BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PACIFIC POWER & LIGHT COMPANY, a Division of PacifiCorp, Respondent.	DOCKET UE-152253 ORDER 12 FINAL ORDER REJECTING TARIFF SHEETS AS FILED; GRANTING ACCELERATED DEPRECIATION WITH MODIFICATIONS; GRANTING RECOVERY OF, BUT NOT RETURN ON, SCR INVESTMENT; GRANTING REQUEST FOR TWO-YEAR RATE PLAN; AUTHORIZING DECOUPLING PROPOSAL WITH MODIFICATIONS; AND REQUIRING COMPLIANCE FILINGS

<u>REDACTED VERSION</u>

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Contains Confidential and Highly Confidential Information[1]

Synopsis*: The Commission rejects the revised tariff sheets Pacific Power & Light Company (Pacific Power or Company) filed on November 25, 2015. Pacific Power proposed a two-year rate plan with a 2.99 percent increase, raising $10 million in additional revenue, effective May 1, 2016, and a 2.99 percent increase, raising $10.3 million, effective May 1, 2017.*

In this Order, the Commission grants Pacific Power's request for a two-year rate plan; although, our final determinations do not authorize the Company to collect the amounts it requested for each of the two years.

Based on the evidence presented, the Commission authorizes and requires the Company to file revised tariff sheets that will result in fair, just, reasonable, and sufficient electric rates. For year one of the rate plan, the Commission authorizes Pacific Power to recover $4.4 million in additional electric revenue, for a 1.33 percent rate increase. Further, the Commission authorizes and requires the Company to file revised tariff sheets with electric rates that will recover $6.6 million in additional electric revenue, for a 1.96 percent rate increase for year two of the rate plan.

For the first year of the two-year rate plan, we grant Pacific Power's request to accelerate depreciation of its Jim Bridger generating plant (Bridger) and Unit 4 of the Colstrip generating plant (Colstrip), and requires the Company to: (1) hold the additional monies collected over and above the current depreciation rates for these plants in a regulatory liability account pending the Commission's review of the Company's 2018 depreciation study; (2) file with the Commission its depreciation study within 30 days of completion of the new study, with its next general rate case, or by December 31, 2018, whichever occurs first; and (3) file decommissioning and remediation (D&R) expenses and revenues with its Commission Basis Reports (CBRs) as described further in paragraph 59, below.

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[1] The evidence in this matter contained both confidential and highly confidential information. The Commission has endeavored, where possible, to avoid the inclusion of such data in this Final Order. We must also, however, provide the reader with the reasoning and basis for our decisions, which necessarily includes discussions of the substantial evidence, both protected and non-protected, in this proceeding. For those authorized to view the protected material, the confidential information in this document will be highlighted in yellow and the highly confidential information will be highlighted in light blue. Those individuals not authorized to view either the confidential or highly confidential data will find their copy of the document redacted where such information has been referenced.

With regard to the Company's request for full recovery of its selective catalytic reduction (SCR) systems on Units 3 and 4 of Bridger, the Commission finds that Pacific Power failed to produce contemporaneous documentation and demonstrate, from May to December 2013, it re-evaluated its options to comply with the Regional Haze Rule obligations when significant changes were occurring in natural gas pricing and coal costs and before it signed the full notice to proceed with the SCR engineering, procurement, and construction services contract. Thus, the Company failed to meet its burden of proof that the investments were prudent. While we recognize that the Company had an environmental compliance obligation and that SCR systems are one compliance option, we find that Pacific Power's failure to re-evaluate its options in the face of changing economic circumstance, including inputting this information into the Company's System Optimizer model during this six month period, exposed ratepayers to considerable risk. As a result, we allow the Company recovery of the SCR systems' expenses for Unit 3 during the first year and for Unit 4 during the second year of its two-year rate plan, but not a return on these investments.

We approve Pacific Power's proposed decoupling mechanism with the addition of a 2.5 percent rate adjustment trigger and a 5 percent rate adjustment cap, which were proposed by the Commission's regulatory staff (Staff), and require the Company to: (1) initiate a stakeholder collaborative to discuss low-income bill assistance (LIBA) program changes for the 2017-2018 program season; (2) ensure the collaborative develops a mutually agreed-upon funding plan and modifications for LIBA, to be filed with the Commission by April 1, 2017; (3) initiate a stakeholder collaborative to discuss changes to its low-income weatherization program; and (4) include an analysis of the potential impacts to low-income customers of a third energy block rate design in the Cost of Service Study and Rate Design collaborative. Given the Company's agreement on an earnings test, reporting/evaluation, increased incremental conservation, reliability metrics, and an extension of Pacific Power's customer guarantees for service quality for the duration of the decoupling mechanism, we approve this proposal effective September 15, 2016, for a five-year term. During this five-year term, we will continue to monitor its implementation and will consider changes in the future, as necessary.

After removing the exceptionally high and low cost of capital results from both Pacific Power and Staff's calculations, the range of reasonable return on equity (ROE) data points to be considered is 8.5 to 10.4 percent. The midpoints of each parties' range produces arithmetic mean and median results that flank the Company's current authorized ROE of 9.5 percent. As a result, we maintain Pacific Power's authorized ROE, which effectively maintains the Company's rate of return at 7.30 percent.

This synopsis focuses on the primary contested issues in this case. A synopsis of our decisions on the remaining issues is included in the summary of the Commission Determination below, and more fully in the body of this Order.

SUMMARY

1 **PROCEEDING:** Pacific Power & Light Company (Pacific Power or the Company), an operating division of PacifiCorp,[2] filed this general rate case[3] with the Washington Utilities and Transportation Commission (Commission) in Docket UE-152253 on November 25, 2015, seeking approval of a two-year rate plan and a decoupling mechanism. The Company requested a 2.99 percent increase in electric rates, raising approximately $10 million, effective May 1, 2016. Pacific Power also requested a second year increase in electric rates of $10.3 million, or 2.99 percent, effective May 1, 2017.

2 **PARTY REPRESENTATIVES:** Katherine McDowell, Lisa Rackner, and Adam Lowney, McDowell Rackner & Gibson PC, Portland, Oregon, represent the Company. Jennifer Cameron-Rulkowski, Christopher Casey, and Julian Beattie, Assistant Attorneys General, Olympia, Washington, represent the Commission's regulatory staff (Staff).[4] Simon ffitch, Senior Assistant Attorney General, and Lisa Gafken, Assistant Attorney General, Seattle, Washington, represent the Public Counsel Division of the Washington Office of Attorney General (Public Counsel).

3 Jesse Cowell, Davison Van Cleve, Portland, Oregon, represents Boise White Paper, L.L.C. (Boise). Brad Purdy, attorney-at-law, Boise, Idaho, represents The Energy Project. Gloria Smith and Travis Ritchie, Associate Attorneys, San Francisco, California, represent Sierra Club. Wendy Gerlitz, Policy Director, Portland, Oregon, and Joni Bosh, Senior Policy Associate, Seattle, Washington, represent the NW Energy Coalition (NWEC).

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[2] Pacific Power's ERF Petition, ¶ 1.

[3] Pacific Power originally designated its revised tariff sheets as an expedited rate filing (ERF). In Order 03, Prehearing Conference Order and Notice of Hearing, the Commission noted that "ERFs are not a formal creation… [and t]he Commission does not recognize this filing as an ERF, but to the extent practicable, we have and will continue to expedite the procedural schedule." Order 03, ¶ 14.

[4] 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 the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. *See* RCW 34.05.455.

4 **COMMISSION DETERMINATIONS:** We reject Pacific Power's proposed tariff revisions, filed on November 25, 2015, and instead require the Company to file tariffs in a compliance filing reflecting the decisions in this Order.

5 The Commission grants the Company's request for a two-year rate plan; although our final determinations do not authorize Pacific Power to collect the amounts it requested for each of the two years.

6 For the first rate year, we grant Pacific Power's request for accelerated depreciation and require the Company to take the following actions:

1. Pacific Power must book the accelerated depreciation differential to Account 254, Other Regulatory Liabilities;

2. The Company must file its 2018 depreciation study within thirty days of the study's completion, with its next general rate case, or by December 31, 2018, whichever occurs first; and

3. Pacific Power must file a report providing full disclosure of its decommissioning and remediation (D&R) costs for Unit 4 of the Colstrip generating plant (Colstrip) and all units of the Jim Bridger generating plant (Bridger) in its Commission Basis Reports (CBRs), including the following elements:

    - The most recently estimated salvage value for the asset.
    - The current depreciation expense related to D&R for the asset being collected through rates.
    - The total amount of depreciation related to D&R for the asset that has been collected through rates.
    - Any expenditures the Company has made related to D&R for the asset with a brief explanation of each action.
    - Any updates to the Company's Asset Retirement Obligations related to the specific asset.

7 We approve Pacific Power's proposal for a decoupling mechanism with the following modifications:

1. The rate adjustment trigger is 2.5 percent and the rate adjustment cap is 5 percent.

2. The Company must apply an earnings test prior to filing a decoupling rate adjustment. If the Company's actual return on equity (ROE) exceeds its Commission-authorized ROE, any proposed decoupling surcharge will be reduced

by up to 50 percent of the excess earnings and for any proposed surcredit, the customers will also receive 50 percent of the excess earnings.

3. The Company must file quarterly reports with the Commission and must, at the end of the third year of the decoupling mechanism, provide the following information:

   - an analysis of the mechanism's impact on conservation achievement,
   - an analysis of the mechanism's impact on Company revenues (i.e., whether there has been a stabilizing effect),
   - an analysis of the extent to which fixed costs are recovered in fixed charges for the customer classes excluded from the decoupling mechanism,
   - an analysis of whether allowed revenues from the following rate classes are recovering their cost of service: residential class, non-residential classes, and customers not subject to decoupling, and
   - an examination of the Company's proposal to separately track and true-up deferrals by rate class.

4. Pacific Power must increase its annual conservation targets by 2.5 percent for the current 2016-2017 biennium, and by 5 percent per biennium thereafter through the period when decoupling is in effect. The Company's failure to meet its incremental conservation target will be subject to financial penalties.

5. The Company must participate in Staff's investigation of reliability metrics in Docket U-151958.

6. Pacific Power's Customer Guarantees for Service Quality shall be extended for the five-year term of the decoupling mechanism.

7. Pacific Power must initiate a stakeholder collaborative to discuss low-income bill assistance (LIBA) program changes for the 2017-2018 program season. The collaborative must conduct an analysis of publicly available data to assess the need for LIBA in the Company's service territory, make a recommendation to the Commission on how to obtain data that is not publicly available, and develop a mutually agreed-upon funding plan and modifications for LIBA, which will be filed with the Commission by April 1, 2017.

8. The Company must initiate a stakeholder collaborative to discuss changes to its low-income weatherization program, with any mutually agreed-upon modifications or additions filed with the Commission by April 1, 2017.

8 Due to its failure to continually evaluate the changing economics surrounding its decision to install selective catalytic reduction (SCR) systems on Units 3 and 4 of Bridger and thus demonstrate whether the investment was prudent, we allow Pacific Power recovery only of the costs for the systems, and we disallow any return the Company would have collected on the SCR. Pacific Power is authorized to collect the expense, but not the return on, the SCR system on Unit 3 during the first year of the two-year rate plan, and the expense of, but not the return on, the SCR system on Unit 4 during the second year of the two-year rate plan.

9 We find prudent Pacific Power's decision to proceed with the Supervisory Control and Data Acquisition Energy Management System (SCADA EMS) and the second phase of the Union Gap Substation upgrade (Union Gap). In the second year of the two-year rate plan, we authorize Pacific Power to include the SCADA EMS and second phase Union Gap expenses as a pro forma rate base addition subject to the Company filing documentation of its expenditures for the projects in its attestation. Pacific Power must file an attestation and supporting documents for actual booked expenditures and rate base amounts for these projects, as well as for the SCR installation on Bridger Unit 4, by July 1, 2017. Thereafter, Staff will review the final costs and provide its analysis to the Commission prior to the start of the second year rates on September 15, 2017. We maintain Pacific Power's ROE at 9.5 percent.

10 The Commission approves the Company's proposal to utilize end-of-period (EOP) methodology, and after reviewing the information submitted pursuant to Bench Request No. 8, which calculated all restating and pro forma adjustments on an EOP basis, requires the application of the EOP methodology to all restating and pro forma adjustments. The use of EOP methodology is particularly appropriate in light of the decision in this Order to approve Pacific Power's request for a two-year rate plan.

11 While we accept Pacific Power's proposal on rebuttal to use its March 2016 full time equivalent (FTE) employee count and known and measurable salary increases through June 2016, we approve Public Counsel's adjustment to pensions and Other Post-Employment Benefits (OPEB) basing these costs on the most recent actuarial report available in the record for the 2016 plan year. The Commission rejects Public Counsel's adjustment to "Other Salary Overheads/Oncosts" as Public Counsel has not shown that the variation it observed is likely to continue.

12 We reject both adjustments proffered by Boise regarding general office expenses and the West Control Area cost allocation for transmission expenses. Boise failed to demonstrate the reasonableness of these modifications. Likewise, we reject Staff's proposal to limit recovery of non-major environmental remediation costs to solely those plants within the state of Washington.

13 With regard to the Idaho Power Transmission Asset Exchange (Idaho Exchange) and in keeping with the Commission's long-standing adherence to the regulatory principle that benefits should follow burdens, we reject inclusion of the contested Idaho Exchange assets and reassignment assets in rates and the associated adjustment. This issue should be considered in a future power cost adjustment mechanism (PCAM) filing from Pacific Power if the Company includes the benefits of these assets in the power cost baseline of its PCAM filing. The Commission accepts the inclusion of the uncontested correction assets in rates, although with concern regarding Pacific Power's failure to discover the 'mistakenly neglected' assets for some time.

14 We approve the inclusion of energy imbalance market (EIM) costs in the Company's PCAM filing. In the Company's next general rate case, however, we direct Pacific Power to propose their recovery in non-power cost rates outside of the PCAM annual true-up and to reflect any offsetting benefits in the power cost baseline. The Commission also accepts Pacific Power's proposal for a one-time credit to return the hydro deferral credit balance to customers, and we authorize the Company to transfer the balance from the Schedule 96 account and issue a one-time credit under that schedule.

15 The Commission finds that rate parity has improved since Pacific Power's last rate case and requires that the first year rate increase be applied on an equal percentage basis to each rate schedule. The Company has agreed to participate in a collaborative on cost of service, rate spread, and rate design issues. If the parties reach consensus prior to the second year rates taking effect, the participants should file that agreement for the Commission's consideration. If the collaborative does not result in a consensus before the start of the second year rates, Pacific Power should apply the approved second year increase on an equal percentage basis across each schedule and address cost of service and rate design issues in its next general rate case.

16 We agree with Staff that the Company's payments for memberships and subscriptions, including payments to the Yakima County Development Association, do not appear to be associated with its core business of providing electric service. These costs are not appropriate for inclusion in rates, and we do not expect to see them in future proceedings absent an evidentiary showing of a direct benefit to customers.

MEMORANDUM

I. Background and Procedural History

17 On November 25, 2015, Pacific Power filed revised tariff sheets, which the Company characterized as an expedited rate filing (Pacific Power ERF Petition), requesting an increase of $10 million in electric rates, or 2.99 percent, effective May 1, 2016. Pacific

Power's request includes a two-year rate plan in which the Company's second year electric rates would increase by $10.3 million, or 2.99 percent, effective May 1, 2017. As part of the rate plan, the Company proposes to defer any further rate case filings it might initiate before the Commission until no earlier than April 1, 2018, and Pacific Power agrees to low-income funding increases for both years of the rate plan. The Company states it would file an attestation prior to the second-year increase's effective date "verifying that each of [its] investments are in service and confirming the final costs of each investment."[5] Finally, Pacific Power proposes a decoupling mechanism for revenue received from residential, general service, and irrigation customers.[6]

18 Boise filed a motion to dismiss Pacific Power's Rate Filing or in the alternative, a Motion to Treat the Rate Filing as a General Rate Case Request (Boise's Motion) on December 10, 2015. In Order 03, the Commission denied Boise's Motion and found that, regardless how Pacific Power chooses to designate its filing, the Commission has a "full ten months to process the [request]."[7] In the same order, entered on December 29, 2015, the Commission established a procedural schedule that balanced the Company's request for expedited treatment and the parties' due process rights.

19 On January 7, 2016, Pacific Power filed the supplemental testimony of Bruce N. Williams, Vice President and Treasurer, PacifiCorp, addressing the Company's long-term cost of debt and current credit ratings. Sierra Club, The Energy Project, Staff, Public Counsel, Boise, and NWEC filed their respective response cases on March 17, 2016. The Commission convened public comment hearings in Yakima and Walla Walla, Washington, on April 25 and 26, 2016, respectively.

20 On April 7, 2016, the Commission received rebuttal testimony and exhibits from Pacific Power and cross-answering testimony and exhibits from Staff, Sierra Club, Boise, and The Energy Project. On April 25, 2016, Staff filed a Confidential Motion for Leave to File Supplemental Testimony and Exhibits of Jeremy Twitchell (Staff's Motion). It argued that Pacific Power had given it incomplete and inaccurate information concerning the Company's coal costs associated with the Bridger mine. It stated specifically that, in response to Staff Data Request No. 99, Pacific Power provided the Company's January 2013 mine plan instead of its October 2013 mine plan. Staff asserted that the Company then failed to rectify this omission of information even after Pacific Power realized that Staff had mistakenly relied on it in its response case. According to Staff, Pacific Power failed to direct Staff to the October 2013 mine plan until April 16, 2016, more than a

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[5] Pacific Power ERF Petition, ¶ 34.

[6] *Id.*, ¶ 42.

[7] Order 03, ¶ 14.

week after Staff's opportunity to file its cross-answering case had passed on April 7, 2016. It was only upon reviewing the Company's rebuttal case, filed April 7, that Staff discovered the problem. At that point, Staff immediately requested the opportunity to file supplemental testimony and exhibits on the issue of the prudence of Pacific Power's installation of the SCRs on Bridger Units 3 and 4, due to newly available material Staff received from Pacific Power.

21 On April 29, 2016, the Commission entered Order 08 granting Staff's Motion. In light of the immediacy of the May 2, 2016, evidentiary hearing, the Commission established a separate procedural schedule to address the SCR matter, allowing Staff to file supplemental testimony on May 6, 2016, and the Company and all other intervenors to file supplemental rebuttal or cross-answering testimony and exhibits on May 13, 2016. A second evidentiary hearing was held on June 1, 2016, to receive testimony on the limited subject of the SCR prudence issue while the evidentiary hearing on May 2, 2016, concerned all other contested issues within the case.

22 The final transcript in this proceeding includes 796 pages and reflects the admission of prefiled testimony and exhibits sponsored by 23 witnesses. The documentary record includes 348 exhibits.

23 We have considered the parties' arguments and reviewed the full record. Our discussion and determination of the issues follows below.

II. Discussion and Decisions

A. Introduction

24 Pacific Power asserts several cost drivers are responsible for its multi-year rate request, including: its request for accelerated depreciation on Colstrip Unit 4 and Bridger; SCR installation on Unit 3 of the Bridger plant for emissions control; the termination of production tax credits for the Company's renewable resources; Pacific Power's SCADA EMS project, which the Company projects will be in service by March 2016; the Union Gap substation, which is expected to be completed and in service by May 2016; and the installation of an SCR system on Bridger Unit 4 by December 2016.

25 In conjunction with its request for a two-year rate plan through April 1, 2018, Pacific Power seeks an increase of twice the residential rate increase, or six percent, for its low-income bill assistance program for both 2016 and 2017.

B. Accelerated Depreciation

26 Pacific Power proposes to shorten the depreciation schedules for two coal plants used to serve its Washington state load, Bridger and Unit 4 of Colstrip.[8]

27 Currently, Bridger's depreciable life ends in 2037, and Colstrip Unit 4's depreciable life ends in 2046. Five of the states in which Pacific Power operates (including Washington)[9] use this schedule for setting depreciation rates. Oregon alone sets Bridger's end of life in 2025, and Colstrip Unit 4's end of life in 2032.[10] Pacific Power proposes that Washington modify current depreciation rates to the shorter schedule currently in place in Oregon. If authorized, this proposed change would allow the Company to fully recover all capital costs for Units 3 and 4 of Bridger approximately 12 years earlier than currently allowed, and for Colstrip Unit 4 approximately four years earlier than currently allowed. Boise and Public Counsel assert that the revenue requirement impact of the Company's proposal makes up all of the Company's first-year rate increase.[11]

28 Prior to 2008, Washington used the shorter depreciation schedule for Bridger and Colstrip Unit 4 that is currently in place in Oregon.[12] In Docket UE-071795, the Commission approved the Company's 2007 depreciation study resulting in the longer depreciation schedule currently in place in Washington.[13]

29 The Company normally provides an updated depreciation study every five years; however, the 2013 depreciation study did not modify the coal plants' depreciation

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[8] A depreciation schedule determines the rate, in dollars per month, at which the initial investment dollars and the return on that investment are paid to the utility. One of the two determinants critical to a depreciation schedule is the date by which all the investment dollars are to be paid back. Once a payback date is determined, the annual depreciation expense is then determined by that date and the interest rate, or rate of return, charged on the dollars invested.

[9] The four states that currently share Washington's depreciable life schedule for Bridger and Colstrip Unit 4 are California, Utah, Wyoming, and Idaho. Huang, Exh. No. JH-1T at 6:10-12.

[10] Huang, Exh. No. JH-1T at 6:10-15.

[11] Mullins, Exh. No. BGM-1CT at 2:30-3:2; Ramas, Exh. No. DMR-1 at 11:21-22. "There would be no Pacific Power rate case at this time absent the request for accelerated recovery of coal plant costs from Washington ratepayers!" Ramas, Exh. No. DMR-1 at 12:18-20.

[12] *In the Matter of the Petition of PacifiCorp, d/b/a Pacific Power for an Accounting Order Authorizing a Revision to Depreciation Rates*, Docket UE-071795, Order 01 (April 10, 2008).

[13] *Id*. Oregon was the only state to reject the longer schedule proposed in the 2007 depreciation study. Huang, Exh. No. JH-1 at 6:10-16.

schedules.[14] Pacific Power has not provided an updated depreciation study to support its request in this case. Staff witness, Joanna Huang, expects the Company to update its depreciation study in 2018.[15]

30 Staff and Public Counsel oppose accelerating depreciation on the coal plants, while NWEC and Sierra Club support it. Boise conditionally supports the Company's proposal.

1. Pacific Power's Proposal

31 Pacific Power argues that it is reasonable to align the depreciation schedules used in Washington and Oregon.[16] The Company states that the "shorter depreciable life for these resources provides the Commission, the Company, and customers additional flexibility in resource planning to address state and federal environmental policies, mandates, and the EPA's Clean Power Plan."[17] Pacific Power further states that it will separately track and report the incremental depreciation expense collected from Washington customers in order to provide transparency.[18]

2. Staff and Public Counsel oppose accelerating depreciation on the coal plants.

32 Staff argues that Pacific Power's proposal lacks adequate support because it is not based on a new depreciation study.[19] Staff points out that the Company has failed to explain why it is desirable for Washington to align with Oregon, only to fall out of alignment with California, Utah, Wyoming, and Idaho.[20] Public Counsel notes that, because Oregon has been using the shorter depreciable life for a longer period of time than is proposed by

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[14] Huang, Exh. No. JH-1T at 7:7-8 (citing, *In the Matter of the Petition of Pacific Power & Light Co. for an Accounting Order Authorizing a Revision to Depreciation Rates*, Docket UE-130052, Order 01 (Dec. 27, 2013)).

[15] *Id.* at 7:8-9.

[16] Dalley, Exh. No. RBD-1T at 11:2-3.

[17] *Id.* at 11:3-6. Staff responds that it is not sure what Pacific Power means that this proposal provides "additional flexibility." Huang, Exh. No. JH-1T at 11:1-6.

[18] Dalley, Exh No. RBD-3T at 15:1-7.

[19] Huang, Exh. No. JH-1T at 11:11-22.

