brief.

404 Despite interpreting CETA differently than Staff,[456] NWEC agrees in its initial brief with Staff's ultimate conclusion that a tracking and true-up mechanism is needed for D&R costs, noting that any monetized PTCs that remain after offsetting unrecovered plant balances would be available to offset D&R costs for Units 3 and 4.

405 In its initial brief, AWEC argues that its disagreement with PSE about when PTCs become monetized is a policy dispute for the Commission to resolve. Additionally, AWEC argues that PTCs also can be used in this case to reduce PSE's depreciation expense for its interest in Units 3 and 4, which would reduce electric revenue requirement by $23.4 million.

406 PSE argues in its initial brief that PTCs will not be sufficient to cover all D&R costs for Units 3 and 4, claiming that the value of the PTCs available to offset Colstrip expenses has decreased since the 2017 GRC settlement agreement as a result of the TCJA and the reduced corporate tax rate. Accordingly, PSE estimates that the value of the PTCs that

---

[456] NWEC argues that nothing in CETA expressly forbids the collection of D&R costs associated with any generating facility over the course of the life that generating facility. In addition, NWEC contends that current practice dictates that even though these costs are being collected in rates, they are only deemed prudent and allowed to be spent after careful review and consideration by the Commission. According to NWEC, existing practice allows for prudence review, which is consistent with the language in CETA.

eventually will be monetized is approximately $240 million, rather than the $280 million referenced in the settlement.

407 PSE urges the Commission to "leave all opportunities open for addressing recovery of decommissioning and remediation, including to allow these costs in depreciation rates as long as the plant are depreciating."[457] After these sources have been exhausted, PSE agrees with Staff's recommendation to use a tracking and true-up mechanism, and agrees that it will work with Staff to develop a proposal to be filed in its next GRC. PSE suggests that such a mechanism should also be used for Colstrip Units 1 and 2.

408 In the interim, PSE suggests that the tracking of D&R costs for Units 3 and 4 can be accomplished through the Annual Colstrip Report that PSE files in compliance with the 2017 GRC settlement agreement. PSE proposes to add to this report an analysis of the adequacy of the PTCs to cover D&R costs.

409 Finally, PSE argues that the 2017 GRC settlement agreement provides for specific prioritization of the use of PTCs for Colstrip, and does not include offsetting depreciation expense on Colstrip units that are in service and used and useful.

410 In its reply brief, Staff argues that the Commission should accept PSE's offer to include actual D&R expenditures in its Annual Colstrip Report, but reject the Company's suggestion that doing so acts as a sufficient tracker of D&R costs. Staff argues that such a report is not a substitute for a ratemaking tool like a tracking and true-up mechanism because it does not allow for inspection and challenge by other parties. Staff further contends that waiting until PTCs are depleted before initiating a tracking and true-up mechanism would create a risk to future ratepayers.

411 In its reply brief, AWEC reiterates its position that its proposed adjustment related to Colstrip Units 1 and 2 is required by the 2017 GRC settlement agreement. AWEC further argues that PSE mischaracterizes its position, and that it does not propose to use PTCs to reduce depreciation expense at all. Rather, AWEC proposes to use monetized PTCs to offset any unrecovered investment that exists at the end of 2025 when these units must be out of customer rates. Thus, AWEC contends that all of PSE's arguments against its position are misplaced.

---

[457] PSE Initial Brief ¶ 108.

412 AWEC also expresses support for Staff's proposal, and argues that its proposal can coexist with Staff's. First, AWEC contends that its proposal complies with RCW 19.405.030 because it will "ensure that PSE's 'allocation of electricity' from Units 3 and 4 will be eliminated by 2025 by ensuring that any unrecovered investment in these units does not exceed PTCs that will be monetized by 2025."[458] Second, AWEC argues that its proposal recognizes that there is an order of priority prescribed by the 2017 GRC settlement agreement, which requires PTCs first to be used to pay off unrecovered investment in Colstrip, and then to pay for prudently incurred D&R costs. AWEC argues that a tracking and true-up mechanism for D&R costs, some or all of which may be offset by monetized PTCs, is perfectly consistent with this approach so long as PSE first recovers the unrecovered investment in the plant.

413 Finally, AWEC agrees with Staff that the record in this case is insufficient to determine how best to recover prudently incurred D&R costs in excess of amounts assumed in depreciation rates. AWEC states that it has no objection to resolving this issue in PSE's next GRC.

414 In its reply brief, NWEC supports Staff's position to collect D&R costs for Units 3 and 4 through accelerated depreciation to 2025, and also supports Staff recommendation to order PSE to file a plan to address the collection of D&R costs of Colstrip Units 3 and 4 in its next GRC so that parties can address this issue, including how Microsoft will contribute to these costs under its special contract.

415 PSE argues in its reply brief that AWEC's proposal "lacks coherence and makes for poor policy."[459] According to PSE, it is undisputed that there is currently no unrecovered plant balance for Colstrip Units 3 and 4 to which PTCs may be applied, which renders AWEC's reliance on the 2017 GRC settlement agreement erroneous.

416 PSE also disagrees with Staff's suggestion that the 2017 GRC settlement agreement may be inconsistent with CETA. PSE argues that the settlement allows for the use of PTCs to cover D&R costs but does not preclude other methods for recovery such as through depreciation rates. PSE contends that CETA allows prudently incurred D&R costs in rates even after 2025, but also does not prohibit recovery through depreciation rates.

---

[458] AWEC Reply Brief ¶ 17.

[459] PSE Reply Brief ¶ 51.

Commission Determination

417 As a preliminary matter, we note that PSE confirmed at the evidentiary hearing that it removed Colstrip Units 1 and 2 from rate base as of December 31, 2019, and subsequently transferred those assets to a regulatory asset account, which resolves AWEC's first concern.[460]

418 In response to Bench Request No. 14, PSE reports that the unrecovered, undepreciated plant balance for Colstrip 1 and 2, as of the December 31, 2019, retirement date is $125.5 million. Because PSE continues to recover Colstrip 1 and 2 depreciation in base rates through July 20, 2020, this balance requires an additional update. As such, PSE is required in its compliance filing to adjust the established regulatory asset that reflects the unrecovered, undepreciated plant balance as of December 31, 2019, to include depreciation allowed in rates through July 19, 2020, and report the updated balance to the Commission. We address the remaining Colstrip-related issues in turn.

419 **ADIT and PP EDIT.** We reject AWEC's proposal to reduce unrecovered Colstrip 1 and 2 plant balances by related PP EDIT, which would treat the PP EDIT benefit related to Colstrip 1 and 2 as an immediate reduction to the related regulatory asset. This outcome is inconsistent with our decision to return PP EDIT ARAM reversals to customers through a separate tariff schedule. As discussed in Section II(B)(3)(vii) above, we require PSE to separate the PP EDIT ARAM reversals from its proposed Colstrip depreciation adjustment. PSE must defer all PP EDIT to separate liability accounts and pass those amounts back to customers through Schedule 141X according to the schedule the Commission establishes in this Order.

420 We also disagree with AWEC that the regulatory asset established for the unrecovered balance of Colstrip 1 and 2 should be adjusted for ADIT, which, in PSE's books of account, also includes EDIT. We agree with PSE that the regulatory asset balance should reflect the balance related to undepreciated investment (net plant) rather than net rate base. ADIT will thus reverse over time and need not be treated as a lump sum adjustment to the regulatory asset. Accordingly, we decline to require PSE to reduce the unrecovered plant balances for Colstrip Units 1 and 2 by the ADIT amount associated with those units.

---

[460] Free, TR 319:24-320:2.

421 **PTC Monetization.** AWEC argues that PTCs become monetized when PSE makes its quarterly tax filings. We disagree. Quarterly filings are based on estimates of taxable income rather than actual taxable income. As PSE observes, "even the best estimate is in jeopardy of significant modification due to operating activities or changes in tax laws."[461] Because taxable income is not known until the Company files its annual tax return, PTC benefits are not realized, or monetized, until that time. We agree with PSE that it is reasonable to apply the PTC benefit only once the benefit actually is known.

422 AWEC also argues that interest related to PTCs should be accounted for on an estimated quarterly basis. This is inconsistent with both the 2017 GRC Settlement and recent Schedule 95A practice. Because the actual amount of PTCs are not known until they are monetized in the Company's annual federal income tax return, the Colstrip Units 1 and 2 regulatory asset will be offset, and interest will begin to accrue, as PTCs are monetized on an annual basis.

423 Consistent with the settlement agreement in PSE's 2017 GRC, the Company should apply any PTCs that have been monetized as of its 2019 annual tax filing to undepreciated plant balances for Colstrip Units 1 and 2.

424 **Treatment of D&R Costs for Colstrip Units 3 and 4.** We approve PSE's proposal to adjust the annual depreciation expense of Units 3 and 4, a portion of which includes D&R costs, to ensure those plants are fully depreciated by 2025 consistent with CETA. We further require the Company to move all D&R costs associated with Units 3 and 4 to a regulatory asset account for tracking purposes.

425 We agree with Staff that the record in this case does not contain sufficient evidence to decide the complex policy issues related to CETA and the recovery of D&R costs. We thus agree with Staff's recommendation and require PSE to file in its next GRC a proposed plan for the recovery of D&R costs for Colstrip Units 3 and 4 that complies with CETA. PSE should include in that plan its assessment of PTCs available to offset D&R costs for Colstrip Units 3 and 4. We further require PSE and Staff to work together to establish a tracking mechanism for D&R costs for all 4 units, and to present that mechanism for Commission approval in the Company's next GRC.

426 For the purposes of this proceeding, we determine (1) that PSE may continue to recover D&R costs through depreciation rates for Units 3 and 4 and record those costs to a

---

[461] Marcelia, Exh. MRM-11T at 13:11-13.

regulatory asset account; (2) that those amounts will be trued up once the units are retired and the actual D&R costs are known (*i.e.*, incurred); and (3) that the Commission will evaluate the prudency of the actual costs for inclusion in rates or refund once PSE incurs those costs.

427 RCW 19.405.030(1)(b) provides that "[t]he commission shall allow in electric rates all decommissioning and remediation costs prudently incurred by an investor-owned utility for a coal-fired resource." Staff interprets that provision to restrict recovery of D&R costs to the actual, prudently incurred costs rather than restricting the timing of when those costs are recovered. Staff's interpretation is both a reasonable reading of the statute and consistent with the Commission's broad discretion under RCW 80.04.250 to allow provisional recovery of rates, subject to refund, when the property, investment, or project does not meet current standards for inclusion in rates prior to rates becoming effective.[462] Under this process, we allow rates to be recovered but make our final decision on rate recovery in the future after sufficient information about the property, investment, or project in question becomes known and the Commission can evaluate it for prudency. We adopt that approach here with respect to the D&R costs for Colstrip Units 3 and 4.

428 We agree with Staff that, for the purposes of this proceeding, a tracking and true-up mechanism will (1) allow rates to be based on projected D&R costs; (2) allow cost recovery to continue beyond the facility's service life; (3) enable regular adjustments to capture updated cost estimates, actual expenditures, and effects of prudency determinations; and (4) ensure that PSE will recover only prudently incurred D&R costs consistent with RCW 80.04.250, RCW 19.405.030, and Commission practice.

429 We also agree with Staff and require PSE to include actual D&R expenditures in its Annual Colstrip Report, but we reject the Company's suggestion that doing so acts as a sufficient tracker of D&R costs. Staff is correct that the Company's Annul Colstrip Report is not a sufficient substitute for a tracking and true-up mechanism because it does not facilitate transparency. Moreover, waiting until PTCs are depleted before initiating a tracking and true-up mechanism would create an unnecessary delay with no corresponding benefit.

---

[462] *In the Matter of the Commission Inquiry into the Valuation of Public Service Company Property that Becomes Used and Useful after Rate Effective Date*, Docket U-190531, Policy Statement on Property that Becomes Used and Useful After Rate Effective Date ¶ 20. (Jan. 31, 2020).

430 Finally, we grant Staff's request and provide notice in this proceeding that the Commission will address the recovery of D&R costs, and Microsoft's fair share thereof, in PSE's next GRC with the same caveat that the prudency review of all D&R costs will occur after those costs are incurred.

4. ACCOUNTING PETITIONS

i. Get to Zero

431 On April 10, 2019, PSE filed with the Commission a petition for an order authorizing deferral of certain expenses related to the Company's investments in short-lived technology assets as part of its Get to Zero (GTZ) program in Dockets UE-190274 and UG-190275 (GTZ Petition). PSE requests that the Commission approve the deferred accounting and ratemaking treatment for the depreciation expense associated with GTZ program related assets associated with non-revenue producing plant. Specifically, PSE seeks to use deferred accounting to allow for later consideration of PSE's recovery in rates of the depreciation expenses associated with the GTZ investments that have a book life of 10 years or less.

432 In its GTZ Petition, PSE argues that the regulatory lag associated with technology assets has a far greater impact on earnings erosion than typical transmission and distribution expenditures due to the shorter lives of the assets and the resulting impact on the Company's depreciation expense. Unlike transmission and distribution assets, which PSE asserts have depreciable lives that range from 30 to 50 years, technology investments typically have a depreciable life of 10 years or less, and sometimes of only three to five years. Accordingly, PSE argues that the "impact of the 27-month regulatory lag is far greater on these short-lived assets and creates significant earnings erosion if not addressed."[463] According to PSE, the recovery lost due to regulatory lag is approximately 8 percent for a transmission and distribution investment, compared to a loss of approximately 45 percent for a technology asset with a much shorter depreciable life.

433 PSE specifically seeks an order authorizing the use of deferred accounting to allow for later consideration of PSE's recovery in rates of the depreciation expense associated with

---

[463] GTZ Petition ¶ 7. In a footnote to paragraph 7, PSE explains its position that "[u]nder AMA ratemaking, it takes a full 13 months for the asset to be fully reflected in customer rates [that,] when combined with case preparation time (a minimum of 3 months) along with the 11 month procedural timeline, results in at least 27 months of regulatory lag."

the GTZ investments with a book life of 10 years or less. Deferral of the investment would continue until the investment was incorporated into rates.

434 PSE requests that the deferral mechanism be ongoing, which would allow this process to continue for any future qualifying GTZ investment placed in service after rates are established in order to preserve PSE's ability to recover its costs from customers. PSE argues that the proposed accounting treatment is consistent with the Commission's previous orders on deferred cost recovery because it does not seek preapproval of any future investments and acknowledges that prudence would be addressed in a future proceeding. PSE proposes that the deferral would include a monthly carrying charge equal to the current ROR, which would cease when the investment was placed into rates in a future proceeding.

435 Staff recommends the Commission (1) allow deferred depreciation for the projects that meet Staff's materiality threshold; (2) deny the request to include a carrying charge on the deferral balance; and (3) deny the request for open-ended deferred accounting treatment for unidentified future projects.[464]

436 Staff argues that the Commission typically authorizes deferred accounting treatment to help mitigate the financial impact of large, unexpected costs that could not have been considered when setting rates and is thus reserved for extraordinary circumstances. According to Staff, extraordinary circumstances are those that are beyond a regulated company's control and generate costs that have a material impact on a company's financial results.[465]

437 Staff believes that PSE is facing extraordinary circumstances due to technological changes that have disrupted the traditional business model, and that the GTZ Petition will have a material impact on the Company's financial results. Staff recommends the Commission apply Staff's proposed materiality threshold to determine whether an individual adjustment contributes materially to a company's financial results. Using Staff's proposed threshold reduces PSE's requested deferred depreciation expense from approximately $30.6 million to approximately $16.7 million.

---

[464] Higby, Exh. ANH-1T at 27:17-22.

[465] *Id.* at 29:2-4.

438 Staff argues that the Commission should reject PSE's proposed carrying charge because deferred accounting for GTZ investments represents extraordinary treatment of depreciation expense, extending even to those expenses PSE occurred during a rate period when the Commission had already determined rates to be sufficient. Staff notes in its brief that PSE's request essentially posits that rates are insufficient before they even take effect, and notes that the deferral would likely overlap with the test year for the Company's next GRC, which would further complicate matters.

439 Finally, Staff opposes ongoing deferred accounting treatment for unidentified future investments because it is not possible to identify in advance whether extraordinary circumstances warranting such treatment exist, nor is it possible to assess materiality when rates for future periods have not yet been authorized.

440 In its brief, PSE argues that Staff's characterization is false because PSE would only defer depreciation on projects that were used and useful and in service at the time they were deferred. PSE also disagrees with Staff's claim that deferred accounting is reserved for extraordinary events, arguing that the Commission has used deferred accounting to capture a wide range of costs and benefits without limiting it to extraordinary events.

Commission Determination

441 For GTZ investments with a book life of 10 years or less, we authorize PSE to defer the depreciation expense that the Company has incurred, or will incur, outside of the test year used in the Company's next GRC. We agree with Staff and the Company that deferred accounting treatment is appropriate because, absent such treatment, the Company is likely to experience earnings erosion between rate cases due to the short-lived nature of the assets. Accordingly, we agree that the Company is faced with extraordinary circumstances that warrant deferred accounting treatment.

442 We decline, however, to authorize the Company's proposed ongoing deferral. Allowing pro forma plant additions through December 31, 2019, in this proceeding, coupled with the additional deferral we authorize until the Company's next GRC, will create a baseline amount of investment in forthcoming test years that will alleviate the need for an ongoing deferral.

443 With an established timeframe for the deferral in place, we are comfortable authorizing a carrying charge equal to the quarterly rate published by the Federal Energy Regulatory

Commission. As is the case with all accounting petitions, we reserve our prudency determination for the Company's next GRC.

444 We are less concerned with the issue Staff raises related to materiality. As we discuss in Section II(B)(7)(i) of this Order, we decline to adopt any broad standard for establishing materiality, instead evaluating pro forma adjustments on a case-by-case basis for inclusion in rates. As Staff's analysis of its proposed materiality threshold highlights, materiality is a regulatory concept that has become increasingly arbitrary and less relevant over time. Because technology evolves rapidly, adopting any broad standard would likely require constant exceptions to effect just results. The Commission prefers to remain flexible so that when unique circumstances arise, our evaluation is not unnecessarily constrained by self-imposed restrictions.

ii. Green Direct

445 On November 27, 2019, PSE filed with the Commission a petition (Green Direct Petition) for an order authorizing deferred accounting treatment for liquidated damages (LDs) accruing under Schedule 139, Voluntary Long Term Renewable Energy Purchase Rider in Dockets UE-190991 and UG-190992. The Green Direct Petition seeks authority for PSE to defer LDs and use them to offset other voluntary long-term renewable energy program costs.

446 Schedule 139 was originally filed in Docket UE-160977 pursuant to RCW 19.29A.090(1), which requires electric companies to offer retail electricity customers qualified alternative energy resources. In April 2017, PSE entered into an initial PPA with Skookumchuck Wind Energy Project, LLC, for the output of its 136.8 MW wind project. The anticipated commercial operation date was on or before December 31, 2018. Once the Commission approved Schedule 139, PSE enrolled 21 of its corporate and government customers in Green Direct's first offering, which was set to commence in January 2019. Due to permitting issues, the Skookumchuck Wind Energy Project (Skookumchuck Project) was delayed until the first quarter of 2020. [466]

---

[466] *In the Matter of the Petition of Puget Sound Energy for an Order Authorizing Deferral Accounting for Liquidated Damages Under Schedule 139 Voluntary Long Term Renewable Energy Purchase Rider*, Dockets UE-190991 and UG-190992 (*Consolidated*) ¶ 6 (Nov. 27, 2019) [hereinafter Green Direct Petition].

447 In January 2018, PSE signed an amended PPA that delayed the Skookumchuck Project commercial operation date until December 31, 2019. As a result of the delays, PSE receives LDs under the terms of the PPA.

448 PSE seeks authority to defer current and future LDs to be used to offset Schedule 139 costs that are not already covered under the Schedule 139 tariff, such as purchasing Renewable Energy Credits (RECs) for Schedule 139 customers to replace renewable energy that the Skookumchuck Project would have otherwise provided. PSE intends to purchase RECs for its Schedule 139 customers to cover the period from July 2019 until commencement of the Green Direct program. As such, PSE requests to offset the deferred LDs with the cost of the RECs purchased on behalf of the Green Direct program prior to the start of the program.

449 PSE also anticipates that there will be a remaining balance of deferred LDs after the purchase of pre-program RECs. The Company proposes that the balance be applied to costs incurred but not originally included in Schedule 139 rates, such as REC purchases to assist customers if projected generation falls short of program usage, or additional program costs not already covered under the Schedule 139 tariff. PSE proposes that, if the credit balance in the deferral account cannot be fully offset by costs, the balance, if material, could be used to adjust Schedule 139 rates in the future.

450 In its brief, Staff recommends the Commission approve the Green Direct Petition. Staff notes that PSE has pledged to use the LDs to offset certain Green Direct costs, and argues that the Commission should approve the Petition on that basis subject to the condition that PSE not discriminate between Green Direct customers when using the LDs to offset costs, which will ensure that the Green Direct program complies with RCW 19.29A.090, RCW 80.28.090, and RCW 80.28.100.

451 Public Counsel argues that the LDs should not be used to purchase RECs or be deferred for theoretical future expenses related to the Green Direct Program. Rather, these funds should be used to offset program costs and decrease Schedule 139 rates for customers consistent with the approach taken by the Wisconsin Public Service Commission.

Commission Determination

452 We grant the Company's petition for deferred accounting treatment for current and future LDs subject to the condition that Staff recommends. To ensure compliance with RCW 19.29A.090, RCW 80.28.090, and RCW 80.28.100, PSE must not discriminate between

Green Direct customers when applying LDs to offset costs. All parties support the proposed accounting treatment, with the exception of Public Counsel, who advocates that PSE use the funds to offset program costs and decrease rates for Green Direct customers.

453 We decline to adopt Public Counsel's proposal. PSE is contractually required to provide renewable energy to its Green Direct customers, all of whom have chosen to participate in this voluntary program. As such, the Company and its Green Direct customers are best situated to determine how the LD funds should be allocated consistent with applicable statutes. To that end, we encourage PSE to work collaboratively with its Green Direct customers to determine how to best use the LDs in compliance with statutory requirements.

