BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of **PACIFIC POWER & LIGHT COMPANY,** **Petition For a Rate Increase Based on a Modified Commission Basis Report, Two-Year Rate Plan, and Decoupling Mechanism**	**DOCKET UE-152253**

POST-HEARING BRIEF ON BEHALF OF COMMISSION STAFF

June 22, 2016

ROBERT W. FERGUSON
Attorney General

JENNIFER CAMERON-RULKOWSKI
Assistant Attorney General
Office of the Attorney General
Utilities & Transportation Division

1400 S Evergreen Park Drive S.W.
P.O. Box 40128
Olympia, WA 98504-0128
(360) 664-1186

HIGHLY CONFIDENTIAL – REDACTED VERSION

TABLE OF CONTENTS

TABLE OF AUTHORITIES

Cases

Administrative Cases

Statutes

Other Authorities

I. INTRODUCTION

1 Pacific Power does not need a rate increase. The Company could have waited to file its next rate case until all of the capital projects in this case had gone into service. Instead it decided to try to pick up a rate increase quickly, bulking up the significance of the filing with a rate plan and a decoupling plan. Staff supports the rate plan and the decoupling plan. In the absence of the rate plan, however, which incorporates additional capital projects and expenses into rates, Pacific Power's rates should be decreased.

2 Pacific Power's "limited-issue" rate filing is propped up by two major revenue requirement components: accelerating depreciation of its Jim Bridger and Colstrip generating facilities (approximately ten million dollars) and adding selective catalytic reduction (SCR) at Jim Bridger to rates (approximately five million dollars). Staff recommends the Commission reject accelerated depreciation and order a partial disallowance for the SCR addition.

3 Staff's case is based on the principle of cost causation and the matching of benefit with burden. Below is corrected Table 2 from Mr. Jason Ball's direct testimony, which sets forth Staff's recommended revenue requirement. Staff calculated its revenue requirement based on a traditional modified historical year with standard pro forma adjustments to reflect changes occurring after the test year.

TABLE 2 – Revenue Requirement Change as Proposed by Staff		
Staff Proposal by major item	**Rate Plan – Year 1**	**Rate Plan – Year 2**
Jim Bridger – SCR	$1,443,576	$1,182,010
Jim Bridger/Colstrip – Accelerated Depreciation	$0	*N/A*
SCADA EMS Replacement	*N/A*	$290,735
Union Gap Substation Upgrade	*N/A*	$516,986
Expiration of Production Tax Credits	*N/A*	$4,234,464
General Adjustments – Other	$(6,774,280)	$(164,801)
Total Modeled Revenue Requirement Change	$(5,330,704)	$6,059,394
Staff Proposed Rate Change	$0	$728,690

4 Discussion follows of Staff's recommendations in this case on the issues listed in the table of contents. Analysis of and recommendations on issues that are not discussed in any depth in this brief are discussed in detail in the prefiled direct testimony of Elizabeth O'Connell: second year capital additions to rate base – SCADA EMS and Union Gap upgrade; production tax credit adjustment; and income tax adjustment.

II. ACCELERATED DEPRECIATION

5 For "policy" reasons only, the Company proposes to accelerate the depreciable lives of two coal-fired generating facilities, Jim Bridger (Bridger) and Colstrip 4.[1] The Commission should reject this proposal (Adjustment 6.4) because it lacks a sufficient evidentiary basis. The Company has offered only its hunch that Bridger and Colstrip 4 will be forced into early retirement. The Commission should not increase customer rates based solely on the Company's speculation. Furthermore, the Company has not explained why the Commission should "align" the depreciable lives of Bridger and Colstrip 4 with those currently approved in Oregon. The Commission should not blindly rely on another state's depreciation decisions.

6 The Company should defer its proposal until it can present a sufficient evidentiary basis. At a minimum, the Company should wait until it completes its next depreciation study in 2018.[2] An updated depreciation study will allow the Commission to analyze depreciation rates based on a sufficiently-developed record. Currently, the record is deficient.

---

[1] *See* Dalley, Exh. No. RBD-3T 7:20-8:3 ("The Company's proposal is not based on a change in technical depreciation assumptions, methodologies, or calculations. Instead, the Company is seeking a policy-based change in the depreciation lives of one set of assets—coal-fueled generation resources—based on new and proposed laws and regulations that may impact the useful lives of these assets.").