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

the Company, Oregon's depreciation rates for the coal plants "are considerably lower than the depreciation rates proposed by Pacific Power in this case."[21]

33 Staff and Public Counsel note that the Company is not promising to close the Bridger plant in 2025 if the Commission adopts its depreciation proposal.[22] Public Counsel argues, "[a]bsent plans to actually remove the plants from service earlier, there is no justification for accelerating the recovery of the plant costs from ratepayers at this time."[23]

34 On rebuttal, the Company responds that the depreciable life used for ratemaking is not necessarily the same as the operating life based on the anticipated plant retirement date.[24] Mr. Dalley reiterated the lack of a firm closure date for either facility at hearing, stating that the Company is "trying to adapt and make sure that we could position customers and the Company for a future where we don't have to have those dramatic increases, but there is no specific shutdown date identified at this time for those facilities."[25]

35 Staff argues that the Company departs from the Financial Accounting Standards Board (FASB) rules on setting depreciation rates by proposing a depreciation schedule that does not match the assets' expected useful lives:[26]

> In accounting, an asset's useful life and its annual depreciation expense are intrinsically linked. The service life is the expected period from which "services are obtained from the use of the facility.[27]

36 Public Counsel also notes that if this proposal is adopted and the plant is not retired in 2025, "current ratepayers will be paying for capital costs that will be used to serve future customers," which would result in "intergenerational inequity."[28]

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[21] Ramas, Exh. No. DMR-1T at 18:11-15. Specifically, Oregon has employed the shorter depreciation schedule since August 2008. See, *PacifiCorp Petition to File Preliminary Study*, Oregon Public Utility Commission, Docket UM-1329, Order No. 08-427 (Aug. 20, 2008).

[22] Huang, Exh. No. JH-1T at 10:12-19; Ramas, Exh. No. DMR-1T at 18:1-4.

[23] Ramas, Exh. No. DMR-1T at 20:1-3.

[24] Dalley, Exh No. RBD-3T at 11:15-16.

[25] Dalley, TR 150:6-10.

[26] Huang, Exh. No. JH-1T at 5:6-13. Ms. Huang cites to the (FASB) ASC 360-35-4.

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

[28] Ramas, Exh. No. DMR-1T at 20:8-12.

37 On rebuttal, the Company argues that, on balance, the risk of intergenerational inequity is actually greater if current depreciation schedules are maintained.[29] Pacific Power points out that Public Counsel's "wait-and-see" approach to shortening the depreciation schedule could expose customers to significantly higher depreciation expense if these plants are forced to retire early.[30]

38 Finally, Staff proposes that the Commission require Pacific Power to submit reports on its D&R expenses and revenues. Specifically, Staff proposes that in future commission basis reports (CBRs), the Company should include a D&R report for any plant Pacific Power expects to need remediation action.[31] The report would include:

a. The most recently estimated salvage value for the asset.
b. The current depreciation expense related to D&R for the asset being collected through rates.
c. The total amount of depreciation related to D&R for the asset that has been collected through rates.
d. Any expenditures the Company has made related to D&R for the asset with a brief explanation of each action.
e. Any updates to the Company's asset retirement obligations related to the specific asset.

Staff argues this recommended reporting requirement will "provide additional information to the Commission and help eliminate uncertainty around the current amount of D&R."[32] Staff notes that this recommendation mirrors that of the final report from the recent Colstrip investigation.[33]

3. NWEC and Sierra Club support, without conditions, accelerating depreciation on the coal plants.

39 NWEC supports Pacific Power's depreciation proposal for the coal plants because, it contends, continued use of the longer depreciation periods "would create an inappropriate

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[29] Dalley, Exh No. RBD-3T at 13:7-15.

[30] *Id.* at 12:18-21.

[31] Ball, Exh. No. JLB-1T at 58:25-59:6.

[32] *Id.* at 60:4-6.

[33] *Id.* at 59:19-20. See *Investigation of Coal-fired Generating Unit Decommissioning and Remediation Costs*, Docket UE-151500, Staff Investigation Report, at 23 (Feb. 2, 2016).

financial incentive for Pacific Power to extend the lifetimes and emissions of some of the Northwest's largest greenhouse gas sources."[34]

40 Sierra Club also supports Commission approval of Pacific Power's accelerated depreciation proposal because it sends a message to the Company that the state is interested in having Pacific Power making rational, least-cost planning decisions, even when such decisions require the retirement of existing resources,[35] and minimizes the risk of intergenerational cost shifting between current ratepayers and future ratepayers, "who may otherwise be required to pay off undepreciated assets after the plant has stopped providing power."[36]

41 However, despite offering support for Pacific Power's accelerated depreciation proposal, Sierra Club expresses concern with the Company's failure to link its proposal to future decisions related to continued operation of the coal plants.[37] That concern centers on the Company's statement that the accelerated depreciation schedule "provide[s] greater resource planning flexibility for the Company and its customers as Washington implements state and federal environmental policies."[38] Sierra Club emphasizes that the unrecovered investment in the coal plants should be treated like a sunken cost and not considered in forward-going planning.[39] Sierra Club also harbors concerns that the Company's rationale implies that absent accelerated depreciation the Company "may choose to avoid making near-term retirement decisions, even where that is the least-cost decision, if it would result in stranded assets."[40]

4. Boise proposed conditions for adopting accelerated depreciation

42 Boise proposes that if the Commission approves Pacific Power's proposal for accelerated depreciation, it should disallow approximately half of the SCR investments, as well as

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[34] Cavanagh, Exh. No. RC-1T at 10:15-18.

[35] Fisher, Exh No. JIF-1CT at 34:23-35:4

[36] *Id.* at 35:7-11.

[37] Fisher, Exh. No. JIF-1CT at 36:6-10.

[38] *Id.* at 36:1-5 (quoting Dalley, Exh. No. RBD-1T at 5:3-5).

[39] *Id.* at 36:7-10.

[40] *Id.* at 36:10-13.

deem all future capital investments attributable to operating Bridger after 2025 as not used and useful to Washington ratepayers.[41]

43 Boise observes that current circumstances, including low natural gas prices and oversupply in power markets, create an increased risk that Pacific Power's coal facilities will become a stranded investment and therefore Boise would support a shorter depreciation schedule.[42] Boise cautions that "[i]f the Commission is to approve accelerated depreciation, however, it should also take action to ensure that ratepayers are not paying for unnecessary costs associated with extending the economic lives of the facilities, costs such as the [Bridger Units 3 and 4 SCR] systems."[43]

44 In response to Boise's suggestion that Bridger be removed from rates in 2025, the Company reiterates that the benefits from the plant can continue to inure to Washington ratepayers even after the capital costs are paid off, provided the full operational costs of Bridger are still included in rates.[44]

5. Public Counsel's alternate proposal to establish a regulatory liability account for coal facility retirement funds.

45 If the Commission were to approve the Company's request for accelerated depreciation, Public Counsel recommends that a separate regulatory liability be established.[45] Under this proposal, current depreciation rates would remain in effect until the Company files a new depreciation study that is adopted by the Commission.[46]

46 Public Counsel proposes that the additional amount that could be collected in rates to fund a regulatory liability account should be determined in a subsequent proceeding.[47] Public Counsel opposes setting the amount to be collected on the increase proposed by the Company in this proceeding, in part, because the Company's depreciation schedule is not based on the useful life of the plant.[48]

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[41] Mullins, Exh. No. BGM-1CT at 4:18-19 and 13:6-10.

[42] *Id.* at 3:16-19.

[43] *Id.* at 4:2-5.

[44] Dalley, Exh No. RBD-3T at 14:8-16.

[45] Ramas, Exh. No. DMR-1T at 25:17-21.

[46] *Id.* at 26:1-5.

[47] *Id.* at 28:13-16.

[48] *Id.* at 28:1-5.

47 Public Counsel states that the establishment of a regulatory liability account would provide the Commission more flexibility to pay off unrecovered costs of two units at Bridger if they were closed earlier than the remaining two units at Bridger.[49]

48 In rebuttal, Pacific Power responds that Public Counsel's alternative recommendation is unnecessary and burdensome.[50] The Company stresses that its proposal to separately track and report the incremental depreciation expense collected from Washington customers already provides sufficient transparency.[51] From an accounting perspective, Pacific Power objects to Public Counsel's proposal to use FERC Account 254 to create a regulatory liability. The Company argues that under the guidelines set forth in FERC's Uniform System of Accounts, FERC Account 108, the account the Company proposes for accelerated depreciation, is the appropriate account for recording depreciation.[52] Further, Pacific Power points out that Public Counsel's proposal would create a difference in the way depreciation is accounted for on the Company's books for Washington compared to its other states.[53]

49 In its rebuttal testimony, Pacific Power buttresses its proposal to shorten the depreciable life of the coal plants by stating, "[t]hese depreciation schedules align with reasonably anticipated implementation timelines for state and federal environmental policies and mandates."[54]

50 The Company characterizes its change in the depreciable lives as a policy-based recommendation influenced by new and proposed laws and regulations that may impact the useful lives of the coal plants.[55] Pacific Power argues that since it filed its last depreciation study in January 2013, significant policy developments with regard to environmental regulations at both the state and federal level have occurred, including the recent publication of the Clean Power Plan (CPP).[56] However, responding to clarification questions from the bench, Mr. Dalley conceded at hearing that no specific requirements

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[49] *Id.* at 26:20-27:1.

[50] Dalley, Exh No. RBD-3T at 14:22.

[51] *Id.* at 14:22-15:2; 15:5-6.

[52] McCoy, Exh. No. SEM-6T at 20:22-21:3.

[53] *Id.* at 21:10-12.

[54] Dalley, Exh No. RBD-3T at 6:22-23.

[55] *Id.* at 7:21-8:3.

[56] *Id.* at 8:11-17. *See*, 80 Fed. Reg. 64,661-65,120 (Oct. 23, 2015) (amending 40 C.F.R § 60).

exist in Washington to accelerate the retirement of PacifiCorp's steam generating units in Wyoming.[57]

51 *Commission Decision.* We agree there are burgeoning legal, policy, and economic forces arrayed against continued long-term operation of coal plants. In particular, the final CPP regulations, if implemented, could result in significant changes in the future operations of coal-based resources. Despite the legal uncertainty created by the Supreme Court's stay of the final CPP rule,[58] states are already taking actions collectively and individually to reduce their reliance on coal-based electricity. For example, the Oregon legislature recently passed legislation that works to remove coal from its state electric portfolio over a 10-16 year timeframe.[59] California imposes a fee on greenhouse emissions from the generation of electricity used in the state. Further, PSE requested, and the Commission approved, an extension of its current rate plan to provide PSE more time to determine the future of its ownership interest in Colstrip Units 1 and 2 in Montana.[60]

52 In addition to these environmental constraints, coal-fired generation has been facing significant headwinds from the market pressures of sustained low natural gas prices and more efficient natural gas combined cycle (NGCC) units. Moreover, lower load growth in electricity consumption caused both by mandatory energy efficiency standards and the slow recovery from the recession in late 2008 has substantially changed the generation and load projections that we consider in the Integrated Resource Planning process. Accordingly, the Commission recognizes that there are significantly greater risks associated with the longer-term operation of existing coal-fired generating units such as Units 3 and 4 of Bridger, although we also recognize that these resources have served our loads in a low-cost and efficient manner for several decades.

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[57] Commissioner Rendahl: So specific to Washington first, what requirement of public authorities is driving this decision in this state, for this state in particular?

Mr. Dalley: Well, I think public authorities could be the Commission as one body. It could also be the EPA from a federal level. But I think what we see in Washington, there's no specific requirement for us to shut down any of our facilities at this point.

TR 196:20-197:2.

[58] *Chamber of Commerce, et al. v. EPA, et al,* 136 S. Ct. 999, 194 L. Ed. 2d 18, 84 U.S.L.W. 3439 (2016).

[59] Pursuant to WAC 480-07-495(2)(a)(i)(A), the Commission takes official notice of Oregon Senate Bill 1547, enacted March 8, 2016, Elimination of Coal From Electricity Supply, 2016 Ore. Laws 28.

[60] *In re Investigation of Coal-Fired Generating Unit Decommissioning and Remediation Costs,* Docket UE-151500.

53 While we acknowledge a long-standing practice of relying heavily on those widely-accepted depreciation standards as a guide, we must also weigh the risk of both potential rate impacts and potential intergenerational inequities. We must also carefully consider potential ratepayer exposure to D&R costs, should the plants close earlier than what has been accounted for in the current depreciation rates. Intergenerational inequity (i.e., future ratepayers burdened with the cost of producing electricity for today's ratepayers) can be mitigated by determining reasonable depreciation schedules that balance the near-term burden of cost recovery with the risk of requiring cost recovery after plant closure.

54 We agree with the parties that environmental and market pressures on existing coal-fired generation will continue in the future, and result in more accelerated retirements of coal plants. We also agree with those who argue that a Commission decision to defer an adjustment to current depreciation rates until the 2018-2019 timeframe, when the Company plans to have completed and filed with the Commission its depreciation study, may expose the Company's Washington ratepayers to increased rates in the long term. That is a risk we seek to mitigate here by approving, in part, the Company's accelerated depreciation proposal and directing the Company to take specific actions while we wait for an updated depreciation study.

55 Public Counsel recommended that, if the Commission approved accelerated depreciation, it should also require the Company to book the difference between revenues from the current depreciation expense and the revenues from the application of the accelerated depreciation rate to a separate regulatory liability account to be used for or applied against decommissioning and environmental remediation or other purposes authorized by the Commission.[61] The Company acknowledged that it can track the difference.[62]

56 Pacific Power has not asserted that the coal plants' closure dates match the depreciable lives used in the calculation of its proposed accelerated depreciation. Rather, the Company states that it intends to continue running the plants until the end of their physical lives as it determined in its most recent depreciation study, unless environmental, economic, or other pressures intervene to compel closure of the plants.

57 Lacking a firm commitment for a retirement date from the Company and given that environmental remediation risks and costs for these facilities have not been fully studied or identified, we find that a deferral of the revenue difference between current and accelerated depreciation of the coal plants is appropriate.[63] Accordingly, we approve

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[61] Public Counsel proposes use of FERC Account 254.

[62] Dalley Exh. No. RBD-3T at 14:22-15:6.

[63] RCW 80.04.350 provides the Commission with this authority.

Pacific Power's proposal to accelerate depreciation of the coal plants, but also require the Company to book the difference between the accelerated and current depreciation amounts to FERC Account 254, Other Regulatory Liabilities.

58 Second, we require Pacific Power to file its 2018 depreciation study within 30 days of the study's completion, with its next general rate case, or by December 31, 2018, whichever occurs first. We expect that when the Company files its 2018 depreciation study, as required herein, it will be accompanied by a proposal for the final disposition of the regulatory liability account. If the depreciation study does not support the change to accelerate depreciation for the plants, or supports a different level of accelerated depreciation, the Commission will reassess the depreciation schedules and, if it determines that accelerated depreciation is not in the public interest, order such refunds to customers or additional rate recovery that may be appropriate at that time.

59 Third, we share Staff's concerns about ratepayer exposure to potential plant closure and the potential D&R costs, and adopt its proposal that the Commission order a reporting requirement to establish the potential outstanding costs. Staff included a similar recommendation in its final report in a recent investigation into PSE's planning for the potential closure of Colstrip Units 1 and 2.[64] We require Pacific Power to file a report in its CBRs providing full disclosure of its D&R costs for Colstrip Unit 4 and the Bridger plant, specifically:

a. The most recently estimated salvage value for the asset.
b. The current depreciation expense related to D&R for the asset being collected through rates.
c. The total amount of depreciation related to D&R for the asset that has been collected through rates.
d. Any expenditures the Company has made related to D&R for the asset with a brief explanation of each action.
e. Any updates to the Company's Asset Retirement Obligations related to the specific asset.

60 If the Commission believes that the information provided in the CBRs is not sufficiently precise or if the 2018 depreciation study reveals a significantly shorter life for the plants than currently anticipated, it will consider at that time whether to open an investigation similar to that of Colstrip Units 1 and 2 in Docket UE-151500. Together with these

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[64] *In re Investigation of Coal-Fired Generating Unit Decommissioning and Remediation Costs,* Docket UE-151500.

requirements, we find Pacific Power's proposed accelerated depreciation is in the public interest and should be approved.

C. SCR System Installation

61 Pacific Power seeks recovery of its SCR emission control systems on Units 3 and 4 (SCR installation) at Bridger. This facility is a 2,123 MW coal-fired generating plant, near Point of Rocks, Wyoming, made up of four units.[65] Pacific Power owns two-thirds of each unit and Idaho Power Company (Idaho Power) owns the remaining one-third. Bridger receives a significant portion of its fuel (Bridger coal) from the Bridger coal mine (Bridger mine) that is adjacent to the plant. The Bridger mine is jointly-owned by Pacific Power and Idaho Power and consists of both a surface mine and an underground mine. A relatively smaller portion of Bridger's coal supply is currently purchased from third parties under contract.

62 Bridger contributes to haze pollution in several national parks and wilderness areas.[66] As a result of this pollution, the Company asserts that it was:

> required to install the SCR system on Jim Bridger Unit 3 by the end of 2015 and on Unit 4 by the end of 2016 as a result of the Environmental Protection Agency's (EPA) Regional Haze Rules, the Jim Bridger facility Best Available Retrofit Technology (BART) permit issued by the state of Wyoming, a BART appeal settlement agreement with the state of Wyoming, and the Wyoming Regional Haze State Implementation Plan.[67]

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[65] Fisher, Exh. No. JIF-1CT at 5:25-26.

[66] *Id.* at 5:27-6:2. Dr. Fisher testifies that:

> Regional haze results from small particles in the atmosphere that impair a viewer's ability to see long distances and color. The main haze-forming pollutants are sulfur dioxide (SO_2), nitrogen oxides (NO_x), and fine particulate matter (PM). These air pollutants contribute to the deterioration of air quality and reduce visibility in our national parks and wilderness areas, designated as Class 1 areas.

Id. at 6:10-14.

[67] Dalley, Exh. No. RBD-1T at 4:13-19. The Regional Haze Rule can be found at 40 C.F.R. pt. 51.308.

63 Under the federal Clean Air Act,[68] the EPA and the states are tasked with improving "visibility at certain protected federal lands."[69] The EPA is specifically responsible for identifying the federal lands that require improved visibility,[70] after which the agency is responsible for drafting "regulations providing the guidelines that states will use to design state implementation plans [SIPs] to reduce haze in the affected areas."[71] Each SIP must be submitted to the EPA for approval.[72]

64 The EPA promulgated the Regional Haze Rules on July 1, 1999,[73] and mandated that SIPs include both a "list of the best available retrofit technology (BART) that emission sources in the state will have to adopt to achieve the visibility goals, along with a schedule for implementing BART."[74] BART is the only portion of the implementation plan that is enforceable against emission sources in a state.[75] Once a state has made its BART determination, the BART controls must be installed and in operation as expeditiously as practicable, but no later than five years after the date of EPA approval of the regional haze SIP.[76]

65 Wyoming, along with Arizona and New Mexico, opted to develop SIPs based on the recommendations of the Grand Canyon Visibility Transportation Commission under 40 C.F.R. § 51.309.[77] The three states failed to submit the plan elements required by 40 C.F.R. § 51.309(q) by the December 17, 2007, deadline, triggering a finding by the EPA on January 15, 2009, of Wyoming's failure to submit a SIP.[78] On January 12, 2011,

[68] The Clean Air Act is codified at 42 U.S.C §7401, *et. seq.* The EPA's regulations implementing the Clean Air Act are set forth at 40 C.F.R. § 50-99.

[69] *Texas v. United States EPA*, 2016 U.S. App. LEXIS 13058 at *7 (5th Cir. July 15, 2016) (citing 42 U.S.C. § 7491).

[70] *Id.* (citing 42 U.S.C. § 7491(a)(2) and 40 C.F.R §§ 81.400-81.437).

[71] *Id.* (citing 42 U.S.C. § 7491(b)(1),(2)).

[72] *See*, Teply, Exh. No. CAT-30CX. *See also*, 40 CFR § 52.

[73] *Texas v. United States EPA*, 2016 U.S. App. LEXIS 13058 at *7 (5th Cir. July 15, 2016) (citing 40 C.F.R. § 51.308 and 64 Fed. Reg. 35,714).

[74] *Id.* at *8 (citing 40 C.F.R. § 51.308(d),(e)).

[75] *Id.* at *9 (citing 64 Fed. Reg. 35,733).

[76] 79 Fed. Reg. 5032, 5036.

[77] 74 Fed. Reg. 2392, 2393.

[78] *Id.*

Wyoming submitted a SIP to the EPA addressing regional haze.[79] The EPA partially approved and partially disapproved Wyoming's SIP on January 30, 2014, almost two months after Pacific Power made its final decision to install SCR systems. It determined that:

> while we believe that these costs [of compliance] and visibility improvements could potentially justify [low NO_x burners/separated overfire air and selective catalytic reduction] as BART, because this is a close call and because the State has chosen to require SCR as a reasonable progress control, we believe deference to the State is appropriate in this instance. We are therefore finalizing our approval of the State's determination to require SCR at Jim Bridger Units 1-4, with an emission limit of 0.07 lb./MMBtu (30-day rolling average), as part of its long-term strategy. We are also finalizing our approval of the compliance dates of December 31, 2022, December 31, 2021, December 31, 2015, and December 31, 2016, for Units 1-4, respectively.[80]

66 Pacific Power filed applications for BART permits for its Bridger plant with the state of Wyoming on January 16, 2007. After public notice, comment, and public hearings, the Wyoming Department of Environmental Quality, Air Quality Division (DEQ/AQD) issued BART permit no. MD-6040 for the Bridger Plant on December 31, 2009.[81] Pacific Power appealed certain provisions of the permit, and ultimately agreed to a settlement with the Wyoming DEQ/AQD. The Company asserts that the SCR installation is the least cost option for complying with its settlement with the Wyoming DEQ/AQD by agreeing to withdraw its appeal and to address NO_x emissions.[82] Specifically, the Company agreed that:

> With respect to Bridger Units 3 and 4, PacifiCorp shall: (i) install SCR; (ii) install alternative add-on NO_x control systems; or (iii) otherwise reduce NO_x emissions to achieve a 0.07 lb/mmBtu 30-day rolling average NO_x emissions rate. These

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[79] 79 Fed. Reg. at 5033.

[80] Teply, Exh. No. CAT-30CX. Cross exhibit CAT-30CX includes a limited portion of 79 Fed. Reg. 5032 *et seq.*, the final rule approving in part the Wyoming SIP. In order to have a complete record, we take official notice of the rule in its entirety pursuant to WAC 480-07-495(2)(a)(i)(A). *See also*, 79 Fed. Reg. at 5048-9.

[81] Teply, Exh. No. CAT-24.

[82] *Id.* at 2.

installations shall occur, and/or this emission rate will be achieved, on Unit 3 prior to December 31, 2015 and Unit 4 prior to December 31, 2016.[83]

67 The Company identified three options for compliance with its state and federal haze obligations: SCR installation on Bridger Units 3 and 4, convert the units to run on natural gas (natural gas conversion), or decommission the plant. Pacific Power used its System Optimizer model (SO model) to perform an economic analysis to determine the least-cost option between the three choices.[84] The SO model is designed to produce a present value revenue requirement differential (PVRR(d)) between the installation of SCR and other alternatives.[85] Key input assumptions in this analysis are the future prices of natural gas, coal costs, and carbon dioxide (CO_2) emissions, as well as the capital costs of natural gas conversion and SCR installation.[86]

68 The Company's original analysis of SCR installations at Bridger Units 3 and 4 included eight different combinations of natural gas and CO_2 price assumptions all tied to the September 2012 official forward price curve (OFPC).[87] Pacific Power's base case analysis performed in May of 2013, using the Company's September 2012 OFPC and January 2013 mine plan, shows that installation of SCR was, according to its analysis, approximately [REDACTED] lower cost than natural gas conversion.[88] This detailed SO model run included both a two-unit scenario, should the Company convert Units 3 and 4 to natural gas, and a four-unit scenario, should Pacific Power install SCR. From Pacific Power's perspective, the net benefit provided a 'reasonably sized cushion' in the PVRR(d) results allowing for some erosion of the favorable economics should long-term

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[83] *Id.* at 2-3.

[84] "The SO model endogenously considers tradeoffs between operating and capital revenue requirement costs of both existing and prospective new resources while simultaneously evaluating tradeoffs in energy value between existing and prospective new resource alternatives…[It] is capable of simultaneously and endogenously evaluating capacity and energy tradeoffs between emission control equipment, required to meet emerging environmental regulations, and a broad range of alternatives including fuel conversion, early retirement, and replacement with Greenfield Resources, market purchases, demand-side management resources, and/or renewable resources." Link, Exh. No. RTL-1CT at 3:10-13; 3:18-23.

[85] *Id.* at 4:17-5:6. All PVRR(d) results are stated on a total-company basis.

[86] *Id.* at 6:16-7:7 (fuel costs); *Id*. at 8:6-21 (natural gas and CO_2 costs).