454 We also determine that we need not reach the question of how the LDs should be applied at this juncture, other than to reiterate the requirement that they only be used to benefit program participants. Because these costs will be deferred, there is no reason to make any determination regarding their application until such time as they have ceased accruing and the final amounts are known. Accordingly, we authorize deferred accounting treatment, but reserve any decision related to the use of the funds until such time as the PPAs are in service and the final amount of the LDs is known. At that time, PSE may bring forward a proposal for the Commission's consideration.

5. COST OF SERVICE, RATE SPREAD, AND RATE DESIGN

i. Electric Cost of Service

455 According to PSE witness Birud Jhaveri, PSE's 2019 Electric Cost of Service Study (COSS) uses the same basic methodology as its 2017 COSS.[467] The parity percentages that result from PSE's COSS are shown in Table 3, below, by customer class.

---

[467] Jhaveri, Exh. BDJ-1T at 7:2-4.

Table 3 – Parity Percentages from PSE's Electric COSS

Customer Class	Rate Schedule	Parity Percentage
Residential	7	97 %
General Service, < 51 kW	24	105 %
General Service, 51 – 350 kW	25	106 %
General Service, >350 kW	26	106 %
Primary Service	31/35/43	101 %
Special Contract	SC	99 %
High Voltage	46/49	106 %
Lighting Service	51 - 59	93 %
Choice/Retail Wheeling	448/449	88 %
Firm Resale/Special Contract	5	50 %
System Total / Average		100 %

456 In its currently effective base rates, PSE's transmission costs are classified as 25 percent demand and 75 percent energy, known as the Fixed Method.[468] In the COSS for this proceeding, PSE classifies transmission costs using the Peak Credit Method. Under the Peak Credit Method, 11 percent of transmission costs are classified as demand and 89 percent are classified as energy.[469]

457 PSE witness Chang summarizes the 2019 Class Load Research that the Company used in its electric COSS and rate design.[470] The Class Load Research is uncontested.

[468] Jhaveri, Exh. BDJ-5T at 9:8-10.

[469] Jhaveri, Exh. BDJ-1T at 11:15-18.

[470] *See* Chang, Exh. CKC-1T.

458 Staff recommends the Commission accept, for the purposes of this case, PSE's electric COSS based on the study's directional accuracy.[471] Similarly, Public Counsel does not contest PSE's electric COSS based on the study's reasonableness.[472]

459 FEA contests certain portions of the electric COSS, and argues that the ongoing cost of service rulemaking "does not obviate the need for a reasonable cost of service determination in this case."[473]

460 First, FEA argues that PSE's Peak Credit Method should be rejected and PSE should be required to use more recent generation resource data.[474] Second, FEA contends that fixed costs should be classified as entirely demand-related and allocated to customer classes exclusively based on four coincident peak (4-CP) allocation factors.[475] Finally, FEA maintains that, if the Commission finds it appropriate to use energy usage to classify and allocate a portion of fixed costs, a more reasonable approach would be to use average and excess based on the four non-coincident peak demand method, which links the energy component to the class's average demands and non-coincident peak demands.[476]

461 On rebuttal, PSE witness Jhaveri provided updated parity percentages based on the revised electric revenue requirement as shown in Table 4, below.[477]

---

[471] Ball, Exh. JLB-1T at 3:2-4.

[472] Watkins, Exh. GAW-1T at 2:10-11.

[473] Al-Jabir, Exh. AZA-1T at 10:4-11.

[474] *Id.* at 2:8-12.

[475] *Id.* at 2:13-3:2.

[476] *Id.* at 14:18-16:18.

[477] Jhaveri, Exh. BDJ-5T at 2:2-6.

Table 4 – Updated Results of PSE's Electric COSS

Customer Class	Rate Schedule	Parity Percentage
Residential	7	97%
General Service, < 51 kW	24	105%
General Service, 51 – 350 kW	25	106%
General Service, >350 kW	26	106%
Primary Service	31/35/43	101%
Special Contract	SC	120%
High Voltage	46/49	104%
Choice/Retail Wheeling	448/449	88%
Lighting Service	50 - 59	94%
Firm Resale/Special Contract	5	50%
System Total / Average		100 %

462 In response to FEA, Jhaveri argues that PSE's proposed Peak Credit Method is "substantially in the form approved by the Commission in 1992."[478] Jhaveri also notes that Staff indicated a preliminary preference for the Renewable Future Peak Credit (RFPC) with net power costs in the cost of service rulemaking, which is substantially similar to the Peak Credit Method with the exception that it uses the cost of a battery for a peaking proxy instead of a single-cycle combustion turbine and wind for a baseload proxy instead of a combined-cycle combustion turbine.[479]

463 Jhaveri maintains that either the proposed Peak Credit Method, or the Fixed Method,[480] approved by the Commission in the 2014 Rate Design Collaborative, provide the most reasonable, neutral positions compared to other methodologies.[481] Further, Jhaveri argues that the alternatives FEA proposes are not obviously superior to PSE's proposed

---

[478] *Id.* at 4:10-15.

[479] *Id.* at 6:12-19.

[480] The Fixed Method classifies costs as 25 percent demand and 75 percent energy.

[481] Jhaveri, Exh. BDJ-5T at 10:2-8.

approach,[482] and provide more diverse results.[483] Finally, Jhaveri contends that the RFPC method provides parity ratios similar to the Fixed Method, although the inputs have not yet been sufficiently vetted or approved by the Commission.[484]

464 In cross-answering testimony, Staff argues that the Commission has repeatedly rejected FEA's arguments that energy usage is unrelated to cost causation, and recommends the Commission do so again in this proceeding.[485] Staff contends that FEA's methodology has the "convenient result of shifting a large amount of costs away from schedules which FEA represents."[486] Additionally, Staff argues that the changes FEA proposes should be considered, if at all, in the generic cost of service rulemaking, a forum in which Staff notes FEA has declined to participate.[487]

465 Also on cross-answer, Public Counsel argues that the majority of PSE's net generation investment (wind and hydro) provides low-cost energy throughout the year and not simply to meet peak load requirements, which undermines FEA's argument that coincident peak demand is the sole driver of production investment.[488] Public Counsel argues that the methods and approaches FEA recommends "bear no resemblance to how generation and transmission costs are planned, operated, or incurred and therefore, should be given no weight or consideration in this case."[489]

466 PSE argues in its brief that its electric COSS is generally consistent with the study performed and approved in its 2017 GRC. PSE notes that only FEA opposes its analysis, and that Public Counsel has minor disagreements with allocation of individual rate base and expense accounts but accepts PSE's Peak Credit Method as producing results within the range of reasonableness and as providing a fair and equitable allocation to all classes. PSE recommends that the Commission accept PSE's electric cost of service analysis,

---

[482] *Id.* at 8:11-20.

[483] *Id.* at 10:6-8.

[484] *Id.* at 11:12-17.

[485] Ball, Exh. JLB-28T at 17:16-20.

[486] *Id.* at 17:21-18:4.

[487] *Id.* at 17:3-12.

[488] Watkins, Exh. GAW-13CT at 2:24-4:14.

[489] *Id.* at 12:13-17.

with updates to the results of the Peak Credit Method to reflect the most currently available information.[490]

Commission Determination

467 On July 6, 2020, the Commission adopted new rules that address (1) the core principles and methods a COSS should utilize; (2) how to streamline the implementation of rates based on a COSS; and (3) the information necessary to ensure an accurate and uniform understanding of the principles upon which a COSS should be based.[491] The new rules provide extensive guidance for undertaking a COSS, which will necessarily inform how the Company's next COSS is performed. We decline to adopt PSE's proposal to change the energy and demand allocation from the Fixed Method to the Peak Credit Method. Requiring major changes to the study, as both PSE and FEA propose, would be premature, as the Company has not had an opportunity to conduct a COSS under the new rules. In these circumstances, we find that maintaining the status quo until the Company's next GRC is reasonable for the purposes of this proceeding.

468 At the evidentiary hearing, PSE acknowledged that it may be beneficial for the Company to "hold the course steady until we have a better idea of where these new methodologies will take us in terms of calculation for cost of service."[492] We agree. Accordingly, we adopt the Company's COSS with the exception of its proposal to change the energy and demand allocation from the Fixed Method to the Peak Credit Method. Instead, we require PSE to continue to classify its production and transmission costs according to the Fixed Method, which classifies 25 percent of production and transmission costs as demand and 75 percent as energy.

469 Staff's point that the cost of service rulemaking was the appropriate forum to address FEA's concerns is well taken. That rulemaking has been ongoing since 2017, and FEA had ample opportunity to participate but chose not to do so. We remind FEA that the Commission provides many avenues for it to advocate its positions other than general

---

[490] PSE Initial Brief ¶ 121.

[491] On July 7, 2020, the Commission entered General Order R-599 in Consolidated Dockets UE-170003 and UG-170004, adopting rules in the Commission's Cost of Service Study rulemaking.

[492] Jhaveri, TR 271:12-14.

rate proceedings. Accordingly, we encourage FEA to participate in Commission workshops and rulemakings in the future.

ii. Electric Rate Spread

470 PSE did not provide direct testimony on electric rate spread. Instead, PSE witness Piliaris discusses "rate impact" as shown in Table 5, below.

Table 5 – Estimated Overall Impacts of PSE's Proposed Electric Rates[493]

Customer Class	Rate Schedule	Overall Impact*
Residential	7	7.67%
General Service, < 51 kW	8/24	7.10%
General Service, 51 - 350 kW	7A/11/25/29	5.46%
General Service, >350 kW	12/26	5.31%
Primary Service, Gen & Irr.	10/31/35	7.23%
Primary Service, Schools	43	9.16%
High Voltage	46/49	4.64%
Lighting Service	50 – 59	8.96%
Special Contract	SC	-12.25%
Retail Wheeling	448/449	0.64%
Total Jurisdictional Retail Sales	**n/a**	6.89%

* Includes base rates, as well as Schedules 95, 141 and 141X.

471 Under PSE's proposal, the typical electric residential customer using 900 kWh a month will see an increase of $5.51 per month, or 6.1 percent, in billed rates. Proposed rates represent a 1.6 percent increase over rates paid by customers using 900 kWh per month in 2009. PSE argues that the increase is less than the 1.8 percent average annual inflation rate over the same period.[494]

---

[493] Piliaris, Exh. JAP-1T at 4:1.

[494] *Id.* at 3:18-25.

472 Staff witness Ball testifies that, historically, the Commission has considered acceptable plus or minus 5 percent of parity, although the Commission also has emphasized balancing rate spread with other principles like gradualism and rate stability. On that basis, Staff proposes the ranges in Table 6 for judging parity ratios.[495]

Table 6 – Staff Proposed Parity Ranges

Parity Ratio Range	Category
+/- 5 (i.e. 0.95 to 1.05)	Error range
+/- 10 (i.e. 0.90 to 1.10)	Range of reasonableness
+/- 20 (i.e. 0.80 to 0.90 or 1.10 to 1.20)	Unreasonable cross-class subsidization
+/-30 (i.e. 0.70 to 0.80 or 1.20 to 1.30)	Excessive cross-class subsidization
+/-40 (i.e. <0.70 or >1.30)	Grossly excessive cross-class subsidization

473 Staff recommends that the Commission set a rate spread that begins to alleviate any parity ratios outside the range of reasonableness, which Staff argues is between 0.90 and 1.10.[496]

474 Public Counsel agrees with Staff to focus on classes with parity ratios plus or minus 10 percent. Specifically, Public Counsel recommends the system average percentage increase to classes with parity ratios plus or minus 10 percent of parity based on general practice.[497] Public Counsel witness Watkins argues that PSE allocates above and below average allocations for rate classes that are within 10 percent of parity, including Rate Schedules 25/29, 26, 46/49, 43 and 50/59. Watkins recommends that all rate schedules except Rates Choice/Retail Wheeling (46/49), Special Contracts, and Firm Resale receive

[495] Ball, Exh. JLB-1T at 13:16-14:8.

[496] *Id.* at 14:12-15:3.

[497] Watkins, Exh. GAW-1T at 39:9-15.

an equal percentage increase.[498] If the Commission approves an electric service revenue requirement less than that requested by PSE, Public Counsel recommends that the change to the Special Contracts and Choice/Retail Wheeling classes remain at the Company's proposed levels, while all other classes' revenue increase should be reduced in proportion to Public Counsel's recommended rate spread.[499]

475 FEA argues that the Company is proposing a base rate revenue subsidy of $47.3 million for the residential class.[500] FEA recommends that no class above parity receive a rate increase. This recommendation would result in no rate increase to Schedules 24, 25, 26, 31, and 46/49. FEA witness Al-Jabir asserts that it is reasonable to maintain the revenue allocation method for the remaining schedules, and that they should receive a prorated share of the revenue requirement from classes that should receive no increase.[501]

476 Kroger witness Kevin Higgins recommends that rate schedules that are at 106 percent of parity, according to PSE's COSS, receive an increase that is 50 percent of the uniform percent increase rather than the 75 percent increase proposed by PSE.[502]

477 On rebuttal, PSE argues that PSE's and Staff's proposals strike the best balance between cost causation and gradualism principles as compared to the alternative rate spread approaches proposed by other parties. PSE further contends that its proposal provides more class equity than Staff's approach, which would give the same increase to a schedule approximately 10 percent below parity (Schedule 43) as it would to a schedule greater than 40 percent below parity (Schedule 35). If the Commission believes PSE's approach too rigidly favors cost causation, PSE would support Public Counsel's proposal to apply an average increase to customers within plus or minus 10 percent of parity.[503]

478 In cross-answering testimony, Public Counsel provides a summary of all parties' electric rate spread proposals as illustrated in Table 7, below.[504]

---

[498] *Id.* at 39:16-40:8.

[499] *Id.* at 41:1-42:2.

[500] Al-Jabir, Exh. AZA-1T at 19:20-23.

[501] *Id.* at 21:16-21, 22:3-9.

[502] Higgins, Exh. KCH-1T at 11:3-15.

[503] Piliaris, Exh. JAP-18T at 7:10-8:10.

[504] Watkins, Exh. GAW-13CT at 14:1-15.

Table 7 – Rate Spread Proposals for all Parities (in percent)

	Percent Increase[16]				
Class	PSE Piliaris	Staff Ball	PC Watkins	Kroger Higgins	FEA Al-Jabir
Residential (Rate 7)	7.68%	7.67%	7.25%	8.20%	12.63%
Secondary Voltage					
Demand <= 50 kW (Rate 24)	7.68%	7.67%	7.25%	8.20%	0.00%
Demand > 50 kW <= 350 kW (Rate 25/29)	5.76%	5.76%	7.25%	4.10%	0.00%
Demand > 350 kW (Rate 26)	5.76%	5.76%	7.25%	4.10%	0.00%
Total Secondary Voltage	6.49%	6.48%	7.25%	5.65%	0.00%
Primary Voltage					
General Service (Rate 31)	7.68%	7.67%	7.25%	8.20%	0.00%
Irrigation (Rate 35)	11.52%	11.52%	10.88%	12.30%	16.79%
Interrup. Electric Schools (Rate 43)	9.60%	11.52%	7.25%	10.25%	14.63%
Total Primary Voltage	7.85%	8.01%	7.26%	8.38%	1.30%
Total High Voltage (Rate 46/49)	5.76%	5.76%	7.25%	4.10%	0.00%
Choice/ Retail Wheeling/Special Contract	-6.39%	-6.39%	-6.39%	-6.39%	-6.39%
Lighting (Rate 50-59)	9.60%	9.60%	7.25%	10.25%	14.63%
Total Jurisdictional Sales	7.14%	7.14%	7.14%	7.14%	7.14%
Firm Resale (Rate 5)	108.00%	108.00%	108.42%	108.00%	108.44%
Total Sales	7.16%	7.16%	7.16%	7.16%	7.16%

479 Public Counsel expresses concerns about both PSE's and Staff's proposals,[505] and specifically argues that the problems with PSE's proposal are exacerbated in Kroger's rate spread proposal.[506] Public Counsel opposes FEA's rate spread proposal because it provides dramatically different treatment for rate classes that are the same percentage points away from 1.00, whether above or below. Additionally, Public Counsel witness

[505] *Id.* at 14:17-22.

[506] *Id.* at 15:10-12.

Watkins argues that because cost of service studies are not "surgically precise," they should not be employed as such.[507]

480 On cross-answer, FEA argues that the rate spread proposals provided by Staff, Public Counsel, and Kroger are unreasonable because they do not exhibit sufficient movement toward cost-based rates, especially for the High Voltage class (Schedules 46 and 49),[508] which FEA claims has been subsidizing other rate schedules for "some time." [509] Finally, FEA asserts that Public Counsel's and Staff's determination that plus or minus 10 percent of parity is in the "range of reasonableness" would severely discount or disregard the COSS results for rate setting purposes, except in the most extreme circumstances.[510]

481 Like FEA, Kroger disagrees with Public Counsel and Staff that plus or minus 10 percent of parity comprises the range of reasonableness.[511] Kroger also argues that Schedules 25/29 and 26 have had parity ratios significantly above parity since at least 2004, as shown in Table 8, below.[512]

Table 8 – Parity Ratios for Schedules 25/29 and 26 as Calculated in Past Cases by PSE

Class	2004	2006	2007	2009	2011	2017	2019
Sch. 25/29	115%	105%	121%	112%	106%	108%	106%
Sch. 26	108%	103%	117%	105%	104%	107%	106%

482 Overall, Kroger reiterates its recommendation that classes at 106 percent of parity receive an increase at 50 percent of the uniform percentage increase. Kroger further recommends

[507] *Id.* at 16:13-17:11.

[508] Al-Jabir, Exh. AZA-6T at 9:10-17.

[509] *Id.* at 10:1-8, 11:1-12:5, 12:17-13:9.

[510] *Id.* at 10:1-8, 11:1-12:5, 12:17-13:9.

[511] Higgins, Exh. KCH-3T at 4:5-18.

[512] *Id.* at 5:5-6:2.

that the Commission reject Public Counsel's proposal because it fails to make any improvement.[513]

483 In its brief, PSE argues that Public Counsel's proposal insufficiently reflects cost causation, Staff's proposal creates too high an increase for Schedule 43, and Kroger and FEA do not fully consider gradualism. PSE contends that its proposal is the most fair and balanced.[514]

Commission Determination

484 We adopt PSE's proposed rate spread, which we conclude strikes a more appropriate balance between cost causation and the principle of gradualism than do other parties' proposals. In light of current economic circumstances created by the COVID-19 pandemic, drastically increasing residential rates, as FEA and Kroger propose, is decidedly contrary to the public interest and violates the principle of gradualism. PSE's proposal, on the other hand, moves the residential class closer to parity without creating rate shock. Notably, PSE's rate spread also brings Schedules 25/29 and 26 closer to parity. In light of these factors, we determine that PSE's proposed electric rate spread will result in rates that are fair, just, and reasonable.

iii. Electric Rate Design

485 Initially, the only contested portion of the electric rate design was PSE's proposal to apply 100 percent of the residential rate increase to the second usage block, or tail-block.[515]

486 Staff recommends the Commission require the Company to spread increases equally over the two residential usage blocks. Staff argues that, on average, PSE's low-income residential customers use more energy than the average residential customer, and that the Company has failed to demonstrate how its proposal is in the best interests of vulnerable customers.[516]

---

[513] *Id.* at 6:13-7:6.

[514] PSE Reply Brief ¶ 47.

[515] Piliaris, Exh. JAP-1T at 17:5-19:3.

[516] Ball, Exh. JLB-1T at 27:1-4 and 31:1-32:12.

487 TEP generally supports the Company's underlying policy goals for its proposed residential rate design, but also recommends that the rate increase be spread equally across the two blocks.[517] TEP additionally recommends that PSE study, in consultation with its Low-Income Advisory Committee, increasing the first residential usage block from 600 kWh per month to 800 kWh per month to encompass most low-income customer usage.[518]

488 Public Counsel also recommends the Commission require the Company to spread any rate increase equally over both residential blocks.[519] Public Counsel supports TEP's recommendation from PSE's 2017 GRC that the Commission require PSE to study the feasibility of changing its residential two-block structure to increase the first block usage to 800 kWh per month.[520]

489 On rebuttal, PSE accepts the recommendation from Staff, TEP, and Public Counsel to spread the residential rate increase proportionally across the first and second usage blocks. Additionally, PSE is open to exploring an expansion of the first block energy rate from 600 kWh to 800 kWh.[521]

Commission Determination

490 We agree with the parties that the residential rate increase should be spread equally over the first and second usage blocks. This approach is more equitable to the Company's low-income customers, many of whom, as Staff notes, use more energy than other residential customers. Our decision related to requiring PSE to study the feasibility of increasing the first usage block from 600 kWh to 800 kWh is addressed in Section II(B)(6), below.

---

[517] Collins, Exh. SMC-1T at 11:16-20.

[518] *Id.* at 15:1-5.

[519] Watkins, Exh. GAW-1T at 46:17-20.

[520] *Id.* at 47:3-10.

[521] Piliaris, Exh. JAP-18T at 2:6-8.

iv. Natural Gas Cost of Service

491 According to PSE witness Taylor, PSE's 2019 natural gas COSS is similar to its 2017 COSS.[522] The parity percentages by customer class that result from PSE's COSS are shown in Table 9, below.[523] Rather than using the natural gas COSS to allocate demand costs, PSE witness Amen testifies that the Company will provide a recommendation for allocating pipeline capacity and storage costs in PSE's PGA filing.[524]

Table 9 - PSE Results of Natural Gas COSS[525]

Customer Class	Schedule	Parity Ratio
Residential	16/23/53	1.07
Commercial & Industrial	31/31T	0.82
Large Volume	41/41T	1.22
Interruptible	85/85T	1.08
Limited Interruptible	86/86T	1.71
Non-exclusive Interruptible	87/87T	0.83
Special Contracts		1.71
Rentals	71/72/74	1.37
Total/System Average		**1.00**

492 The only contested portion of PSE's natural gas COSS is the Company's allocation of distribution mains. PSE witness Taylor testifies that PSE used the Peak and Average methodology to classify and allocate distribution main costs based on a combination of peak demand and average demand, which, in turn, is based on an estimate of the system load factor. PSE calculated a weather-normalized design day load factor at 32.23 percent, thereby classifying 32.23 percent as commodity-related and 67.77 percent as demand-related.[526] Taylor argues that this method generally aligns with PSE's past allocation of

[522] Taylor, Exh. JDT-1T at 11:8-14.

[523] *Id.* at 19:13.

[524] Amen, Exh. RJA-1T at 2:25-28.

[525] Many of these parity ratios changed in PSE's Corrected/Supplemental filing as noted in Ball, Exh. JLB-1T at 12:10-15.

[526] Taylor, Exh. JDT-1T at 16:2-6.

mains, with the following exceptions: (1) the direct assignment of mains through a special study to the Special Contracts class;[527] (2) full exclusion of Interruptible, Limited Interruptible, and Non-Exclusive Interruptible from the allocation of mains less than two inches;[528] and (3) exclusion of the Non-Exclusive Interruptible class from the allocation of medium mains (two, 3-inch mains).[529]

493 AWEC contested PSE's initial allocation of distribution mains related to the Tacoma LNG Project to transportation customers.[530] PSE accepted AWEC's recommendation on rebuttal.[531]

494 Public Counsel argues that the allocation of distribution mains has been a "gradual, yet continual, moving of the cost of service goal line as it relates to the assignment of costs to the Residential class."[532] The Peak and Average method, approved by the Commission in 1990, classified distribution mains as 50 percent commodity and 50 percent demand; PSE then moved to system load factor equal to 32 percent commodity and 68 percent demand. According to Public Counsel, this has a material impact on the Residential class, which has a lower load factor than industrial customers. Additionally, Public Counsel witness Watkins asserts that the use of a system load factor instead of the actual peak demand increases demand charges because the system load factor is based on the coldest theoretical day possible. Finally, Watkins argues that PSE separates mains by pipe size so that large volume customer classes are not fully responsible for the costs of all distribution mains.[533]

495 Public Counsel recommends that the Commission reject PSE's proposed new methodology concerning distribution mains and instead "rely upon the results of the

---

[527] According to Taylor, *id.* at 16:15-16, the study results in 0.1315 percent of mains directly assigned to Special Contracts.

[528] According to Taylor, *id.* at 17:19-22, a review of meter sizes for the Non-Exclusive Interruptible (87 and 87T) showed that it is reasonable to assume that none of these customers are served from mains smaller than four inches.

[529] *Id.* at 18:6-19.

[530] Mullins, Exh. BGM-1T at 43:6-14.

[531] Taylor, Exh. JDT-9T at 2:9-13.

[532] Watkins, Exh. GAW-1T at 51:4-5.

[533] *Id.* at 51:1-52:4.

approach that has been used by PSE for the last several rate cases; *i.e.*, the compromise method" consistent with Commission precedent.[534] Watkin provides a comparison of the COSS results based on the old and new methods in Table 10, below.[535]

Table 10 – Comparison of GAS COSS Results

		Parity Ratio		ROR @ Current Rates	
		Old Method	New Method	Old Method	New Method
Residential	(16, 23, 53)	107%	107%	5.73%	5.62%
Comm & Ind	(31, 31T)	82%	82%	1.04%	0.96%
Large Volume	(41, 41T)	124%	122%	9.22%	8.96%
Interruptible	(85, 85T)	109%	108%	6.30%	6.26%
Limited Interrupt.	(86, 86T)	158%	171%	16.71%	19.67%
Non-Excl. Interrupt.	(87, 87T)	75%	83%	-0.19%	1.22%
Special Contracts	(SC)	66%	171%	-1.54%	20.17%
Rentals		137%	137%	15.97%	15.97%
Total Company		100%	100%	4.55%	4.55%

496 On rebuttal, PSE provided an updated COSS model based on its updated revenue requirement, as shown in Table 11, below.

[534] *Id.* at 54:17-21

[535] *Id.* at 55:8.

Table 11 – Updated Results of PSE's Gas COSS[536]

Customer Class	Schedule	Direct Parity Ratio	Rebuttal Parity Ratio
Residential	16/23/53	1.07	1.05
Commercial & Industrial	31/31T	0.82	0.84
Large Volume	41/41T	1.22	1.26
Interruptible	85/85T	1.08	1.13
Limited Interruptible	86/86T	1.71	1.77
Non-exclusive Interruptible	87/87T	0.83	0.85
Special Contracts		1.71	1.69
Rentals	71/72/74	1.37	1.31
Total/System Average		**1.00**	**1.00**

497 In response to Public Counsel, PSE argues that the proposed changes are a "refinement of the Compromise method to better account for the engineering and operational aspects of PSE's distribution system."[537] Specifically, Taylor argues that PSE's new method creates consistency because it accounts for the size of mains in the demand portion of the allocation factor in the same manner that the Compromise Method accounts for the peak portion.[538] Regarding Commission precedent, Taylor asserts that the facts here are distinguishable because the Special Contracts class consists of one customer with nine unique service locations under a single contract approved by the Commission, and the direct assignment of distribution main costs to the Special Contract customer is representative of the initial bypass cost analysis that the Company performed and the Commission approved.[539] Finally, Taylor notes that Staff agrees with the Company's proposed changes.[540]

[536] Taylor, Exh. JDT-9T at 12:7.

[537] *Id.* at 6:3-8. According to Watkins, the Compromise Method refers to an approach developed by PSE in its 2009 rate case that was informed by collaborative earlier in 2009. *See* Watkins, Exh. GAW-1T at 49:12-50:17.

[538] Taylor, Exh. JDT-9T at 4:12-19.

[539] *Id.* at 7:9-18.

[540] *Id.* at 8:13-9:1.

498 AWEC does not contest the Peak and Average allocation for the purposes of this case given the ongoing cost of service rulemaking. AWEC recommends the Commission accept the Company's proposal rather than Public Counsel's because it uses direct assignment of costs where possible and adjusts small main allocation for interruptible customers.[541]

499 In its brief, Public Counsel argues that the Commission should reject PSE's proposed allocation of distribution mains because it would significantly shift cost responsibility away from the Interruptible and Special Contract classes to the firm and small volume classes, including the Residential class. Just as the Commission rejected the proposal in Docket UG-101459, Public Counsel argues that the Commission should reject the proposal to allocate mains to its Special Contract customer in the way proposed by PSE and supported by AWEC.[542]

500 For the purposes of this case, Staff supports the Company's proposed changes because PSE designed them to appropriately allocate costs to cost causers.[543]

501 AWEC recommends the Commission accept PSE's natural gas COSS with respect to its direct assignment of mains where possible. AWEC argues that Public Counsel is the only party that disputes PSE's "improved Peak and Average method"[544] because the methodology results in increased costs for residential ratepayers. AWEC requests the Commission approve PSE's refinements to the approved Peak and Average method while allowing larger questions to be addressed in the cost of service rulemaking. However, if the Commission agrees with Public Counsel that PSE should not change its cost of service methodology as proposed, AWEC requests the Commission "continue the status quo" with respect to all cost of service issues for PSE, which includes applying the natural gas rate increase on an equal percent of margin basis.[545]

502 PSE argues that it used the Peak and Average methodology for allocating natural gas distribution main costs consistent with a long-standing practice dating back to PSE's 2007 GRC. This methodology allocates natural gas costs based on a combination of peak

---

[541] Collins, Exh. BCC-1T at 4:1-21.

[542] Public Counsel Reply Brief ¶ 78.

[543] Ball, Exh. JLB-1T at 12:3-4.

[544] AWEC Initial Brief ¶ 44.

[545] *Id.* ¶ 46.

demand and average demand (or average throughput). PSE argues that its methodology is also consistent with its most recent 2017 GRC, Docket UG-170034. PSE notes that Staff recommends that the Commission accept PSE's natural gas COSS.

Commission Determination

503 For the purposes of this proceeding only, we accept PSE's natural gas COSS, including the Company's more detailed allocation in its application of its Peak and Average method because it produces better, more accurate data. As noted above, the Commission's recently-approved cost of service rules provide extensive guidance for undertaking a COSS, which will necessarily inform how the Company's next COSS is performed. We expect all regulated energy companies, including PSE, and parties to GRCs to develop studies consistent with the new cost of service rules going forward.

v. Natural Gas Rate Spread

504 PSE's proposed natural gas rate spread is summarized in Table 12, below.

Table 12 – PSE's Proposed Gas Rate Spread[546]

Parity Ratio	Proposed Rate Spread	Applicable Rate Schedules
0.90 – 1.10	System average	16, 23, 53, 85, and 85T
1.10 – 1.50	50 percent of system average	41 and 41T
>1.50	No increase	86 and 86T
<0.90	150 percent of system average	31, 31T, 87, and 87T

505 PSE witness Taylor testifies that the water heater rentals class was set to its cost of service, which is a targeted margin decrease of $643,783, to reflect PSE's expectation to sell or end this program in the near future.[547]

506 Staff recommends a rate spread that is largely similar to PSE's proposal, as shown in Table 13, below. Staff notes that the only difference is that Staff proposes a 25 percent of

---

[546] Taylor, Exh. JDT-1T at 23:13-24:5.

[547] *Id.* at 24:5-8.

the system average increase for the limited interruptible class, Schedule 86/86T, instead of a zero percent increase.

Table 13 – Staff Recommended Natural Gas Service Rate Spread

Rate Schedule	**PSE** *(Supplemental Filing)*	**Staff**
Residential, Sch 16/23/53	100%	100%
Comm. & Ind., Sch 31/31T	150%	150%
Large Volume, Sch 41,41T	50%	50%
Interruptible, Sch 85, 85T	100%	100%
Limited Inter., Sch 86, 86T	0%	25%
Non-Excl. Inter., Sch 87, 87T	150%	150%

507 Staff recommends that the Commission accept its rate spread because it better balances the principles of fairness and perceptions of equity by assigning all classes at least some of the proposed revenue requirement increase.[548]

508 Public Counsel recommends two changes to PSE's proposed rate spread. First, Public Counsel witness Watkins recommends that the Special Contract class receive an increase equal to the system average increase of 21.75 percent because the Special Contract class is exhibiting a negative ROR based on the Compromise approach to cost of service.[549] Second, Watkins recommends that the Rental class rates remain unchanged, rather than reduced, because PSE is seeking approval to sell its rental business.[550] If the Commission authorizes an overall increase that is lower than the Company's request, Watkins recommends no change to the rental revenues, and that all other class revenues be reduced in proportion to Public Counsel's proposed rate spread.[551]

509 On rebuttal, PSE recommends the Commission reject Public Counsel's proposal to keep the Rental class unchanged. PSE argues that, if rates are set above the class's cost to

---

[548] Ball, Exh. JLB-1T at 19:6-21:2.

[549] Watkins, Exh. GAW-1T at 56:4-57:4, 57:10-13.

[550] *Id.* at 57:5-7. This matter is currently before the Commission in Docket UG-200112.

[551] *Id.* at 58:1-6

serve, the lost revenue cannot be recovered from other classes when PSE sells the rental business, and PSE will experience a revenue deficiency.[552]

510 With respect to its Special Contract, PSE recommends the Commission reject Public Counsel's proposed rate increase for two reasons. First, PSE disagrees with Public Counsel's analysis based on the Compromise Method. Second, PSE argues that any change to the Special Contract rate would violate the terms of the contract. PSE argues that any concerns related to parity for the Special Contract class should be addressed when the contract is up for renewal in 2035.

511 PSE also recommends the Commission reject Staff's recommendation to allocate rate increases to all customer classes, arguing that the Limited Interruptible class (Schedule 86/86T) should not receive any increase.[553]

Table 14 – PSE's Updated Proposed Natural Gas Rate Spread[554]

Parity Ratio	Proposed Rate Spread	Applicable Rate Schedules
0.90 – 1.10	System average	16, 23, and 53
1.10 – 1.50	50 percent of system average	85, 85T, 41, and 41T
>1.50	No increase	86 and 86T
<0.90	150 percent of system average	31, 31T, 87, and 87T

512 In cross-answering testimony, AWEC witness Mullins recommends that the Commission reject Staff's and Public Counsel's proposals, and instead "maintain its current posture and apply any natural gas rate changes. . . on an equal percent of margin basis to all rate schedules."[555] Mullins notes that in PSE's 2017 GRC, the Commission declined to adopt any specific rate spread method outside of equal percent of margin while parties discuss

[552] Taylor, Exh. JCT-9T at 13:13-20.

[553] *Id.* at 14:1-15.

[554] The figures in the table are based on the original rate spread proposal in Taylor's Exh. JDT-1T at 23:13-24:5 and updated for Schedule 85/85T based on Taylor's Exh. JDT-9T at 14:21-15:2.

[555] Mullins, Exh. BGM-8T at 13:7-9.

the issue in the ongoing cost of service rulemaking. Because the proceeding remains open, "the Commission's prior decision remains valid today."[556]

513 In its brief, Staff argues that AWEC's and Public Counsel's studies insufficiently reflect cost causation, while PSE's insufficiently reflects equity and perceptions of fairness. Staff recommends the Commission accept its proposed rate spread because it most appropriately balances the factors the Commission considers.[557]

Commission Determination

514 We accept PSE's proposed natural gas rate spread because it most appropriately allocates rate increases across all customer classes.

515 We appreciate Public Counsel's concerns related to the Special Contract class, but agree with PSE that any change to the Special Contract rate would violate the terms of the contract, and any concerns related to parity for the Special Contract class should be addressed when the contract is up for renewal in 2035. We also decline to adopt Public Counsel's proposal to keep the Rental class unchanged. We agree with PSE that it is appropriate to set the Rental class at its actual cost of service in light of the fact that the sale of the Water Heater Rental Program is pending in Docket UG-200112. Setting the Rental class below its cost of service would result in losses that PSE would be unable to collect from other customers if the schedule were discontinued, which we determine is not a reasonable outcome in this proceeding.

516 We recognize Staff's concerns related to PSE's decision to impose no increase on Schedules 86 and 86T, but find that PSE's proposal is nonetheless reasonable because it reduces cross-class subsidization. Scheduled 86 and 86T are so far removed from parity that increasing rates for those schedules simply for its own sake, or for the sake of the perception of fairness, fails to produce fair results. In this instance, we conclude that it is more reasonable to let parity ratios guide our decision.

517 Finally, we are not persuaded by AWEC's argument that we find ourselves in the same position now as we did when we approved PSE's gas rate spread in the Company's 2017 GRC, because the cost of service rulemaking is no longer ongoing. For the purposes of

---

[556] Mullins, Exh. BGM-8T at 13:6-17.

[557] Staff Initial Brief ¶ 113.

this proceeding, we are satisfied that the Company's proposal results in rates that are fair, just, and reasonable.

vi. Natural Gas Rate Design

518 There are two contested portions of PSE's proposed rate design. First, PSE proposes to maintain the current level of monthly basic charges for all customer classes and incorporate the addition of Schedule 141 (ERF) and Schedule 141X (EDIT) basic service charge adjustments, which would increase the residential basic charge from $11 to $11.52 per month. Second, PSE proposes to keep the Special Contract rate unchanged and unstudied.

519 Staff supports the Company's proposed rate design provided that PSE updates the economic bypass study because it has not been updated since 1995. Staff argues that "it is important to keep these economic bypass alternatives updated on a reasonable basis so that these customer rates remain in compliance with RCW 80.28.090 and RCW 80.28.100."[558]

520 Public Counsel recommends that the Residential class customer charge be set at $11.20 per month, based on Public Counsel's residential natural gas customer cost analysis.[559]

521 On rebuttal, PSE recommends that the Commission reject Public Counsel's direct customer charge analysis because its analysis "assumes … customer connections and the maintenance of customer accounts can be accomplished without any vehicles, office space, office furniture, tools and equipment, office supplies, insurance, or employee benefits."[560] PSE reiterates its proposal to increase the residential basic service charge from $11.00 to $11.52, which PSE witness Taylor argues is well within the COSS model results at $18.66.[561]

---

[558] Ball, Exh. JLB-1T at 34:1-11.

[559] Watkins, Exh. GAW-1T at 59:1-14.

[560] Taylor, Exh. JCT-9T at 15:16-19.

[561] *Id.* at 15:12-16:11.

522 Taylor also recommends waiting to consider the need for an updated economic bypass study for the Special Contract class until its June 1, 2035, expiration is near. Taylor argues that conducting the study 14 years prior to the end of the contract is premature.[562]

523 In cross-answering testimony, AWEC opposes Staff's recommendation to update the Special Contract economic bypass study because doing so would "effectively renegotiate these contracts by increasing costs to these customers that were not authorized by the contracts."[563] Additionally, AWEC notes that the Commission rejected this same recommendation in PSE's last GRC, and that the Commission approved an extension of the Special Contract in 2009. Finally, AWEC argues that, if an updated study is performed, it should be done when the contract is next up for renewal.[564]

524 In its brief, Staff argues that a special contract must avoid undue preference or prejudice, and that its charges must also "recover all costs resulting from providing the service during its term" and contribute to the utility's fixed costs.[565] Staff argues that the proposed update will ensure the Commission has the data to verify compliance with these requirements if the contract is renewed, and nothing more.

525 AWEC argues that Staff has not even attempted to demonstrate that the Special Contract customer receives an undue or unreasonable advantage. AWEC also contends that Staff fails to articulate any basis to support its position that RCW 80.28.090 and RCW 80.28.100 require that economic bypass alternatives must be "updated on a reasonable basis," particularly when such an update would occur during the contract term.[566] AWEC maintains that it is unaware of any occasion when the Commission has revisited the terms of a special contract while it was in effect.[567]

526 In its reply brief, PSE argues that it is premature to order Staff's proposed economic bypass study now because the contract does not expire until June 2035, and the data

---

[562] *Id.* at 9:3-10.

[563] Collins, Exh. BCC-1T at 9:3-6.

[564] *Id.* at 9:11-20.

[565] Staff Initial Brief ¶ 115.

[566] AWEC Initial brief ¶ 49.

[567] *Id*.

would be stale. PSE argues that such a study should be completed closer to the Special Contract termination date.[568]

Commission Determination

527 We adopt PSE's proposed natural gas rate design. We approve the increase to the Residential class basic charge to incorporate the addition of Schedule 141 (ERF) and Schedule 141X (EDIT) basic service charge adjustments. The increase from $11 to $11.52 per month is well within the Company's COSS model, which shows that actual cost for the residential basic service charge is $18.66 per customer.[569] The $0.52 increase is thus consistent with principles of gradualism and cost-causation.

528 We decline Staff's request to require an economic bypass study. Staff argues that it is important to update economic bypass alternatives on a reasonable basis so that customer rates remain in compliance with RCW 80.28.090 and .100. These statutes provide that no gas or electric company may grant any undue or unreasonable preference to any person or corporation, nor may it subject any person or corporation to any undue or unreasonable prejudice or disadvantage in any respect whatsoever. Although we agree with Staff that the data produced by an economic bypass study would be useful to evaluate whether the Special Contract rates recovered all costs and contributed to the utility's fixed costs if and when the contract is renewed, it is premature to require an updated economic bypass study at this juncture. Because the Special Contract does not expire until 2035, an updated study should be conducted closer to the contract end date.

6. LOW-INCOME PROGRAMS

529 PSE initially proposed increasing low-income bill assistance funding for electric and natural gas service by twice the percentage of residential bill impacts the Company has proposed, which would have resulted in a funding increase of approximately $2.9 million for electric and $700,000 for natural gas assistance.[570]

530 TEP argues that there is a substantial unmet need for energy assistance in PSE's service territory. TEP witness Collins testifies that, using 150 percent of Federal Poverty Level as

---

[568] PSE Reply Brief ¶ 49.

[569] Taylor, Exh. JDT-9T at 16:9-11.

[570] Piliaris, Exh. JAP-1T at 19:11-17, 44:5-12.

a qualification threshold, PSE's assistance programs currently serve only about 12 percent of eligible residents.[571]

531 TEP accepts PSE's proposal for low-income bill assistance funding if the Company's full request is approved, but recommends calculating program increases using base rate increases if the Commission approves a lower increase for the Company.[572] If the Commission approves a rate decrease, TEP proposes the Commission order that no reductions to low-income bill assistance funding be made.[573]

532 Although TEP initially recommended additional funding for Community Action Agency costs to administer the Home Energy Lifeline Program (HELP), TEP accepted on brief Staff's recommendation that would allow any increase in allowable agency HELP administrative fees to be addressed between PSE and the agencies under current contracts, with Advisory Committee input as appropriate. As such, TEP does not request the Commission take any action related to this issue at this time.

533 Additionally, as discussed in Section II(B)(5)(iii), above, TEP recommends increasing the upper limit of the first residential usage block to 800 kWh to encompass most of the usage for the Company's low-income customers. TEP recommends the Commission require PSE to study the potential of this change and report on the results in the Company's next rate case. In response testimony, Public Counsel makes the same recommendation.[574]

534 TEP also addresses PSE's practices for customer disconnection due to non-payment, citing a pattern of PSE rate increases as well as costs of technology investments and clean energy transition. TEP witness Collins argues it is important to develop a regulatory strategy to reduce disconnections as much as possible.[575]

535 Collins explains that Washington investor-owned utilities last provided detailed information on disconnections in a 2013 docket that examined customer payments during

---

[571] Collins, Exh. SMC-1T at 2:20-3:4.

[572] *Id.* at 7:2-6.

[573] *Id.* at 7:8-11.

[574] Watkins, Exh. GAW-1T at 47:3-10.

[575] Collins, Exh. SMC-1T at 15:16-16:7.

premise visits at the time of disconnection. In this docket, TEP asked PSE to update the same information through 2018.[576] The requested data, Collins claims, show that payments made during premise visits regularly stop customer disconnections for nonpayment.[577] The Company has not, however, analyzed the impact of discontinuing premise visits, and continues to plan for reducing premise visits in the Commission's AMI rulemaking and in other proceedings.[578]

536 Collins recommends the Commission require PSE to:

- Develop a disconnection reduction plan to be filed with the Commission one year after the date of the final order in this docket;[579]
- Continue premise visits once remote disconnection is implemented and until a disconnection reduction plan is filed with the Commission and approved;[580] and
- File an annual report, providing the following data by month:
  - Total disconnections for all purposes,
  - Total residential disconnections for non-payment,
  - Total disconnections of customers receiving low-income bill assistance,
  - Total remote disconnections of residential customers for non-payment,
  - Total remote disconnections of customers receiving low-income bill assistance,
  - Total disconnections of customers with a medical emergency verified at the service location within two years,
  - Number of premise visits for "dunning" purposes related to disconnection,
  - Number of disconnections prevented by receipt of payment at the premises,
  - Number of payments received during premise visits to prevent disconnection and the method of payment,
  - Number of free pay stations, and

---

[576] *Id.* at 16:10-18.