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

[88] *Id.* at 13:1-9 and Ralston, Exh. No. DR-1CT at 3:20-4:10. The Company presents its analysis as a PVRR(d), which is the total cost of meeting load with SCR at Bridger compared to the total cost of meeting load with natural gas at Bridger. The SO model included Bridger mine reclamation cost based on mine operations in January 2013 mine Plan. Link, Exh. No. RTL-1CT at 7:8-20.

natural gas prices or CO_2 prices change from what was assumed in the base case analysis.[89] Based on the SO model analysis, Pacific Power made the decision to install SCR on Units 3 and 4, and on May 31, 2013, the Company signed a limited notice to proceed (LNTP) on an engineering, procurement, and construction services (EPC) contract for SCR installation.[90]

69 The Company states that at the time it committed to the full notice to proceed (FNTP), which it signed on December 1, 2013, the SCR scenario was [REDACTED] lower cost than gas conversation based on its September 2013 OFPC and the January 2013 mine plan.[91] The SCR system on Unit 3 went into service in November 2015, and the SCR system on Unit 4 is under construction and scheduled to go into service in November 2016.[92]

70 *Staff's Position.* Staff contests the prudence of the installation of SCR, arguing that gas conversion is a lower cost alternative. It asserts that the Company's analyses failed to capture the risks or accurately represent the benefits of SCR installation at Bridger.[93] Staff also states that the Company "failed to reasonably respond to known changes that had a clear, negative impact on the economics of SCR."[94]

71 According to Staff, one of those changes, falling natural gas prices, would have spurred a reasonable board of directors or company management to examine gas price forecasts available to it prior to signing the FNTP on December 1, 2013.[95] Staff notes that the benefits of SCR fell 42 percent from [xxx] million in the Company's 2011 analysis to [xxx] million in the Company's May 2013 analysis and then further to [xxx] million based on the Company's September 2013 OFPC.[96] Using gas forecasts available to the Company prior to December 1, 2013, Staff constructs a gas forecast using three consultant's long-term forecasts that coupled with Staff's adjustment for coal costs and

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[89] Link, Exh. No. RTL-1CT at 22:10-14.

[90] *Id.* at 26:7-9. *See also*, Teply, Exh. No. CAT-1CT at 14:14-20.

[91] Link, Exh. No. RTL-1CT at 20:14-21 and Teply, Exh. No. CAT-1CT at 14: 20-23. The Company's January 2013 Mine Plan costs includes contributions to mine reclamation for both the two-unit scenario and the four-unit scenario. Link, Exh. No. RTL-4C.

[92] Teply, Exh. No. CAT-1CT at 15:20-22 and 24:15-16.

[93] Twitchell, Exh. No. JBT-1CT at 16:4-8.

[94] *Id.* at 16:6-8.

[95] *Id.* at 28:1-19.

[96] *Id.* at 16:9-14; 19:18-20. In responsive testimony, Staff refers to the Company's May 2013 analysis as the 2012 analysis because the natural gas data used in the analysis is primarily from 2012. *Id.* at 19:18-21.

replacement power results in a net benefit of approximately [xxx] million for the natural gas conversion option.[97]

72 Staff asserts that it asked "the Company to quantify the difference in power costs that resulted from [even the] difference in modeling assumptions [i.e., assuming a January/February outage for conversion versus a September to November outage window in the SO model]."[98] Pacific Power responded to Staff's inquiry in the negative, stating that "the costs of the replacement power cannot be isolated as the [SO model] rebalances the system when resource availability changes through dispatch and market transactions on an economic basis."[99] Staff disagrees with this response, stating that "[r]unning a model with an outage period in one part of the year and a model with the outage period moved to another part of the year may have taken a day or two for the models to actually run, but in my opinion, it was a request that the Company could have reasonably met within 10 business days."[100]

73 During supplemental response, Staff argues the Company should have used the updated coal costs from the October 2013 mine plan to calculate changes in coal costs.[101] Staff calculates that this information increases Bridger's coal costs by [xxx] percent relative to the January 2013 mine plan.[102] Staff asserts this would negatively impact the economics of SCR installation.[103]

74 Staff then conducts the analysis that it believes the Company should have undertaken, noting that even using Pacific Power's break-even price (which excludes Staff's coal cost adjustment), and applying the December 2013 OFPC to the Company's analysis, the net

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[97] Twitchell, Exh. No. JBT-1CT at 53:10-23.

[98] *Id.* at 42:7-9.

[99] *Id.* at 42:9-12 (citing to Twitchell, Exh. No. JBT-15).

[100] *Id.* at 42:20-43:1.

[101] The October 2013 mine plan includes the Company's [xxxxxxxxxxxxxxxxxxxxxxxxxxxxxx REDACTED – CONFIDENTIAL xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxxx].

[102] Twitchell, Exh. No. JBT-28HCT at 13:1-5.

[103] *Id.* at 19:17-21. Staff calculated its coal costs adjustment by comparing the January 2013 and October 2013 mine plans to determine, on a percentage basis, the degree to which costs increased in the October 2013 mine plan. *Id.* at 10:5-15. To arrive at its final adjustment, Staff calculated the net present value of Bridger coal costs modeled in the low, base, and high gas cases, then adjusting each by the [xxx] percent increase it determined.

benefit associated with SCR installation is [xxx] million.[104] Staff points out this change represents an approximate 90 percent decline from the Company's initial net benefit analysis that was based on the December 2011 OFPC.[105]

75 In total, Staff asserts that by combining the natural gas update and its coal cost update, there would be approximately [xx] million in net benefits associated with gas conversion compared to the Company's [xx] million benefit for SCR installation that is based on the September 2013 OFPC and the January 2013 mine plan.[106]

76 Noting that the Company built a great deal of flexibility into the EPC contract,[107] Staff then asserts that had Pacific Power examined the natural gas pricing and coal cost data, recognizing these clearly negative changes, it "[xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxxx REDACTED – CONFIDENTIAL xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx xxxxxxxxxx].[108]

77 Specifically, based on additional information provided in the Company's rebuttal and through subsequent discovery, Staff asserts in its supplemental response testimony that the Company had until January 1, 2014, a month after signing the FNTP, to analyze new information and cancel the EPC.[109] Staff argued that Pacific Power failed to act on either new natural gas prices available to it or new coal price information from the October 2013 mine plan.[110] Staff states that "there is no evidence that [the Company] even evaluated them."[111]

78 *Sierra Club's Position*. While the Company had an obligation under the Clean Air Act and the Regional Haze Rule to reduce emissions at the Bridger facility, Sierra Club argues that the approval by the EPA and the Wyoming DEQ/AQD of the SCR systems for BART purposes did not forestall Pacific Power from examining and selecting other

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[104] Twitchell, Exh. No. JBT-28HCT at 27:17-19. Staff calculates a December 2013 OFPC of [xxxxxxxxxx].

[105] *Id.* at 27:20-28:1.

[106] *Id.* at 33:3-6.

[107] Twitchell, Exh. No. JBT-1CT at 27:11-13.

[108] *Id.* (citing to Twitchell, Exh. No. JBT-12C).

[109] Twitchell, Exh. No. JBT-28CT at 29:8-13. [xxxxxxxxxxxxxREDACTED – HIGHLY CONFIDENTIALxxxxxxxxxxxxxx] *Id.* at 30:4-9.

[110] *Id.* at 1:15-2:17.

[111] *Id.* at 2:15-16.

least-cost alternatives for compliance. Dr. Jeremy Fisher, on behalf of Sierra Club states that:

> [t]he Regional Haze Rule's requirements are based on both a control technology and an emissions limit at each unit. PacifiCorp could therefore comply with the rule either by installing the required pollution controls necessary to meet that limit, or by shutting down or converting Jim Bridger units to run on natural gas. There are several examples of coal plants shutting down or switching to natural gas fuel as an alternative compliance path under the Regional Haze Rule.[112]

79 Accordingly, Sierra Club challenges the prudence of the SCR installation, stating that between the Company's May 2013 analysis and December 1, 2013, "significant new information was available to the Company that should have indicated the decision to retrofit was not the least cost alternative available to the Company."[113]

80 Sierra Club presents evidence of falling natural gas prices noting that between the Company's analysis in May 2013 and the update using the September 2013 OFPC, the benefit of SCR installation fell 30 percent due to natural gas prices alone.[114] For its analysis, Sierra Club adjusts the Company's claimed May 2013 SCR benefit of [xxx] million downward by [xxx] million to [xxx] million based on the use of the Company's December 2013 OFPC.[115] Noting [xxxxxxx REDACTED – CONFIDENTIAL xxxxxxx] eflected in the October 2013 mine plan, Sierra Club also adjusts the SCR benefits downward by [xxx] million to account for its calculation of higher coal costs.[116]

81 In response to Staff testimony describing the Company's refusal to run the SO model on the grounds of the complexity of doing so, Sierra Club disputes that the Company could not have rapidly rerun the SO model in response to Staff's request. Sierra Club points out that the Company had plenty of time to run the model again after its May 2013 LNTP and prior to the December 2013 FNTP.[117] Further, Sierra Club agrees with Staff that the

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[112] Fisher, Exh. No. JIF-1CT, n 13 (citing Apache Unit 2, Arizona (80 Fed. Reg. 19,220); Naughton Unit 3, Wyoming (79 Fed. Reg. 5045); and Muskogee 4 & 5, Oklahoma).

[113] *Id.* at 4:3-5.

[114] *Id.* at 28:1-4.

[115] *Id.* at 25:4-6.

[116] *Id.* at 4:7-11. To develop its own coal cost analysis, Sierra Club substituted the cash cost of coal delivered to Bridger as provided in the 2015 Integrated Resource Plan (IRP) for the cash cost for the four-unit operations in the October 2013 mine plan. *Id.* at 4:7-11; 14:10-13.

[117] Fisher, Exh. No. JIF-17CT at 3:13-19.

Company could easily run the SO model for any party within the 10-day timeframe provided for discovery responses.[118]

82 Sierra Club's final analysis adjusts the coal cost calculation in its cross-answering testimony.[119] It estimates that the impact of higher coal costs for a four-unit operation diminishes the SCR benefit by [xxx] million instead of the original [xxx] million reduction.[120] This amount reflects changes Sierra Club made to coal mining capital costs to address the Company's criticism of its response testimony, but unlike its response testimony, does not rely on information found in Pacific Power's 2015 IRP.[121] Sierra Club reiterates its conclusion, originally reached in its response testimony, that gas conversion and not SCR installation is the least-cost option.

83 *Company's Rebuttal.* Pacific Power criticizes Staff and Sierra Club's singular focus on the results from the base case analysis without due consideration of the high gas price scenario.[122] The Company states that natural gas price assumptions are an important driver to the Bridger Units 3 and 4 SCR analysis,[123] and that it considered the risk reflected in the high gas price scenarios.[124] Pacific Power disagrees with Staff's choice of third-party price forecast consultants for the long-term forecast explaining that, when it creates its OFPC, it "strives to adopt a moderate long-term projection that represents neither the highest nor the lowest forecast available from third-party experts."[125]

84 Pacific Power asserts that "[b]etween January 2013 and November 2014, the Company did not prepare a new long-term fueling forecast for the Jim Bridger plant because no

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[118] Fisher, Exh. No. JIF-17CT at 4:20-23.

[119] Fisher, Exh. No. JIF-24CT at 3:1-6.

[120] *Id.* at 3:7-10.

[121] *Id.* at 17:1-7.

[122] Link, Exh. No. RTL-11CT at 19:19-21:3.

[123] *Id.* at 20:11-12.

[124] *Id.* at 20:22-21:3.

[125] *Id.* at 17:23-18:2. Pacific Power received an updated long-term natural gas price forecast from three different third-party experts after it finalized its September 2013 OFPC – an updated forecast from [xxxxxxxxxxxx] dated October 22, 2013; an updated forecast from [xxxx] dated November 20, 2013; and an updated forecast from [xxxx] dated December 11, 2013. Link, Exh. No. RTL-11CT at 18:5-9. The Company did not supply the [xxxx] forecast in its response to a Staff data request because "[t]he [xxxx] price forecast, issued in November 2013, was not included in the response to Staff Data Request 92 because the Company did not use it in developing the December 2013 OFPC." Link, Exh. No. RTL-15CT at 7:20-8:2.

significant cost events occurred that would lead it to believe a material change would result."[126] The Company also states that it did not rely on the October 2013 mine plan for determining coal costs and objects to the use of this document by others to do so. It notes that the October 2013 mine plan was only developed for budgeting purposes and was not a long-term fueling plan.[127]

85 In response to Staff and Sierra Club's use of this plan for determining long-term coal costs, the Company states that "the long-term cost and revenue assumptions included in the October 2013 mine plan were not developed with the same analytical rigor that the Company uses to develop its long-term fueling plans [i.e. the January 2013 mine plan] because this data is used solely to determine appropriate contributions to the reclamation sinking fund during the 10-year budget horizon."[128] That aside, Mr. Dana Ralston, on behalf of Pacific Power, testifies that after the completion of the October 2013 mine plan the Company concluded that it did not indicate a material change in coal costs or the type of increase in coal costs projected in Staff and Sierra Club's analysis.[129]

86 Setting aside the limitations of the October 2013 mine plan, the Company derives a coal price for a four-unit scenario by correcting what it says are errors in Staff's calculations.[130] Pacific Power calculations show that overall coal costs for Bridger increased by only [xxxxxx] during the 10-year budget horizon covered by the October 2013 mine plan.[131] Pacific Power claims this is consistent "with the [xxxxxxx] increase

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[126] Ralston, Exh. No. DR-1CT at 9:3-10.

[127] *Id.* at 3:18-19. In rebuttal testimony, the Company begins to refer to the January 2013 mine plan as a fueling plan used in the "SCR analysis" done in early 2013 and the October 2013 mine plan as 10-year budgeting plan. In contrast to the October 2013 mine plan used for budgeting, the January 2013 mine plan contains third-party coal pricing and capital mining costs beyond the first ten years. *Id.* at 7:5-14. The January 2013 mine plan included a two- and four-unit analysis whereas the October 2013 mine plan only performed a four-unit analysis. *Id.* at 10:17-11:4. A coal cost analysis for a scenario in which two units are converted to natural gas and two units remain coal fueled is a "two-unit" analysis. A reduction in the coal cost of a two-unit scenario increases the benefit of the natural gas conversion scenario.

[128] Crane, Exh. No. CAC-1CT at 6:1-5.

[129] Ralston, Exh. No. DR-1CT at 2:21-22; 7:16-22.

[130] Crane, Exh. No. CAC-1CT at 4:11-12.

[131] *Id.* at 4:11-14.

reflected in the Company's long-term fueling plan for the Jim Bridger plant used for the 2015 Integrated Resource Plan (IRP) for the 2016-2030 period."[132] It argues that:

> [i]f the Company had updated costs by this percentage increase in both the two-unit operating scenario (the natural gas conversion alternative) and four-unit operating scenario (the SCR alternative), the SCR benefits would have decreased by approximately [xxxxxxxxx] over the 10-year budget period...[133]

87 Pacific Power also argues that Staff and Sierra Club's analyses contain numerous, critical flaws and that Sierra Club, in particular, relies on information not available to the Company at the time of its December 1, 2013, decision.

88 It contends that Staff's natural gas forecast, presented in response testimony, mixed real gas forecast prices with nominal gas forecast prices.[134] With regard to Staff's projected coal costs, the Company argues that Staff's updated coal cost analysis projects an increase in costs based on the use of the January 2013 mine plan, not the October 2013 mine plan.[135] The Company asserts that Staff incorrectly includes "depreciation, depletion, and amortization costs from past investments, because these non-cash costs are the same among all future compliance scenarios and, therefore, have no impact on the Jim Bridger SCR analysis."[136]

89 Turning to Sierra Club's arguments, Pacific Power notes that Sierra Club's use of the December 2013 OFPC is improper because it "was developed using data that was not available to the Company at the time the FNTP was issued to the EPC contractor."[137] Similarly, the Company points out that "Sierra Club uses coal cost assumptions for the Jim Bridger plant that were developed long after the Company decided to proceed with

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[132] Crane, Exh. No. CAC-1CT at 4:14-17.

[133] *Id.* at 4:17-20 (citing to Crane, Exh. No. CAC-2C).

[134] Link, Exh. No. RTL-11CT at 13:3-18. At hearing, Staff admits that it erred in mixing nominal and real natural gas price forecasts. Twitchell, TR. 708:3-7.

[135] Link, Exh. No. RTL-11CT at 7:20-8:2

[136] *Id.* at 6:9-12.

[137] *Id.* at 19:4-8.

installation of the SCRs."[138] The Company states, "[t]his increase would not have materially impacted the SCR analysis even if it had been known in fall 2013."[139]

90 Pacific Power insists that Sierra Club's coal cost analysis contains an error that "omits the change in Bridger Coal Company's forecasted capital expenses when comparing coal costs used in the Company's SCR analysis with coal costs used in the 2015 IRP."[140]

91 The Company defends its decision to install the SCR as prudent, saying it "reasonably used the September 2013 OFPC and appropriately considered natural gas forecast volatility before issuing the FNTP on December 1, 2013."[141] Pacific Power asserts that prior to signing the FNTP, it "reviewed all key decision factors:"

- its most recent OFPC (dated September 2013), which remained well above the SCR's break-even point;
- its 10-year budget projections that showed that Jim Bridger coal costs were not projected to increase significantly; and
- a [xxxxxxx] cost reduction the Company negotiated in the EPC contract.[142]

92 On cross-examination, Mr. Chad Teply, Vice President of Strategy and Development for Pacific Power, acknowledges that it was his "responsibility to make sure those reassessments [of the changing commodity prices] were completed from May to December [2013]."[143] He argues that he and his team did evaluate the changing economic circumstances by telephone and in-person meetings almost daily.[144] When asked by Staff about contemporaneous documentation of his analysis and decision-making process regarding the changing commodity prices from May to December 2013, Mr. Teply admits that the Company did not provide any. He states that:

> the reviews that we would have completed here prior to issuing full notice to proceed would have been literally sitting down at a desk, looking at the screen,

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[138] Link, Exh. No. RTL-11CT at 3:18-19.

[139] Ralston, Exh. No. DR-1CT at 3:3-4.

[140] Link, Exh. No. RTL-11CT at 10:3-5.

[141] Link, Exh. No. RTL-15CT at 10:19-21.

[142] Teply, Exh. No. CAT-40CT at 4:22-5:3.

[143] Teply, TR 553:21-554:2.

[144] Teply, TR 554:7-13.

> looking at the actual data, and making a decision as to whether there was any material change there that would have then triggered a reason to go back and reassess compliance approaches. In this instance there were none […] There would be no memo documenting these three particular decision points in one place, no.[145]

93 Mr. Teply reiterates this point when asked by Commissioner Jones whether his communications with Mr. Link and Mr. Durning of Pacific Power were all verbal regarding an analysis of the commodity price changes between May and December 2013 by stating, "[o]f those specific discussions, yes."[146]

94 *Commission Decision.* Regulated public service companies bear the burden of proof that their decisions are prudent,[147] just as they are required to demonstrate generally that their proposed rates are just and reasonable reflecting capital expenditures that are used and useful to end-users.[148] In the instant matter, Pacific Power bears the specific burden of demonstrating that its decision to proceed with installation of SCRs, as opposed to alternatives, was prudent with respect to recovery of such costs from Washington ratepayers. The Commission has often cited the prudence legal standard as thus:

> What would a reasonable board of directors and company management have decided given what they knew or reasonably should have known to be true at the time they made a decision?[149]

In other words, we may not use the benefit of hindsight in our evaluation of Pacific Power's decision to pursue and install the SCRs. Moreover, the prudence standard applies both to the question of need and the appropriateness of the substantial capital investment in the SCRs.[150]

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[145] Teply, TR 464:25-465:11.

[146] Teply, TR 555:9.

[147] *WUTC v. Cascade Natural Gas Corporation,* Docket UG-941408, Third Supplemental Order, 1995 Wash. UTC LEXIS 46, at *5 (Oct. 30, 1995) (citing *WUTC v. Puget Sound Power & Light Co.,* Docket Nos. UE-921262, *et al*., Eleventh Supplemental Order (Sept. 21, 1993).

[148] *Id. See also* RCW 80.04.130(4).

[149] *WUTC v. Puget Sound Power & Light Company,* Cause No. U-83-54, Fourth Supplemental Order at 32 (Sept. 28, 1984).

[150] *Id.*

95 Three factors are considered in our evaluation of whether the Company's decision was prudent: (1) Was the initiation of the project prudent? (2) Was the continued construction of the project prudent? and (3) Were the construction expenses prudently incurred?[151] As the Commission explained in *WUTC v. The Washington Water Power Company,* the second and third factor are examined using the same prudence test as the first factor but "applied at a different point in time and necessarily premised on a reevaluation of the project."[152] In other words, our examination of prudence on a specific capital expenditure is not limited to a single point in time, but is considered in the continuum of the specifics of the terms of the contract at issue.

96 We accept that Pacific Power faced compliance obligations under the federal Clean Air Act's Regional Haze Rule and the Wyoming SIP for its Bridger generating plant units. We also recognize the complex challenges associated with resolving these long-standing issues. In this case, these haze pollution reduction obligations left Pacific Power with three options for the Bridger plant's future: installation of the SCR systems on all four units, conversion of the steam boilers and electrical generation units from coal to natural gas, or ultimate closure of these generation units.[153]

97 The record shows that leading up to signing the Limited Notice to Proceed (LNTP) in May 2013, Pacific Power conducted a thorough analysis of its compliance options using its SO model. The analysis performed was rigorous, included all three options available to the Company, and focused on the economics of each option by examining natural gas prices and coal costs. Further, the Company negotiated an EPC contract which it described as offering substantial flexibility, including the right to abandon the project up to and even following Pacific Power's signing of the Final Notice to Proceed (FNTP) in December 2013. The Company provided adequate contemporaneous documentation of both its initial analysis and the decision to pursue SCR installation when it signed the LNTP. If we place ourselves in the position of Pacific Power's oversight board in May 2013 when the Company entered into an EPC for installation of SCR systems and consider all of the evidence in this specific record, as discussed further below, we find that the initial decision *at that time* was prudent.

98 However, our inquiry does not end there. Simply because a decision to begin a project is initially prudent does not, *ipso facto,* make the continuation or actual completion of the

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[151] *WUTC v. Washington Water Power Company*, Cause No. U-83-26, Fifth Supplemental Order, 1984 Wash. UTC LEXIS 69 at *21 (Jan. 19, 1984). (*Washington Water Power*)

[152] *Id.* at *22.

[153] Link, Exh. No. RTL-1CT at 3:18-23.

project prudent.[154] We have required that companies "continually evaluate a project as it progresses to determine if the project continues to be prudent from both the need for the project and its impact on the company's ratepayers."[155] For that reason, we must ask, based on what Pacific Power knew or should have known from May 2013 when it entered into the LNTP, through December 1, 2013, when it signed the FNTP and committed itself to the installation, whether a reasonable board of directors or company management would have continued the SCR project. Based on the evidence, or lack thereof, in the record, and as discussed below, we find that the Company has failed to present the requisite contemporaneous documentation to show that the continued implementation of the SCR systems was ultimately prudent.

99 By its own account, between its initial economic analysis in 2011 and the May 2013 analysis, the net benefits of SCR installation dropped from [xxx] million to [xxx] million due to falling natural gas prices alone. The Company describes the latter May 2013 net benefits amount as a reasonably sized "cushion" should natural gas prices decline further.[156] Natural gas prices did continue to fall throughout 2013. In fact, Pacific Power admits that, relying on its September 2013 OFPC, the net benefits of SCR installation fell further from [xxx] million in May 2013 to [xxx] million in early October.[157] This represents a 58 percent decline in net benefits from its 2011 analysis.

100 During this six month period, the Company elected <u>not</u> to rerun the SO model it had used in the rigorous analysis it had completed earlier. Clearly, the Company did not engage in the same rigorous process for evaluating natural gas and coal prices during this critical period. Instead, the Company presented Mr. Teply's testimony stating that he and his team considered the effect of changing commodity costs on the net benefits of SCR installation in connection with the original May 2013 findings. In response to cross-examination and clarification questions from the bench, Mr. Teply admitted that he had not provided the Commission with any contemporaneous documentation of the reassessments he alleges occurred after May 2013.

101 A re-examination of the benefits to SCR installation is critical during this time period. The record shows that from May to December 2013, not only were natural gas prices

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[154] *Washington Water Power* at *23.

[155] *Id.*

[156] Link, Exh. No. RTL-1CT at 22:12.