[577] *Id.* at 17:1-21:6.

[578] *Id.* at 17:1-22:2.

[579] *Id.* at 22:4-23:11.

[580] *Id.* at 23:13-17.

- Number and nature of customer complaints related to disconnections.[581]

537 On rebuttal, PSE accepts TEP's proposals to (1) develop a disconnection reduction plan in consultation with the Company's Low-Income Advisory Committee to be filed one year after the effective date of this Order;[582] and (2) file an annual report with the information TEP requests to analyze and monitor disconnection trends.[583] PSE also states the Company is open to exploring the expansion of the first block of residential electric usage from 600 kWh to 800kWh.[584] At the evidentiary hearing, PSE accepted TEP's proposal to tie PSE's HELP funding increase to the base rate increase rather than to the residential bill impact.[585]

538 PSE does not, however, accept TEP's recommendation to continue premise visits until a disconnection reduction plan is filed and approved. PSE disagrees with TEP's assertion that the Company significantly reduces disconnects through site visits,[586] and argues that rules for remote disconnection are being addressed in the AMI rulemaking.[587]

539 On cross-answer, Staff opposes TEP's proposal to tie HELP funding to a base rate increase and instead recommends the Commission increase funding by twice the percentage of the residential bill impact or $1.4 million, whichever is greater.[588]

540 Staff witness Liu argues that bill increases, not base rate increases, more accurately represent the impact of a rate increase on low-income customers.[589] Liu notes that the Company's proposed increases to base rates are the result of moving several rider schedules — including riders for Expedited Rate Filing (ERF, Schedule 141), Power Cost Adjustments (Schedule 95), and PP EDIT (Schedule 141X) — will result in a larger

---

[581] *Id.* at 22:9-23:7.

[582] Wappler, Exh. AW-5T at 15:11-14.

[583] *Id.* at 15:15-17.

[584] Piliaris, Exh. JAP-18T at 2:6-8, 9:13-10:5.

[585] Wappler, TR 360:12-23.

[586] Wappler, Exh. AW-5T at 19:9-14.

[587] *Id.* at 17:5-11.

[588] Liu, Exh. JL-24T at 6:5-9.

[589] *Id.* at 7:11-13.

increase to base rates that may not correspond with a bill increase.[590] Liu also asserts that HELP funding has already increased once due to the Company's ERF filing. Liu argues that calculating additional HELP funding from a base rate increase in this case would result in a second increase due to the ERF.[591] Liu responds to TEP's argument that base rate increase would be consistent with Avista's approved increase, arguing that Avista does not have the ERF or other rider schedules PSE proposes moving into base rates.[592]

541 Liu agrees with TEP's argument that HELP funding should not be reduced in the event of a rate reduction and that requiring a minimum $1.4 million increase would ensure a meaningful funding increase. Liu believes this outcome would be consistent with the Commission's funding increase for Avista's low-income program.[593]

542 On cross-answer, Public Counsel expresses support, in part, for TEP's recommendation that a utility representative be present when a customer's service is remotely disconnected for non-payment to preserve opportunities to avoid disconnection. However, to preserve AMI economic benefits and retain consumer protections for vulnerable populations, Public Counsel recommends the Commission limit this requirement to low-income customers and customers whose electric service is medically necessary.[594]

Commission Determination

543 **HELP Funding.** As we recognize throughout this Order, all of PSE's customers are impacted by the economic uncertainties created by the COVID-19 pandemic. Undoubtedly, the Company's low-income customers are among the hardest hit. Accordingly, we agree with PSE that tying HELP funding to base rates is a more proportionately accurate basis for increasing low-income assistance. Often base rates can be offset by amounts owed to customers, resulting in little to no change to billed rates. Tying the HELP funding increase to a bill impact that has been intentionally offset would be counterproductive to our goal of relieving the financial burden that *any* rate increase

---

[590] *Id.* at 6:15-17.

[591] *Id.* at 7:14-19.

[592] *Id.* at 8, n. 10.

[593] *Id.* at 8:11-9:2.

[594] Alvarez, Exh. PJA-8T at 6:10-17.

will impose on low-income customers. Accordingly, we agree with TEP that the bill impact approach can be "unpredictable and misleading."[595] When offsets such as UP EDIT reversals are exhausted, customers experience a secondary rate increase. If HELP funding levels are established in proportion to a bill impact that includes an expiring offset, fewer HELP funds will be available to mitigate the impact of the secondary rate increase.

544 Staff argues that HELP funding was already increased as part of the Company's ERF settlement, and that calculating additional HELP funding from a base rate increase in this case would result in a second increase due to the ERF. Rather than viewing these issues as problematic, we see them as an available avenue to provide additional relief to PSE's most vulnerable customers during an economic crisis. Accordingly, we require PSE to increase HELP funding by twice the percentage of the increase to residential base rates or $1.4 million, whichever is greater.

545 **Expanding the First Block Energy Rate.** We appreciate that PSE is open to the idea of expanding the first block energy rate from 600 kWh to 800 kWh. To that end, we direct PSE to study the feasibility of expanding the first block energy rate, in consultation with the Company's Low-Income Advisory Committee, and report its findings in the Company's next GRC. If, after conducting its study, PSE decides not to expand the first energy block, the Company must provide a detailed analysis and explanation for its decision as part of its findings.

546 **Disconnection Reduction Plan.** We are pleased that PSE agrees with TEP's proposal to develop a disconnection reduction plan in consultation with the Company's Low-Income Advisory Committee, and to file an annual report for the purpose of analyzing and monitoring disconnection trends. Accordingly, we direct PSE to file its disconnection reduction plan within one year from the effective date of this Order, and to file an annual report that contains all of the information specified in paragraph 536, above. The Company's first annual report should be filed concurrently with its disconnection reduction plan, then annually thereafter.

547 **Community Action Agency Funding.** Although TEP agreed to withdraw its request for additional Community Action Agency (CAA) funding, we direct PSE to file a report that itemizes actual costs for CAAs to administer the Company's energy assistance programs.

---

[595] TEP Initial Brief ¶ 14.

PSE must file this report either concurrently with PSE's disconnection reduction plan or as part of the Company's next GRC, whichever occurs first.

548 **Premise Visits Prior to Disconnection.** Finally, we require PSE to continue the practice of conducting premise visits prior to disconnection until the Commission's AMI rulemaking in Docket U-180525 is complete and the new rules become effective. The Company must adhere to the current rules, which require a "last knock" prior to disconnection, unless and until the Commission amends those rules.

7. NON-REVENUE POLICY ISSUES

i. Materiality Threshold

549 In response testimony, Staff proposes a new pro forma adjustment materiality threshold. To determine what is "major" for the sake of meeting Staff's proposed threshold, Staff uses a "gross cost" method that reflects the sum of the annual depreciation of an asset, plus that asset's portion of return on rate base. For PSE, Staff's gross cost threshold is $2.71 million for electric assets, $1.17 million for natural gas assets, and $3.89 million for combined electric and natural gas assets.[596]

550 According to Staff, the Commission's traditional method determines the size of the asset based on the percentage of a utility's net plant in service it represents. Staff explains that, historically, the Commission has determined a "major" asset to comprise at least 0.5 percent of a utility's total net plant in service.[597]

551 Staff argues that short-lived assets that do not meet the traditional materiality threshold may impact a utility's final results more significantly than a long-lived asset that meets the threshold.[598] Staff witness McGuire contends that the gross-cost formula better addresses short-lived assets because it factors an asset's annual depreciation expense. Staff argues that considering annual depreciation becomes more important as utilities make more investments in short-lived assets. AWEC supports Staff's proposal.

---

[596] McGuire, Exh. CRM-1T at 40:16-19.

[597] *Id.* at 41:9-10.

[598] *Id.* at 41:13-20.

552 To develop its gross cost threshold, Staff began by translating the Commission's traditional major threshold into gross-cost terms. First, Staff assumes that a traditional, major electric utility investment has a 50-year book life, and a major natural gas investment has a 40-year book life.[599] Staff calculated the traditional materiality threshold for PSE in this case as $32.4 million for electric, $13.3 million for natural gas, and $45.6 million for combined operations.[600] Next, Staff divided the depreciation component of the gross cost by the assumed book life.[601] To calculate the return on investment, the gross cost of the investment was multiplied by the rate of return.[602] Finally, Staff summed the two components, and then added a 10 percent tolerance threshold for investments that are close to meeting the threshold.[603]

553 PSE uses the materiality threshold employed by Staff in the Company's 2017 GRC, which defined "material" as impacting the rate of return by one basis point.[604] For electric, PSE's net operating income threshold is $500,000, and the rate base threshold is $9.5 million. For natural gas, the net operating income threshold is $200,000, and the rate base threshold is $3.7 million.

554 PSE disagrees that the Commission needs to establish a materiality threshold for pro forma adjustments,[605] and advocates that the Commission maintain its flexibility.

---

[599] *Id.* at 42:9-20.

[600] *Id.* at 42:9-13.

[601] *Id.* at 42:14-20. For electric operations, $32.3 million ÷ 50 years = $0.65 million per year.

[602] For electric operations, $32.3 million x 7.33 percent = $2.37 million.

[603] McGuire, Exh. CRM-1T at 42:21-43:8.

[604] Free, Exh. SEF-1T at 11:1-11.

[605] Free, Exh. SEF-17T at 29:5-7. Free cites McGuire's Exh. CRM-1T at 9:19-20, which states that the Commission has generally concluded that extraordinary events are those that have a material impact on the utility's financial results, and Exh. CRM-1T at 12:17-19, which states that traditionally "the Commission has determined that a plant addition is material (or 'major') if it represents at least 0.5 percent of the utility's net plant in service. As Staff witness Higby explains, a materiality threshold that is 0.5 percent of net plant in service is agnostic to a project's book life and, therefore, does not account for a project's contribution to depreciation expense." Free also cites Higby's testimony, Exh. ANH-1T at 3:2-3, which states, "From a policy perspective, I propose a modification to the materiality threshold for projects placed in service after the test year."

However, should the Commission adopt Staff's proposal, PSE argues that it should adjust Staff's calculation.[606]

555 According to PSE's recalculation, the gross cost test for common costs should be $3.4 million rather than the $3.9 million proposed by Staff.[607] PSE witness Free further recommends that the gross cost threshold be applied at the functional level, consistent with the approach Staff advocated in PSE's 2017 GRC, which would allow additional projects to be included.[608] Even with PSE's modified gross cost test at a functional level, PSE is concerned that the Public Improvement adjustment would not qualify for inclusion,[609] which is problematic because public improvement projects are required by outside agencies and are nonrevenue generating.

Commission Determination

556 We find that applying a strict materiality threshold as Staff proposes would unnecessarily limit the Commission's flexibility, particularly in light of recent changes to RCW 80.04.250 that clarify the Commission's discretion for determining how, when, and by which methods utilities may recover investments. We appreciate that Staff's proposal aims to mitigate issues that can limit a utility's ability to fully recover the costs of short-lived investments from ratepayers absent special accounting treatment. However, we ultimately determine that adopting a bright-line threshold is not an appropriate solution.

557 From an historical standpoint, PSE correctly observes that the Commission "has not established bright-line standards governing the timing or the number of adjustments that can be accepted in a given case, and has not established a minimum size for pro forma adjustments to be recognized."[610] This was true even prior to the legislature clarifying the Commission's regulatory flexibility in 2019. As such, adopting a firm threshold at this juncture, with as-yet unexplored areas of Commission authority, would be contrary to both past practice and the legislature's intent.

---

[606] Free, Exh. SEF-17T at 31:12-32:2.

[607] *Id.* at 36:7-10.

[608] *Id.* at 37:9-18.

[609] *Id.* at 38:1-7.

[610] *Id.* at 29:11-31:11; 30:14-17, quoting *Washington Utils. and Transp. Comm'n v. Avista Corporation, d/b/a Avista Utilities,* Dockets UE-160228 and UG-160229, Order 06 ¶ 82 (Dec. 15, 2016).

558 Bearing in mind that PSE filed the current GRC prior to the implementation of CETA and prior to the Commission's publication of its Used and Useful Policy Statement, Staff's proposal makes an earnest endeavor to solve a real problem; however, other, more flexible resolutions have since emerged. We decline to adhere to one particular formula prior to endeavoring to develop jurisprudence under the new law. Instead, the Commission intends to focus on forging new paths forward. To that end, we anticipate that the Commission will address on a case-by-case basis the relationship between short-term investments and regulatory lag in the larger context of how and when we include for later recovery post-test year expenses.

559 Notably, many of Staff's concerns related to short-term investments are addressed by our decision to include in rate base pro forma adjustments through December 31, 2019, as discussed in Section II(B)(3)(i)(a) of this Order.

560 We similarly decline to adopt the Company's proposed materiality threshold, or endorse any particular methodology for defining "major" projects. Rather, we will evaluate individual adjustments for inclusion in rates on a case-by-case basis to maintain the Commission's discretion to adapt to evolving technologies and circumstances. In doing so, we will base our acceptance or rejection of proposed pro forma adjustments on our evaluation of multiple factors relevant to the particular proposed adjustment, including, but not limited to, the life of the asset, whether the asset is used and useful, whether the costs of the asset are known and measurable, and whether the costs were prudently incurred.

ii. On-Bill Repayment Program

561 NWEC recommends that the Commission order PSE to design and implement an on-bill repayment program to increase energy efficiency for its customers. NWEC recommends that the program: (1) be designed in collaboration with PSE's Conservation Resource Advisory Group (CRAG) and its Low-Income Advisory Committee; and (2) be filed by December 31, 2020.[611]

562 Specifically, NWEC recommends that PSE offer a "tariffed" on-bill repayment program with the following features:

---

[611] Gerlitz, Exh. WMG-1T at 20:14-17.

- Allow any proven technology that: (1) produces reliable and calculable savings; and (2) has projected annual savings greater than the service charge;
- If upgrades fail, ensure that customer payments stop until the upgrade has been repaired; and
- Limit the repayment period to the expected life of the upgrade and the structure.[612]

563 NWEC also notes that programs typically require that updates pass the "80 percent rule" to be eligible. The "80 percent rule" is based on a location-specific, on-site cost effectiveness analysis and means that both: (1) the total annual on-bill charge must not exceed 80 percent of the estimated annual utility bill; and (2) the maximum cost-recovery term cannot exceed 80 percent of the useful life of the update or a full parts and labor warranty, whichever is greater.[613]

564 NWEC states that having an on-bill repayment option for customers will significantly increase the number of customers participating in energy efficiency programs by removing barriers related to the upfront costs of these projects.[614] NWEC notes in its reply brief that the program should be implemented before the end of the year and possibly sooner due to the impacts of COVID-19 to create a low-cost, long-term financing option that could reduce immediate expenses.[615]

565 NWEC explains that on-bill repayment programs are designed to allow utility customers to finance customer improvements related to electricity or natural gas service on an opt-in basis. According to NWEC, the programs are intended to overcome barriers to the upfront costs of energy efficiency or distributed renewable generation projects by allowing customers to pay back the investments over a period of time directly on their utility bills.[616]

---

[612] *Id.* at 16:8, 17:5-6, 19:11-13, 16:14-17.

[613] *Id.* at 17:9-14.

[614] *Id.* at 14:5-8.

[615] NWEC Reply brief ¶ 13.

[616] Gerlitz, Exh. WMG-1T at 14:19-15:1.

566 PSE is agnostic to NWEC's proposal, but requests that, if the Commission accepts the proposal, the Commission:

- Direct PSE to work with its CRAG to develop an on-bill repayment service for <u>conservation</u> within one year of the conclusion of the case.
- Direct PSE to work with its CRAG *and other interested stakeholders* to develop on-bill repayment services for <u>other investments</u> within one year of the conclusion of the case.[617]

567 PSE expresses concerns that the program may be a poor use of customer funds because, according to the Company, the estimated costs to add on-bill repayment capacity to PSE's billing system could range from $750,000 to $1.5 million, in addition to significant administrative costs associated with third-party financing, program operations, and marketing costs. PSE also projects that participation would likely be low because the Company's financing option would not be competitive with the multitude of competitive options available coupled with the region's low energy rates.[618]

568 Staff opposes NWEC's recommendation, arguing that it is premature for the Commission to take such action until additional information is collected and analyzed.[619] Instead, Staff recommends that the Commission order PSE to evaluate the cost effectiveness of a tariffed on-bill repayment program with select external stakeholders, including PSE's CRAG and Low-Income Advisory Committee, and provide a brief report to the Commission within three months of the effective date of the final order in this case.[620]

Commission Determination

569 We agree with Staff that ordering the Company to implement an on-bill repayment program is premature at this juncture, particularly in light of the Company's preliminary findings that such a program would not necessarily prove to be cost-effective or particularly advantageous to customers. In light of this information, and considering the multiple competing priorities the Commission and its stakeholders will be facing in the coming biennium, we conclude it would be more appropriate to reexamine this proposal

---

[617] Piliaris, Exh. JAP-18T at 28:3-19.

[618] *Id.* at 26:3-27:10.

[619] Woodward, Exh. JTW-1T at 3:5-9.

[620] *Id.* at 3:19-23, 11:8-19.

at a later date, but only if circumstances change such that the benefits of initiating an on-bill repayment program outweigh its costs. Accordingly, we decline at this time to order PSE to convene a workgroup and report its findings. However, we expect the Company to revisit this proposal if and when the Company determines that it may be a viable option for providing benefits to customers.

iii. Pricing Pilots

570 Staff proposes that the Commission require PSE to:

- Prepare pilot programs for both electric time of use rates and electric critical peak-pricing (CPP) rates, which are dynamic pricing structures that have already been reviewed or tested in other jurisdictions;
- Engage with local resources, such as the Pacific Northwest National Laboratory, to evaluate the potential for real-time pricing pilots; and
- Entertain deferred accounting treatment for expenses associated with developing and administering pricing pilots.[621]

571 Staff witness Ball defines "pricing pilots" as an offer of unique electricity pricing with a rate structure available to a limited number of customers on a temporary basis. Ball testifies that pricing pilots allow a utility to gather data such as program costs and benefits, price responsiveness, and administrative complexity. Additionally, Ball argues that because pricing pilots typically rely on volunteers, pilots allow utilities to engage with customers most willing to provide feedback and tolerate fluctuations in program design, which allows utilities to evaluate potential benefits and solve potential problems before offering the rates to the entire ratepayer population.[622]

572 Ball further recommends the Commission provide PSE with guidance related to required components of a pricing pilot given new energy laws and state policy, as well as the lead-time needed to collect information from pilots.[623] Ball also provides seven recommendations regarding pricing pilot design and evaluation related to goals, structure,

---

[621] Ball, Exh. JLB-1T at 37:1-37:7.

[622] *Id.* at 37:9-18.

[623] *Id.* at 54:1-18.

administration, standards for study findings, study development and administration, evaluation of program costs and benefits, and an evaluation of program risk.[624]

573 Finally, Ball recommends that investor-owned utilities provide the Commission with annual updates on pricing pilots and full evaluations upon completion of the pilots, and that the Commission clarify that pricing pilots should last no more than three years.[625]

574 On rebuttal, PSE acknowledges that Staff's general design provides "useful illustrative guidance," but then cautions against such pilots "being overly prescriptive in their application."[626] If the Commission ultimately directs PSE to conduct pilots consistent with Staff's recommendation, PSE requests that "whatever guidance the Commission deemed appropriate to align expectations before PSE expends the time, effort and resources required to launch these pilots. Otherwise, PSE states it would appreciate the Commission's consideration in affording flexibility to develop such pilots at the time and in the manner it deems most appropriate."[627]

575 PSE agrees that it is appropriate to begin exploring time-based rate options at this juncture, particularly in light of the Company's AMI roll out. PSE is somewhat concerned with, but not opposed to, the prospect of CPP rates. Piliaris argues that CPP rates are a relatively punitive pricing approach and that peak time rebates (PTR) appear more customer friendly. Piliaris notes that both CPP and PTR have limited applications.[628]

576 PSE is less optimistic about the prospects for real-time pricing until there is a wholesale market for electricity in the region where such pricing is transparently available.[629]

577 Public Counsel witness Watkins testifies that Public Counsel does not oppose PSE's implementing and offering various voluntary pilot programs. However, Public Counsel recommends that the Commission disregard Staff's recommendation to "entertain" the

---

[624] *Id.* at 55:5-58:23.

[625] *Id.* at 58:26-59:4.

[626] Piliaris, Exh. JAP-18T at 14:10-13.

[627] *Id.* at 22:1-8.

[628] *Id.* at 20:18-21:12.

[629] *Id.* at 21:13-15.

notion of deferred accounting associated with pricing pilots. Specifically, Public Counsel argues that PSE's employee salaries, benefits, and other overhead comprise the majority of the program costs associated with the creation and administration of the pilots. Further, Watkins argues those costs are already incorporated and reflected in the Company's revenue requirement.[630]

578 In its brief, NWEC supports Staff's recommendations, and suggests that pilots should be developed in a collaborative process with stakeholders to ensure effective, fair, and equitable future rate designs.[631]

Commission Determination

579 While we commend Staff's efforts, we decline to adopt its proposal at this time in the limited context of a general rate proceeding for a single regulated company. Pricing pilots generally are a topic best addressed through a collaborative process rather than in an adjudicative proceeding, which is inherently adversarial and usually limited to a single company. We also will not direct the Company, Staff, or stakeholders to undertake a more global process at this time. The Commission is faced with multiple competing priorities ranging from CETA implementation to adjudicating back-to-back rate cases in the face of a serious budget crisis. We find merit in Staff's proposal, however, and hope to see it brought forward again at some point in the future. Because pricing pilots have a natural nexus to regulatory reform, Staff's proposal is likely a good fit with our future exploration and evaluation of performance-based regulation.

iv. Conjunctive Demand Service Option Pilot

580 PSE proposes a Conjunctive Demand Service Option Pilot (Pilot) that will allow certain customers with multiple service locations taking service under Schedules 26 or 31 to pay a demand charge based on the coincidental peak of all their metered locations rather than the arithmetic sum of the demand charges (in dollars) resulting from each service location's non-coincidental peak demand.[632] The Pilot would be open to all Schedule 26 and 31 customers that also provide transportation electrification service, and to a limited

---

[630] Watkins, Exh. GAW-13CT at 17:17-18:8.

[631] NWEC Initial Brief ¶ 29.

[632] Piliaris, Exh. JAP-1T at 32:6-10.

number of other Schedule 26 and 31 customers on a first come, first served basis.[633] The duration of the proposed Pilot is 5 years, beginning January 1, 2021.[634]

581 PSE proposes the Pilot for three primary reasons. First, large customers with multiple locations expect to be treated as one large customer.[635] Second, for power and transmission, there is no material difference in the cost of service between a single customer taking service at one location and a customer with multiple service locations that, in the aggregate, have similar load characteristics.[636] Third, the Pilot will support, or at least remove the barrier to, transportation electrification because it may reduce the demand charges for a customer operating multiple electric vehicle charging locations.[637]

582 PSE proposes to limit the Pilot to a total of 20 MW for non-electrification customers to mitigate potential revenue loss,[638] and estimates that customers could save up to 45 percent by moving to a conjunctive demand rate.[639] Due to the uncertainty in the expected amount of lost revenue, PSE will wait to recover any revenue deficiency in a future rate case. PSE also believes that an administrative fee may become necessary in the future, particularly if the program is broadly offered.[640]

583 PSE commits to a Pilot evaluation that includes the following components:

- Measuring the magnitude of customer savings;
- Evidence of customer load shifting as a result of the Pilot (that is shifted for the purpose of additional cost savings available due to the program);

[633] *Id.* at 34:11-35:8. For those customers not involved solely in electrification of transportation, the Pilot "is limited to 50 participating locations, with no more than five locations and 2 MW being associated with a single customer participating in the program" and no more than 20 MW for the total non-electrification program.

[634] *Id.* at 36:4-6, 38:9-14.

[635] *Id.* at 32:12-16.

[636] *Id.* at 32:16-20.

[637] *Id.* at 33:3-11.

[638] *Id.* at 36:3-4.

[639] *Id.* at 37:13-17.

[640] *Id.* at 38:15-39:1.

- Evaluation of the administrative process (billing, metering, accounting, etc.) and the potential for scalability; and
- Potential for other (or additional) rate design approaches that may be more suitable with AMI.[641]

584 Staff witness Ball conceptually supports PSE's Pilot but recommends the Commission require PSE to re-file its Pilot to incorporate Staff's design and evaluation elements.[642] Additionally, Ball argues that any pricing pilots filed with the Commission should be evaluated against Staff's recommended criteria.[643]

585 Ball concludes that the Pilot's unclear goals and lack of defined purpose "makes judging the pricing pilot, and measuring its practicality, relationship to cost-causation, or level of internal validity uncertain."[644] Further, Ball states that PSE lacks a description of "how it will evaluate the program, how the goals of the program will determine its success, or the proposed process for reviewing the pricing pilot."[645] Ball also states that the Company's proposal does not meet the S.M.A.R.T. goals described in Ball's testimony.[646]

586 Kroger strongly supports the Pilot. Kroger witness Higgins additionally recommends expanding the Pilot to include up to 10 locations and 5 MW per customer, with a maximum cap of 100 locations.[647] Higgins describes a similar program administered by Consumers Energy in Michigan that is available to any customer with at least 7 locations with a minimum average on-peak billing demand of 250 kW.[648] The coincidental peak calculation of the Pilot treats multiple loads of single customers in a comparable manner to a customer's single load with the same load shape.[649] Higgins asserts that this is how a

[641] *Id.* at 39:14-23.

[642] Ball, Exh. JLB-1T at 60:1-2.

[643] *Id.* at 56:17-58:24.

[644] *Id.* at 61:4-7.

[645] *Id.* at 61:9-13.

[646] *Id.* at 61:17-19. "S.M.A.R.T." is an acronym for Specific, Measurable, Achievable, Relevant, and Time-Bound. *Id.* at 55:6-7.

[647] Higgins, Exh. KCH-1T at 16:9-12.

[648] *Id.* at 16:20-17:1.

[649] *Id.* at 15:4-8.

customer's load would be viewed in a competitive market.[650] Further, Higgins agrees with the Company's position that a given level of MW load looks the same at the power and transmission level whether it is at a single location or multiple locations.[651]

587 FEA also supports the Pilot and recommends that after PSE has some experience with the Pilot, it should be expanded to other rate schedules such as Schedule 49.[652] FEA witness Al-Jabir argues that the Pilot's billing approach "recognizes the fact that the Company plans its generation and transmission system in a manner that recognizes demand diversity,"[653] and that the Pilot's pricing mechanism can help reduce the "rate of growth in the simultaneous peak demands that drive incremental generation and transmission investment."[654]

588 On rebuttal, PSE opposes Staff's recommendation that the Company be required to refile its Pilot with additional details, suggesting instead that the Commission approve the Pilot based on the clarifications the Company presents on rebuttal. PSE witness Piliaris suggests a less prescriptive evaluation framework than Staff proposes, agreeing to include "a discussion of the customer communication and education conducted, a review of the costs and benefits, and the analytical approach to conduct the evaluation."[655] Piliaris invites further guidance from the Commission on which of Staff's criteria to include in an evaluation.[656]

589 Piliaris argues that many of Staff's proposed evaluation elements for the Pilot lack relevance, and that the Pilot meets many of the more important elements.[657] Piliaris testifies that the general purpose of the Pilot is "primarily to better align the recovery of costs from these customers with cost-causation."[658] With regard to electric vehicle-related

---

[650] *Id.* at 15:8-9.

[651] *Id.* at 15:15-22.

[652] Al-Jabir, Exh. AZA-1T at 30:22-31:2.

[653] *Id.* at 28:17-19.

[654] *Id.* at 30:8-7.

[655] Piliaris, Exh. JAP-18T at 19:3-9.

[656] *Id.* at 19:5-9.

[657] *Id.* at 15:11-14.

[658] *Id.* at 16:4-6.

customers, Piliaris states the purpose of the Pilot is to reduce one potential barrier to transportation electrification related to mass transit.[659] Additionally, Piliaris states that PSE's Pilot is practical and understandable, and describes how the pilot meets Staff's five S.M.A.R.T goals.[660]

590 Responding to the structural design elements, Piliaris testifies that the Pilot will provide a "cost-based price signal" to participating customers focused on volume of use and location.[661] Piliaris considers FEA's and Kroger's testimony in support of the Pilot as evidence that "the pilots appear feasible from the customers' standpoint." Piliaris addresses Staff's administrative design elements, arguing that Schedule 26 and 31 customers "are generally more sophisticated and require less programmatic engagement and communications."[662]

591 Although Kroger generally supports Staff's proposed design and evaluation criteria for the Pilot, it does not support Staff's recommendation that PSE be required to re-file the proposed Pilot. Kroger argues that the Pilot is distinguishable from Staff's proposed pricing program because the Pilot does not "change the existing pricing structure, but rather changes the measurement of demand for purposes of billing customers with multiple service locations."[663]

592 Similarly, FEA argues that Staff's arguments are insufficient to warrant delaying the Pilot. Al-Jabir argues that the Pilot is intended to test customer interest, and, due to the sophistication of larger customers, "it is not necessary to define the target audience and the customer outreach strategy at the level of detail suggested by Ball prior to program implementation."[664]

593 In its brief, FEA recommends the Commission approve the proposed Pilot because it is consistent with cost-causation principles and appropriately reflects the manner in which PSE plans its generation and transmission system. FEA further argues that the Pilot

---

[659] *Id.* at 16:6-9.

[660] *Id.* at 16:10-17:10.

[661] *Id.* at 17:13-16.

[662] *Id.* at 18:7-9.

[663] Higgins, Exh. KCH-3T at 8:2-8:5.

[664] Al-Jabir, Exh. AZA-6T at 18:1-11.

appropriately recognizes demand diversity, *i.e.*, that not all customers or customer locations impose their maximum individual demands on the system at the same time.[665]

594 Kroger notes in its brief that it has participated in similar programs in other jurisdictions and has found that they successfully reduce the upward bias in the billing demand that would otherwise be charged to a multi-site customer by aggregating the customer's billing demands for peak demand measurement purposes. Kroger argues that, in this respect, aggregation billing sends more accurate price signals and better reflects cost-causation for multi-site customers.[666]

Commission Determination

595 We approve PSE's proposed Conjunctive Demand Service Option Pilot Program, which supports the legislative goal of transportation electrification and appears to have broad customer support. Notably, no party opposes the Pilot.

596 Although we decline to require PSE to refile the Pilot as Staff proposes, we require the Company to file a report that incorporates elements of Staff's pricing pilot proposal. At the evidentiary hearing, PSE witness Piliaris testified that the Company had specific ideas for reporting, but would very much appreciate specific guidance from the Commission to ensure the information it provides is valuable for the purpose of our evaluation of the Pilot's success.[667] Accordingly, we require the Company to use the design and evaluation elements in Staff's pricing pilot proposal as general guidelines, applying those elements it deems relevant and providing discussion for those that the Company deems have little or no application to this particular Pilot. In addition, the Commission would like to see more detail regarding the pros and cons of the Pilot and how the Company envisions expanding the Pilot over time. PSE should file a report addressing these issues within 90 days of the effective date of this Order.

597 We also require PSE to provide documentation showing whether the revenue requirement for Schedule 26 and Schedule 31 customers has increased or declined over time and whether Schedule 26 and Schedule 31 customers are recovering their share of revenue. PSE should provide its best information as to the number of electric vehicles that use

---

[665] FEA Initial Brief, p. 16.

[666] Kroger Reply Brief, p. 2.

[667] Piliaris, TR 266:22-277:2.

charging facilities offered by Schedule 26 or Schedule 31, and the approximate electric load used by those customers. PSE should file a report addressing these issues within 18 months of the Pilot's implementation.

v. Water Heater Rental and Gas Conversion Burner Rental Services

598 In its direct case, PSE proposed discontinuing the Company's water heater rental service and its gas conversion burner rental service. PSE's proposal to discontinue its gas conversion burner rental service is uncontested. In its compliance filing, PSE proposes to adjust its revenue requirement by removing the rate base associated with the conversion burner business, which was discontinued on March 31, 2020.[668] No party opposes this adjustment and we approve PSE's proposal.

599 On February 19, 2020, during the pendency of this proceeding, PSE filed with the Commission proposed tariff revisions that would discontinue PSE's water heater rental service. That same day, PSE filed an application seeking a Commission determination that its water heater rental service and associated assets are no longer necessary or useful, per WAC 480-143-180(2), or, in the alternative, Commission authorization for the sale of the water heater rental service to Grand HVAC Leasing USA LLC. These matters were assigned Docket UG-200112. On March 13, 2020, the Commission convened a prehearing conference and established a procedural schedule, including an evidentiary hearing set for July 15, 2020. Because issues related to the Company's water heater rental service will be resolved in that docket, we decline to address them here.

vi. Natural Gas Line Extension Allowances

600 NWEC recommends the Commission require PSE to revert back to its previous line extension allowance calculation methodology, or, in the alternative, revisit the issue in a collaborative forum.[669] PSE currently uses the Perpetual Net Present Value (PNPV) methodology for determining natural gas line extension allowances.

601 In responsive testimony, NWEC raises concerns about continued incentives to convert to natural gas and corresponding line extension allowances.[670] NWEC witness Wheeless

---

[668] PSE Response to BR-8.

[669] Wheeless, Exh. AEW-1T at 20:12-13, 20:17-19.

[670] *Id.* at 15:17-19.

argues that expanding the natural gas customer base ignores both risks and climate change policies.

602 NWEC asserts that natural gas customers are subject to several risks, including: (1) the potential volatility of natural gas prices; (2) possible legislative or public initiatives that could impose a carbon price mechanism in Washington; (3) electric heating and water heating technology advances that have improved efficiency and cost; (4) the recently enacted clean energy legislation that requires the electricity sector to become carbon free; and (5) recent decisions by local governments banning fossil fuel usage in new construction.[671] NWEC argues that fuel conversion efforts (electric to natural gas) commits customers to equipment and infrastructure for long periods of time and, if usage is less than expected, requires existing customers to subsidize those new customers.[672] Further, NWEC questions whether continuing to provide line extension allowances remains a prudent use of ratepayer funds.[673]

603 Notwithstanding the question of continuing the allowances, Wheeless argues that the PNPV methodology for determining natural gas line extension allowances is based on economic assumptions that increase the subsidization risk for existing customers. Further, Wheeless argues the previous method for calculating line extension allowances (the Facilities Investment Analysis, or FIA) was "more cautious on the expected revenue of a new given customer and thus reduces the risk of existing natural gas customers significantly subsidizing new gas customers."[674] Additionally, Wheeless argues the pilot for the PNPV methodology was never fully evaluated before becoming the permanent methodology used for Avista, PSE, and Cascade.[675]

---

[671] *Id.* at 15:21-18:14.

[672] *Id.* at 18:14-16.

[673] *Id.* at 19:10-12.

[674] *Id.* at 20:12-15. According to Wheeless, the FIA methodology "provides an allowance based on the estimated annual revenue from the customer, which was estimated based on the square footage of the house if heating with natural gas and the use of other natural gas powered appliances, as well as other factors, including whether a main extension was required, how soon service would begin, and whether there would be other new customers along the same main extension." *Id.* at 4:14-20; Wheeless, Exh. AEW-5.

[675] Wheeless, Exh. AEW-1T at 21:3-5.

604 Staff opposes both of NWEC's recommendations, arguing that the previous methodology is an "assumption driven calculation that treats customers inequitably based on highly variable numbers."[676] Further, Staff witness Ball testifies that PSE's Natural Gas Technical Advisory Group provides the appropriate forum to address natural gas infrastructure expansion issues, and that a Commission-directed proceeding is unnecessary.[677]

605 Ball argues that the PNPV methodology simplifies the tariff structure and is easier to calculate, understand, and apply. Further, Ball contends that this method provides a good proxy for the financial break-even point of adding new customers to the system.[678] From a policy perspective, Ball argues that "care should be taken to avoid providing preference (a form of subsidy) to one type of service over another." Finally, Ball argues that NWEC inappropriately equates PSE's use of the PNPV method with Avista's LEAP pilot, and that, as a policy matter, only the Avista pilot proposed to use remaining margin allowance to offset customer purchase of energy efficient natural gas furnaces.[679]

606 With respect to NWEC's argument regarding the purpose of pilot programs, Ball argues that the previous investigation in Docket UG-143616 supported consideration of four alternative policy goals: (1) reducing greenhouse gas emissions; (2) addressing environmental concerns associated with emissions from oil furnaces and wood burning stoves; (3) promoting economic development by expanding service to areas not currently served by natural gas; and (4) promoting energy efficiency.[680]

607 Staff suggests several alternative options for addressing the economic and climate risks NWEC identifies: (1) incorporate the social cost of carbon into the margin allowance method for both electric and natural gas; (2) wait for the legislature to direct utilities to

---

[676] Ball, Exh. JLB-28T at 3:11-12.

[677] *Id.* at 3:18-4:3.

[678] *Id.* at 8:6-12. Ball's rationale is based on Staff comments in PSE's 2017 tariff filing establishing the PNPV methodology in Docket UG-161268.

[679] *Id.* at 6:14-7:9.

[680] *Id.* at 10:20-11:8.

include some form of carbon price in overall rates; or (3) adjust the margin allowance calculation to use a shorter timeframe.[681]

608 Regarding the third option, above, Ball testifies that flexibility exists within the PNPV formula to adjust the timeframe considered for the margin allowance calculation (ranging from one year to in perpetuity) providing a "sliding-scale" to balance how long customers must remain on a system to account for their margin allowance.[682]

609 Finally, Ball testifies that further evaluation of the impact of margin allowances on existing customers would require the utilities to specifically track new customers that receive a margin allowance, compare the margin allowance to their actual revenue, and then aggregate that data for impact considerations.[683]

610 PSE also opposes NWEC's recommendation, at least within the context of this proceeding. First, PSE witness Piliaris argues that current state policy, as set out in RCW 43.21F.088(1)(d), is consistent with the expansion of natural gas.[684] Further, Piliaris argues that no significant changes should be made without more "thoughtful and inclusive discussions."[685] Finally, PSE offers the same option that Staff proposes to adjust the PNPV formula to reflect a shorter period of time to reduce the margin allowance, resulting in a more acceptable, policy-driven decision.[686]

611 In its brief, NWEC recommends the Commission direct new work in Docket UG-143616 or open a new collaborative docket to examine natural gas line extension policies more generally. NWEC argues it is appropriate for PSE to revert back to its previous policy because the current policy: (1) was not thoroughly considered when initially adopted;

---

[681] *Id.* at 12:9-21.

[682] A lower number indicates a higher risk of reduced or eliminated gas usage and holds existing customers harmless to new customers' reduced revenue potential, while choosing a number closer to 75 years would indicate less perceived risk. *Id.* at 14:9-15:1.

[683] *Id.* at 15:11-16:13.

[684] Piliaris, Exh. JAP-18T at 23:8-15.

[685] *Id.* at 24:5-7.

[686] *Id.* at 24:11-17.

(2) does not further Washington policies related to reducing carbon intensity and greenhouse gas emissions; and (3) unnecessarily increases risk for customers.[687]

612 In its reply brief, Staff argues that NWEC's concerns can be addressed in ways other than reverting to the Company's previous methodology. First, Staff suggests the Commission can address NWEC's concerns through modification, rather than replacement, of PSE's current method. Second, Staff argues that the Commission need not open a discussion forum to discuss line extensions because such forums already exist.

613 PSE argues in its reply brief that the Company's methodology is consistent with similar methodologies used by other regulated natural gas providers in Washington, and that reverting hastily back to the prior methodology after only three years, without a thorough process, would be premature.[688]

Commission Determination

614 We decline to adopt NWEC's recommendation. PSE's current methodology was originally adopted as the result of a collaborative process. As such, any proposed changes should similarly be addressed in a broader context outside of a single utility's general rate proceeding, particularly in light of the fact that other regulated utilities use the same method to calculate line extension allowances. We also will not pursue this matter further at this time due to multiple competing priorities, as discussed in other sections of this Order.[689] Moreover, we agree with Staff that forums other than individual rate cases or Commission-led proceedings exist to address the issues NWEC raises, and thus close Docket UG-143616.

vii. Distribution System Planning and Advisory Groups

615 Public Counsel proposes the Commission establish a standalone distribution planning group and require PSE to file distribution system plans.[690] Public Counsel "believes that a stakeholder process for distribution planning and distribution system plans should be

[687] NWEC Initial Brief ¶ 18.

[688] PSE Reply Brief ¶ 55.

[689] Chair Danner dissents on this issue and Commissioner Rendahl has prepared a separate concurring statement.

[690] Colamonici, Exh. CAC-1T at 18:4-16.

established in order to increase transparency and understanding of utility investments."[691] Public Counsel cites the difficulty in deciphering and understanding "PSE's rationale and assumptions in their AMI Business Case" as its impetus to propose the stakeholder process.[692]

616 Public Counsel presents two bases for its proposal. First, it argues that "the integration of distribution system plans can assist in understanding how these investments are chosen and determine whether the investments are cost-effective in relation to other options."[693] Second, Public Counsel argues that, to achieve CETA's goals, "distribution planning is essential to the integration of new renewable and non-emitting energy, as well as the integration of distributed generation, while maintaining a reliable and safe grid" and that the distribution system plans will "assist in understanding the investments made pursuant to CETA."[694]

617 Public Counsel further argues that the Distribution Planning Group would "serve a similar purpose as other advisory groups, such as the integrated resource plan advisory group" and would be a standalone advisory group.[695] Finally, Public Counsel recommends that distribution system plans have "independent filings that are reviewed similarly to an integrated resource plan."[696]

618 On rebuttal, PSE opposes Public Counsel's proposal. The Company acknowledges that stakeholder engagement is beneficial, and explains that "PSE is developing methods and processes to meet future requirements as a result of CETA and Integrated Resource Planning rulemaking."[697] Nevertheless, PSE witness Koch argues that stakeholder engagement for the AMI investment would provide no more benefit than "asking

---

[691] *Id.* at 16:19-17:2. Colamonici provides a citation to Public Counsel Comments on Distribution Planning, Rulemaking for Integrated Resource Planning, WAC 480-100-238, WAC 480-90-238, and WAC 480-107 (May 17, 2018) (Docket U-161024).

[692] Colamonici, Exh. CAC-1T at 16:8-16. Colamonici references Public Counsel witness Alvarez's testimony.

[693] *Id.* at 17:5-7.

[694] *Id.* at 17:8-13.

[695] *Id.* at 17:17-19, 18:4-5.

[696] *Id.* at 18:9-11.

[697] Koch, Exh. CAK-6T at 24:20-22.

stakeholders whether they think PSE should continue to use Microsoft Windows 7 after Microsoft no longer supports the operating system or move to the more current Windows 10."[698]

619 In its brief, NWEC requests the Commission require that "firm rules" related to distribution system planning be established in the IRP rulemaking docket.[699] NWEC also supports Public Counsel's proposal to open a distribution system planning proceeding docket.

Commission Determination

620 We decline to adopt Public Counsel's proposal, and instead encourage PSE to work with stakeholders to address distribution system planning issues to the extent that PSE and stakeholders find engagement on the issue to be valuable.

621 Although we are cognizant that Public Counsel has opposed AMI from its inception, we are not persuaded that forming an advisory group is an appropriate way to address its difficulty understanding the Company's AMI business case. Public Counsel has had ample opportunity to pose questions and seek additional information about AMI through discovery and cross-examination in this and prior GRCs.

622 Accordingly, we decline to require such a specific workgroup for project-level decisions that are best left to Company management. As it has done with AMI, Public Counsel will have multiple opportunities to weigh in on the prudency of the Company's project-level decisions when the Commission conducts its corresponding prudency review. On a going-forward basis, if Public Counsel or other stakeholders have questions or issues they would like to address related to the distribution system planning process, they are welcome to raise them in the IRP Advisory Group.