[157] In one portion of its testimony, the Company represents that after considering the September 2013 OFPC it committed to installing SCR. Link, Exh No. RTL-1CT at 20:14-21. Later in the development of the record the Company states it made its decision on December 1, 2013. Link, Exh. No. RTL-11CT at 17:1-2.

continuing to fall, but the Company's plans for its mining operations reversed course as well. The coal costs used in the Company's May 2013 analysis were based on the mine operations from the January 2013 mine plan, which included the projected effects of the [xxxxxxx REDACTED xxxxxxxxx] However, the October 2013 mine plan reversed course indicating the [xxxxxxxxxxxxxxx REDACTED –CONFIDENTIAL xxxxxxxxx xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx REDACTED –CONFIDENTIAL xxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxxx]

102 There is little in the record to indicate that the Company responded to or even considered the effects of reversal of its apparent view on a change to [xxxxxxx] operations. In fact, the only document in the record describing the decision to move forward with the FNTP is a December 5, 2013, memo. However this memo was prepared after the final decision to proceed was made, and therefore cannot be shown to have played a part in the Company's decision-making.[158] Even if we were to consider the December 5, 2013, memo, there are no documents describing the decision-making leading to the actual FNTP decision. The change in mining operations altered the capital costs, operational costs, and the purchased coal amount. The Company did not re-run its SO model which is specifically designed to account for the changes in forward-looking capital costs, operational costs, and coal purchases over the projected operating horizon of the plant.

103 The Commission is presented with statements from the Company's witness of what the Company says its employees did or thought at the time, but is provided no supporting contemporaneous documentation. Mr. Ralston states that nothing in the October 2013 mine plan "suggest[s] that coal costs were rapidly increasing."[159] The Company however, does not present any documentation from that time to support how it weighed the information from the October 2013 mine plan to reach such a conclusion or even that it made such a determination. There is no documentation that Pacific Power's board of directors or senior Company management were adequately informed or on what basis they concluded that the change in coal operations would result in a relatively minor change in costs for those mine-mouth coal generation units at Bridger. As to whether the October 2013 mine plan was a reliable document for determining coal costs, the Company's witnesses contradict themselves arguing in one instance that the October 2013 mine plan is only for use in 10-year budgeting and does not have the "same

[158] We conclude that the appropriate point in time to end our examination of prudence is on December 1, 2013. Although the Company, Staff, and intervening parties made vigorous attempts to include evidence and analysis after this point in time, we choose not to give any weight to such evidence and argument.

[159] Ralston, Exh. No. DR-1CT at 2:21-22.

analytical rigor" as the January 2013 mine plan,[160] but arguing in another instance that it concluded from the October 2013 mine plan that the reversal of the mining operations would not impact the economics of SCR installation.[161] Only in calculations of the two-unit coal costs, performed for supplemental rebuttal testimony and not as part of a review in the May to December 2013 time period, does the Company present quantitative evidence of how the October 2013 mine plan could have been used "if it had been done" at the time of the decision making.[162]

104 Importantly, the Company provides no explanation based on contemporaneous documents for why, in the face of falling natural gas prices and a reversal of mining operations, it decided there was no need to produce a more rigorous mine fueling plan in the fall of 2013. Instead, the Company's decision to sign the FNTP on December 1, 2013, was based on its earlier May economic analysis that used coal costs derived from mine operations that it knew no longer represented how coal would be mined or procured over the remaining expected life of the Bridger generating units.

105 We now turn to the Company's consideration and assessment of falling natural gas prices during the May through December 1, 2013, period. The Company states that from September through November 2013 it considered the three consultants' updates of long-term gas price forecasts as they arrived. Yet the Company provides no contemporaneous documentation showing how it considered those falling gas price forecast updates. Pacific Power witness Ms. Crane argues that the Company did not use the lowest of the three consultant forecasts to construct its OFPC because it "strives to adopt a moderate long-term projection," yet the Company fails to present contemporaneous documents explaining its criterion for excluding the low forecast while including the other two consultants' higher forecasts. We are troubled by this omission and find the record particularly lacking in light of the Company's use of forecasts in previous economic analyses that were consistently high.

106 As a result, the Commission cannot know what results may have been produced from an analysis of a more rigorous mine fueling plan late in 2013 or from a thorough analysis of natural gas prices prior to December 1. The record fails to show that the Company continuously evaluated the economics of SCR installation and gathered and considered reasonably available information from May to December 1, 2013. Instead the Company's decision to sign the FNTP was based on an economic analysis that used out-of-date coal

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[160] Crane, Exh. No. CAC-1CT at 6:1-5.

[161] Link, Exh. No. RTL-15CT at 6:1-6.

[162] Crane, Exh. No. CAC-1CT at 12:6-8.

costs derived from mine operations that it knew had changed, and a fairly consistent trend in falling natural gas price forecasts.

107 Although helpful, we find that Mr. Teply's testimony at hearing regarding the verbal exchanges he and his team had among themselves and management in place of a full SO model reassessment is not sufficiently documented or precise enough to support an ultimate decision of prudence on the basis of continuous and rigorous analysis over this seven month period. In our view, Mr. Teply's explanation simply does not prove that the Company adequately examined the changing circumstances in coal and natural gas prices, which could have impacted a prudent or imprudent decision. As we stated in a previous order involving PSE:

> 'robust discussions' about various resources, with 'a consensus' on the decisions, are not sufficient to demonstrate prudence […] The parties and the Commission therefore should be able to follow the company's decision-making process, knowing what elements the company used, and the manner in which the company valued those elements. Such a process should certainly be documented.[163]

108 Pacific Power has failed to meet its burden of demonstrating that its final decision to continue with the SCR installations on Units 3 and 4 was prudent. That is not the same as a finding by the Commission that the Company was imprudent in its initial decision, which we regard as preliminary in light of a flexible EPC contract, to install SCR systems. We find that, considering the significant economic changes in both coal costs and natural gas pricing between May and December 2013, the decision to continue the SCR installation project was not sufficiently demonstrated by the Company to be prudent in all respects, and the full costs of its decision should not be borne by the ratepayers in Washington.

109 The Commission is authorized only to approve electric rates that are fair, just, reasonable, and sufficient.[164] The general ratemaking principle is that ratepayers should not bear any costs for which the company has failed to demonstrate prudence, up to and including the full costs of the investment.

110 In cases of imprudence or failure to meet the prudence burden, the Commission typically disallows the difference between the cost of the chosen project (i.e., SCR installation) and

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[163] *Petition of Puget Sound Power & Light Company for an Order Regarding the Accounting Treatment of Residential Exchange Benefits; WUTC v. Puget Sound Power & Light Company; WUTC v. Puget Sound Power & Light Company,* Dockets UE-920433, UE-920499, and UE-921262, respectively, Nineteenth Supplemental Order at 30 (Sept. 27, 1994).

[164] RCW 80.28.010(1).

the expense of the least cost option. However, in this case the Company's lack of contemporaneous documentation that it analyzed a two-unit scenario involving natural gas conversion after May 2013 provides scant guidance for determining the lower cost option in calculating a disallowance.

111 Significantly, no party has argued for complete disallowance of the Company's SCR investments, and both Staff and Sierra Club offer alternatives to avoid such an outcome. However, Staff's and Sierra Club's proposals prove problematic in their own ways. Staff's model, while well-reasoned, contains a modeling error related to the booking of "Mine and Equipment Maintenance" expense and the discounting of mmBTUs, as well as being based on limited information provided by Pacific Power. Sierra Club bases its disallowance proposal on information not available to the Company at the time of its decision to execute the FNTP.

112 Instead, we find the "used and useful" regulatory concept particularly applicable. This principle provides that "there should be no recovery of certain amounts (i.e., return of the asset and/or return on the asset) that exceed the original benefit for which the asset was established."[165] In addition, the "used and useful" principle is in keeping with the Commission's overall statutory duty to balance ratepayer and shareholder interests, as well as the well-established regulatory principle that benefits generally follow an assessment of the specific risk.[166]

113 Pacific Power increased the risk Washington ratepayers would bear by failing to rerun the SO model when confronted with significantly changed circumstances to its original inputs, namely decreasing gas prices and a revised coal plan. The Company further increased the overall risk of the investment by not maintaining contemporaneous decisional records after it signed the LNTP in May 2013. In the Company's best case scenario, the benefit calculation of SCR as compared with gas conversion had fallen from [xxx] million to [xxx] million in the run up to Pacific Power fully committing to SCR installation. As previously discussed, this reduced by 58 percent the SCR benefit and should have led to a substantial re-evaluation by the Company of its options.

114 As stated earlier, we recognize that the Company faced a regulatory obligation with both the Wyoming DEQ and federal EPA to reduce emissions and meet the regional haze requirements, and that the installation of SCR's on Units 3 and 4 was one means to achieve this goal. We do not accept, however, that the Company was without options in meeting this obligation or that it could decline to maintain contemporaneous

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[165] *WUTC v. Puget Sound Energy, Inc.*, Docket No. UE-031725, Order 14 at 23 (May 13, 2004).

[166] *WUTC v. PacifiCorp, et al*, Dockets UE-050684, *et al*, Order 04 at 65 (Apr. 17, 2006).

documentation in determining the most appropriate option. Keeping in mind the interests of Washington ratepayers and the interests of Company shareholders, we find that while Pacific Power ratepayers would face some higher costs as the Company complied with the environmental regulations, Pacific Power placed ratepayers at risk of larger-than-appropriate expenses when declining its responsibility to pursue, and document its pursuit of, the least-cost option. Accordingly, we conclude that it is appropriate to authorize the Company to include in Washington rates only the return of, but not the return on, the Washington portion of its investment in the capitalized component of the SCR systems.

115 In balancing such interests during previous prudency determinations, the Commission has disallowed return on an asset when the Company failed to comprehensively demonstrate that its investment decisions, including the execution of contracts and continuously evaluating potentially lower cost options, were prudent.[167] At the federal level, FERC has on occasion disallowed the return on an asset when a company failed to demonstrate its investment was prudent.[168]

116 We find a similar situation here. Pacific Power has failed to meet its burden to demonstrate the prudence of its decision to install the SCR systems on Bridger Units 3 and 4. The SCR systems provided one option for the Company to fulfill its regional haze reduction compliance obligation, and it is reasonable to allow Pacific Power recovery of the SCR capital expenditures. We will not, however, reward the Company recovery in rates of that portion of return on the Company's regulated rate base associated with the SCR investment since Pacific Power did not demonstrate the prudence of this particular compliance option, nor did the Company provide documentation that would satisfy its responsibility to continually evaluate alternative compliance options prior to its execution of the FNTP in December 2013. We note that the SCR on Unit 3 became operational in December 2015, and that Unit 4 is scheduled to become operational by the end of 2016. Yet we caution that any potential future investments in Units 3 and 4 by the Company, for regulatory compliance or any other purpose, will be subject to the same prudence standard we described here based on the specific evidence before us. We authorize Pacific Power to recover the expenses for Unit 3 in the first year of the two-year rate plan and the expenses for Unit 4 in the second year. We do not authorize the Company to collect any return on either investment as a result of the above discussion.

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[167] *WUTC v. Puget Sound Energy, Inc.*, Docket No. UE-031725, Order 14 (May 13, 2004).

[168] *Connecticut Yankee Atomic Power Company*, 84 F.E.R.C. P63,009; 1998 FERC LEXIS 1705 (Aug. 31, 1998).

D. SCADA EMS and the Union Gap Substation

117 Pacific Power also planned to replace and upgrade its SCADA EMS by March 2016 and upgrade the Union Gap substation by May 2016.[169] SCADA EMS is a system of computer-aided tools used by operators of electric utility grids to monitor, control, and optimize the performance of the generation and transmission systems.[170] The Company states that SCADA EMS "is essential to operations and grid monitoring … [w]ithout [it], the Company would have no visibility into the real-time status of its electric system and no way to operate that system in response to system conditions."[171]

118 Pacific Power argues that the Union Gap project "will ultimately add a 230/115 kilovolt (kV) transformer and result in a rebuild of the substation."[172] This project consists of three phases of work, with the second phase contained within the Company's second year of its rate plan and encompassing the relocation of "the 230 kV bus and constructing it into a ring bus with six new 230 kV breakers to accommodate the addition of a 230/115 kV, 250 MVA transformer."[173] Pacific Power pledges to file an attestation with the Commission verifying the final costs of SCADA EMS, Union Gap, and the SCR on Bridger Unit 4 and that the investments are used and useful.[174] The Company proposed to provide this attestation in late 2016 or early 2017, well before the second year rate increase of its two-year rate plan.[175]

119 *Staff's Position.* Staff also analyzed the SCADA EMS data provided by the Company, performed an onsite visit of the SCADA EMS facilities, and reviewed Pacific Power's direct testimony.[176] Staff witness Ms. Elizabeth O'Connell testifies that the Company has demonstrated its need for this investment as the existing SCADA platform is obsolete.[177] Ms. O'Connell states that Pacific Power considered its options, and the Company's decision to invest in a more modern SCADA "reflects adequate long-term planning by

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169 Dalley, Exh. No. RBD-1T at 17:7-14.

170 Kelly, Exh. No. SJK-1T at 2:6-9.

171 *Id.* at 2:11-14.

172 Vail, Exh. No. RAV-1T at 2:3-4.

173 *Id.* at 2:20-3:4.

174 Dalley, Exh. No. RBD-1T at 17:18-18:1.

175 *Id.* at 17:18-20.

176 O'Connell, Exh. No. ECO-1T at 10:13-14.

177 *Id.* at 15:18-20.

preventing additional costs in the next five years."[178] Further, Ms. O'Connell asserts that the Company kept its management involved in the selection process and provided adequate documentation "demonstrating the reasonableness of the decision to invest in the SCADA EMS project."[179]

120 With regard to the Union Gap project, Staff notes that it consists of three phases, the second of which is at issue in this proceeding. Again, Staff witness, Ms. O'Connell reviewed the testimony of Pacific Power's witnesses and the Company's responses to data requests including "invoices and purchase orders for the Union Gap expenses."[180] Staff states that the Union Gap project is necessary to meet a North American Electric Reliability Corporation (NERC) standard requiring "bulk electric system elements including transmission transformers, to be within thermal limits following the single contingency loss of a transmission system element."[181] Further, Staff asserts that the Company considered several options for compliance with this NERC standard and "chose the option that was the most cost-effective and that maintained their levels of technical and safety requirements."[182] Staff states that Pacific Power provided information on the Union Gap project to top management in the initial investment appraisal document and subsequent documents, and Staff asserts that the Company provided it with "adequate records and supporting analysis demonstrating the reasonableness of the decision to invest in Union Gap."[183] Staff recommends that the Commission find that the decision to proceed with this phase of Union Gap and SCADA EMS was prudent.[184]

121 Staff notes that SCADA EMS will not be completed until April 26, 2016,[185] and the second phase of the Union Gap project will not be in service until May 2016.[186] Final costs for both projects were unknown at the time Staff filed its response testimony. As a result, Staff recommends that the Commission authorize the Company to include the SCADA EMS and Union Gap second phase expenses in the second year of the rate plan

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[178] O'Connell, Exh. No. ECO-1T at 16:21-17:2.

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

[180] *Id.* at 21:8-10.

[181] *Id.* at 21:20-22:5.

[182] *Id.* at 23:3-10.

[183] *Id.* at 24:4-10.

[184] *Id.* at 10:14-16.

[185] *Id.* at 19:9.

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

as a pro forma rate base addition subject to Pacific Power filing its attestation and the Commission conducting a final review of project costs thereafter.[187] Staff recommends that the Commission direct Pacific Power to file the attestation on a date certain, allowing a 60-day review period prior to the effective date of the second year of the rate plan.[188] Following its review of the attestation, Staff would provide its analysis to the Commission on the known expenses of SCADA EMS, Union Gap, and the SCR installation on Bridger Unit 4.[189]

122 *Commission Decision.* The Commission finds the Company's decision to proceed with the SCADA EMS and the second phase of the Union Gap substation to be prudent. It appears that Pacific Power carefully considered alternatives to both projects and provided contemporaneous documentation of its decision process. As the final expenses of SCADA EMS, the Union Gap project, and the SCR installation at Bridger Unit 4 are unknown, we direct Pacific Power to file the second year attestation of the final costs associated with these projects and supporting documents for actual booked expenditures and rate base amounts for the investments by July 1, 2017, 60 days prior to the start of the second year of Pacific Power's proposed two-year rate plan. Staff should review the final expenses and provide the Commission with its analysis prior to the start of the second year rates on September 15, 2017.

E. Decoupling

123 In its Final Order in the 2014 general rate case, the Commission invited Pacific Power to implement a decoupling mechanism similar to that adopted for PSE and Avista Utilities d/b/a Avista Corporation (Avista).[190] The Company has presented such a proposal in the instant proceeding. In many respects, Pacific Power has modelled its proposal after the Commission's Decoupling Policy Statement,[191] Commission-approved decoupling

[187] O'Connell, Exh. No. ECO-1T at 20:7-9 and 27:1-3.

[188] Ball, Exh. No. JLB-1T at 24:19-21.

[189] While Mr. Ball testifies that Staff will review the attestation during the 60 days and "provide a recommendation to the Commission on the prudence of the [SCADA EMS, Union Gap, and the SCR installation on Unit 4 of Bridger] Projects," we have evaluated and determined the prudence of these projects in this Order and view the attestation as a true-up of the actual costs prior to their inclusion in rates during the second rate year. *Id.* at 25:3-5.

[190] *WUTC v. PacifiCorp*, Docket UE-140762 et al., Order 08, ¶ 222 (Mar. 25, 2015).

[191] *See In the Matter of the Washington Utilities and Transportation Commission's Investigation into Energy Conservation Incentives*, Docket U-100522, Report and Policy Statement on Regulatory Mechanisms, Including Decoupling, to Encourage Utilities to Meet or Exceed their Conservation Targets (Nov. 4, 2010) (Decoupling Policy Statement).

mechanisms for Avista and PSE,[192] and guidance from the Commission's order rejecting Pacific Power's proposed decoupling mechanism in its 2005 general rate case.[193]

124 Like PSE's and Avista's approved mechanisms, Pacific Power's proposed decoupling mechanism compares actual annual non-weather adjusted revenues to allowed revenues and defers the difference for later true-up through a surcharge or credit to customers. Most major elements of the Company's proposed decoupling mechanism are uncontested and consistent with other Commission-approved decoupling mechanisms. A unique component of Pacific Power's proposal is to separately track and defer revenue differences by rate schedule for decoupled non-residential schedules (Schedules 24, 36, and 40). No party contests this design choice.

125 Two components of the proposed decoupling mechanism's design remain contested in this proceeding. First, the Company and Staff have each presented recommendations designed to balance revenue stability to the Company with rate stability for customers. Staff has proposed creating a mechanism to "trigger" a rate adjustment when the deferral balance in the balancing account reaches a certain threshold. Second, both Staff and the Company have presented separate recommendations for a cap on the annual rate increase due to decoupling. No other party contests these elements of the decoupling mechanism. We discuss each in turn.

1. Trigger mechanism for deferral

126 To limit the frequency of rate changes, Staff proposes that the decoupling mechanism include a threshold at which the deferral balance associated with each customer class would trigger a rate adjustment.[194] This component is not included in either PSE's or Avista's current decoupling mechanisms, which are subject to annual true-ups regardless of the amount in the balancing account. Staff proposes that rate adjustments to Schedule 93 be triggered for a decoupled rate class only if the amount in the balancing account exceeds approximately plus or minus 2.5 percent of allowed revenue at the end of the deferral period for the rate class.[195] Staff argues that the addition of this element is necessary to ensure customers do not experience significant changes in rates when the

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[192] *WUTC v. Avista Corporation*, Dockets UE-140188 and UG-140189 (consolidated), Order 05 (Nov. 25, 2014) and *WUTC v. Puget Sound Energy, Inc.* Dockets UE-130137 and UG-130138 (consolidated), Order 07 (June 25, 2013).

[193] *WUTC v. PacifiCorp*, Dockets UE-050684 and UE-050412, Order 04, ¶¶101-110 (Apr. 17, 2006).

[194] Ball, Exh. No. JLB-1T at 37:8-11

[195] *Id.* at 50:5-9.

deferral balance becomes too high or too low[196] and to avoid frequent and unnecessary rate revisions.[197]

127 On rebuttal, Pacific Power states that a trigger mechanism is "a helpful design feature" to improve rate stability and agrees to modify its proposed decoupling mechanism to include such a trigger.[198] However, instead of Staff's proposed trigger threshold of 2.5 percent, the Company proposes that the threshold be set at 0.5 percent, to ensure more certainty of its ability to recover fixed costs from customers.[199] The Company argues that Staff's proposed 2.5 percent trigger threshold will be too high for the mechanism to achieve its goal of providing the Company with better fixed cost recovery.[200]

128 *Commission Decision:* The purpose of a decoupling mechanism is to allow for more stable cost recovery over time, even as revenues fluctuate. As with all rate setting mechanisms, we must balance the interests of the ratepayers and the utility and its shareholders. We believe that 2.5 percent of allowed revenue per customer is a reasonable point to trigger a rate adjustment in contrast to the Company's proposal to trigger a rate adjustment at 0.5 percent of allowed revenue per customer because the latter does not provide sufficient rate stability for customers. We therefore adopt the Staff recommendation to use a threshold of 2.5 percent of allowed revenue per customer to trigger a rate adjustment for each decoupled rate class. We will monitor the implementation of Pacific Power's decoupling mechanism, which we recognize is a new rate design component for the Company, and will consider changes to the trigger threshold in the future, if necessary.

2. Rate Adjustment Cap

129 In its initial filing, Pacific Power proposed to limit the annual rate increase from decoupling adjustments to 3 percent,[201] with any amounts exceeding the annual cap

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196 Ball, Exh. No. JLB-1T at 49:14-18. If the balance in any specific deferral account exceeds the trigger value in either the surcharge or the credit direction on June 30 of each year, then the Company would include a proposed rate adjustment to Schedule 92 rates in its annual decoupling filing. However, if none of the deferral account balances exceed the trigger amount, there would be no change in decoupling rates. *Id.* at 51:9-15.

197 *Id.* at 51:3-4.

198 Steward, Exh. No. JRS-9T at 9:6-8.

199 *Id.* at 9:15-18.

200 *Id.* at 9:8-16.

201 Steward, Exh. No. JRS-1T at 18:7-11. Surcredits are not subject to an annual cap.

remaining in the balancing account for future recovery from customers.[202] While the Company's proposal is consistent with both PSE's and Avista's decoupling mechanisms, Staff argues that, if the deferral balance becomes too large, the rate adjustment cap could conflict with Staff's proposed trigger mechanism.[203] Staff therefore recommends increasing the Company's proposed rate cap of 3 percent to 5 percent for rate surcharges.[204] Staff supports the Company's proposal for no rate cap on surcredits.

130 On rebuttal, the Company argues that Staff's proposal would result in fewer, but larger, annual adjustments that would make it more challenging for the decoupling mechanism to achieve its goal of better fixed cost recovery.[205] To mitigate rate shock, Pacific Power recommends that the cap remain at 3 percent, as originally proposed.[206]

131 *Commission Decision:* As we continue to monitor the implementation of decoupling, we recognize that one size does not fit all. Setting the rate adjustment cap too low may result in a rolling and substantial deferral balance, which is inconsistent with the goals of decoupling. To mitigate against this possibility, we adopt the Staff recommendation to limit the annual rate increase from decoupling adjustments to 5 percent for each decoupled rate class. When combined with Staff's proposed trigger mechanism, we believe that Staff's proposal appropriately balances the goals of revenue stability to the Company with rate stability for customers.

3. Conditions of Decoupling

132 The Company agrees to several conditions as a result of decoupling:

a. Earnings Test

133 Prior to filing a decoupling rate adjustment, Pacific Power will apply an earnings test. The earnings test is based on the Company's return on equity (ROE), before temperature normalizing adjustments to actual results of operations and rate base.[207] Pacific Power's proposed earnings test, described below, is the same as the earnings test approved for both PSE and Avista:

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[202] Steward, Exh. No. JRS-1T at 18:7-11.

[203] Ball, Exh. No. JLB-1T at 52:3-6.

[204] *Id.* at 45:21-22.

[205] Steward, Exh. No. JRS-9T at 9:12-15.

[206] *Id.* at 9:16-19.

[207] McCoy, Exh. No. SEM-1T at 34:20-35:4.

134 If the actual ROE exceeds the most recently-authorized ROE:

- any proposed decoupling surcharge will be reduced or eliminated by up to 50 percent of the excess earnings, and
- any proposed decoupling surcredit will be returned to customers as well as 50 percent of the excess earnings.

135 If the actual ROE is less than the most recently authorized ROE, no adjustment is made to any decoupling surcharge or surcredit.

b. Reporting and Evaluation

136 The Company's proposal includes a commitment to file quarterly reports with the Commission and to evaluate the effectiveness of the mechanism at the end of the third year of the decoupling mechanism. Pacific Power agrees to examine the same issues that will be examined as part of a similar review of Avista's decoupling mechanism.[208] The Commission ordered that Avista's shareholders pay for a third-party evaluation that includes:

- an analysis of the mechanism's impact on conservation achievement,
- an analysis of the mechanism's impact on Company revenues (i.e., whether there has been a stabilizing effect),
- an analysis of the extent to which fixed costs are recovered in fixed charges for the customer classes excluded from the decoupling mechanisms, and
- an analysis of whether allowed revenues from the following rate classes are recovering their cost of service: residential class, non-residential class, and customers not subject to decoupling.[209]

137 NWEC recommends that Pacific Power's evaluation also include an examination of the Company's proposal to separately track and true-up deferrals by rate class.[210] The

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[208] Steward, Exh. No. JRS-1T at 18:18-19. *WUTC v. Avista Corp.*, Dockets UE-140188 & UG-140189, Order 05 at 13-14, ¶ 28 (Nov. 25, 2014).

[209] Avista is also required to consult with its conservation advisory group in the development of the evaluation's request for proposals (RFP), and incorporate the input from its advisory group in a draft RFP. It must file a draft RFP for Commission approval that includes the scope of evaluation query, allowing sufficient time for Commission consideration, and consult with its conservation advisory group on the selection of the entity to perform the evaluation. See *WUTC v. Avista Corp.*, Dockets UE-140188 & UG-140189, Order 05, ¶ 28 (Nov. 25, 2014).

[210] Cavanagh, Exh. No. RC-1T at 4:19-5:2.

Company does not contest this additional requirement. Staff agrees with the Company that five years is a reasonable time period for evaluating a decoupling mechanism, and that a review after three years is an appropriate time frame that allows the mechanism to operate before evaluating its effectiveness.[211]

c. Staff's Recommended Conditions

138 Staff recommends that the Commission approve Pacific Power's decoupling proposal, with several modifications. On rebuttal, the Company agreed to the following Staff conditions:

- *Incremental Conservation:* Both Staff and NWEC recommend that Pacific Power be required to achieve additional conservation beyond its current targets as a condition of decoupling.[212] The Company agrees to Staff's recommendation that its annual conservation target be increased by 2.5 percent for the current 2016-2017 biennium,[213] and 5 percent each biennium thereafter through the period when decoupling is in effect.[214] Staff recommended that the Company's failure to meet its incremental conservation target be subject to the same penalty that applies to conservation targets under RCW 19.285.030.[215] On rebuttal, the Company agrees to voluntarily submit to financial penalties for failing to meet this incremental conservation requirement.[216]

- *Reliability Metrics:* The Company agrees to participate in Staff's investigation of reliability metrics in Docket U-151958.[217]

- *Customer Guarantees for Service Quality:* Staff recommends that the Company's Customer Guarantees related to service quality be made permanent.[218] Rather than making the Customer Guarantee program permanent, the Company agrees to extend the program for the proposed five-year term of the decoupling

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[211] Ball, Exh. No. JLB-1T at 43:14-18

[212] Cavanagh, Exh. No. RC-1T at 5:13-15.

[213] *See* Steward, Exh. No. JRS-18.

[214] Steward, Exh. No. JRS-9T at 10:9-12.

[215] Ball, Exh. No. JLB-1T at 42:1-3.

[216] Steward, Exh. No. JRS-9T at 5:3-8.

[217] *Id.* at 7:3-5.

[218] Ball, Exh. No. JLB-1T at 56:15-17.

mechanism.[219] Pacific Power states that the Company has no plans to cancel its customer guarantee program, and acknowledges that discontinuing or altering the program would require Commission approval.[220]

139 *Commission Decision:* We approve Pacific Power's proposed decoupling mechanism, including the additional commitments agreed to by Pacific Power, subject to the Company's fulfillment of the conditions recommended by Staff:

- Incremental conservation: The Company's annual conservation target must be increased by 2.5 percent for the current 2016-2017 biennium, and 5 percent each biennium thereafter through the period when decoupling is in effect. Failure to meet this incremental conservation requirement shall be subject to the same financial penalties as apply under RCW 19.285.030.[221]
- Reliability Metrics: The Company must participate in Staff's investigation of reliability metrics in Docket U-151958.
- Customer Guarantees for Service Quality: The Company's Customer Guarantees related to service quality are extended through August 31, 2021, the five-year term of the decoupling mechanism.

Pacific Power proposes that the Commission approve its decoupling mechanism for a minimum of five years, beginning on July 1, 2016.[222] Consistent with the effective date of this order, we adjust the timeline for the effective period for the decoupling mechanism as follows:

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[219] Steward, Exh. No. JRS-9T at 7:8-11.

[220] Steward, Exh. No. JRS-9T at 7:14-16. Pacific Power's Customer Guarantees are established in Tariff WN-U75, Rule 25. This issue appears to be uncontested because the Company has agreed to preserve the Customer Guarantees for Service Quality as a condition of implementing decoupling. The tariff may not be changed without Commission approval.

[221] At the August 12, 2016, Recessed Open Meeting, the Commission discussed whether conservation achieved in excess of a biennial target pursuant to RWC 19.285.040(1)(c)(i) may be applied to a company's incremental conservation requirement for decoupling. We recommended that the companies continue to discuss this issue with their conservation advisory groups and present a proposal to the Commission at a later date. This issue was not discussed in the record of this proceeding, and we do not make a determination on this issue at this time.

[222] The Company's initial case was predicated on an effective date of May 1, 2016. This was modified at the prehearing conference and in rebuttal testimony.

Table 1: Timeline for Decoupling:

Year 1 (Sept. 15, 2016 – Sept. 14, 2017)	
Sept. 15	Effective date of filing. Start of first deferral period.
Oct. 31	CBR filed for results of operations July 1, 2015 – June 30, 2016
Sept. 14	End of first deferral period
Years 2-5 (Sept. 15, 2017 – Sept. 14, 2021)	
Sept. 15	Start of deferral period
Oct. 31	CBR filed
Dec. 1	Proposed rate adjustment to Schedule 93
Feb. 1	Effective date of Schedule 93 rate adjustment
Sept. 14	End of deferral period (12 months)*

*Pacific Power has committed to conducting an evaluation of its decoupling mechanism at the end of Year 3, ending on September 14, 2019.

F. Cost of Capital

140 As discussed in footnote 2 above, Pacific Power originally characterized this proceeding as an ERF that includes a two-year rate plan and a decoupling mechanism. The Company sought to portray this matter as a limited issue proceeding, where some elements of a traditional rate proceeding have been or should be excluded from consideration. Consistent with that perspective, the Company has not proposed changes to its capital structure or cost of capital (COC), contending it is unnecessary to re-litigate these issues at this time. In essence, the Company relies on the COC findings set forth in Final Order 08, in the preceding general rate case, in which the Commission left, undisturbed, the ROE and equity ratio of Pacific Power's capital structure because the Commission had recently heard and decided these issues, and they were the subject of an appeal by the Company.[223]

141 Nevertheless, anticipating perhaps that a change in COC may be raised by other parties in their responsive testimony, the Company proffers testimony and exhibits to support, if necessary, a higher ROE than the Commission authorized in the preceding general rate case. To facilitate expeditious review of this ERF and rate plan, however, the Company

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[223] *PacifiCorp v. Utils. & Transp. Comm'n,* __ Wn. App. __, 376 P.3d 389 (2016). Final Order 08, Docket Nos. UE-140762, UE-140617, UE-131384, UE-140094 (*Consolidated*), March 25, 2015. In Order 08, the Commission adopted a capital structure for Pacific Power of 49.10 percent equity, 50.69 percent long-term debt, 0.19 percent short-term debt, and 0.02 percent preferred stock. The Commission retained the authorized ROE of 9.5 percent which, when factored in with a 5.19 percent cost of long-term debt, 1.73 percent cost of short-term debt, and 6.75 cost of preferred stock, resulted in an overall authorized ROR of 7.30 percent.

makes clear that it is not formally requesting a change in its authorized ROE, capital structure, or overall rate of return (ROR).

142 As the Company predicted, Staff advocates a modest reduction to Pacific Power's ROE, from 9.5 to 9.25 percent, and updates to the Company's costs of short and long-term debt. The result is a recommended reduction of 11 basis points to the Company's authorized ROR from 7.3 to 7.19 percent.

143 The table below sets forth the differences between Pacific Power's currently authorized COC, at the levels and mix of COC elements the Company seeks to retain, relative to the cost of equity and debt modifications to the capital structure and ROR advocated by Staff.

Table 2

	Currently Authorized			Staff Proposed (Parcell)		
	Share	Cost	Weighted Cost	Share	Cost	Weighted Cost
Equity	49.10%	9.50%	4.66%	49.10%	9.25%	4.54%
LT Debt	50.69%	5.19%	2.63%	50.69%	5.21%	2.64%
ST Debt	0.19%	1.73%	-----	0.19%	2.15%	-----
Pf. Stock	0.02%	6.75%	0.01%	0.02%	6.75%	0.01%
ROR			7.30%			7.19%

1. Return on Equity

144 As in previous proceedings, the COC witnesses base their ROE recommendations on traditional or well-recognized financial models, coupled with observations on trends in capital market conditions.

145 Pacific Power relies on the testimony of Mr. Kurt G. Strunk, Vice President at National Economic Research Associates, Inc. Mr. Strunk utilizes several COC methodologies, including the Discounted Cash Flow (DCF) method, Capital Asset Pricing Model (CAPM), risk premium, and an examination of comparable earnings (CE) and allowed returns by other state commissions.[224] He begins his modeling efforts by using the same proxy group of companies that he analyzed in the most recent Pacific Power general rate case in Washington, contending it is a good starting point for the instant analysis because

[224] Strunk, Exh. No. KGS-1T at 8:8-13.

it was recognized to be a reasonable comparable group by the COC experts in that proceeding.[225] Mr. Strunk alters the proxy group by removing eight companies that have been involved, in varying degree, in recent merger and acquisition activity, while adding seven additional proxy companies that he deems to be comparable to Pacific Power for reasons discussed in the Company's rebuttal testimony in the preceding general rate case.

146 The resulting proxy group that Mr. Strunk relies on consists of the following companies: Ameren Corporation, American Electric Power Company, Inc., Avista Corporation, Centerpoint Energy Inc., Consolidated Edison, Inc., Dominion Resources, Inc., DTE Energy Company, Edison International, El Paso Electric Company, Eversource Energy, Great Plains Energy Incorporated, IDACORP, Inc., NorthWestern Corporation, OGE Energy Corp., Pinnacle West Capital Corporation, Portland General Electric Company, Public Service Enterprise Group Incorporated, SCANA Corporation, Sempra Energy, The Empire District Electric Company, Vectren Corporation, Westar Energy, Inc., and Xcel Energy Inc.[226]

147 Mr. Strunk then subjects the proxy group to the array of financial models he advocates should be considered too as a means to derive an appropriate ROE for the Company. As shown in Table 3 below, Mr. Strunk's analysis produces a variety of results that he asserts may then be used to develop the Company's ROE recommendation:

Table 3

Discounted Cash Flow (DCF):	
Proxy Group Single-Stage DCF	8.88%
Yield + Growth	10.40%
Risk Premium:	
Capital Asset Pricing Model (CAPM)	9.29%
Risk Premium	10.15%
Comparable Earnings (CE):	
CE (Dow Jones Utilities Index)	9.69%
CE (Dow Jones Industrial Average)	16.62%

148 Mr. Strunk's analysis produces a range of potential ROE results, ranging from 8.88 percent on the low end to 16.62 percent on the high end, a range of nearly 800 basis points. He argues that if the Commission were inclined to revise Pacific Power's ROE in

[225] Strunk, Exh. No. KGS-1T at 8:15-16.

[226] *Id.* at 9:13-10:2.

this proceeding, something the Company is not specifically advocating, his analysis suggests the currently authorized ROE should be raised to approximately 10.0 percent.[227]

149 He buttresses his precautionary support for raising the Company's ROE by pointing out that recent ROE awards by other state commissions over the first nine months of 2015 for electric utilities averaged 10.01 percent, a result that is nine basis points higher than the comparable figure for calendar year 2014.[228]

150 In contrast to Pacific Power's analysis, Staff offers the testimony of David C. Parcell, President and Senior Economist of Technical Associates, Inc., who recommends a reduction to Pacific Power's ROE to 9.25 percent based on his financial modeling results. Like Mr. Strunk for the Company, Mr. Parcell used several recognized financial methodologies to estimate the Company's ROE, each of which he applied to proxy groups of electric utilities. The first group is the same as Staff used in support of its ROE recommendation in the preceding Pacific Power general rate case, while the second proxy group is identical to that used by Mr. Strunk in his analysis in this proceeding.

151 As shown in Table 4 below, Mr. Parcell derives a range of results for three financial modeling methodologies he looks to as a basis for the development of his ROE recommendation:

Table 4

DCF	8.5 - 9.5% (9.00% mid-point)
CAPM	6.7%
CE	9.0 - 10.0% (9.50% mid-point) [229]

152 Mr. Parcell acknowledges the low-end CAPM result of 6.7 percent, suggesting that the prolonged period of low interest rates has, perhaps, tempered or unduly influenced investor long-term expectations; a condition he contends makes CAPM unreliable for contemporary purposes.

153 As a result, Mr. Parcell removes the CAPM result from consideration in the development of his ROE recommendation, concluding that Pacific Power's ROE should be within a

[227] Strunk, Exh. No. KGS-1T at 10:4-6.

[228] *Id.* at 19:17-19.

[229] Parcell, Exh. No. DCP-1T at 4:8-9.

range of 9.0 percent to 9.5 percent, which reflects the mid-point of the range of the results derived from the DCF and CE models.[230]

154 Mr. Parcell points out this proceeding includes consideration of a decoupling mechanism and two-year rate plan, which he believes may reduce risk or otherwise be beneficial to the Company from a financial standpoint. Despite a potentially positive effect on the Company, he does not recommend a discrete downward adjustment to Pacific Power's ROE to reflect the risk-reducing impacts of decoupling or a two-year rate plan.[231] However, because of the rate plan and decoupling mechanism, Mr. Parcell contends that the Company's ROE should be no higher than the mid-point of his derived ROE range, or 9.25 percent.[232]

155 In rebuttal, Pacific Power challenges specific elements of Mr. Parcell's analysis, supporting the Company's proposal to leave each component of its COC at currently authorized levels. Specifically, Mr. Strunk points out there have been no material trends or movement in capital markets that would warrant a reduction to Pacific Power's authorized ROE from the level established in the Company's previous general rate case.[233] He also implies that Mr. Parcell's ROE analysis is deficient because his lower ROE recommendation of 9.25 percent is not supported by Staff's apparent recommendation to maintain the Company's equity ratio at the hypothetical level of 49.1 percent: a level he notes is below the equity ratios of Mr. Parcell's selected proxy group of companies.[234] Finally, Mr. Strunk also updates the ROE analysis he presented in his direct testimony and maintains that the updated results continue to support an ROE of 10.0 percent, assuming the Commission is inclined to alter the Company's authorized ROE.

2. Capital Structure and Costs of Short and Long Term Debt

156 Pacific Power proposes no change to its currently authorized capital structure.[235] Staff defers to the Company's proposal.[236]

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[230] Parcell, Exh. No. DCP-1T at 34:17-19.

[231] *Id.* at 36:16-18.

[232] *Id.* at 37:1-2.

[233] Strunk, Exh, No. KGS-19T, at 7:7-13.

[234] *Id.* at 11:4-10.

[235] Dalley, Exh, No. RBD-1T, at 11:16-18.

[236] Parcell, Exh, No. DCP-1T, at 20:12-14.

157 Because Mr. Parcell proposes a reduction to Pacific Power's ROE based on his assessment of current financial market conditions, he makes a similar recommendation to adjust the Company's cost of short and long term debt based on updated Company information.[237] The resulting effect on ROR is negligible should we accede to Mr. Parcell's recommendation.

158 *Commission Decision*. We turn now to a closer examination of the relationship of the results from each method used by the witnesses as a means to further narrow the range for considering Pacific Power's ROE. In doing so, we recognize each witness' meticulous application of financial formulae to selected historical and projected financial information to derive data points for consideration and develop their overall ROE recommendation. We also recognize that such precision is overlaid or influenced by a degree of subjectivity applied by each witness to his analysis in arriving at his ultimate recommendations. Our decision is also guided by our respect for the principle of gradualism in setting an appropriate ROE for the Company, in order to avoid dramatic swings that may be disruptive to a regulated utility's ability to attract and retain capital.[238]

159 As in previous proceedings, we look to specific methods for determining an appropriate ROE for Pacific Power based on various analytical tools employed by the COC witnesses in developing their recommendations. Our decision is framed by a range of potential outcomes presented by Mr. Strunk and Mr. Parcell that reflect potential ROE data points.

160 Collectively, their analyses range from 16.62 percent on the high end, representing Mr. Strunk's CE result for the Dow Jones Industrial Average, to 8.5 percent on the low end, reflecting the low end of Mr. Parcell's DCF analysis (excluding by his own hand the 6.7 percent CAPM result he developed).

161 Just as Mr. Parcell removes the exceptionally low CAPM result on his own initiative, we believe a similar adjustment is warranted on the high end of the remaining range, by removing Mr. Strunk's CE result of 16.62 percent for the companies he used from the Dow Jones Industrial Average. We find that result to be well outside the acceptable

[237] Parcell, Exh, No. DCP-1T, at 21:7-14.

[238] We note here criticism in the record concerning a potential discrepancy between the actual results of Mr. Parcell's financial modeling analysis that is presented in his exhibits versus the related results summarized and reported on in his testimony. Although Mr. Strunk raised the issue in his rebuttal testimony, the apparent discrepancies were not answered or discussed at hearing. Mr. Strunk's contentions reappear in the Company's Brief. Although we do not rely materially on Mr. Strunk's critique of Mr. Parcell's transference of information from his exhibits into his testimony, we note that Mr. Strunk's concerns are not without merit.

bounds of reasonableness given the preponderance of results from other financial modeling methods both witnesses employed. In our view, the method also suffers because it relies on data related to the broader members of the Dow Jones Industrial Average, and is neither based on nor reflects results for proxy groups of utilities that are more directly comparable to Pacific Power. By removing that remarkably high result, the remaining range of acceptable ROE data points to be considered in determining the Company's ROE narrows to 8.5 to 10.40 percent based on the witnesses' results using the DCF and CE approaches.[239]

162 With respect to the DCF method, Mr. Strunk's two DCF variants produce results that range from 8.88 to 10.40 percent, with a 9.64 percent midpoint. In contrast, Mr. Parcell's DCF analysis produces a range of 8.5 to 9.5 percent, with a midpoint of 9.0 percent. Similarly, Mr. Strunk arrives at a 9.69 percent result for the remaining CE approach he utilized based on companies making up the Dow Jones Utilities Index while Mr. Parcell establishes a CE range of 9.0 to 10.0 percent, with a 9.5 percent midpoint.

163 Setting aside Mr. Strunk's critique of Mr. Parcell's presentation of his financial modeling results, we note that using the midpoints of each range and Mr. Strunk's remaining CE result, produces arithmetic mean and median results of 9.46 and 9.57, respectively; results that effectively and reasonably flank both sides of Pacific Power's currently authorized ROE of 9.5 percent. Accordingly, we maintain the Company's authorized ROE at 9.5 percent, which effectively maintains Pacific Power's ROR at 7.30 percent. [240]

G. End-of-Period/Average-of-Monthly-Averages

164 Pacific Power proposes to use EOP rate base balances rather than AMA[241] as a means of mitigating regulatory lag and breaking the cycle of continuous general rate cases (eight filings since 2005). The Company believes the EOP method[242] provides a better

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[239] The range has narrowed to 190 basis points with an effective midpoint of 9.45 percent; a data point not materially different from the Company's currently authorized ROE of 9.5 percent.

[240] We also decline Mr. Parcell's proposal to modify the Company's costs of short and long term debt given the negligible effect doing so would have on Pacific Power's ROR.

[241] The AMA method is an averaging concept producing a matching of the rate base investment with the revenues generated by the investment and the costs incurred in the process over a 12-month period related to the results of operations for the period. Robert L. Hahne & Gregory E. Aliff, Accounting for Public Utilities § 7.04[1] (2015).

[242] In contrast, the EOP approach uses the year-end rate base, capital costs, and annualized revenues and costs which has the effect of moving the test year forward by a full six

indication of plant balances and depreciation expense, making the two-year rate plan a viable option. Pacific Power points to recurring attrition based on its contention that the Company has been under-earning its authorized ROE by an average of more than 500 basis points and nine consecutive years of not earning its authorized ROR, despite aggressively managing costs.[243]

165 In support of its position, Pacific Power references the Commission's approval of EOP in PSE's expedited rate filing/rate plan/decoupling case, and Pacific Power's 2013 rate case as an appropriate response to mitigate regulatory lag.[244]

166 Staff supports the Company's use of EOP as a means of addressing regulatory lag and improving the opportunity for the Company to earn its authorized ROR. It contends that EOP is a suitable approach for the proposed two-year rate plan because it moves plant balances six months forward to align rate base with the rate-effective period for each year.[245]

167 Public Counsel recommends use of the AMA approach to better match capital investments to the associated revenues and operating expenses. Public Counsel argues the AMA approach is generally preferred over EOP to avoid distortion among rate base, revenue, and expenses in the revenue requirement for the rate-effective period.

168 The basis for Public Counsel's opposition to the EOP approach stems from the Commission's decision in Pacific Power's 2014 general rate case to reject the use of EOP. In that case, the Commission provided four conditions under which EOP may be an appropriate regulatory tool:

(a) Abnormal growth in plant,
(b) Inflation and/or attrition,
(c) Significant regulatory lag, or
(d) Failure of utility to earn its authorized ROR over an historical period.[246]

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months. Using the EOP method moderates the time gap problem of using the averages. *Id*., § 7.04[6] (2015).

[243] Dalley, Exh. No. RBD-1T at 8:20-9:1.

[244] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-130137 and UG-130138 (consolidated) *et al*., Order 07, ¶ 48; *WUTC v. Pacific Power & Light Company*, Docket UT-130043, Order 05, ¶ 184.

[245] Huang, Exh. No. JH-1T at 4:7-9.

[246] *WUTC v. Pacific Power & Light Company*, Docket UE-140762, Order 08, ¶ 145.

169 Public Counsel argues the Company has neither met its burden to demonstrate abnormal growth in capital expenditures nor provided any evidence of inflationary pressures during the recent period of exceptionally low inflation in the U.S. economy. It argues, too, that the Company has not affirmatively produced a formal study in this evidentiary record to demonstrate it is suffering from attrition. However, Public Counsel does not dispute the Company's claim of regulatory lag, or its historical failure to earn its ROR.

170 Boise does not support the use of EOP balances due to the Company's inconsistent use of EOP calculations for all adjustments of the revenue requirement. Boise views the use of EOP for existing plant rate base and AMA for accelerated depreciation as unfair to ratepayers. It argues this inconsistent treatment is a violation of the matching principle, and if EOP was applied consistently to each pro forma adjustment, the Company's Washington-allocated revenue requirement would decrease by $1.5 million.[247] Additionally, Boise argues that the Company is putting forth the same argument here as it did in its 2014 general rate case, in which the Commission rejected the use of EOP.[248] Boise recommends the Commission use AMA balances, which the Commission has repeatedly recognized as "a sound method of accounting, more so than EOP rate base."[249]

171 In rebuttal, Pacific Power responds:

> The use of [EOP] for the June 30, 2015 historical balances is a better indicator of rate base during the rate-effective periods by bringing the AMA rate base balances forward six month[s]. Pro forma rate base adjustments are then incorporated on an AMA basis to reflect the average rate base impact of these changes. The combination of these approaches provides a closer representation of the average rate base that will be in place during the rate-effective period. Thus, the Company's approach appropriately matches expected rate base with the revenues for the rate-effective period.[250]

172 *Commission Decision:* The Commission has traditionally required that utility rates be established relying on the measurement of rate base using the AMA approach. However, the Commission has recognized in some recent cases that the alternate approach of utilizing EOP rate base may be appropriate considering the evidence and circumstances at

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247 Mullins, Exh. No. BGM-1CT at 23:10-13.

248 *WUTC v. Pacific Power & Light Company*, Docket UE-140762 (consolidated), Order 08, ¶ 151.

249 Mullins, Exh. No. BGM-1CT at 20:21-21:2.

250 McCoy, Exh. No. SEM-6T at 25:9-16.

that time. In this case we agree with the Company, in part, to apply EOP methodology as a means to address the overall issues of regulatory lag. We agree with Staff that using EOP is appropriate in this case especially in the context of this two-year rate plan, as it more appropriately aligns rate base balances with the rate effective period in both year one and year two of the plan. We also reference the 2013 general rate cases of both Pacific Power and PSE in which we authorized the use of EOP based on the specific circumstances and data in those cases.[251]

173 We do not agree with Pacific Power's mixed methodology approach of applying EOP for historical balances and AMA to certain pro forma rate base adjustments, for the reasons discussed by Boise. Thus, we accept Pacific Power's proposal of EOP using the modification submitted per Bench Request No. 8,[252] which calculated all restating and pro forma adjustments on an EOP basis and reduces the Company's rebuttal revenue requirement by $572,256.