623 We also decline to adopt NWEC's proposal to require that "firm rules" related to distribution system planning be established in the IRP rulemaking docket. We do, however, encourage NWEC to participate in the IRP rulemaking, which is the appropriate forum to bring forth its concerns, ideas, and suggestions.

---

[698] *Id.* at 25:5-7.

[699] NWEC Initial Brief ¶ 28.

8. OTHER ISSUES

i. Restating Adjustments 20.09 – Excise Tax & Filing Fee and 20.10 – D&O Insurance

624 In its initial filing, PSE proposes to remove restating adjustments for both Directors and Officers (D&O) Insurance and its Excise Tax and Filing Fee. PSE explains that it relied on Staff's testimony from its 2017 GRC when developing its materiality threshold. The Company established a materiality threshold of $500,000 for net operating income (NOI) and $9.5 million for rate base for electric, and a threshold of $200,000 for NOI and $3.7 million for rate base for natural gas. The D&O Insurance adjustment annualizes insurance proceeds and adjusts the percentage of total premiums charged above the line to align with test year allocation factors. The Excise Tax and Filing Fee adjustment restates the level of expense and fees to match test year revenues. PSE applied this threshold to its restating adjustments and determined that both the D&O Insurance and the Excise Tax and Filing Fee restating adjustments are "consistently below the thresholds"[700] and thus requests Commission authorization to discontinue these adjustments in future rate cases.

Commission Determination

625 We deny the Company's proposal to remove restating adjustments 20.09 – Excise Tax and Filing Fee and 20.10 – D&O Insurance both in this case and on a going-forward basis. As discussed in other sections of this Order, the Commission does not adhere to any particular materiality threshold when evaluating pro forma adjustments. More importantly, the Commission has never applied a materiality threshold to a *restating* adjustment. We decline to begin doing so now.

626 Although the Company may regard these adjustments as "immaterial," we disagree. Both of these adjustments typically inure to the benefit of ratepayers, and the effect of removing them would increase the Company's revenue requirement. In any proceeding, but particularly in this proceeding, shifting that burden to ratepayers would be contrary to the public interest. Maintaining the D&O Insurance restating adjustment decreases revenue requirement by $7,055 for electric and $5,080 for natural gas. Maintaining the Excise Tax and Filing Fee adjustment reduces revenue requirement by $95,604 for electric and $92,675 for natural gas.

---

[700] Free, Exh. SEF-1Tr at 12:2-3.

ii. Miscellaneous Uncontested Adjustments

627 PSE proposes 27 restating and pro forma adjustments to its electric revenue requirement and 22 restating and pro forma adjustments to its natural gas revenue requirement that are uncontested by any party. These adjustments are listed in Appendix A to this Order, including revenue requirement metrics. All of these adjustments are uncontested and adequately supported by the record. Accordingly, we find that the remaining uncontested adjustments should be approved without condition.

iii. Issues Resolved on Rebuttal

628 On rebuttal, one common adjustment, three adjustments to electric revenue requirement, and two adjustments to natural gas revenue requirements were resolved by PSE's adoption of other parties' proposals. Each of those adjustments is described below.

629 **Temperature Normalization.** Temperature normalization is a common adjustment to both electric and natural gas operations that adjusts the test year revenue requirements and billing determinants to reflect sales volumes under "normal" weather conditions.[701] On rebuttal, PSE accepts Staff's recommendations to (1) calculate the temperature adjustment for electric and natural gas using the results of the rate schedule-level models and not reconciling to the system level model; (2) exclude electric rate Schedule 29 from the temperature adjustment because it is not a good fit at this time; and (3) use the SAP accounting system report for performing the temperature normalizing pro forma adjustment for natural gas revenue, but with one modification -- PSE proposes to include the SAP data through the actual therm data within the pro forma revenue model and not the temperature normalization adjustment. This way, PSE argues, the change is picked up by all appropriate revenue adjustments. PSE argues that the revenue impact between Staff's and PSE's approaches are the same.[702] Piliaris provides Exhibit JAP-19 for an update for the normalized natural gas test year revenue.[703] Staff's recommendation reduces PSE's electric revenue requirement by $3.6 million and increases its natural gas revenue requirement by $0.8 million.[704]

---

[701] Molander, Exh. LIM-1T at 2:5-10.

[702] Piliaris, Exh, JAP-18T at 5:7:16.

[703] *Id.* at 6:1-5.

[704] Liu, Exh. JL-1CTr at 6:3-7.

630 **Gain on Sale of Shuffleton**. On September 17, 2019, PSE filed supplemental testimony to update the deferred gain and loss on sale of property for the sale of the Shuffleton Electric Transmission Switching Station (Shuffleton). In its direct filing, PSE estimated its pre-tax gain on the sale to be approximately $12 million. Staff recommends the Commission allow PSE to include the sale proceeds in rates but require PSE to remove the sold property, Shuffleton, from rate base, and to remove the associated depreciation from the Company's revenue requirement.[705] On rebuttal, PSE accepts Staff's recommendation to exclude the net book value of the Shuffleton property from rate base and remove the depreciation expense from revenue requirement.[706]

631 **Contract Capacity along West Coast Gas Pipeline.** In its proposed power costs, PSE adjusts the availability of its capacity on the Enbridge Westcoast Energy pipeline (Enbridge) based on actual 2017 pipeline data. PSE explains that it seeks to decrease capacity because full capacity is not available at all times due to both planned and unplanned maintenance.[707] Staff opposes PSE's proposal to de-rate its fixed transport capacity on the Enbridge pipeline, and requests that capacity be maintained at 100 percent.[708] On rebuttal, PSE accepts Staff's proposal to assume 100 percent availability of the Enbridge Pipeline for the rate year power costs.[709] This update reduces the rate year power costs by $1.4 million.[710]

632 **Centralia Purchase Power Agreement Equity Adder**. Staff recommends that the Commission reduce the equity adder to the Centralia Power Purchase Agreement to $1.23/MWh to account for the reduction of the federal income tax rate from 35 percent to 21 percent.[711] The adjustment increases net operating income by $652,491 and reduces

---

[705] Steward, Exh. CSS-1T at 3:9-12, 11:15-17.

[706] Free, Exh. SEF-1Tr at 70:13-15.

[707] Wetherbee, Exh. PKW-1CT at 70:4-9.

[708] Gomez, Exh. DCG-1CT at 32:8-16.

[709] Wetherbee, Exh. PKW-34CT at 21:8-9.

[710] *Id.* at 22:4-6.

[711] Liu, Exh. JL-1CT at 42:19-21.

the revenue requirement by $868,389.[712] On rebuttal, PSE accepts Staff's change to the tax rate for the Centralia PPA equity adder.[713]

633 **Fredonia Generating Station**. Staff proposed a power cost adjustment to increase the normalized production O&M at the Fredonia gas generation plant to reflect actual major inspection costs. On rebuttal, PSE accepts Staff's $42,500 increase for major maintenance for the Fredonia Generating Station.[714]

Commission Determination

634 Each of the issues resolved on rebuttal achieve outcomes that are reasonable and well supported by the record. We approve them without condition. These adjustments are listed in Appendix A to this Order, including revenue requirement metrics.

9. COVID-19 PANDEMIC CONSIDERATIONS

635 On April 22, 2020, the Commission issued Bench Request No. 15 (BR-15) seeking proposals from all parties to mitigate the impact in the short-term of any rate increase on customers that will result from the final resolution of this case due to the COVID-19 pandemic. The Commission encouraged parties to submit proposals that address variables such as timing, amortization periods, or the use of existing mechanisms that may not be at issue in this proceeding. BR-15 clarified that parties should not seek to re-litigate contested issues in this proceeding, including those related to their respective positions on PSE's level of revenue requirement or individual adjustments. BR-15 set a deadline of May 1, 2020, for parties to file proposals, and a May 8, 2020, deadline to respond to other parties' proposals.

636 On April 30, 2020, NWEC filed a response to BR-15. NWEC states it had no specific recommendations, but that it looks forward to hearing the other parties' suggestions.

637 On May 1, 2020, TEP, PSE, Public Counsel, Nucor Steel, and Staff filed responses.

638 TEP recommends the Commission delay the effective date of any rate increase at least six months beyond the suspension date so that no rate increase would occur in calendar year

[712] *Id.* at 43:4-7.

[713] Free, Exh. SEF-17T at 69:8-14.

[714] Roberts, Exh. RJR-14T at 23:5-11.

2020. Preferably, TEP suggests the Commission delay any increase by 12 months, or use a "phase-in" approach to avoid a rate increase in the winter heating season.

639 PSE recommends the Commission use an "EDIT Matching" approach, which would lengthen the amortization period for several regulatory assets that are currently in rates or proposed to be set in rates, some of which are included in this proceeding and some of which are not. These regulatory assets would be held in new accounts, the amortization of which would be matched with the reversal of ARAM for protected EDIT in this case. PSE estimates the ARAM reversal to be $37.8 million. Because customers' rates are currently supporting nearly $165 million in annual costs to amortize the regulatory assets that would be included in the new holding accounts, this EDIT Matching approach would create approximately $127 million in potential rate relief for PSE's customers in the rate year. PSE provides three example scenarios using the EDIT Matching approach that result in a range of $72 million to $127 million available to mitigate a rate increase.

640 Public Counsel makes multiple recommendations, including (1) expanding the moratorium on disconnections and related fees; (2) imposing additional consumer protections, such as waiving late payment fees and security deposits, implementing deferred payment plans for past-due bills, developing a debt forgiveness program, and increasing assistance programs; (3) encouraging PSE to communicate with its customers about how to receive help and manage their bills; (4) requiring PSE to track and report information regarding customer affordability challenges; (5) requiring PSE to work with its small business customers to avoid disconnection; and (6) denying or delaying any rate increase.

641 Nucor Steel recommends that the Commission delay the implementation of any rate increase until business conditions have returned to normal, and then gradually phase-in new rates. Alternatively, Nucor Steel requests delayed implementation until no sooner than mid-2021 followed by the same phase-in approach for any rate increase.

642 Staff identifies a number of possible mitigation factors: (1) extending the amortization of the electric storm damage and environmental remediation deferrals; (2) extending the amortization of natural gas environmental remediation deferrals; (3) extending the amortization of both electric and natural gas decoupling deferrals; (4) accelerating the amortization of unprotected EDIT for both electric and natural gas; (5) updating the electric power supply cost baseline; (6) updating natural gas PGA rates; and (7) extending amortization of any amounts related to AMI and GTZ that the Commission authorizes for recovery.

643 On May 8, 2020, FEA, NWEC, TEP, Public Counsel, PSE, and Staff filed replies.

644 FEA supports Nucor's and Public Counsel's proposals to delay any rate increase until no sooner than mid-2021, with a subsequent phased-in rate increase because it is the more straightforward approach. If the Commission declines to adopt that approach, FEA supports Staff's and PSE's proposals to extend the amortization of regulatory assets and accelerate the amortization of EDIT to mitigate the impact of any rate increase.

645 NWEC raises concerns that both Staff's and PSE's proposals may create intergenerational inequities and overall higher costs to customers. NWEC recommends the Commission consider whether it can resolve this case in a manner that allows it to combine whatever solution it adopts with other true-up mechanisms that will "inevitably develop from the COVID-19 situation."[715]

646 TEP describes Staff's proposal as "reasonable," noting that it concurs with Staff's comment about the "whiplash" effect of a sudden return to higher levels after mitigation measures expire.[716] TEP reiterates its preference that the Commission delay and then "phase in any approved rate increase gradually in a structured multi-year approach,"[717] and expresses support for Public Counsel's recommendations to extend the disconnection moratorium and fee waiver, adopt additional consumer protections, encourage communication with customers, and gather relevant data. TEP recommends the Commission address these issues for all regulated companies in a new Commission rulemaking.

647 Public Counsel prefers Staff's proposal to PSE's, arguing that removing regulatory assets and EDIT liabilities from PSE's regulatory balance sheet would make its books less transparent. Public Counsel further contends that the Commission can extend amortization periods for regulatory asset balances without tying those amortizations to EDIT reversals and without removing the regulatory asset and EDIT liability balances from the regulatory balance sheet. In addition, Public Counsel argues that Staff's approach is preferable because it does not limit the regulatory asset amortization savings

---

[715] NWEC Reply to BR-15 Responses, p. 4.

[716] TEP Reply to BR-15 Responses ¶ 2.

[717] *Id.* ¶3.

to the EDIT reversals and does not remove asset and liability balances from the regulated balance sheet.

648 Public Counsel next suggests that the Commission consider intergenerational inequities that could result from lengthening amortization periods, and expresses support for both Nucor's and TEP's proposal to delay or phase-in any rate increase.

649 Finally, Public Counsel urges the Commission to be mindful of current circumstances, including increased residential energy use due to people spending more time at home. Public Counsel also notes that PSE is able to acquire very low interest or no interest short-term loans if it requires cash flow assistance during this time.

650 PSE argues that only Staff and the Company provided options to mitigate rate impacts and appropriately balanced the interests of both PSE and its customers. PSE objects to the responses filed by Public Counsel, TEP, NWEC, and NUCOR to the extent that they exceed the scope of BR-15 and attempt to re-litigate the issues in this case. PSE observes that many of Staff's proposals are similar to the Company's, but argues that its proposal "offers a more long-term solution, avoids the whiplash of steep rate increase in the near term, and is more powerful in terms of rate increase mitigation."[718] With respect to Staff's proposal to extend the amortization of certain regulatory assets and deferral balances, PSE argues that its proposal extends the amortization for a longer period and matches it to the reversal of PP EDIT, thereby providing additional mitigation beyond that proposed by Staff. With respect to decoupling deferrals, PSE is concerned that extending the regulatory asset associated with deferrals from PSE's electric and natural gas decoupling mechanisms would make it difficult for the Company to fully recognize its 2020 deferrals in light of limits on decoupling-related rate increases.

651 PSE also disagrees with Staff's suggestion to shorten the amortization of UP EDIT for both electric and natural gas due to concerns with a steeper increase in the short term when the amortization ends.

652 PSE does not oppose Staff's proposal that the Company file updated power costs, but estimates that an update would likely increase the power cost baseline rate by approximately $6 million. PSE suggests the Commission could consider placing the PCA deferred balance of approximately $42 million in the regulatory asset accounts PSE proposed in its initial response to BR-15 and, once the electric decoupling balance was

[718] PSE Reply to BR-15 Responses, p. 2.

fully amortized, begin amortizing the PCA balance at the level of amortization expense approved in this case until it is fully amortized. Under this scenario, the remaining electric regulatory assets in the holding account would begin amortizing, which would lengthen the amortization for all regulatory assets under one of PSE's proposed scenarios.

653 PSE notes that Staff's proposal to amortize the $70.6 million PGA deferral balance over three years rather than the remaining one year of amortization is generally consistent with the Company's proposal, but PSE's proposal prioritizes the PGA deferral recovery to avoid significant carrying costs that accrue on PGA deferrals.

654 Finally, PSE argues that Public Counsel's and TEP's responses are inappropriate because (1) they attempt to re-litigate the central issue of this case, which is the level of revenue requirement the Commission should approve; and (2) they would require the Commission to disregard legal standards it is required to follow and deny any rate increase in light of the pandemic. PSE notes it has already voluntarily delayed the effective date of its rate increase, which diminished the ultimate rate increase by one-sixth in the rate year.

655 Staff largely disagrees with the proposals made by Public Counsel, TEP, Nucor, and NWEC. Staff argues that Public Counsel's and TEP's recommendation to deny PSE a rate increase is "tantamount to attempting to re-litigate PSE's revenue requirement, which the Commission explicitly disallows in its bench request."[719] Staff also disagrees with other parties' proposals to delay implementation of any rate increase because a prolonged delay could negatively impact the Company's finances and operations, which would in turn impact ratepayers. Staff argues that, "[e]ven in a time of economic downturn, the Commission still has the obligation to set utility rates at a level sufficient for the utility to recover its costs based on the evidence presented in this case."

656 Staff does not object to parties' proposals to increase consumer protections such as improving bill assistance, potentially expanding the moratorium on disconnection and related fees, and developing a debt forgiveness program. Ultimately, Staff recognizes that the Commission and PSE have taken measures, and that the Commission can implement more such measures outside the context of a GRC.

657 Like PSE, Staff recognizes that its approach is similar to the Company's, primarily focusing on the amortization periods for regulatory assets to reduce amortization expense in the rate year. Staff distinguishes its approach from the Company's in three distinct

---

[719] Staff's Reply to BR-15 Responses, p. 2.

ways: (1) PSE's EDIT Matching method; (2) PSE includes contested deferral balances; and (3) the length of the amortization periods.

658 Staff argues that there is a possibility that PSE's proposed EDIT Matching approach will result in a divergence between (1) the amortization expenses of regulatory assets and EDIT that PSE will actually experience and (2) what is built into rates going forward. In that scenario, Staff contends that PSE's approach would have the potential to benefit the Company at the expense of ratepayers. Staff argues that if and when the IRS allows the balance sheet offset that PSE proposes, the Company would begin booking levels of regulatory asset amortization expense and EDIT amortization that are different than the levels embedded in the rates the Commission authorizes here. Staff explains:

> Because the amortization period for the regulatory assets is shorter than that of protected EDIT, offsetting regulatory assets with protected EDIT on the balance sheet will create a significant net reduction to the level of expense the Company books. Given that this would occur after rates from this GRC go into effect, customers would not benefit from the net reduction to annual expense. In other words, PSE will have reduced substantially the protected EDIT balance it owes to customers, but customers would not receive a commensurate reduction to the amortization expense.[720]

659 Staff recommends that, even if the Commission sees merit in PSE's EDIT Matching proposal, the Commission need not approve the use of PP EDIT to offset regulatory assets. Instead, the Commission should extend the amortization periods for regulatory assets such that the selected group of assets amortizes at $38 million per year. Staff urges the Commission to also request a filing from PSE if it obtains approval from the IRS that clarifies whether the potential imbalance described above would exist and, if so, propose a new remedy.

660 Finally, Staff cautions the Commission against ordering excessively long amortization periods for regulatory assets identified in response to BR-15. Like Public Counsel, Staff has concerns related to intergenerational inequity, and argues that extending the amortization of regulatory assets over longer periods is inconsistent with the Commission's direction to propose short-term mitigation options. For that reason, Staff

---

[720] *Id*. at p. 4.

urges the Commission to target amortization periods closer to six, rather than 15, years, and ultimately requests the Commission adopt Staff's proposal.

661 On May 29, 2020, PSE filed a supplemental response to BR-15. In its supplemental response, PSE explains that each of the scenarios presented would result in $11.8 million less in rate mitigation on the natural gas side than was reflected in its initial response.

Commission Determination

662 The Commission appreciates the parties' thoughtful and creative proposals to mitigate the rate increase authorized by this Order. After careful consideration, we determine that Staff's proposal best balances the interests of the Company and its customers and appropriately limits extended amortization periods to avoid intergenerational inequities. In addition, Staff's proposal has the greatest impact in the short-term. Specifically, we adopt Staff's proposals to extend the amortization period for certain regulatory assets to five years, which decreases revenue requirement by $17.7 million for electric and $4.4 million for natural gas. On the electric side only, we extend the decoupling deferral to two years, which decreases revenue requirement by $10.9 million. On the gas side only, we extend PSE's PGA deferral to three years, which decreases revenue requirement by $30.8 million. Finally, we accelerate the amortization of UP EDIT for both electric and natural gas to three years, which reduces PSE's revenue requirement by approximately $16 million for electric and approximately $1.3 million for natural gas. To address PSE's concerns related to extending the regulatory asset associated with deferrals from the Company's electric and natural gas decoupling mechanism, we extend only the electric amortization period and leave the gas deferral unchanged.

663 We agree with Staff that PSE's proposal includes lengthy amortization periods that are both inconsistent with our direction to address mitigation in the short-term and would create intergeneration inequities. With respect to Public Counsel's and TEP's proposal that we decline to authorize any rate increase, we agree with the Company that the Commission's statutory authority requires us to establish fair, just, reasonable, and sufficient rates. Denying any rate increase whatsoever based solely on the public health crisis would be inconsistent with our statutory obligation because it would require us to disregard the evidence in the record that supports the rate increase we approve by this Order.

664 We also determine that additional mitigation strategies are appropriate to reduce the impact of the rate increase authorized by this Order, as follows:

- Requiring PSE to reverse ARAM PP EDIT for both 2019 and 2020 over a 12-month period for both gas and electric,[721] and
- Shortening the amortization of the gain on the sale of Shuffleton from three years to two years on the electric side.

665 By ensuring a minimum of two years of rate impact mitigation, we afford our best estimate of the amount of time necessary to allow economic recovery from the COVID-19 pandemic. We are mindful that a rate increase will occur at the end of the two years as certain offsetting items are exhausted; however, PSE represents it will be in the process of seeking approval for new rates at that time.

666 Our overall approach to authorizing rates in this proceeding carefully balances the Company's needs with customers' needs by allowing pro forma capital additions for an extended period through December 31, 2019, valuing rate base on an EOP basis, and returning dollars PSE owes customers sooner rather than later. As we have reiterated throughout this Order, our decisions are entirely specific to the record evidence in light of the current economic circumstances created by the COVID-19 pandemic.

667 Finally, we appreciate the parties' multiple proposals to increase consumer protections. We applaud PSE for the efforts it has taken thus far with respect to ceasing disconnections in advance of the Governor's moratorium on disconnections and late fees. We also appreciate the Company's work to create the Crisis Affected Customer Assistance Program and develop a transition plan following the expiration of the Governor's moratorium. On June 16, 2020, the Commission conducted a special open meeting specifically to address regulated utilities' transition plans. The Commission intends to continue to work with all regulated companies on these issues to engage the broadest possible cross-section of stakeholders and ensure that consumers are adequately protected during these uncertain times.

III. FINDINGS OF FACT

668 Having discussed above in detail the evidence received in this proceeding concerning all material matters, and having stated findings and conclusions upon issues in dispute among the parties and the reasons therefor, the Commission now makes and enters the

[721] *See* ¶ 383, *supra*.

following summary of those facts, incorporating by reference pertinent portions of the preceding detailed findings:

669 (1) The Commission is an agency of the State of Washington vested by statute with the authority to regulate rates, regulations, practices, accounts, securities, transfers of property and affiliated interests of public service companies, including electric and natural gas companies.

670 (2) PSE is a "public service company," an "electrical company," and "gas company" as those terms are defined in RCW 80.04.010 and used in Title 80 RCW. PSE provides electric and natural gas utility service to customers in Washington.

671 (3) PSE's currently effective rates were determined on the basis of the Commission's Final Order in Dockets UE-180899 and UG-180900.

672 (4) The rates established by the 2018 ERF Rate Plan updated PSE's rates previously established in the Company's 2017 GRC.

673 (5) On June 20, 2019, PSE filed this GRC with the Commission proposing revisions to its currently effective Tariffs WN U-20, Electric Service, and Tariff WN U-2, Natural Gas Service.

674 (6) PSE requests an increase in its annual electric revenue requirement of approximately $138.4 million (6.8 percent), and an increase to its annual natural gas revenue requirement of approximately $65.5 million (7.9 percent), which includes an attrition adjustment of $23.9 million for electric and $16.2 million for natural gas.

675 (7) Due to the economic crisis created by the COVID-19 pandemic and the absence of a multi-year rate plan, the record evidence does not support a finding that an attrition adjustment would be in the public interest at this time.

676 (8) The record evidence demonstrates a range of reasonable ROE between 8.9 percent and 9.5 percent.

677 (9) PSE's proposed short-term cost of debt, long-term cost of debt, and hypothetical capital structure are uncontested and supported by the evidence in the record.

678 (10) The record evidence demonstrates that PSE's customers are benefitting from the GTZ program.

679 (11) The record evidence supports a finding that GTZ investments made through December 31, 2019, were prudently incurred. The record evidence is insufficient to establish that any GTZ investments made after that date were prudently incurred.

680 (12) The Commission would benefit from additional reporting on the GTZ program and its benefits.

681 (13) The record evidence demonstrates that PSE's business decision to install AMI was prudent.

682 (14) PSE has not yet satisfactorily demonstrated the benefits of AMI.

683 (15) The record evidence demonstrates the PSE prudently incurred the costs to relocate its data centers. PSE satisfactorily demonstrated that its prior centers could not support accelerated growth, heavier and denser equipment, increased power, redundancy and cooling requirements, virtualization, and that they did not meet current cyber security and environmental monitoring standards.

684 (16) The Tacoma Liquefied Natural Gas Plant is not yet in service, and is thus not yet used and useful.

685 (17) PSE failed to produce any contemporaneous documentation related to its decision to install SmartBurn. PSE concedes that its decision to install SmartBurn was not required by any federal, state, or local law. Accordingly, PSE's investment in SmartBurn was not prudently incurred.

686 (18) The record evidence demonstrates that PSE prudently incurred the costs of its HR TOPS software system. The system is used and useful and its costs are known and measurable.

687 (19) The record evidence demonstrates that PSE prudently incurred costs related to the replacement of its High Molecular Weight Cable. The new cable is used and useful and its costs are known and measurable.

688 (20) PSE incurred $13.6 million in electric and $6.3 million in natural gas expenditures through June 30, 2019, in response to requests by municipalities to relocate facilities as specified in jurisdictional franchise agreements and other public improvement projects. The record evidence demonstrates that the costs of these public improvement projects were prudently incurred.

689 (21) Extending the pro forma capital additions period to December 31, 2019, is an appropriate tool to reduce regulatory lag, particularly for short-lived investments.

690 (22) Valuing rate base on an EOP basis addresses regulatory lag for short-term investments and accurately reflects rate base values during the rate effective period.

691 (23) For the purposes of this proceeding, all components of rate base should be similarly valued. As such, investor supplied working capital should be valued on an EOP basis.

692 (24) The record evidence demonstrates that the wind studies PSE relied on to set its capacity factors for wind resources in AURORA provide the most recent and accurate information available.

693 (25) PSE is likely to incur some level of major maintenance costs for Colstrip Unit 4 in 2020. Those costs should be deferred to ensure that only actual costs incurred by PSE are recovered from ratepayers.

694 (26) The record evidence demonstrates that PSE's decision to shift common costs from Colstrip Units 1 and 2 to Colstrip Units 3 and 4 was reasonable, and PSE's estimate is reasonably based on test year costs.

695 (27) The record evidence does not support PSE's proposal to change its hydroelectric modeling in AURORA to use the average of 80 years of hydro data to perform a single AURORA run.

696 (28) Neither of the Green Direct PPAs are currently in service. Accordingly, a prudency determination is not appropriate at this time.

697 (29) The record evidence demonstrates that PSE's annual incentive compensation plan is reasonable and benefits ratepayers.

698 (30) PSE proposes to pass back to ratepayers in base rates $38.9 million of UP EDIT, which is not subject to IRS normalization requirements, over a four-year period. To reduce the impact of the rate increase on ratepayers, grossed-up UP EDIT should be passed backed to ratepayers over a three-year period through a separate tariff schedule.

699 (31) PP EDIT amounts PSE owes customers are actual amounts and are not based on estimates or projections.

700 (32) Embedding PP EDIT reversals in base rates, as PSE proposes, would impair the ability of the Commission and other parties to determine whether the over-collected taxes are appropriately returned to ratepayers and is thus not in the public interest.

701 (33) PSE removed Colstrip Units 1 and 2 from rate base as of December 31, 2019, and subsequently transferred those assets to a regulatory asset account.

702 (34) On April 10, 2019, PSE filed with the Commission a petition for an order authorizing deferral of certain expenses related to the Company's investments in short-lived technology assets as part of its GTZ program in Dockets UE-190274 and UG-190275.

703 (35) PSE specifically seeks an order authorizing the use of deferred accounting to allow for later consideration for recovery in rates the depreciation expense associated with the GTZ investments with a book life of 10 years or less. PSE requests an ongoing deferral. Allowing pro forma plant additions through December 31, 2019, in this proceeding, coupled with the additional deferral we authorize until the Company's next GRC, will create a baseline amount of investment in forthcoming test years that will alleviate the need for an ongoing deferral.

704 (36) On November 27, 2019, PSE filed with the Commission a petition related to its Green Direct program for an order authorizing deferred accounting treatment for liquidated damages accruing under Schedule 139, Voluntary Long Term Renewable Energy Purchase Rider in Dockets UE-190991 and UG-190992. The Green Direct Petition seeks authority for PSE to defer liquidated damages and use them to offset other voluntary long tern renewable energy program costs. PSE should be authorized to defer the liquidated damages until such time as the final amount is known.

705 (37) Currently, PSE's transmission costs are classified as 25 percent demand and 75 percent energy. It is necessary to maintain PSE's transmission cost classification for the purposes of this proceeding until PSE is able to develop a new electric COSS under the Commission's recently promulgated cost of service rules in Chapter 480-85 WAC.

706 (38) The record evidence demonstrates that PSE's proposed electric rate spread moves the residential class closer to parity without creating rate shock, thus striking an appropriate balance between cost causation and the principle of gradualism.

707 (39) PSE's low-income residential customers, on average, use more energy than the average residential customer, and thus would be disproportionately affected by a larger increase to tail block rates.

708 (40) PSE's natural gas COSS, including the Company's more detailed allocation in its application of its Peak and Average method, produces the most accurate data.

709 (41) PSE's proposed natural gas rate spread, as compared to other parties' proposals, most appropriately allocates rate increases across all customer classes.

710 (42) PSE's proposed increase to the natural gas Residential class basic charge to incorporate the addition of Schedule 141 (ERF) and Schedule 141X (EDIT) basic service charge adjustments is reasonable. The increase from $11 to $11.52 per month is well within the Company's COSS model, which shows that actual cost for residential basic service charge is $18.66 per customer.

711 (43) Staff's request to require an economic bypass study for the Special Contract class is premature because the contract does not expire until 2035.

712 (44) Base rates provide a more proportionally accurate basis for calculating PSE HELP fund increases. Low-income programs should be increased by twice the percentage increase to base rates or $1.4 million, whichever is greater.

713 (45) PSE is receptive to considering expanding the first block energy rate from 600 kWh to 800 kWh.

714 (46) PSE agrees with TEP's proposal to develop a disconnection reduction plan in consultation with the Company's Low-Income Advisory Committee, and to file an annual report for the purpose of analyzing and monitoring disconnection trends.

715 (47) The evidence in the record raises questions about administrative costs incurred by Community Action Agencies to administer PSE's HELP funds.

716 (48) Staff's proposed materiality threshold would unnecessarily restrict the Commission's discretion under RCW 80.04.250.

717 (49) NWEC proposes that PSE offer an on-bill repayment program. The record evidence demonstrates that such a program would be premature in light of the Company's preliminary findings that such a program would not necessarily be cost effective for the Company or its customers.

718 (50) Staff's proposed pricing pilots would be better addressed through a collaborative process rather than in the context of an adjudicative proceeding.

719 (51) PSE proposes a Conjunctive Demand Service Option Pilot that would allow certain customers taking service under Schedules 26 or 31 with multiple service locations to pay a demand charge based on the coincidental peak of all their metered locations. The Pilot, which supports the legislative goal of transportation electrification and appears to have broad customer support, is reasonable and should be approved.

720 (52) The Commission requires further information to aid in its evaluation of the Pilot's success.

721 (53) On February 19, 2020, during the pendency of this proceeding, PSE filed with the Commission proposed tariff revisions that would discontinue PSE's water heater rental service. That same day, PSE filed an application seeking a Commission determination that its water heater rental service and associated assets are no longer necessary or useful, per WAC 480-143-180(2), or, in the alternative, Commission authorization for the sale of the water heater rental service to Grand HVAC Leasing USA LLC.

722 (54) PSE's proposal to discontinue its gas conversion burner rental service is uncontested. In its compliance filing, PSE proposes to adjust its revenue requirement by removing the rate base associated with the conversion burner business, which was discontinued on March 31, 2020.

723 (55) NWEC proposes the Commission require PSE to revert back to its previous line extension allowance calculation methodology, or, in the alternative, revisit the issue in a collaborative forum. PSE's current methodology was originally adopted as the result of a collaborative process. As such, any proposed changes should similarly be addressed in a broader context outside of a single utility's general rate proceeding, particularly in light of the fact that other regulated utilities use the same method to calculate line extension allowances. Due to resource constraints and multiple competing priorities, PSE should not be required to revisit this issue in a generic collaborative forum at this time. Moreover, forums other than individual rate cases or Commission-led proceedings exist to address the issues NWEC raises.

724 (56) Public Counsel proposes the Commission establish a standalone distribution planning group and require PSE to file distribution system plans. PSE should not be required to form such a specific workgroup for project-level decisions that are best left to Company management, nor should it be required to file distribution system plans.

725 (57) In its initial filing, PSE proposes to remove restating adjustments for both D&O Insurance and its Excise Tax and Filing Fee because they do not meet PSE's materiality threshold. The Commission does not apply a materiality threshold to restating adjustments.

726 (58) PSE proposes 27 uncontested restating and pro forma adjustments to its electric revenue requirement and 22 uncontested restating and pro forma adjustments to its natural gas revenue requirement. These 49 adjustments are depicted in Appendix A to this Order, including revenue requirements metrics. These uncontested adjustments are supported by substantial competent evidence in the record of this proceeding.

727 (59) On rebuttal, three common adjustments and one adjustment to electric revenue requirement were resolved by PSE's adoption of other parties' proposals. Each of the issues resolved on rebuttal achieve outcomes that are reasonable and well supported by the record.

728 (60) On April 22, 2020, the Commission issued BR-15 seeking proposals from all parties presenting options to mitigate the impact in the short-term of any rate increase on customers that will result from the final resolution of this case due to the rapid change in circumstances during the pendency of this proceeding related to the COVID-19 pandemic. Staff's proposal, which has the greatest impact in the short-term, best balances the interests of the Company and its customers and appropriately limits extended amortization periods to avoid intergenerational inequities.

729 (61) PSE's currently effective electric and natural gas rates do not provide sufficient revenue to recover the costs of its operations and provide a rate of return adequate to compensate investors at a level commensurate to what they might expect to earn on other investments bearing similar risks.

IV. CONCLUSIONS OF LAW

730 Having discussed above all matters material to this decision, and having stated the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:

731 (1) The Commission has jurisdiction over the subject matter of, and parties to, these proceedings.

732 (2) PSE is an electric company, a natural gas company, and a public service company subject to Commission jurisdiction.

733 (3) At any hearing involving a proposed change in a tariff schedule the effect of which would be to increase any rate, charge, rental, or toll theretofore charged, the burden of proof to show that such increase is just and reasonable will be upon the public service company. RCW 80.04.130(4). The Commission's determination of whether the Company has carried its burden is adjudged on the basis of the full evidentiary record.

734 (4) PSE's existing rates for electric service are neither fair, just, and reasonable, nor sufficient, and should be adjusted prospectively after the date of this Order.

735 (5) PSE's existing rates for natural gas service are neither fair, just, and reasonable, nor sufficient, and should be adjusted prospectively after the date of this Order.

736 (6) PSE's request for an attrition adjustment will not result in rates that are fair, just, reasonable, and sufficient, at this time and therefore should be denied.

737 (7) Consistent with the evidence presented in the record and the principle of gradualism, PSE's ROE should be set at 9.40 percent.

738 (8) Based on an ROE of 9.40, the uncontested hypothetical capital structure, and the uncontested cost of debt, the Commission should approve and adopt an overall rate of return of 7.39 percent for purposes of establishing revenue requirements and rates in this proceeding.

739 (9) PSE should be authorized to amortize deferred GTZ expense and rate base amounts for the GTZ assets placed in service between July 2018 and June 2019 over a three-year amortization period beginning June 20, 2020.

740 (10) The Commission should require PSE to file a report that (1) itemizes and describes each component of the GTZ program placed in service to date, (2) documents, by itemized component, the program's costs and customer benefits, (3) reports on the program's overall performance and metrics, and (4) describes the GTZ components not yet deployed, with an estimated in-service date for each.

741 (11) PSE should be allowed to recover in rates the test year AMI costs, deferral, and pro forma adjustments through December 31, 2019. The Commission should require PSE to continue to defer recovery of the return on each portion of the investment until the AMI project is complete.

742 (12) PSE should be allowed to recover in rates costs related to its Data Center Relocation.

743 (13) PSE should be allowed to defer for later recovery the costs associated with Upgrades 1 and 3 to its Tacoma LNG facility until the facility is operational.

744 (14) PSE's pro forma adjustment for costs related to its SmartBurn investment should be disallowed.

745 (15) PSE should be allowed to recover in rates costs related to its HR TOPS investments through December 31, 2019.

746 (16) PSE should be allowed to recover in rates costs related to its High Molecular Weight Cable investments through December 31, 2019.

747 (17) PSE should be allowed to recover in rates costs related to its Public Improvement investments through December 31, 2019.

748 (18) PSE should be allowed to recover in rates costs related to its Energy Management System investments through December 31, 2019.

749 (19) Extending the pro forma period until December 31, 2019, is consistent with RCW 80.04.250 and will result in rates that are fair, just, reasonable, and sufficient.

750 (20) Valuing rate base on an EOP basis will result in rates that are fair, just, reasonable, and sufficient.

751 (21) Valuing ISWC on an EOP basis will result in rates that are fair, just, reasonable, and sufficient.

752 (22) PSE's capacity factors of wind resources in AURORA should be accepted.

753 (23) PSE should defer the recovery of any major maintenance costs for Colstrip Unit 4 to ensure that only actual costs incurred by PSE are recovered from ratepayers.

754 (24) The Commission should accept PSE's adjustment that shifts common costs from Colstrip Units 1 and 2 to Colstrip Units 3 and 4.

755 (25) The Commission should require PSE to restore its practice of separately modeling 80 hydro years in AURORA and then averaging the power costs rather than using a single model run as proposed.

756 (26) PSE's proposal to combine power costs for Green Direct program participants with power costs for non-participants does not adequately ensure compliance with RCW 19.29A.090(5), which prohibits cost-shifting to non-participants.

757 (27) The Commission should require PSE to remove $13.1 million in power costs from the power cost baseline to ensure that Green Direct customers are not subsidized by other customers.

758 (28) The Commission should allow PSE to recover costs related to its annual incentive compensation plan.

759 (29) The Commission should require PSE to defer its grossed-up UP EDIT amounts of $47.9 million and $3.8 million to separate FERC Accounts 254 – Other Regulatory Liabilities, for electric and natural gas, respectively. The Commission should further require PSE to pass back grossed-up UP EDIT using a new separate Schedule 141Z over a three-year period for both electric and natural gas.

760 (30) Reversing PP EDIT amounts through separate Schedule 141X does not violate IRS normalization rules because they are actual dollar amounts, not estimates or projections.

761 (31) IRS Private Letter Rulings issued in response to specific taxpayer questions apply only to the matter at hand and are non-precedential.

762 (32) The IRS Private Letter Rulings PSE cites in its testimony and evidence are neither relevant to this proceeding nor binding on the Commission.

763 (33) The Commission should require PSE to (1) defer all PP EDIT balances in FERC Accounts 282, grossed-up to separate FERC Accounts 254 – Other Regulatory Liabilities, for both electric and natural gas; (2) separate the PP EDIT ARAM reversal from PSE's proposed federal income tax revenue requirement adjustment; (3) separate the PP EDIT ARAM reversal from PSE's proposed Colstrip depreciation adjustment (21.07 ER); (4) return grossed-up PP EDIT to customers through Schedule 141X on a going-forward basis; (5) annually update Schedule 141X for the current year's PP EDIT reversals consistent with ARAM; and (6) annually true-up each previous year's return of PP EDIT reversal amounts with actual amounts refunded through volumetric rates. The Commission should require PSE to submit its annual filing no later than June 20 of each year going forward to update Schedule 141X for that year's ARAM reversal and to true-up the prior period reversals with amounts actually refunded.

764 (34) The Commission should require PSE to return to customers the grossed-up 2019 and 2020 PP EDIT ARAM reversals for both electric and natural gas over a 12-month period beginning July 20, 2020.

765 (35) The Commission should require PSE in its compliance filing to adjust the established regulatory asset for Colstrip Units 1 and 2 that reflects the unrecovered, undepreciated plant balance as of December 31, 2019, to include depreciation allowed in rates through July 19, 2020, and report the updated balance to the Commission.

766 (36) CETA requires PSE to accelerate the depreciation rate of the remaining plant balances for Colstrip Units 3 and 4 through December 31, 2025.

767 (37) The Commission should require PSE to file a proposed plan for the recovery of decommissioning and remediation costs for Colstrip Units 3 and 4 that complies with the decommissioning and remediation provisions of CETA in its next GRC, and should include in that plan an assessment of PTCs available to offset decommissioning and remediation costs for Colstrip Units 3 and 4.

768 (38) The Commission should approve PSE's proposal to adjust the annual depreciation expense of Colstrip Units 3 and 4, a portion of which includes decommissioning and remediation costs, to ensure those plants are fully depreciated by 2025 consistent with CETA. The Commission should further require PSE to move all decommissioning and remediation costs associated with Colstrip Units 3 and 4 to a regulatory asset account for tracking purposes.

769 (39) The Commission should authorize PSE to continue to recover decommissioning and remediation costs through depreciation rates for Colstrip Units 3 and 4. Those amounts will be trued up once the units are retired and the actual decommissioning and remediation costs are known. The Commission will evaluate the prudency of the actual costs for inclusion in rates or refund once PSE incurs those costs. This treatment is consistent with CETA and RCW 80.04.250.

770 (40) The Commission should authorize PSE to defer the depreciation expense for GTZ investments with a book life of 10 years or less that the Company has incurred, or will incur, outside of the test year used in the Company's next GRC.

771 (41) The Commission should authorize PSE to defer current and future liquidated damages received in connection with its Green Direct program.

772 (42) To ensure compliance with RCW 19.29A.090, RCW 80.28.090, and RCW 80.28.100, PSE must not discriminate between Green Direct customers when applying liquidated damages to offset Green Direct costs.

773 (43) PSE should maintain its transmission cost classification using the Fixed Method for the purposes of this proceeding until PSE is able to develop a new electric COSS under the Commission's recently promulgated cost of service rules in Chapter 480-85 WAC. With this modification, PSE's electric COSS is reasonable and the Commission should approve it.

774 (44) PSE's proposed electric rate spread will result in rates that are fair, just, reasonable, and sufficient.

775 (45) PSE's electric residential rate increase should be spread equally over the first and second usage blocks.

776 (46) The Commission should approve PSE's natural gas cost of service for purposes of this proceeding until PSE is able to develop a new natural gas COSS under the Commission's proposed cost of service rules in Chapter 480-85 WAC. PSE's natural gas COSS is reasonable and the Commission should approve it.

777 (47) PSE's proposed natural gas rate spread will result in rates that are fair, just, reasonable, and sufficient.

778 (48) The Commission should not require PSE to update its economic bypass study until closer to the date that the Special Contract expires in 2035.

779 (49) The increase to PSE's HELP funding by the greater of twice the percentage of the increase to base rates or $1.4 million is in the public interest and will result in rates that are fair, just, and reasonable.

780 (50) The Commission should require PSE to study the feasibility of expanding the first block energy rate and report its findings in the Company's next GRC. If, after conducting its study, PSE decides not to expand the first energy block, the Company should provide a detailed analysis and explanation for its decision as part of its findings.

781 (51) The Commission should require PSE to file its disconnection reduction plan within one year from the effective date of this Order, and to file an annual report that contains all of the information specified in paragraph 536, above. The Company's first annual report should be filed concurrently with its disconnection reduction plan, then annually thereafter.

782 (52) The Commission should require PSE to file a report that itemizes actual costs for Community Action Agencies to administer the Company's energy assistance programs. PSE should file this report either concurrently with PSE's disconnection reduction plan or as part of the Company's next GRC, whichever occurs first.

783 (53) WAC 480-90-128(6)(k) and WAC 480-100-128(6)(k) require that a utility representative dispatched to disconnect service must accept payment of a delinquent account at the service address.

784 (54) The Commission should require PSE to continue its practice of conducting premise visits prior to disconnection consistent with Commission rules until the Commission's AMI rulemaking in Docket U-180525 is complete and the new rules become effective.

785 (55) Staff's proposed materiality threshold will not result in rates that are fair, just, reasonable, and sufficient.

786 (56) The Commission should not require PSE to offer an on-bill repayment program.

787 (57) The Commission should not require PSE to implement pricing pilots at this time.