174 The Company's request to use EOP methodology is directly tied to its proposed two-year rate plan and the intention to break the cycle of continuous rate cases. In recent years where the Commission has approved a multi-year rate plan, it has been part of a negotiated settlement among the parties that necessarily included a moratorium on further rate case requests for a given period of time. Not only does this case not involve a settlement, there has been no enforceable commitment from the Company to forestall its next general rate case filing during the pendency of the two-year rate plan, absent the Commission's approval of its full rate request.

175 When a utility proposes and we approve a multi-year rate plan, we do so with the understanding that the Company intends to honor a stay-out or moratorium on rate case requests for the duration of the rate plan. While no such commitment has been made by the Company, we expect that any rate request made prior to the expiration of the second year of the rate plan, at the very least, will not include a relitigation of previously litigated expenditures.

H. Labor Expenses

176 The Company proposes a pro forma adjustment to annualize the effect of salary increases that occurred during the test year.[253] Public Counsel and Boise propose three adjustments

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[251] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-130137 and UG-130138 (consolidated) *et al.*, Order 07, ¶ 48; *WUTC v. Pacific Power & Light Company*, Docket UT-130043, Order 05, ¶ 184.

[252] Pacific Power's Response to Bench Request No. 8 (May 20, 2016).

[253] McCoy, Exh. No. SEM-1T at 17:13-15.

to Pacific Power's expenses, including: (1) an update to the number of employees included in rates; (2) the use of the most recent actuarial report to set pension and OPEB expenses; and (3) a small adjustment to salary overhead.

1. Salary expenses and employee levels

177 The Company proposes a pro forma adjustment to annualize the effect of salary increases that occurred during the test year.[254] The Company states that it is "relying on test-year FTE employees and wages."[255] Intervenors do not contest the Company's proposal, but propose to adjust the number of FTE employees used to calculate the EOP salary level.

178 In its initial filing, Pacific Power proposes to include in rates the average number of FTEs in the test year.[256] Public Counsel and Boise propose to use the FTE count in December 2015, six months after the test year, as a known and measurable change that should be reflected in rates.[257]

179 Public Counsel provides data supporting a decline in the FTEs. From the start to the end of the test year, the FTE count fell by 48.5 employees.[258] From the end of the test year to December 2015, the employee count dropped by an additional 103.5 FTEs.[259] In December 2015, the actual number of employees was 180 FTEs lower than the June 2014 level reflected in rates from the last Pacific Power rate case.[260] Public Counsel used the December 2015 employee count, resulting in a reduction to revenue requirement of $687,000.

180 In Pacific Power's most recent rate case, the Commission ordered a pro forma adjustment to the Company's employee count, as proposed by Public Counsel, because the "record demonstrates that the reductions in workforce reflect a continuing trend over several

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[254] McCoy, Exh. No. SEM-1T at 17:13-15.

[255] Hymas, Exh. No. KCH-1T at 4:19-20.

[256] *Id.* at 3:17-18.

[257] Ramas, Exh. No. DMR-1T at 35:20-36:2; Mullins, Exh. No. BGM-10T at 3:16-18.

[258] Ramas, Exh. No. DMR-1T at 35:17-20.

[259] *Id.*

[260] *Id.* at 1-3.

years."[261] Boise supports Public Counsel's adjustment in this proceeding because employee levels continue to decrease dramatically.[262]

181 On rebuttal, Pacific Power objects to using an employee count from beyond the test year without also adjusting salaries to post-test-year levels.[263] Pacific Power proposes including the employee count from March 2016, and consistent with Commission rulings in prior general rate cases, salary increases through June 2016.[264] To support the known and measurable nature of its proposal, the Company notes that the June 2016 salary increases "have already been implemented, with the exception of negotiated and ratified union contracts."[265]

182 *Commission Decision:* In recent cases, we have used known and measurable salary increases up to one year after the test year, and an up-to-date employee count, to set Pacific Power's rates. On rebuttal, the Company presented an adjustment that closely adheres to our past practice.

183 We accept Pacific Power's proposal to use its March 2016 FTE count and known and measurable salary increases through June 2016. This adjustment results in a combined revenue requirement decrease of approximately $237,000.

2. Pension and Other Post-Employment Benefits

184 The Company's initial filing used test year pension costs totaling $24.7 million and Other Post-Employment Benefits (OPEB) totaling ($4.0 million), on a total Company basis.[266]

185 Public Counsel proposes to reduce the test year pension expenses to $21.9 million, and OPEB to ($8.2 million) on a total Company basis, based on the most recent actuarial

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[261] *WUTC v. Pacific Power & Light Co.*, Docket UE-140762 (*Consolidated*) Order 08, ¶ 42 (March 25, 2015).

[262] Mullins, Exh. No. BGM-10T at 3:16-18.

[263] Hymas, Exh. No. KCH-1T at 4:17-5:9.

[264] In Pacific Power's 2010, 2011, 2013, and 2014 GRCs, the Commission accepted known and measurable salary increases up to one year after the test year. *WUTC v. Pacific Power & Light Co.*, Docket UE-140762 (*Consolidated*) Order 08, ¶¶ 42-46 (March 25, 2015) (citing Ramas, Exh. No. DMR-1CT at 35:18-36:18). Ms. Hymas' proposal on rebuttal also includes salary increases up to one year after the test year.

[265] Hymas, Exh. No. KCH-1T, n 5.

[266] Ramas, Exh. No. DMR-1T at 39:6-7; *Id*. at 41:1-2; Hymas, Exh. No. KCH-1T at 5:12-15. Numbers in parentheses indicate a negative number.

report for the 2016 plan year.[267] Public Counsel's adjustments reduce the Company's Washington-jurisdictional pension revenue requirement by about $78,000, and OPEB revenue requirement by about $178,000.[268]

186 Boise asserts that it is appropriate for the Commission to make the adjustment proposed by Public Counsel because:

> the Company has proposed to include many other pro forma adjustments in this case meant to increase revenue requirement, without taking into consideration those, such as pension and OPEB expense [sic] that might result in a reduction to revenue requirement.[269]

187 On rebuttal, the Company rejects these adjustments, pointing out that the amounts reflect unaltered test year expenses. Pacific Power asserts that this case was "intended as a limited and expedited filing and, for that reason . . . updates to non-wage labor costs should not be made."[270] The Company goes on to note that:

> if the Commission were to consider the non-wage labor costs that have increased, as well as, decreased since the end of the test year—such as medical and 401(k) costs—the parties' pension and PBOP [sic] adjustments would be largely offset.[271]

188 *Commission Decision:* In recent cases, the Commission has used the most up-to-date pension and OPEB costs available to set Pacific Power's rates. The Commission adopted an adjustment similar to the one proposed here by Public Counsel in Pacific Power's 2014 general rate case.[272] Pacific Power responds that the use of test year expenses are more appropriate in this case because other non-wage labor costs have increased since the end of the test year. Pacific Power does not quantify the increases it alleges, so we are unable to determine if those increases are material. Public Counsel does quantify the change to pension and OPEB costs, and they are material. In this case, Pacific Power

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[267] Ramas, Exh. No. DMR-1T at 38:13-21; *Id.* at 40:16-20.

[268] *Id.* at 37:1-40:11.

[269] Mullins, Exh. No. BGM-1T at 31:12-17.

[270] Hymas, Exh. No. KCH-1T at 6:17-7:2.

[271] *Id.* at 6:17-7:2. Ms. Hymas does not quantify post-test year impact of medical and 401(k) costs.

[272] *WUTC v. Pacific Power & Light Co.*, Docket UE-140762 (*Consolidated*) Order 08, ¶ 46 (March 25, 2015).

bears the burden to justify its requested rate increase, and the Company has not provided any evidence to support its position on rebuttal. Thus, we continue our past practice and accept the adjustment proposed by Public Counsel to base these costs on the most recent actuarial report available in the record for the 2016 plan year, which reduces the Company's Washington-jurisdictional pension revenue requirement by about $78,000, and OPEB revenue requirement by approximately $178,000.

3. Salary Overhead

189 Pacific Power's test year expenses include $1.743 million, on a company-wide basis, for "Other Salary Overheads/Oncosts," a category that includes charges from outside vendors that provide services in the labor cost area.[273] Public Counsel proposes the use of the average of 2014 and 2015 expense levels for salary overhead. Supporting its position, Public Counsel argues that the test year expenses are not reflective of a normal annual cost level, are higher than expenses included in the last rate case, and are higher than the expense incurred in calendar years 2014 and 2015.[274] The Washington revenue requirement impact of Public Counsel's proposal to use average salary overhead is a reduction of about $18,000.[275] In cross-answering testimony, Boise supports Public Counsel's adjustment.[276]

190 On rebuttal, the Company rejects this adjustment for three reasons. First, the higher costs were due to the Company's recurring requirement to mail descriptions of benefit plans to employees and retirees.[277] Second, the Company "expects higher salary overhead costs in 2016 and 2017 as additional requirements of the federal Affordable Care Act take effect."[278] Finally, the Company notes that Public Counsel's position on salary overhead is inconsistent with its position that the FTE count should not be based on an historical average.[279]

191 *Commission Decision:* This Commission strongly prefers to use test year expenses when setting rates; however, in some instances when costs vary significantly across years, we have used a multi-year average approach to set rates, as proposed by Public Counsel. The

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[273] Ramas, Exh. No. DMR-1T at 41:13-42:13.

[274] *Id.*

[275] *Id*.

[276] Mullins, Exh. No. BGM-10T at 3:13-21.

[277] Hymas, Exh. No. KCH-1T at 7:15-22.

[278] *Id.* at 7:3-22.

[279] *Id.*

record in this case does not show that the variation observed by Public Counsel is likely to continue, that it constitutes a significant outlier as to be non-representative, or that it is materially significant. With only three years of data, we are unable to conclude that using of a multi-year average is more appropriate than using test year costs. We also do not find Public Counsel's proposed adjustment to be material. Thus, we reject Public Counsel's adjustment and use test year costs for "Other Salary Overheads/Oncosts."

I. West Control Area Allocations

1. General Office Expense

192 Boise recommends applying the System Overhead (SO) factor to general office expense that the Company has assigned to the generation-related FERC Account 557.[280] Boise claims the general office expenses are not generation-related and should therefore be allocated using the SO factor.[281]

193 Pacific Power responds that the expenses are in fact generation-related expenses "such as administration and engineering that cannot be assigned to specific resources."[282] The Company also argues that Boise's proposal is based on a section of the West Control Area Inter-Jurisdictional Cost Allocation Methodology (WCA Methodology) Manual used for the allocation of costs in a different FERC account, and that the Commission has rejected similar one-off changes to the WCA methodology in previous cases.[283]

194 *Commission Decision.* Boise raises, but does not sufficiently substantiate, a claim that Pacific Power has mistakenly assigned general office expenses not related to generation to the FERC account for generation-related expenses. We accept the Company's statements that the expenses are related to generation and reject Boise's proposal.

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[280] Mullins, Exh. No. BGM-1CT at 32:6-10. (Section IV of the WCA Manual "clearly states 'general office – SO,' when describing the allocation factor used for general office expenses."). *Id.* at 32:12-16

[281] *Id.* at 32:17-33:4. Mr. Mullins identifies amounts included in FERC Account 557 that "were booked in SAP under as a general office expense, under location "1," "GENERAL OFFICE AND ALL OTHER."

[282] McCoy, Exh. No. SEM-6T at 22:7-9.

[283] *Id.* at 22:12-22 ("The section of the manual that Boise refers to, however, is not describing the allocation of costs in FERC Account 557. That section of the manual is describing FERC Account[s] 920 through 935.")

2. Boise Transmission Costs

195 Boise proposes to modify the way that certain transmission operation and maintenance (transmission O&M) expenses are allocated. Pacific Power disagrees with this proposal, which it describes as a change to the WCA Methodology.

196 Currently, when allocating transmission O&M expenses, Pacific Power first determines if the expense is directly related to assets in the east or west control area as it will assign expenses directly-related to a control area's assets to that control area. Expenses that are not directly assignable to a control area are allocated using a company-wide rolled-in System Generation (SG) factor.[284] Pacific Power justifies using the SG factor to allocate transmission O&M expense by stating that it is following the WCA Methodology.[285]

197 Boise proposes allocating transmission O&M expense using the Wheeling Revenue Generation (WRG) factor that is based on the proportion of transmission plant in each balancing area.[286] It states that 28 percent of Pacific Power's transmission assets are in the western balancing area and 78 percent are in the eastern balancing area.[287]

198 Boise argues that the Company uses the WRG factor to allocate firm transmission wheeling revenues between the east and west balancing areas, even though transmission revenues cannot be clearly allocated to a specific balancing area.[288] It proposes that the transmission O&M expenditures that cannot be clearly allocated to a specific balancing area should also be assigned using the WRG factor that the Company uses for wheeling revenues. Boise points to the smaller transmission plant in the western balancing area and asserts there should be less transmission O&M expense being incurred, and therefore costs allocated by the WRG factor that are proportionate to the amount of transmission in each balancing area is a more appropriate result than that achieved using the SG factor.[289]

199 According to Boise, the Company relies heavily on transmission service from the Bonneville Power Administration (BPA) in its western balancing area, and less on

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[284] Pacific Power develops a SG factor for each state based on that relationship between the state's respective demand and energy and the Company's entire system.

[285] Mullins, Exh. No. BGM-5C at 27 (Pacific Power's Response to Boise Data Request 0093) (Feb. 22, 2016).

[286] Mullins, Exh. No. BGM-1CT at 29:15-17; 27:12-28:3.

[287] *Id.* at 28:11-12. Mr. Mullins' percentages from his table 4 add up to 106 percent.

[288] *Id.* at 2.

[289] *Id.* at 30:4-6.

Company-owned transmission. Under the WCA methodology, BPA transmission costs are entirely allocated to the western balancing area rather than on a rolled-in basis.[290] Boise asserts that Washington ratepayers are effectively overpaying for transmission O&M expense if they are required to pay the full cost of BPA's transmission rates in addition to a fully rolled-in share of Pacific Power's owned facilities using the SG factor approach.[291]

200 On rebuttal, the Company states that there is no basis in the WCA methodology for allocating the transmission costs Boise identifies with the WRG factor used to allocate wheeling revenues.[292] The Company also argues the Commission has repeatedly indicated that it will not make selective modifications to the WCA such as those proposed by Boise.[293]

201 *Commission Decision.* The party advocating a modification to a previously-approved methodology has the burden to show that the WCA cost allocation should be revised. While Boise has proposed a modification of one aspect of the WCA methodology, it has done so without the context of an overall review of the WCA methodology. As we have in previous proceedings, we find that the WCA methodology offers a reasonable allocation of expenses and for the Commission to "endorse any unilateral change, or any change that is disputed, the party advocating the change must make a detailed and persuasive showing demonstrating that the proposed change is appropriate."[294]

3. Staff Remediation Exclusion

202 Pacific Power proposes a restating adjustment to account for non-major environmental remediation costs on a company-wide basis.[295] Staff proposed limiting the Company's non-major environmental remediation adjustment to those projects located in Washington State,[296] as it views as unreasonable the Company's suggestion that Washington ratepayers bear the financial burden of environmental remediation costs for facilities and

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[290] Mullins, Exh. No. BGM-1CT at 28:13-29:2.

[291] *Id.* at 29:1-7.

[292] McCoy, Exh. No. SEM-6T at 23:18-19.

[293] *Id.* at 23:20-21.

[294] *Wash. Util. & Trans. Comm'n v. PacifiCorp*, Docket UE-130043, Order 05, ¶ 94 (Dec. 4, 2013).

[295] McCoy, Exh. No. SEM-1T at 24:18-25:5.

[296] *Id.* at 15:4-5 and O'Connell, Exh. No. ECO-1T at 32:10-11.

properties in jurisdictions that do not contribute to electric service in Washington.[297] Staff argues the Company's proposed adjustment is at odds with the used and useful principle as interpreted by the Commission and the WCA methodology.[298]

203 Staff points out the Commission approved recovery of non-major environmental remediation costs in Docket UE-031658 with the requirement that Pacific Power allocate the remediation costs according to the WCA methodology. [299]

204 Pacific Power responds that Staff applies a company-wide overhead allocation factor to its Washington situs environmental costs, resulting in an allocation of only 6.65 percent of those amounts to Washington customers.[300] As the Company states:

> When the correct WCA factors are applied to west control area environmental remediation costs, the allocation to Washington customers increases by approximately $137,000 compared to the Company's filing.[301]

205 *Commission Decision.* Non-major environmental remediation costs are allocated on a WCA methodology that includes plant outside of Washington State but that nonetheless serves load in Washington State. Staff proposes modifying this allocation by including only non-major environmental remediation costs incurred for plant in Washington. Staff provides no rationale for excluding remediation costs for plant outside of Washington that are used and useful for serving Pacific Power's Washington State load. Having failed to make a detailed and persuasive showing demonstrating that the proposed change is appropriate, we reject Staff's proposed limitation.[302]

J. Idaho Power Transmission Asset Exchange

206 The Company proposes rate base additions to reflect transmission assets that, it argues, serve Washington load as a result of the Idaho Power Transmission Asset Exchange (Idaho Exchange). The Bridger plant entered service in 1974, and transmission of its

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[297] O'Connell, Exh. No. ECO-1T at 33:5-7.

[298] *Id.* at 33:14-16.

[299] *Id.* at 33:9-16 (citing *Wash. Utils. & Transp. Comm'n v. Pacific Power*, Docket UE-031658, Order 01, ¶ 19 (Apr. 27, 2005)).

[300] McCoy, Exh. No. SEM-6T at 16:1-3.

[301] *Id.* at 16:8-10.

[302] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-130043, Order 05, ¶ 92 (Dec. 4, 2013).

output into Idaho Power's and Pacific Power's service territories was established through various agreements and tariffs, which are referred to as the "legacy agreements." In September 2015, the Commission approved the Idaho Exchange, which converted the legacy agreements to a transmission agreement that conforms to the utilities' Open Access Transmission Tariffs (OATT).[303]

207 As a result of the Idaho Exchange, Pacific Power traded like-kind transmission facilities of nearly equal net book value with Idaho Power.[304] The legacy agreements provided Pacific Power 1,600 megawatts (MW) of total transmission capacity, including 200 MW of dynamic transfer capability.[305] The Idaho Exchange increases Pacific Power's dynamic transfer capability to 400 MW.[306] The Idaho Exchange also provides increased reliability and flexibility. Due to the Idaho Exchange, Pacific Power also undertook a review of the inter-jurisdictional cost allocation of its transmission assets and identified additional assets, beyond those received in the Idaho Exchange, that it now proposes to incorporate into Washington rates.[307]

208 *Staff's Position.* Staff groups the Company's proposed transmission rate base additions into three categories: Exchange Assets, Reassignment Assets, and WCA Correction Assets. Staff contests inclusion of the first two categories of assets in rates, but accepts the third. It defines Exchange Assets as those transmission properties that Pacific Power acquired as part of the Idaho Exchange.[308] Staff classifies Reassignment Assets as those transmission facilities related to the Goshen transmission line that Pacific Power acquired a one-third ownership right in as a result of the Idaho Exchange.[309] The Goshen transmission line runs from Bridger to the Goshen substation in Idaho.[310] Prior to and subsequent to the Idaho Exchange, the Company owned transmission-related assets

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[303] *In re Petition for an Order Authorizing the Exchange of Certain Transmission Assets with Idaho Power Company,* Docket UE-144136, Order 1 (Sept. 24, 2015).

[304] McCoy, Exh. No. SEM-1T at 10:5-13.

[305] The additional dynamic transfer capability allowed under the Idaho Exchange would allow Pacific Power to change a portion of its scheduled flow on the path between its balancing authorities more or less continuously enabling the dynamic transfer portion of its transmission rights to be used for EIM transfers on the five-minute interval instead of just the 15 minute interval.

[306] McCoy, Exh. No. SEM-1T, n 10.

[307] *Id.* at 11:10.

[308] Ball, Exh. No. JLB-1T at 61:2-5.

[309] *Id.* at 65:3-66:6.

[310] *Id.* at 65:11-66:6.

associated with the Goshen transmission line.[311] The Company asserts that the assets it is reassigning to the WCA support the flow of power from Jim Bridger on this newly acquired line.[312]

209 WCA Correction Assets are characterized by Staff as transmission assets that were not previously assigned to the WCA but were owned by the Company prior to the Idaho Exchange and connected to Pacific Power's transmission lines that move power from Bridger to Pacific Power's west balancing area.[313] Staff states that the Company "mistakenly neglected to account for these assets in previous WCA cost allocations."[314] Staff is not opposing inclusion of the costs of the WCA Correction Assets in rates.[315]

210 Staff opposes the inclusion of the Exchange Assets and the Reassignment Assets in rates on the principles of cost causation and the matching of benefits and burdens.[316] Specifically, Staff opposes the inclusion of the cost of these assets without the corresponding benefit of a lower power cost baseline.[317] Notably, the Company did not propose, and Staff does not support, revising Pacific Power's power cost baseline in this proceeding.[318]

211 In support of its position, Staff quotes the Commission order approving the Idaho Exchange:

> As Staff noted, the potential for a minor rate increase is balanced by the potential benefits, such as improved operational efficiency, increased reliability, and reduced wheeling expenses. Furthermore, the Commission's practices ensure that

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[311] Ball, Exh. No. JLB-1T at 65:11-6:6.

[312] McCoy, Exh. No. SEM-1T at 10:14-21.

[313] Ball, Exh. No. JLB-1T at 61:11-16.

[314] *Id.*

[315] *Id.* For a list of WCA Correction assets, see Ball, Exh. No. JLB-1T at 64:1.

[316] *Id.* at 70:11:15.

[317] *Id.* at 71:4-11.

[318] *Id.* at 71:7-11; 71:19-20.

> any cost increases arising from this transaction will only be passed on to ratepayers if the Company can identify commensurate benefits.[319]

212 Staff acknowledges several benefits from the Idaho Exchange. The first benefit is an increase in 200 MW of the dynamic transfer capability between the east and west balancing areas, which Staff asserts would lower the Company's power cost baseline.[320] Second, Staff acknowledges that the Idaho Exchange simplifies administration of the transmission operating agreements.[321] Staff asserts that the benefits of the Company's use of the additional dynamic transfer in the EIM market are not included in the PCAM's power cost baseline.[322] Third, Staff recognizes the benefits of reliability that the Company claims, but states that the benefits would take the form of reduced market purchases and wheeling costs.[323] Keeping with its principle of matching benefits and burdens, Staff states that without reflecting in rates the lower power cost baseline that would result from these benefits, removal of the Reassignment Assets and Exchange Assets from Pacific Power's proposed revenue requirement is proper.[324] Staff asserts that the Company pursued the Idaho Exchange to serve load in its eastern balancing area, not in Washington state or even the WCA.[325]

213 *Pacific Power's Rebuttal.* The Company asserts that the reliability and flexibility provided by the Idaho Exchange does provide benefits that are commensurate with its costs.[326] Pacific Power argues that one of the biggest benefits of the Idaho Exchange "is the additional [dynamic] capacity that can be provided to support the Energy Imbalance Market (EIM)."[327] The Company asserts that the benefits associated with participation in

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[319] Ball, Exh. No. JLB-1T at 69:19-70:5 (citing *In Re Petition of Pacific Power & Light Company, For an Order Approving the Exchange of Certain Transmission Assets with Idaho Power Company*, Idaho PUC Docket UE-144136, Order 01, ¶ 9 (Sept. 24, 2015)).

[320] Ball, Exh. No. JLB-1T at 71:7-72:24.

[321] *Id.* at 71:7-11.

[322] *Id.* at 71:21-72:3.

[323] *Id.* at 71:13-20.

[324] *Id.* at 74:10-14.

[325] *Id.* at 73:4-5 (*citing* Pacific Power response to Staff Data Request 105).

[326] Vail, Exh. No. RAV-3T at 2:18-3:3.