788 (58) The Commission should approve PSE's proposed Conjunctive Demand Service Option Pilot.

789 (59) The Commission should require PSE to file a report that incorporates elements of Staff's pricing pilot proposal. PSE should use Staff's design and evaluation elements as general guidelines. PSE also should provide more detail regarding the pros and cons of the Pilot and how the Company envisions expanding the Pilot over time. PSE should be required to file a report addressing these issues within 90 days of the effective date of this Order.

790 (60) The Commission should require PSE to provide documentation showing whether the revenue requirement for Schedule 26 and Schedule 31 customers has increased or declined over time and whether Schedule 26 and Schedule 31 customers are recovering their share of revenue. PSE should provide its best information as to the number of electric vehicles that use charging facilities offered by Schedule 26 or Schedule 31, and the approximate electric load used by those customers. PSE should be required to file a report addressing these issues within 18 months of the Pilot's implementation.

791 (61) The Commission will consider PSE's water heater rental service in Docket UG-200112.

792 (62) PSE's discontinuation of its gas conversion burner rental service is consistent with the public interest.

793 (63) The Commission should not require PSE to modify its methodology for calculating natural gas line extension allowances at this time, and Docket UG-143616 should be closed.

794 (64) The Commission should not require PSE to form a distribution system planning group or file distribution system plans.

795 (65) The Commission should require PSE to maintain its restating adjustments for both D&O Insurance and its Excise Tax and Filing Fee in both this and future proceedings.

796 (66) The Commission should accept each of the uncontested restating and pro forma adjustments and issues resolved on rebuttal.

797 (67) The Commission should adopt Staff's proposal provided in response to BR-15, which will result in rates that are fair, just, reasonable, and sufficient.

798 (68) The Commission should authorize and require PSE to make a compliance filing in these consolidated dockets to recover in prospective rates its revenue deficiency of $29.5 million for electric operations and its revenue deficiency of $36.5 million for natural gas operations. PSE is required to apply the mitigation strategies detailed in this Order to arrive at a final rate increase of approximately $857,000 for electric operations and approximately $1.3 million for natural gas operations.

799 (69) The Commission should authorize the Commission Secretary to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Order.

800 (70) The Commission should retain jurisdiction over the subject matters and the parties to this proceeding to effectuate the terms of this Order.

V. ORDER

THE COMMISSION ORDERS THAT:

801 (1) The Commission rejects the proposed tariff revisions Puget Sound Energy filed in these dockets on June 20, 2019, and suspended by prior Commission order.

802 (2) The Commission authorizes and requires Puget Sound Energy to make a compliance filing in this docket including all tariff sheets that are necessary and sufficient to effectuate the terms of this Final Order. The stated effective date included in the compliance filing tariff sheets must allow five business days after the date of filing for Commission review.

803 (3) The Commission authorizes the Commission Secretary to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Final Order.

804 (4) The Commission retains jurisdiction over the subject matters and parties to this proceeding to effectuate the terms of this Order.

DATED at Lacey, Washington, and effective July 8, 2020.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DAVID W. DANNER, Chair

Except as to paragraphs 614, 723, and 793

ANN E. RENDAHL, Commissioner

JAY M. BALASBAS, Commissioner

Except as to paragraphs 197-99, 685, and 744

NOTICE TO PARTIES: This is a Commission Final Order. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-07-850, or a petition for rehearing pursuant to RCW 80.04.200 and WAC 480-07-870.

SEPARATE STATEMENT OF CHAIR DANNER, DISSENTING IN PART

1 I respectfully dissent from those portions of this Order that retain the current methodology for financing natural gas line extensions. This methodology, the Perpetual Net Present Value (PNPV) methodology, has the potential in many instances to require existing gas customers to subsidize the costs of bringing new customers on to its system. In my view, this methodology is based on outdated assumptions and was approved in furtherance of state policy that has evolved and is no longer defensible.

2 I agree with Northwest Energy Coalition witness Amy Wheeless that "it is time to question the rationale for aggressively expanding the natural gas customer base, and, certainly, to rethink the idea of incentivizing switching from electric to natural gas service."[722]

3 To be sure, state policy has shifted in recent years. The Legislature recently noted the "significant contribution of natural gas to the state's greenhouse gas emissions," and stated, in the context of energy efficiency legislation:

> Considering the benefits of and the need for additional energy efficiency to meet regional energy demand, the legislature notes that attaining as much of this resource as possible from the buildings sector can have a significant effect on state greenhouse gas emissions by deferring or displacing the need for natural gas-fired electricity generation and *reducing the direct use of natural gas.*[723]

4 PSE witness Jon Piliaris cites to an older statute as a statement of legislative intent to promote natural gas expansion.[724] That 2010 statute reads that the state's energy strategy should be guided by principles that include the following:

> Reduce dependence on fossil fuel energy sources through improved efficiency and development of cleaner energy sources, such as bioenergy, low-carbon energy

---

[722] Wheeless, Exh. AEW-1T at 15:17-19.

[723] H.B. 1257, 66th Leg., Reg. Sess. §1 (Wash. 2019), 2019 Wash. Sess. Laws 1551, 1552 (emphasis added).

[724] Piliaris, Exh. JAP-18T at 23:8-16.

> sources, *and natural gas*, and leveraging the indigenous resources of the state for the production of clean energy.[725]

Yet this language does not support the Company's position. Rather, it suggests that natural gas should be considered only where it "reduce[s] dependence on fossil fuels" and is itself a cleaner energy resource than alternatives. In Washington, the passage of the Clean Energy Transformation Act (CETA)[726] in 2019 ensures that electrification and energy efficiency will be the cleaner energy resources in the near future by eliminating coal as a power source by 2025 and mandating that electric service be net carbon neutral by 2030. In any event, nothing in RCW 43.21F.088 calls for regulators to ask existing customers to subsidize natural gas costs for new customers.

5 Quite simply, it is contrary to the legislative intent of reducing the direct use of fossil fuels to maintain a methodology that in many cases effectively promotes the direct use of fossil fuels.

6 I am pleased that Commissioner Rendahl, Staff, and the Company have expressed their willingness to explore alternatives to the PNPV methodology in the future. However, I believe the suggestion to address this in a separate proceeding involving all gas utilities would be lengthy and cumbersome. As the Commission notes in paragraph 579 of this Order, "[t]he Commission is faced with multiple competing priorities ranging from CETA implementation to adjudicating back-to-back rate cases in the face of a serious budget crisis." It is unclear given our current workload, resources, and priorities that we can turn to this any time soon, or that it could be concluded expeditiously. In the meantime, we will continue to allow potential subsidies for new gas customers, contrary to legislative intent, pending the outcome of that proceeding and the subsequent implementation by utilities.

7 In my view, the better course of action is to direct PSE in this Order to revert to its previous methodology and to propose a new line extension methodology for our consideration in its next general rate case. While I do not disagree with Staff witness Jason Ball that the previous methodology is more complicated than PNPV, I also note that it is familiar to PSE as it was the Company's standard practice as recently as three years ago. Moreover, the prior methodology significantly reduces the risk of existing

---

[725] RCW 43.21F.088(1)(d) (emphasis added).

[726] Chapter 19.405 RCW.

natural gas customers subsidizing new gas customers. The Company has stated that it is contemplating another general rate case within a year,[727] and as I expect that other regulated companies will be in for general rate cases in due course, I predict we would address the matter more promptly and effectively in those proceedings than in a lengthy industry-wide one.

8 For these reasons, I respectfully dissent from paragraphs 614, 723, and 793 of this Order.

DAVID W. DANNER, Chair

[727] Piliaris, TR 246:5-8.

SEPARATE STATEMENT OF COMMISSIONER RENDAHL, CONCURRING IN PART

1 The Northwest Energy Coalition (NWEC) raises concerns about the potential economic and environmental impacts on natural gas customers of the current Perpetual Net Present Value (PNPV) methodology in Puget Sound Energy's (PSE or Company) tariff for determining natural gas line extension margin allowances. While NWEC states a valid concern about whether this methodology may shift burdens to existing customers if customers cease using natural gas, or if state law or policy changes relating to natural gas infrastructure, the record in this case is not sufficient to justify a change to PSE's line extension margin allowance.

2 As Staff witness Ball noted, the PNPV methodology arose from discussions in Docket UG-143616, an investigation "to address environmental concerns associated with emissions from oil furnaces and wood burning stoves, and promote economic development, by expanding natural gas service to areas not currently served by natural gas," that stemmed from the opportunity provided by low natural gas prices.[728] Following the discussions in that docket, PSE filed, and the Commission approved, changes to the Company's natural gas line extension tariff adopting the PNPV method for calculating customer allowances.[729] Staff supported the change in allocation methodology, asserting that it is simpler to calculate and relies on data from the Company's most recent rate case.[730]

3 To address the risks and concerns NWEC raises, Staff witness Ball provided in cross-answering testimony several suggested options, including modifying the calculation of margin allowances under the PNPV method. Mr. Ball included a table with different years for the Company to recover margin allowances, ranging from 1 to 75 years.[731] Mr. Ball recognizes that changing the calculation requires that the Commission determine the impact of these different margin allowance amounts on PSE's existing customers to avoid cross-subsidization, but that the data to evaluate the impact is not currently available.[732]

---

[728] Ball, Exh. JLB-28-T at 7:14-17, quoting Notice of Opportunity to File Written Comments, UG-143616 (December 15, 2014) at 1.

[729] Exh. JLB-29 (January 12, 2017, open meeting staff memorandum in Docket UG-161268).

[730] *Id*.

[731] Ball, Exh. JLB-28T at 15.

[732] *Id*., 15:9-13, 16:2-6; Exh. JLB-31.

While the record in this case provides a starting point for discussion about PSE's, and other natural gas utilities', natural gas line extension margin allowances, it is not sufficient for us to adopt an alternative to the PNPV method, or adjust the calculation of the allowance.

4 NWEC suggests the Commission initiate a collaborative process or reopen Docket UG-143616 to address this issue. Staff recommends the Commission close the docket, as the issue can be addressed through other processes. Both Staff and PSE suggest that this be taken up in the Company's Natural Gas Technical Advisory Group for further discussion and review. Given the lack of specific data and analysis in this docket, that course of action would serve all parties better, and ensure an opportunity to evaluate the potential impact on PSE's natural gas customers before modifying the calculation of the margin allowance. As the majority decision notes, given the number of proceedings currently pending before the Commission, including the important work of implementing the Clean Energy Transformation Act, the issue of the calculation of natural gas line extension margin allowances is best addressed in the forum of a technical advisory group.

ANN E. RENDAHL, Commissioner

SEPARATE STATEMENT OF COMMISSIONER BALASBAS, CONCURRING IN PART AND DISSENTING IN PART

1 I agree with today's Order that the current economic circumstances weigh against granting the Company an attrition adjustment at this time. I write separately to express my view that attrition adjustments are an important tool to address regulatory lag going forward, and that such adjustments should be considered on an equal basis with the tools listed in Section II(B)(1) of today's Order.[733]

2 As the Company and other utilities continue implementation of the Clean Energy Transformation Act, more capital additions and operating costs necessarily will come before the Commission for rate recovery. It is not a question of whether most or all of these capital projects or operating costs are put into rates, but when. Ratepayers deserve transparency regarding what they are paying for utility services and using all available flexible tools to address regulatory lag will become even more important in the future. These tools include attrition adjustments, which the Commission should not hesitate to use as appropriate.

3 Although our decision today does not reach the standards for evaluating an attrition adjustment, I disagree that attrition should be allowed only in extraordinary circumstances or when a utility demonstrates chronic under-earning. The recent legislative changes to RCW 80.04.250 grant the Commission broad authority to set rates "for up to forty-eight months after the rate effective date using any standard, formula, method, or theory of valuation reasonably calculated to arrive at fair, just, reasonable, and sufficient rates." In my reading of the statute, a utility need only demonstrate that, absent an attrition adjustment, the Commission will not be able to fulfill its statutory duty to set rates that are fair, just, reasonable, and sufficient.

4 That said, I am satisfied that the extension of the pro forma adjustment period to 12-months beyond the test year, which produced a result very similar to an attrition adjustment, is a welcome use of the flexible authority granted to the Commission in RCW 80.04.250 and an important tool to consider going forward.

5 With respect to the majority's decision to disallow rate recovery for SmartBurn, I respectfully disagree with my colleagues that the costs were not prudently incurred. It

---

[733] *See* ¶ 77, *supra*.

appears from the record in the Company's 2017 GRC that the costs of SmartBurn for Colstrip Unit 2 were installed in 2016 and embedded in the test year.[734] The Commission approved those test year expenses for recovery as part of our final order in that case. If the investment was uncontested in 2017, I see no rational basis for treating the installation of the same technology in Units 3 and 4 any differently. If parties had a prudence concern about SmartBurn, the appropriate time to raise it was in the 2017 GRC. I would have approved for recovery the SmartBurn costs as proposed by the Company in today's Order. We should incentivize actions that reduce emissions rather than create barriers.

JAY M. BALASBAS, Commissioner

[734] Dockets UE-170033 and UG-170034, RJR-1CT at 14:17-20

APPENDIX A

ADJUSTMENTS TO REVENUE REQUIREMENTS

ELECTRIC OPERATIONS

Adj. No.	Adjustment	Commission Decision NOI	Rate Base	Revenue Requirement
	Actual Results of Operation	391,140,691	5,208,778,506	(8,267,390)
Uncontested Adjustments				
	Restating Adjustments			
6.01	Revenues and Expenses	8,327,800	-	(11,083,325)
6.02	Temperature Normalization	4,922,913	-	(6,551,820)
6.04	Tax Benefit of Interest	33,059,305	-	(43,998,058)
6.05	Pass-Through Revenues and Expenses	(1,955,986)	-	2,603,188
6.06	Normalize Injuries and Damages	66,597	-	(88,633)
6.07	Bad Debts	303,154	-	(403,462)
6.09	Excise Tax & Filing Fee	71,835	-	(95,604)
6.10	Directors & Officers Insurance	5,301	-	(7,055)
6.11	Interest on Customer Deposits	(803,909)	-	1,069,909
6.12	Rate Case Expenses	(496,558)	-	660,860
6.13	Pension Plan	(1,726,149)	-	2,297,302
6.14	Property & Liability Insurance	319,951	-	(425,818)
6.15	Wage Increase	(61,810)	-	82,262
6.16	Investment Plan	(13,157)	-	17,510
6.17	Employee Insurance	(23,850)	-	31,742
6.23	Rent Expense	340,893	-	(453,689)
7.02	Montana Electric Energy Tax	(68,620)	-	91,325
7.03	Wild Horse Solar	167,531	(1,615,371)	(381,839)
7.04	ASC 815	(32,912,586)	-	43,802,792
7.05	Storm Damage	(11,001)	-	14,641
	Pro Forma Adjustments			
6.01	Revenues and Expenses	(25,679,090)	-	34,175,857
6.02	Temperature Normalization	8,570,014	-	(11,405,684)
6.04	Tax Benefit of Interest	(768,317)	-	1,022,540
6.14	Property & Liability Insurance	(442,588)	-	589,033
7.02	Montana Electric Energy Tax	526,903	-	(701,247)
7.05	Storm Damage	(10,681,805)	-	14,216,229
7.08	Energy Imbalance Market (EIM)	4,478,734	(3,321,470)	(6,287,344)
	Other Party Adjustments			
12.02	Remove Colstrip Outage (Staff)	-	-	-
12.03	Remove Green Direct (Staff)	-	(211,405)	(20,792)
12.04	Remove Shuffleton (Staff)	45,030	(550,000)	(114,023)
Contested Adjustments				
	Restating Adjustments			
6.03	Federal Income Tax	(19,874,205)	-	26,450,236
6.08	Incentive Pay	184,145	-	(245,076)
6.18	AMA to EOP Rate Base	-	182,818,242	17,980,583
6.19	AMA to EOP Depreciation	(16,904,953)	(16,904,953)	20,835,871
7.01	Power Costs	(7,589,560)	-	10,100,815
7.07	Colstrip Depreciation	1,855,595	(12,991,853)	(3,747,358)
	Pro Forma Adjustments			
6.09	Excise Tax & Filing Fee	-	-	-
6.10	Directors & Officers Insurance	-	-	-
6.15	Wage Increase	(3,003,557)	-	3,997,382
6.16	Investment Plan	(208,177)	-	277,060
6.17	Employee Insurance	(691,247)	-	919,969
6.20	Deferred Gains/Losses on Property Sales	4,520,668	-	(6,016,479)
6.21	Environmental Remediation	(120,118)	-	159,863
6.22	AMI	(6,154,931)	-	8,191,491
6.23	Rent Expense	394,549	-	(525,098)
6.24	Get to Zero	(12,677,569)	36,080,289	20,420,934
6.25	Credit Card Payment Processing Costs	477,331	-	(635,271)
6.26	Unprotected EDIT	-	-	-
6.27	Public Improvement	(582,530)	25,767,063	3,309,527
6.28	Contract Escalations	(1,330,726)	-	1,771,040
6.29	HR TOPS	(567,399)	5,798,358	1,325,423
7.01	Power Costs	3,429,888	-	(4,564,779)
7.06	Regulatory Assets and Liabilities	9,100,115	(23,391,892)	(14,411,831)
7.09	High Molecular Weight Cable	(809,932)	34,322,392	4,453,609
7.10	Energy Management System (EMS)	(2,484,594)	4,143,549	3,714,230
	Other Party Adjustments			
12.01	SmartBurn (Staff)	431,825	(5,272,401)	(1,093,260)
AWEC-1	Bothell Data Center (AWEC)	-	-	-
	Total Adjustments	(67,044,845)	224,670,547	111,325,677
	Revenue Requirement Before Other Tariff Schedules	**324,095,846**	**5,433,449,053**	**103,058,288**
	Less Riders			(3,117,000)
	Less EDIT Separate Credit Tariff Sch.			(70,484,295)
	Revenue Requirement Before Mitigation Strategy	**324,095,846**	**5,433,449,053**	**29,456,992**
	Extend Amortization of Regulatory Assets - Estimated			(17,700,000)
	Decoupling Deferral - Estimated			(10,900,000)
	Final Revenue Requirement	***324,095,846***	***5,433,449,053***	***856,992***

NATURAL GAS OPERATIONS

Adj. No.	Adjustment	NOI	Rate Base	Revenue Requirement
		Commission Decision		
	Actual Results of Operation	103,864,304	1,951,252,143	53,485,466
Uncontested Adjustments				
	Restating Adjustments			-
6.01	Revenues and Expenses	1,442,871	-	(1,913,375)
6.02	Temperature Normalization	54,148	-	(71,805)
6.04	Tax Benefit of Interest	12,916,466	-	(17,128,388)
6.05	Pass-Through Revenues and Expenses	(1,412,119)	-	1,872,595
6.06	Normalize Injuries and Damages	(1,256,319)	-	1,665,991
6.07	Bad Debts	(125,429)	-	166,330
6.09	Excise Tax & Filing Fee	69,886	-	(92,675)
6.10	Directors & Officers Insurance	3,831	-	(5,080)
6.11	Interest on Customer Deposits	(204,504)	-	271,190
6.12	Rate Case Expenses	(438,078)	-	580,931
6.13	Pension Plan	(770,451)	-	1,021,687
6.14	Property & Liability Insurance	(52,646)	-	69,813
6.15	Wage Increase	(359,399)	-	476,596
6.16	Investment Plan	(4,190)	-	5,557
6.17	Employee Insurance	(10,645)	-	14,117
6.23	Rent Expense	520,589	-	(690,348)
	Pro Forma Adjustments			
6.01	Revenues and Expenses	(7,393,164)	-	9,803,996
6.02	Temperature Normalization	12,260,525	-	(16,258,552)
6.04	Tax Benefit of Interest	(501,416)	-	664,923
6.14	Property & Liability Insurance	(24,480)	-	32,463
8.01	Remove 2018 CRM	31,240	(9,327,511)	(955,504)
8.02	Proforma Exiting CRM	(5,263,989)	(6,388,044)	6,354,504
	Other Party Adjustments			-
12.05	Tacoma LNG (Staff)	627,299	(26,191,470)	(3,398,566)
Contested Adjustments				
	Restating Adjustments			
6.03	Federal Income Tax	(100,714)	-	133,555
6.08	Incentive Pay	(187,098)	-	248,109
6.18	AMA to EOP Rate Base	-	150,665,688	14,764,937
6.19	AMA to EOP Depreciation	(9,738,308)	(9,738,308)	11,959,531
	Pro Forma Adjustments			
6.09	Excise Tax & Filing Fee	-	-	-
6.10	Directors & Officers Insurance	-	-	-
6.15	Wage Increase	(1,909,978)	-	2,532,802
6.16	Investment Plan	(92,854)	-	123,132
6.17	Employee Insurance	(308,532)	-	409,141
6.20	Deferred Gains/Losses on Property Sales	72,647	-	(96,336)
6.21	Environmental Remediation	(676,944)	-	897,688
6.22	AMI	(2,682,091)	-	3,556,692
6.23	Rent Expense	134,162	-	(177,910)
6.24	Get to Zero	(6,475,730)	18,429,892	10,393,490
6.25	Credit Card Payment Processing Costs	344,098	-	(456,305)
6.26	Unprotected EDIT	-	-	-
6.27	Public Improvement	(128,060)	17,461,761	1,881,037
6.28	Contract Escalations	(303,817)	-	402,889
6.29	HR TOPS	(289,829)	2,961,814	674,591
	Other Party Adjustments			
12.03	Remove Green Direct (Staff)	-	(105,392)	(10,328)
AWEC-1	Bothell Data Center (AWEC)	-	-	-
	Total Adjustments	(12,233,023)	137,768,432	29,723,113
	Revenue Requirement Before Other Tariff Schedules	91,631,281	2,089,020,576	83,208,579
	Less Riders			(32,408,666)
	Less EDIT Separate Credit Tariff Sch.			(14,267,653)
	Revenue Requirement Before Mitigation Strategy	91,631,281	2,089,020,576	36,532,261
	Extend Amortization of Regulatory Assets - Estimated			(4,400,000)
	PGA Deferral - Extend to 3 years - Estimated			(30,800,000)
	Final Revenue Requirement	***91,631,281***	***2,089,020,576***	***1,332,261***