[327] *Id.* at 6:12-13.

the EIM are provided to Washington customers as part of the Company's recently-approved PCAM.[328]

214 Pacific Power states that serving load in Goshen was one of the main drivers behind the Idaho Exchange, but was not the only driver.[329] The Company describes the benefits as follows:

- Prior to the Idaho Exchange, transmission from Bridger to the west balancing area was subservient to Idaho Power's use of its transmission system for its own load obligations, potentially resulting in curtailments of the delivery of Bridger power to Washington customers when Idaho Power could not meet its load.[330]
- Prior to the Idaho Exchange, loss of service at the Hurricane or La Grande substations interrupted delivery of power from Bridger, requiring Pacific Power to purchase additional transmission service or make more expensive market purchases.[331]
- Prior to the Idaho Exchange, only a portion of the total transmission capacity could be used to move power other than Bridger's output; after the Idaho Exchange, Pacific Power uses its capacity rights to move any resource's power to serve Washington load.[332]
- Under the new OATT, Pacific Power can redirect firm transmission service to other points of delivery that allow the power to flow on Pacific Power's system to the west balancing area, or assign differing levels of deliveries between two substations.[333]

215 Staff asserts that the Company's proposed adjustment increases rates, even though at the time of the approval of the Idaho Exchange the Company stated the transaction would be revenue neutral. Pacific Power responds that the estimates provided at the time of the request for approval of the Idaho Exchange were based on preliminary analysis of the transaction.[334] The Company asserts that subsequent to the transaction, it conducted a detailed analysis to reflect verified plant balances in rates according to the associated

[328] Vail, Exh. No. RAV-3T at 6:15-17.

[329] *Id.* at 7:6.

[330] *Id.* at 4:4-7; 5:17-19.

[331] *Id.* at 4:7-12.

[332] *Id.* at 5:11-12.

[333] *Id.* at 6:5-9.

[334] McCoy, Exh. No. SEM-6T at 19:4-6.

allocation factors, resulting in an increased Washington-allocated rate base under the WCA methodology.[335]

216 *Commission Decision.* While we did approve the Idaho Exchange in Docket UE-144136, there was no determination on rate treatment. With regard to the Exchange and Reassignment Assets, we agree with Staff that the reliability benefits are achieved through fewer or lower cost power purchases and reduced purchases of short-term transmission service that the Company is not proposing to reflect in the power cost baseline. The Company has not calculated the quantifiable benefits of the exchange or provided for their inclusion in the power cost baseline, nor is it proposing to reflect power costs savings resulting from the additional 200 MW of dynamic transfer capability. As with the EIM costs dispute raised by Boise and discussed below, the Company did not file to reset power costs, including the power cost baseline, which is necessary to provide the benefits to ratepayers in balance with the burdens the Company is requesting they carry. In keeping with the Commission's long-standing principle of benefits following burden we reject inclusion of the exchange assets and reassignment assets in rates and the associated adjustment.[336] Should Pacific Power propose to include the benefits of these assets in the power cost baseline of its PCAM, we will consider inclusion of the costs associated with these assets at that time.

217 As for the WCA Correction Assets, we accept the inclusion in rates of the uncontested assets but do so with some concern. The Company "mistakenly neglected" to include these assets in previous rate filings going back for some period of time. The Commission expects utility's rate filings to be accurate representations of its costs to provide electric service, no more and no less. Achievement of such expectations is the necessary first step in assuring a utility timely and sufficient rates. We encourage the Company to strive for more accuracy and transparency in its rate filings.

K. Power Costs – EIM

218 Boise proposes an adjustment to remove expenses related to the Company's participation in the EIM from general rates and, instead, allow them to be collected through the actual variable power costs included in the annual PCAM filing.[337] It argues that including EIM costs in general rates, without reflecting EIM benefits through an update of the power

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[335] McCoy, Exh. No. SEM-6T at 19:6-17.

[336] The revenue requirement in the compliance filing may vary from the dollar amount of the revenue requirement as stated in this order as the compliance filing reflects the removal of the cost of these groups of assets.

[337] Pacific Power filed its PCAM true-up on June 1, 2016, in Docket UE-160783.

cost baseline, violates the matching principle.[338] As an alternative to excluding the EIM costs, Boise recommends a $2.2 million reduction in the Company's power cost baseline.[339] Pacific Power and Staff do not support updating power costs in this proceeding.[340]

219 To support the proposed adjustment, Boise identifies approximately $16.2 million in EIM-related capital additions to rate base and approximately $1.8 million in annual EIM-related O&M expense, on a Company-wide basis.[341] It cites studies showing that these EIM-related expenses result in $26.2 million in benefits to Pacific Power's power costs for year 2015.[342] Boise then uses the WCA methodology's SG factor to estimate that power cost savings on a Washington basis are $2.2 million lower.[343]

220 Boise agrees with the Company that "[EIM] benefits will flow through the Company's net power costs (NPC), and will be reflected in the annual power cost adjustment mechanism (PCAM) filings."[344] Boise argues that to be fair, EIM costs should be excluded from the rates set in this proceeding if power costs are not updated. Boise asserts that the Company can recover its EIM costs through the annual PCAM, as actual power costs will be reduced due to the benefits of the EIM.[345]

221 On rebuttal, the Company agrees with Boise's primary proposal with certain modifications. Pacific Power removes the EIM costs identified by Boise from general rates, plus certain depreciation and amortization expenses associated with EIM,[346] conceding that recovery can be addressed through the PCAM's annual true-up. However, the total effect of the Company's approach to removing EIM costs is a reduction to Pacific Power's revenue requirement that exceeds Boise's proposal.

222 *Commission Decision.* When fixed costs that reduce variable power costs are included in general rates, the PCAM's baseline power costs must be reset to reflect the benefits in order for ratepayers to realize the net benefits of the fixed costs they are being asked to

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[338] Mullins, Exh. No. BGM-1T at 34:5-7.

[339] *Id.* at 35:3-4.

[340] Dalley, Exh. No. RBD-1T at 11:16-18. Ball, Exh. No. JLB-1T at 12:4-19.

[341] Mullins, Exh. No. BGM-1CT at 35:7-12.

[342] *Id.* at 34:12-35:1.

[343] *Id.* at 35:3-4.

[344] *Id.* at 34:7-11. Exh. No. BGM-5C at 10 (the Company's Response to Boise Data Request 014).

[345] Mullins, Exh. No. BGM-1CT at 33:17-34:2.

[346] McCoy, Exh. No. SEM-6T at 7:8-12.

pay for. Doing so matches the benefits with the burden. The Commission approves, with the following modifications, Pacific Power's final proposal to remove EIM costs from non-power cost rates and include them instead in the actual power costs of its annual PCAM true-up filing.

223 In this proceeding, Pacific Power chose not to file for a change in power costs and therefore precluded a change to the baseline power cost in the PCAM. Without a means for matching benefits with the burden of the EIM costs, recovery of EIM costs in non-power cost rates is limited.

224 In approving Pacific Power's proposal, we are allowing Pacific Power to include fixed costs related to the EIM in the actual power costs in its annual PCAM filing, but we do not approve their inclusion indefinitely. Pacific Power, in its next general rate case, must remove the EIM fixed costs from the PCAM's annual true-up and propose their recovery in non-power cost rates. The Commission will determine at that time if the costs are commensurate with the benefits.

L. Rate Spread/Rate Design

225 In this filing, Pacific Power did not present a new Cost of Service Study (COSS) and has not proposed changes to rate spread for most classes.[347] The Company proposes to apply its requested increase on an equal percentage basis to each rate schedule in the first and second years of the rate plan.[348] According to the Company, this treatment is appropriate because the 2014 general rate case[349] brought all classes to within 10 percent of their cost of service, a reasonable range of parity.[350]

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[347] Steward, Exh. No. JRS-1T at 2:19-20. Changes to Schedule 48T – Large General Service are discussed later in this section.

[348] *Id.* at 2:20-21.

[349] In that proceeding, Pacific Power presented a COSS for the 12 months ending December 31, 2013. *WUTC v. PacifiCorp,* Docket UE-140762, Steward, Exh. No. JRS-13T. In our final order in Docket UE-140762, we accepted the Company's proposal to move each customer class closer to parity with its cost of service, while emphasizing principles of fairness, perceptions of equity, economic conditions in the service territory, gradualism, and rate stability. *WUTC v. PacifiCorp,* Docket UE-140762, Order 08, ¶ 202 (Mar. 25, 2015).

[350] A parity ratio of one means that the customer class is paying the approximate amount needed to cover its share of costs. A COSS uses precise math to follow elaborate cost assignments. Commission practice considers the error or range of accuracy to be +/-0.05. In other words, COSS results within the range 0.95 to 1.05 are considered within the precision of the COSS. A parity ratio of 0.90 means that the utility is collecting 90 percent of the revenue needed to cover

1. Staff's proposal for a collaborative to address rate spread, rate design, and cost of service issues

226 Staff does not support a rate increase in the first year and does not believe that rate spread issues can be fully resolved under the expedited timeline for this case.[351] It contests the Company's proposed rate spread and rate design in the second year of the rate plan, absent Pacific Power's participation in a collaborative to address cost of service, rate spread, and rate design issues.[352] Staff recommends the collaborative include an evaluation of a third volumetric block for residential rates.

227 Staff states that parity remains a concern for the Company's rate spread.[353] It would agree with the Company's rate spread proposal for rates effective in the first year of the rate plan, if the Company participates in a collaborative process to resolve cost of service and rate spread issues over the next several months.[354] Staff envisions that a collaborative process to address parity ratios could be concluded in time to incorporate the results into the second year's rates.[355]

228 On rebuttal, Pacific Power agrees to participate in Staff's proposed collaborative and, "if consensus is reached," to implement changes in the second year of the rate plan. If

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the cost of serving that customer class, or put another way, that customer class is not paying its full share of costs. A parity ratio of 1.10 means that the utility is collecting 110 percent of the revenues needed to serve that customer class, or put another way, that customer class is paying more than needed to cover its share of costs.

[351] Van Meter, Exh. No. TMV-1T at 7:1-5

[352] *Id.* at 8:11-9:2. Ms. Van Meter further states: "[W]e believe the best approach to solving [cost of service] and rate spread issues is through a collaborative process over the next several months, rather than attempting to make significant changes within the accelerated timeline of this case. Therefore we are not contesting the Company's proposed rate spread for the present case." *Id.*, at 7:1-5.

[353] *Id.* at 6:27-28. In Pacific Power's 2014 general rate case, Staff offered a rate spread proposal designed to bring each schedule to within 5 percent of parity with its cost of service. In the instant case, Staff recommends that the collaborative also include an evaluation of the effects of a third block in residential rates, and formulation of a rate spread to assure fair cost recovery from non-decoupled customers.

[354] *Id.* at 7:1-5.

[355] *Id.* at 8:11-17. Staff recommends that the collaborative have a similar objective as the collaborative and subsequent settlement adopted by the Commission for PSE's general rate case, Docket UE-130617.

consensus is not reached before second-year rates go into effect, the Company proposes to address cost of service and rate design issues in its next general rate case.[356]

229 *Commission Decision:* The timeline for this proceeding did not allow for a full examination of cost of service and rate spread issues. However, the parties and the Commission gave a significant amount of attention to these issues in Pacific Power's last general rate case, and rate parity has improved since that time. We therefore believe it is reasonable for the Company to apply the approved first-year increase on an equal percentage basis to each rate schedule. The Company has agreed to participate in a collaborative with Staff to address cost of service, rate spread, and rate design issues. We expect the stakeholders to initiate that process in time to complete it prior to the second year of the rate plan. If consensus is reached before second-year rates go into effect, the stakeholders should make a filing for the Commission's consideration. If consensus is not reached, the Company should apply the approved second-year increase on an equal percentage basis to each schedule and address cost of service and rate design issues in its next general rate filing.

230 In the 2014 general rate case, the Commission approved the use of the Peak & Average (P&A) methodology, but ordered the Company to return to using the Peak Credit method or provide a more detailed justification for using an alternative approach in its next general rate case.[357] Pacific Power continues to use the P&A method, without presenting a new COSS. Thus, the collaborative should examine the issues surrounding the classification and allocation of costs from the prior general rate case which remain unresolved.

2. Rate Design – schedules excluded from decoupling mechanism

231 Pacific Power does not propose changes to rate design for schedules included in the decoupling mechanism. For residential rates, the Company proposes to maintain the current basic charge of $7.75 and apply all of the allocated increase to energy charges. The Company's proposed residential rate design proposal is not contested. Pacific Power

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[356] Steward, Exh. No. JRS-9T at 20:6-11.

[357] *WUTC v. PacifiCorp*, Docket UE-140762, Order 08, ¶ 191 (March 25, 2015). In that case, Public Counsel supported the use of the P&A methodology but objected to the Company's use of the single highest hour of system peak (1-CP). Public Counsel recommended that Pacific Power use the estimate from the update of the 2013 IRP, or alternatively, 4-CP, 6-CP, or 8-CP. Boise did not support the use of any type of the Peak Credit method and instead proposed that Pacific Power classify all of the "fixed" generation costs as demand-related, and all of the "variable" generation costs as energy-related.

proposes changes to rate design for some non-residential schedules excluded from the decoupling mechanism. Only the changes to Schedule 48T are contested.

232 *Schedule 48T.* Pacific Power proposes to apply a higher increase to demand charges and a smaller increase to the basic charge, load size and energy charges, to better align Schedules 48T and 48T-Dedicated Facilities (48T-DF) with their cost of service.[358] For Primary and Secondary voltage customers on Schedule 48T (Large General Service using 1,000 kilowatts), the Company proposes to apply the class average increase to all charges. The Company is proposing to apply a higher percentage increase to the demand charges for Schedule 48T-DF, to better reflect that customer's cost of service.[359]

233 Boise contests Pacific Power's rate design proposal, proposing instead to apply a uniform methodology to Schedules 48T and 48T-DF, increasing basic charges by 25 percent, and applying the remainder of the increase to demand charges. Boise argues that:

- Assigning more costs to the fixed billing determinants provides greater certainty of fixed cost recovery and is more consistent with Pacific Power's move toward decoupling.[360]
- Pacific Power's proposal unfairly singles out a specific transmission voltage customer.[361]
- Boise's proposal will result in a higher rate increase for customers with a low load factor compared to those with a high load factor. [362]

234 On rebuttal, the Company clarifies that Schedule 48T-DF rates are currently set slightly below its cost of service, while other Schedule 48T rates are set slightly above their cost of service.[363] Compared to Schedule 48T, Pacific Power finds that Boise's Schedule 48T-DF rates are under-collecting fixed costs through the demand and customer charges.[364]

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[358] Steward, Exh. No. JRS-1T at 12:15-21, 13:1-7.

[359] *Id.* at 3:1-4.

[360] Mullins, Exh. No. BGM-1T at 42:9-17.

[361] *Id.* at 43:13-16.

[362] *Id.* at 44:3-6.

[363] Steward, Exh. No. JRS-1T at 5, Table 1 – parity ratios.

[364] *Id.* at 12, Table 2. Pacific Power's rate design proposal for Dedicated Facilities will recover 102 percent of demand/customer-related costs through the demand charge, compared to the current 92 percent.

235 Pacific Power accepts Boise's rate design proposal for Schedule 48T-DF but contests Boise's proposal to apply the same rate design treatment to other Schedule 48T customers. The Company states that applying the same rate design to Schedules 48T and 48T-DF ignores the unique cost characteristics for the single 48T-DF customer, unfairly distributes the revenue increase across the class, and is inconsistent with past treatment.[365]

236 *Commission Decision:* Given the timeline for this proceeding, and our decision to approve a cost of service, rate spread, and rate design collaborative, we do not believe it is necessary or appropriate for us to order changes to rate design for Schedule 48T and Schedule 48T-DF at this time. The issue warrants further discussion. Therefore, we reject Boise's proposal to increase the basic charge by 25 percent and apply the rest of the increase to demand charges. We also reject Pacific Power's proposal to apply a higher percentage increase to the demand charges for Schedule 48T-DF. Instead, the Company should apply the class average increase to all charges on both Schedules 48T and 48T-DF. We encourage the parties to explore in the collaborative options for making these schedules' rate designs more consistent with the goals of decoupling.

M. Memberships and Subscriptions

237 In its response case, Staff recommended that the cost of Pacific Power's payments to the Yakima County Development Association, the Utah Taxpayers Association, and the Wyoming Taxpayers Association be removed from the test year because they are not associated with the Company's core business of providing electric service.[366] On rebuttal, Pacific Power supports the inclusion in rates of $12,000 associated with payments to the Yakima County Development Association.[367] Boise supports Staff's argument that these items should be removed.[368]

238 At hearing, the Company acquiesced to Staff's recommended removal of the expenses associated with the taxpayer associations.[369] Staff also proposes that the Commission

[365] Steward, Exh. No. JRS-9T at 16:10-14, 18:1-4.

[366] Van Meter, Exh. TMV-1T at 5:6-14.

[367] McCoy, Exh. SEM-6T at 12:15-13:6.

[368] Mullins, Exh. BGM-10T at 3:6-11.

[369] McCoy, TR 293:17-18. See also, Rackner, TR 295:20-22. On rebuttal, Pacific Power agrees to remove costs associated with the Utah Taxpayers Association and Wyoming Taxpayers Association memberships.

send a message to Pacific Power that recovery of taxpayer lobbying membership expenses is inappropriate for this proceeding, as well as any future rate case.[370]

239 With regard to its Yakima County Development Association membership, Pacific Power states that the purpose of its membership is to "[strengthen] relationships with key community and business leaders and building sustainable communities through enhanced economic development, environmental and educational opportunities."[371] The Company argues that it is appropriate to include these costs in rates because working with state and regional economic development agencies indirectly assists prospective customers with relocation, which has the potential to "enhance electrical system asset utilization and reduce overall costs."[372] At hearing, Pacific Power witness, Shelley McCoy, reiterated that its challenge grant, in the amount of $4,500, and pledge, in the amount of $7,500, to the Yakima County Development Association indirectly helped Pacific Power provide prompt, expeditious, and efficient electric service to its customers.[373]

240 *Commission Decision.* We agree with Staff's position that Pacific Power's payments for memberships and subscriptions, including payments to the Yakima County Development Association, do not appear to be associated with its core business of providing electric service. While such organizations may provide indirect benefits to customers, Pacific Power has failed to quantify these benefits, or demonstrate that they exceed the associated costs.[374] These costs are not appropriate for inclusion in rates. Absent an evidentiary demonstration that such groups provide a direct benefit to customers, we do not expect to revisit this issue with Pacific Power in future rate proceedings.

N. Low-Income Bill Assistance and Weatherization

241 In 2012, the Commission approved an all-party settlement that included a five-year plan (Plan) to increase funding for Pacific Power's Low-Income Bill Assistance (LIBA) program gradually over time.[375] The parties to that settlement agreed that the Plan

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[370] Cameron-Rulkowski, TR 296:10-15.

[371] McCoy, Exh. SEM-6T at 12:17-24.

[372] *Id.* at 13:1-3.

[373] McCoy, TR 299:23-300:2.

[374] At hearing, Company witness Ms. Shelley McCoy was unable to speak to whether the benefits of Pacific Power's payments to the Yakima County Development Association exceed the costs. McCoy, TR 309:11-17.

[375] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-111190, Order 07, ¶ 17 (Mar. 30, 2012).

resolved all issues related to the five-year term. In the instant proceeding, Pacific Power has proposed to increase LIBA funding through Schedule 91 by twice the residential rate increases on July 1, 2016, and July 1, 2017, of the two-year rate plan consistent with the five-year LIBA Plan.[376] The Company also proposes to convene a stakeholder group to discuss LIBA program changes to be effective beginning with the 2017-18 winter heating season.[377]

242 Intervenors propose several conditions to Pacific Power's proposed rate plan and decoupling mechanism to address the needs of low-income customers. Collectively, the intervenors recommend that the Commission require Pacific Power to:

- commit at least $50,000 in shareholder funding toward conservation projects for low-income customers;[378]
- hire a professional facilitator for a low-income collaborative to address LIBA, as well as its low-income weatherization program; [379]
- finance a comprehensive study of its low-income customer population to obtain data necessary to address the questions raised concerning low-income customers in its last general rate case;[380] and
- increase funding for its LIBA program proportionately with any annual increases in residential bills as a result of decoupling surcharges.

243 *Low-income Conservation:* In the Decoupling Policy Statement in Docket U-100522, the Commission addressed the need for a commitment to low-income conservation as one of the criteria necessary for approval of a full decoupling mechanism:

> A utility proposing a full decoupling mechanism must demonstrate whether or not its conservation programs provide benefits to low-income ratepayers that are roughly comparable to other ratepayers and, if not, it must provide low-income ratepayers targeted programs aimed at achieving a level of conservation

[376] Steward, Exh. No. JRS-1T at 8:24-26. Based on the Company's proposed revenue requirement on rebuttal, this results in a 5.4-percent increase in Year 1, and a 6.0-percent increase in Year 2 of the rate plan. Steward, Exh. No. JRS-10.

[377] Steward, Exh. No. JRS-1T at 9:2-4.

[378] Ball, Exh. No. JLB-1T at 42:23-24.

[379] Collins, Exh. No. SMC-1T at 8:21-22.

[380] *Id.* at 10:15-22.

> comparable to that achieved by other ratepayers, so long as such programs are feasible within cost-effectiveness standards.[381]

244 As a condition of approving decoupling, Staff recommends that the Company be required to commit at least $50,000 in shareholder funding to its low-income conservation program.[382] It argues this proposal is consistent with a condition of the Commission's approval of PSE's decoupling mechanism.[383] The Energy Project supports Staff's position.[384] On rebuttal, Pacific Power states that it currently reimburses up to 100 percent of measure costs for low-income conservation. The Company believes that additional funding is not necessary at this time because its expenditures for low-income conservation do not yet exceed the program's annual budget cap of $1 million.[385]

245 *Commission Decision*. While we can encourage shareholder contribution towards low-income conservation, we do not have the authority to require such charitable acts. Mr. Ball's citation to our Order in PSE's Decoupling case fails to appreciate our statement in footnote 245 in which the Commission explained:

> We cannot order PSE's investors to follow through on their offer in the Multiparty Settlement to provide an additional $100,000 per year for energy efficiency funding. Additional funding at this level, or more, remains an option for PSE to consider as a gesture of goodwill, not just to the low-income customers, but to the ongoing energy efficiency goals of the State of Washington.[386]

246 As part of a multi-party settlement in that proceeding, PSE offered to contribute $100,000 from its shareholders per year for low-income energy efficiency funding.[387] The

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[381] Decoupling Policy Statement, Docket U-100522, ¶ 28

[382] Ball, Exh. No. JLB-1T at 42:23-24.

[383] *Id.* at 48:19-21. PSE 2013 Decoupling Order, Order 07, ¶ 182. Staff also notes that low-income weatherization represents a smaller proportion of Pacific Power's overall residential conservation budget that Avista was achieving at the time it requested a decoupling mechanism.

[384] Collins, Exh. SMC-3T, at 4:21-5:8.

[385] Steward, Exh. No. JRS-9T at 2:12-17.

[386] *In re Petition of Puget Sound Energy, Inc. and Northwest Energy Coalition for an Order Authorizing PSE to Implement Electric and Natural Gas Decoupling Mechanisms and to Record Accounting Entries Associated with the Mechanisms,* Docket UE-121697, *et al,* Order 07, n 245 (June 25, 2013).

[387] *Id*., ¶ 178 (citing PSE Brief, ¶ 83).

Commission rejected the terms and conditions of that multi-party settlement as a matter of law.[388] Instead, recognizing that low-income customers would be disproportionately impacted by the rate plan and decoupling mechanism we approved for PSE, we conditioned that approval on “an additional amount of $1.0 million per year [funding for] for PSE’s low income bill assistance program.”[389] However, these additional monies did not come from PSE investors.

247 In rejecting Staff’s recommendation to require Pacific Power shareholders to contribute $50,000 toward conservation projects for low-income customers, we note that Staff and other stakeholders may pursue this issue with the Company in the collaboratives discussed in more detail below.

248 *Low-income collaborative:* In its initial filing, Pacific Power commits to convene a stakeholder group to discuss LIBA program changes for the 2017-18 program season. This coincides with the end of the five-year plan.[390] The Energy Project supports the convening of a collaborative, but proposes two conditions:

- The Commission should adopt a deadline of Jan. 31, 2017, for the submission of a comprehensive funding and modification plan for LIBA, as well as, Pacific Power’s low-income weatherization program.[391] Pacific Power supports convening a stakeholder process to discuss its low-income weatherization program, but recommends that it be conducted separately from the LIBA collaborative because different staff members are involved.[392]
- The Company should be required to hire a professional facilitator for the collaborative.[393]

249 We support the convening of a stakeholder process for both LIBA and low-income conservation. We believe that the Company should have the flexibility to staff and

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[388] *Id.*, ¶ 179 (citing *In the Matter of the Petition of Puget Sound Energy, Inc., for Approval of a Power Purchase Agreement for Acquisition of Coal Transition Power, as Defined in RCW 80.80.010, and the Recovery of Related Acquisition* Costs, Docket UE-121373, Order 07 (June 25, 2013)).

[389] *Id.*, ¶ 182.

[390] Steward, Exh. No. JRS-1T at 9:2-4.

[391] Collins, Exh. No. SMC-1T at 8:12-19.

[392] Steward, Exh. No. JRS-9T at 12:24:13:6.

[393] Collins, Exh. No. SMC-1T at 8:21-22.

schedule these collaborative discussions as its resources permit. However, we are concerned that a deadline of January 31, 2017, would not allow enough time for the stakeholders to develop a consensus proposal. It is reasonable to give the stakeholders until April 2017, the end of the 2016-17 program year, to develop a funding proposal for the following year.

250 Pacific Power argues that the extra cost to hire a facilitator is not warranted because previous efforts with this group of stakeholders have achieved positive results without a facilitator.[394] In response to Bench Request No. 10, the Energy Project and Pacific Power agreed that a professional facilitator is not necessary.[395]

251 *Low-income study:* In rejecting a proposal for a third block in Pacific Power's residential rate design in its 2014 general rate case, the Commission ordered:

> We expect the Company and others to continue developing data and undertaking analyses of low-income customer usage patterns in Pacific Power's service territory. These can inform thoughtful consideration in testimony in the Company's next general rate case concerning the price signals a third block rate design will likely have on such customers.[396]

252 In the instant proceeding, the Energy Project argues that Pacific Power has not made a significant effort to obtain the type of data needed to conduct this analysis. The Energy Project recommends that the Commission order Pacific Power to "finance and fully cooperate" in a study of its eligible, low-income customer population, to procure the data necessary to satisfy the Commission's order in its last general rate case.[397]

253 Pacific Power argues that a study is not necessary because information regarding the number of low-income households in its service territory is publicly available. The Company agrees to discuss the potential impacts to low-income customers of a third energy block rate design in the Cost of Service Study and Rate Design collaborative.[398] In response to Bench Request No. 10, the Energy Project and Pacific Power stated that the

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[394] Steward, Exh. No. JRS-9T at 13:9-14. Ms. Steward points toward the dispute resolution process outlined in Dockets A-950243 and A-940351.

[395] The Energy Project and Pacific Power responses to Bench Request No. 10, at 2.

[396] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-140762, Order 08, ¶ 219 (Mar. 25, 2015).

[397] Collins, Exh. No. SMC-1T at 10:15-22.

[398] Steward, Exh. No. JRS-9T at 13:19-21.

Company has committed to working with interested stakeholders to evaluate data availability as part of the collaborative process.[399]

254 *LIBA:* As a condition of approving a decoupling mechanism, NWEC recommends that Pacific Power be required to increase LIBA rate credits proportionately with any annual increases in residential bills as a result of decoupling surcharges.[400] The Energy Project supports this proposal on cross-answering.[401] On rebuttal, Pacific Power contests this proposal. The Company argues that LIBA funding should not be tied to changes in its decoupling schedule because such adjustments are not part of base revenues and can be subject to frequent upward and downward adjustment.[402] We agree with Pacific Power that it would not be appropriate to tie LIBA funding to changes in its decoupling schedule. The Company should take other measures to mitigate the impact of decoupling on low-income customers.

255 *Commission Decisions:* We approve Pacific Power's decoupling mechanism and two-year rate plan, as modified in this order, subject to the following modifications concerning low-income customers:

1. Pacific Power must initiate a stakeholder collaborative to discuss LIBA program changes for the 2017-18 program season. In addition to Staff and the Energy Project, the Company should invite Public Counsel, Boise, and NWEC to participate. The collaborative must conduct an analysis of publicly available data to assess the need for low-income bill assistance in Pacific Power's service territory, and make a recommendation to the Commission for how to obtain data that is not publicly available.
2. The LIBA collaborative should develop a mutually agreed-upon funding plan and modifications for LIBA, to be filed with the Commission by April 1, 2017. If the stakeholders do not agree upon modifications or funding for LIBA by that time, the current funding plan shall remain in place for the 2017-18 program season, and Pacific Power should present a multi-year funding plan for LIBA in its next general rate case.
3. Pacific Power must also initiate a stakeholder collaborative to discuss changes to its low-income weatherization program. This collaborative may be conducted in concert with the LIBA collaborative; or separately, as resources permit. In addition to Staff and the Energy Project, the Company should invite Public

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[399] The Energy Project and Pacific Power responses to Bench Request No. 10, at 2.

[400] Cavanagh, Exh. No. RC-1T at 3:1-5, *Id.* at 9:12-15.

[401] Collins, Exh. No. SMC-3T at 7:8-12.

[402] Steward, Exh. No. JRS-9T at 10:16-19. Ms. Steward further notes that LIBA funding is not tied to other adjustment schedules that are not part of base revenue.

Counsel, Boise, and NWEC to participate. Any mutually agreed-upon modifications or additions should be filed with the Commission by April 1, 2017.

4. Pacific Power must include an analysis of the potential impacts to low-income customers of a third energy block rate design in the Cost of Service Study and Rate Design collaborative. In addition to Staff, the Company should invite Public Counsel, Boise, the Energy Project, and NWEC to participate.

O. Hydro Deferral

256 Boise proposes including the approximately $132,000 credit balance in the hydro deferral account in the Company's revenue requirement for this proceeding.[403]

257 On rebuttal, Pacific Power agrees with providing the hydro deferral balance as a credit to customers, but objects to building the credit into base rates.[404] The Company describes the deferral balance as a small, residual over-collection from the deferral approved in Docket UE-080220 and states that it should not be treated as an on-going credit in rates.[405] Pacific Power estimates that if the credit were included in base rates for the duration of the rate plan, it would result in a credit to customers of nearly two times the existing balance.[406] As an alternative, Pacific Power proposes returning the balance through Schedule 96—Renewable Energy Revenues as a more appropriate way to credit a one-time item.[407]

258 *Commission decision*. The Commission accepts Pacific Power's proposal for a one-time credit to return the hydro deferral credit balance to customers. The Commission authorizes the hydro deferral balance to be transferred to the Schedule 96 account and a one-time credit to be issued under that schedule.

P. Schedule 300 – Non-Radio Frequency Meter Charge

259 In Pacific Power's most recent rate proceeding, we granted the Company's request to collect fees from its customers who chose to opt out of receiving a Non-Radio Frequency Meter. We expressed some concern over the amount of the fee Pacific Power proposed and directed the Company to include additional justification of the opt-out fee in its next rate case. Specifically, we stated:

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[403] Mullins, Exh. No. BGM-1CT at 36:6-18.

[404] McCoy, Exh No. SEM-6T at 24:15-18.

[405] *Id.* at 24:8-10.

[406] *Id.* at 24:10-12.

[407] *Id.* at 24:15-18.

> Although it is a close call, we will accept, for purposes of this case, the proposed new fee for a Non-Radio Frequency Meter Charge. We allow the fees principally because they are linked to a new service that some customers may wish to have available. Ms. Coughlin's testimony, however, falls short of demonstrating to our full satisfaction that the proposed fees are reasonable. It appears from her testimony that Company personnel will not perform this work efficiently. In addition, the proposed fee does not compare favorably with significantly lower fees for the same service in other jurisdictions. *The bases for these fees warrant further investigation and we expect to see a more fully developed record in the Company's next general rate case. We also expect our Staff to investigate fully the bases and support for this charge.*[408]

260 Despite our order, neither Pacific Power nor Staff provided any discussion of or evidentiary support for the Non-Radio Frequency Meter Charge in this proceeding. We intend to open a proceeding in the coming year to examine the costs and policies surrounding the imposition of the Non-Radio Frequency Meter Charge, and will decide in that proceeding whether continuation or amendment of the tariff is justified.

FINDINGS OF FACT

261 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 therefore, the Commission now makes and enters the following summary of those facts, incorporating by reference pertinent portions of the preceding detailed findings:

262 (1) The Washington Utilities and Transportation Commission is an agency of the State of Washington, vested by statute with authority to regulate rates, rules, regulations, practices, and accounts of public service companies, including electrical companies.

263 (2) Pacific Power is a "public service company" and an "electrical company," as these terms are defined in RCW 80.04.010 and as these terms otherwise are used in Title 80 RCW. Pacific Power is engaged in Washington State in the business of supplying utility services and commodities to the public for compensation.

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[408] *Wash. Utils. & Transp. Comm'n v. PacifiCorp, et al,* Docket UE-140762, *et al,* Order 08, ¶ 239 (Mar. 25, 2015). (Emphasis added).

264 (3) Pacific Power's current rates do not yield sufficient compensation for the electric services it provides in Washington.

265 (4) Pacific Power requires relief with respect to the rates it charges for electric service provided in Washington State so that it can recover its electric service revenue deficiencies.

266 (5) The Commission finds that there are increasing legal, economic, and policy considerations limiting the long-term viability of coal-fired generation plants. The current depreciable lives for the Jim Bridger generating plant (Bridger) and Unit 4 of the Colstrip generating plant (Colstrip) are possibly overstated and not consistent with these general policy and economic trends.

267 (6) Washington ratepayers risk rate shock and intergenerational inequities, as well as exposure to decommissioning and remediation costs, should the Bridger and Colstrip plants close earlier than predicted in the current depreciation schedules.

268 (7) Pacific Power has not pledged to close either plant by a date certain, nor did it present a depreciation study with its accelerated depreciation request.

269 (8) The Commission finds the Company's accelerated depreciation request is in the public interest, but the Company must take certain actions to ensure accelerated depreciation continues to be appropriate.

270 (9) With regard to the issue of recovery of costs for the selective catalytic reduction (SCR) systems for Bridger Units 3 and 4, Pacific Power faced compliance obligations pursuant to the federal Clean Air Act's Regional Haze Rule and the Wyoming State Implementation Plan for Bridger. The Company's three options included: installation of the SCR systems, converting the plant to natural gas fuel, or closure.

271 (10) Pacific Power conducted a thorough analysis of the options using its system optimizer (SO) model prior to entering into an engineering, procurement, and construction services contract (EPC) in May 2013 for SCR installation on Bridger Units 3 and 4. The EPC contract signed at that time was not final and offered the Company opportunities to abandon the project up to and even following Pacific Power's signing of the full notice to proceed (FNTP) in December 2013.

272 (11) After signing the EPC and prior to the FNTP, the Company did not reevaluate its SCR installation decision using the SO model, despite continually falling natural gas prices, a significant shift in Pacific Power's plan for mining operations for the Bridger Mine providing coal to fuel Bridger, and a 58 percent decline in the

benefits associated with SCR from its 2011 analysis. The Company failed to present contemporaneous documentation that it re-examined the installation decision in light of these changing circumstances. Any contemplation by Pacific Power of the natural gas price declines and coal plan changes were verbal and not recorded or documented.

273 (12) The Company's failure to rerun the SO model when confronted with these significantly changed circumstances increased the risk Washington ratepayers would bear with the SCR systems.

274 (13) Pacific Power carefully considered alternatives to implementation of its Supervisory Control and Data Acquisition Energy Management System (SCADA EMS) and the second phase of the Union Gap Substation upgrade (Union Gap) and provided contemporaneous documentation of its decision process for both projects.

275 (14) The final costs associated with the SCADA EMS, the Union Gap substation, and SCR installation at Bridger Unit 4 are unknown.

276 (15) It is reasonable and appropriate for Pacific Power to file an attestation of the final costs of the Company's SCADA EMS, the Union Gap substation, and SCR system on Bridger Unit 4 to ensure review of these expenses before they are included in rates for the second year of the rate plan.

277 (16) The Company's decoupling mechanism, like those of Avista Utilities and Puget Sound Energy, is intended to allow for more stable cost recovery over time, even as revenues fluctuate. Staff's proposed rate adjustment trigger of 2.5 percent, in contrast to Pacific Power's 0.5 percent proposed trigger, will provide rate stability to customers.

278 (17) Staff's proposed rate adjustment cap of 5 percent likewise balances rate stability for customers with revenue stability for the Company.

279 (18) In regard to the cost of capital issue, the midpoint of each range and the remaining Comparable Earnings result produces arithmetic mean and median results of 9.46 and 9.57, respectively. These results effectively flank both sides of Pacific Power's currently authorized return on equity of 9.5 percent.

280 (19) The use of end-of-period (EOP) methodology is an appropriate means to address regulatory lag, especially within the context of the Company's two-year rate plan. The use of EOP for historical balances and the average-of-monthly-averages for pro forma adjustments is unfair to ratepayers.

281 (20) For salary adjustments, we have used known and measurable salary increases up to one year after the test year, and an up-to-date employee count, to set Pacific Power's rates. On rebuttal, the Company presented an adjustment that closely adheres to our past practice.

282 (21) As for pension and other post-employment benefits, the Commission typically uses the most up-to-date costs available to set Pacific Power's rates. The Company has not presented evidence to support its contention that non-wage labor costs have increased since the end of the test year.

283 (22) Public Counsel has failed to demonstrate that the variation in test year "Other Salary Overheads/Oncosts" expenses is likely to continue in its effort to support the use of a multi-year average.

284 (23) Boise failed to substantiate its claim that Pacific Power has mistakenly assigned general office expenses not related to generation to the FERC account for generation-related expenses. Similarly, Boise did not demonstrate that its proposal to modify one aspect of the West Control Area Inter-Jurisdictional Cost Allocation Methodology was appropriate.

285 (24) Staff provides no rationale for its recommendation to exclude from rates non-major environmental remediation costs incurred for plants outside Washington State.

286 (25) Pacific Power has not calculated the quantifiable benefits of the Idaho Power Transmission Asset Exchange assets (Exchange Assets) and reassignment assets (Reassignment Assets) or provided for their inclusion in the power cost baseline, and the Company is not proposing to reflect power cost savings resulting from the additional 200 megawatts of dynamic transfer capability. Pacific Power did not file to reset its power cost baseline.

287 (26) When non-power costs that reduce variable power costs are included in general rates, the power cost adjustment mechanism's (PCAM's) power cost baseline must be reset to reflect the benefits ratepayers are being asked to pay.

288 (27) The Commission and parties paid a significant amount of attention to Pacific Power's cost of service and rate spread issues in its last general rate case, and rate parity has improved since that time. Also in the Company's 2014 general rate case, the Commission approved the use of the Peak & Average (P&A) methodology, but ordered Pacific Power to return to using the Peak Credit method or provide a more detailed justification for using an alternative approach in its

next general rate case. The Company continues to use the P&A method without providing a new cost of service study.

289 (28) The Company has agreed to participate in a collaborative with Staff to address cost of service, rate spread, and rate design issues.

290 (29) Pacific Power's payments for memberships and subscriptions, including payments to the Yakima County Development Association, are not associated with the Company's core business of providing electric service. Pacific Power has failed to quantify any direct benefits to customers or demonstrate they exceed the associated costs.

CONCLUSIONS OF LAW

291 Having discussed above all matters material to this decision, and having stated detailed findings, conclusions, and the reasons therefore, the Commission now makes the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:

292 (1) The Washington Utilities and Transportation Commission has jurisdiction over the subject matter of, and parties to, these proceedings.

293 (2) Pacific Power failed to show that the rates it proposed by tariff revisions filed on November 25, 2015, which were suspended by prior Commission order, are fair, just, or reasonable. These as-filed rates accordingly should be rejected.

294 (3) Pacific Power carried its burden to prove that its existing rates for electric service provided in Washington State are insufficient to yield reasonable compensation for the service rendered.

295 (4) Pacific Power requires relief with respect to the rates it charges for electric service provided in Washington State.

296 (5) The Commission must determine the fair, just, reasonable, and sufficient rates to be observed and in force under Pacific Power's tariffs that govern its rates, terms, and conditions of service for providing electricity to customers in Washington State.

297 (6) Approval of the Company's accelerated depreciation proposal is in the public interest, but the Company must take certain actions to ensure accelerated depreciation continues to be appropriate. First, Pacific Power shall place the

additional depreciation amounts in a regulatory liability account, specifically FERC Account 254, Other Regulatory Liabilities; second, the Company must file its 2018 depreciation study within 30 days of the study's completion, with its next general rate case, or by December 31, 2018, whichever occurs first; and third, Pacific Power must file a report along with its Commission Basis Report providing full disclosure of its decommissioning and remediation costs for Unit 4 of Colstrip and the Bridger plant, including the five elements listed in paragraph 59, above.

298 (7) Regulated public service companies bear the burden of proof that their investment decisions are prudent. The Commission's legal standard for assessing the prudence of such decisions is "what would a reasonable board of directors and company management have decided given what they knew or reasonably should have known to be true at the time they made a decision." We may not use hindsight in our evaluation of the Company's actions, and the prudence standard applies both to the question of need and the appropriateness of the investment.

299 (8) We examine three factors in evaluating whether the investment was prudent: (a) Was the initiation of the project prudent? (b) Was the continued construction of the project prudent? and (c) Were the construction expenses prudently incurred? The second and third factors are examined using the same prudence test as the first factor but applied at a different point in time and necessarily premised on a reevaluation of the project.

300 (9) The Company's May 2013 decision to enter into an EPC services contract, based on the Company's SO model's rigorous analysis, was prudent at that time. However, simply because a decision to begin a project is initially prudent does not, *ipso facto*, make the continuation or completion of the project prudent.

301 (10) The Commission requires that regulated companies continually evaluate a project as it progresses to determine if the project continues to be prudent from both the need of the project and its impact on the company's ratepayers.

302 (11) The parties and the Commission should be able to follow the company's decision-making process, knowing what elements the company considered, and the manner in which the company valued those elements. Such a process must be documented.

303 (12) The verbal communications among Mr. Teply and his team in place of a full SO model reassessment are not sufficiently documented or concrete to inform the Commission as to what elements the Company considered or the manner in which

Pacific Power values those elements during the months from May to December 2013, and prior to signing the full notice to proceed with the EPC on December 1, 2013. The Company has failed to demonstrate that it adequately examined the changing circumstances in coal and natural gas prices that could have impacted a prudent or imprudent decision.

304 (13) Considering the significant economic changes in both coal costs and natural gas pricing between May and December 2013, Pacific Power's decision to continue the SCR installation project was not sufficiently demonstrated to be prudent in all respects and the costs of Pacific Power's decision should not be borne completely by the ratepayers.

305 (14) While the general ratemaking principle is that ratepayers should not bear any costs for which the company has failed to demonstrate prudence, up to and including the full costs of the investment, no party has argued for complete disallowance of the Company's SCR investments. We find the "used and useful" regulatory concept particularly effective; the concept provides that "there should be no recovery of certain amounts (i.e., return of the asset and/or return on the asset) that exceed the original benefit for which the asset was established." The principle is in keeping with our responsibility to balance ratepayer and shareholder interests and the regulatory theory that costs and benefits usually follow risks.

306 (15) Pacific Power placed ratepayers at risk of larger-than-appropriate expenses in abandoning its responsibility to pursue, and document its pursuit of, the least-cost option. However, we accept that the SCR systems should reduce regional haze as required by the Clean Air Act and the Wyoming State Implementation Plan and the Company has testified that the systems are used and useful. Accordingly, we authorize the Company to include in Washington rates only the return of, but not the return on, the Washington portion of its investment in the SCR systems.

307 (16) We find that the decision to proceed with SCADA EMS and the second phase of Union Gap were prudent.

308 (17) Pacific Power must file an attestation and supporting documents for actual booked expenditures and rate base amounts of the SCADA EMS, the Union Gap substation upgrade project, and the SCR system on Bridger Unit 4 by July 1, 2017. Staff must review the final costs and provide its analysis to the Commission prior to the initiation of the Company's second year rates on September 15, 2017.

309 (18) Staff's proposed decoupling rate adjustment trigger of 2.5 percent and rate adjustment cap of 5 percent are reasonable. With these adjustments to the Company's proposed mechanism, as well as the requirements detailed above, including the earnings test and the reporting and evaluation requirements, Pacific Power's decoupling mechanism should be approved.

310 (19) The Company's current ROE is within the zone of reasonableness presented by the two parties offering testimony on this issue and should remain at 9.5 percent.

311 (20) Pacific Power's proposal of EOP using the modification submitted pursuant to Bench Request No. 8 is approved.

312 (21) The Company's proposal to use its March 2016 full-time employee count and known and measurable salary increases through June 2016 is reasonable and should be approved.

313 (22) The pension and other post-employment benefits adjustment proposed by Public Counsel, which bases these costs on the most recent actuarial report available in the record for the 2016 plan year is reasonable and should be approved.

314 (23) Public Counsel's adjustment to the "Other Salary Overheads/Oncosts" should be rejected.

315 (24) The proposed adjustment by Boise White Paper, LLC (Boise) to the general office expenses for generation-related expenses should be rejected. Similarly, we find that Boise's proposed modification to the allocation of transmission operations and maintenance expenses should be denied.

316 (25) Staff's recommendation to limit the environmental remediation costs in Washington rates solely to those plants within the state of Washington should be denied.

317 (26) The proposal to include the Idaho Power Exchange Assets and Reassignment Assets in Washington rates and the associated adjustment should be rejected as Pacific Power has not proposed to include the benefits of these assets in the power cost baseline. We allow the Company to include in rates the uncontested West Control Area correction assets.

318 (27) Pacific Power's request to include its energy imbalance market (EIM) expenses in its actual power costs within its annual power cost adjustment mechanism (PCAM) true-up filing should be approved, and the Company is required to

remove its EIM costs from its annual PCAM true-up and propose their recovery in its next rate case under non-power costs.

319 (28) It is reasonable for Pacific Power to recover the authorized first-year rate increase on an equal percentage basis for each schedule. We expect the stakeholders' collaborative to address cost of service, rate spread, and rate design issues, as well as the classification and allocation of costs from the prior general rate case which Pacific Power neglected to handle in this proceeding. The Commission also expects the parties to initiate the collaborative process in time to complete it prior to the second year of the rate plan. If the stakeholders reach consensus before second-year rates go into effect, they should file the settlement agreement with the Commission for review. If the stakeholders do not reach consensus, Pacific Power should apply the same equal percentage method to each schedule and raise the cost of service and rate design issues in its next rate filing.

320 (29) Boise's proposal to increase the basic charge for Schedules 48T and 48T-DF by 25 percent and apply the rest of the increase to demand charges should be denied. Pacific Power's proposal to apply a higher percentage increase to the demand charges for Schedule 48T-DF should also be rejected. The Company should apply the class average increase to all charges on both Schedules 48T and 48T-DF.

321 (30) Pacific Power has failed to demonstrate that the memberships and associations expenses, including to the Yakima County Development Association, provide any direct benefits to Washington ratepayers, and these costs should be disallowed.

322 (31) Pacific Power's proposal for a one-time credit to return the hydro deferral credit balance to customers should be approved. The Company should be authorized to transfer the hydro deferral balance to the Schedule 96 account and a one-time credit issued under that schedule.

323 (32) Pacific Power should be authorized and required to make a compliance filing to recover its revenue deficiency of $4,476,959, for the first year of the rate plan. The Company should also be authorized and required to make a compliance filing to effectuate the second year rates, commencing September 15, 2017, and to recover its revenue deficiency of $6,611,219 for the second year of the two-year rate plan.

324 (33) The rates, terms, and conditions of service that will result from this Order are fair, just, reasonable, and sufficient.

325 (34) The rates, terms, and conditions of service that will result from this Order are neither unduly preferential nor discriminatory.

326 (35) The Commission Secretary should be authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Order.

327 (36) The Commission should retain jurisdiction over the subject matters and the parties to this proceeding to effectuate the terms of this Order.

ORDER

THE COMMISSION ORDERS THAT:

328 (1) The proposed tariff revisions Pacific Power & Light Company filed on November 25, 2015, which were suspended by prior Commission order, are rejected.

329 (2) Pacific Power is authorized and required to file tariff sheets that are necessary and sufficient to effectuate the terms of this Order. The Company must file tariff sheets that will provide increased revenues of $4,476,959 for the first year of the rate plan. The Company is also authorized and required to file tariff sheets that increase revenues of $6,611,219, for the second year of the two-year rate plan, effective September 15, 2017. Pacific Power must file the required tariff sheets at least five full business days prior to their stated effective date, which shall be no sooner than September 15, 2016.

330 (3) The Company's decoupling mechanism and two-year rate plan are approved, together with the requirements regarding low-income customers set out in paragraph 255 above.

331 (4) The Commission Secretary is authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Final Order.

332 (5) The Commission retains jurisdiction to effectuate the terms of this Final Order.

Dated at Olympia, Washington, and effective September 1, 2016.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DAVID W. DANNER, Chairman

PHILIP B. JONES, Commissioner

ANN E. RENDAHL, Commissioner

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.