[2] Dalley, TR. 163:5-10 ("We typically file [depreciation studies] every five years, and our last depreciation study was effective January of 2014, filed in—I think it was a 2012 study approved in 2013. So to get to your question, five years from that point would be the 2018 timeframe, potentially for depreciation rates effective in 2019.").

A. The Company's Accelerated Depreciation Proposal Lacks Evidentiary Support

1. The Company has the burden to justify the proposal's $10 million cost.

7 The Company proposes to accelerate Jim Bridger's depreciable life to 2025 from 2037, and Colstrip 4's depreciable life to 2032 from 2046.[3] This proposal will ratchet up the Company's revenue requirement by approximately $10 million—i.e., the *entirety* of the Company's proposed first-period rate increase.[4] Public Counsel witness Donna Ramas accurately testifies, "There would be no Pacific Power rate case at this time absent the request for accelerated recovery of coal plant costs from Washington ratepayers."[5]

8 The Company has the burden to justify its costly proposal.[6] Even assuming that the Commission may alter depreciation rates for "policy" reasons only, the Commission's decision must be "supported by evidence that is substantial when viewed in light of the whole record."[7] The Commission should not accept the Company's policy justifications unless those justifications amount to "evidence sufficient to persuade a fair-minded person"[8] that accelerated depreciation will support rates that are "just, fair, reasonable and sufficient."[9] As discussed below, the Company's justifications fall short of these standards.

---

[3] Dalley, Exh. No. RBD-3T 6:21-22.
[4] McCoy, Exh. No. SEM-2 1:28; McCoy, Exh. No. SEM-6T, 3, Table 1; Dalley, TR. 152:21 - 153:9 (agreeing with statement by Public Counsel's attorney that "the impacts of accelerating the depreciation on Jim Bridger and Colstrip actually exceeds the amount of the increase that [the Company is] requesting in the first year of [its] two-year rate plan proposal.").
[5] Ramas, Exh. No. DMR-1T (revised), 12:18-20.
[6] *PacifiCorp v. Wash. Utils. & Transp. Comm'n*, No. 46009-2-II, Slip. Op., 12 (Wash. App. Div. 2 Apr. 27, 2016) ("The burden of proof for increased rates is on the utility.") (citing RCW 80.04.130(4)). Administrative Law Judge Friedlander took official notice of the decision. TR. 265:10-10.
[7] RCW 34.05.570(3)(e).
[8] *PacifiCorp,* No. 46009-2-II, Slip. Op. at 12 ("The Commission's findings are reviewed for substantial evidence supporting the finding. Substantial evidence is 'evidence sufficient to persuade a fair-minded person of their truth.'") (citation omitted) (quoting *City of Vancouver v. State Pub. Emp't Relations Comm'n*, 180 Wn. App. 333, 347, 325 P.3d 213 (2014)).
[9] RCW 80.28.010(1).

2. The Company merely speculates that Bridger and Colstrip 4 will be forced into early retirement.

9 Company witness Bryce Dalley claims that accelerated depreciation "mitigates future customer risk associated with coal-fueled generation" and "provides the Company additional flexibility to respond to existing and emerging environmental regulations."[10] Mr. Dalley's big assumption is that anti-coal laws and public policies will force Bridger and Colstrip 4 to retire (or convert to natural gas) sooner than their currently-approved depreciable lives of 2037 and 2042, respectively. Mr. Dalley is merely speculating.

10 As proof that "laws and regulations . . . may shorten the useful lives" of coal-fired resources like Bridger and Colstrip 4,[11] Mr. Dalley points to several Washington enactments (Energy Independence Act, Greenhouse Gas Emissions Performance Standard, Climate Action and Green Jobs bill, Energy Strategy bill, second Climate Action bill, and Executive Order 04-14) as well as EPA's Clean Power Plan. This parade of citations is meaningless absent *evidence* that some law or regulation will, in fact, shorten the useful lives of Bridger and Colstrip 4.

11 At hearing, Mr. Dalley downplayed the need for certainty and argued that the Commission should approve accelerated depreciation to mitigate the "risk" of early retirement. But when asked by Staff counsel to quantify this "risk," Mr. Dalley equivocated:

> **Q. What would you say is the probability that either of these plants will actually go out of service earlier than their currently-approved depreciable lives?**
>
> A. I think it's difficult to determine, but I would say, based on the political environment, and as well as the policies, it's more likely than not that the useful lives would be shortened rather than—to even maintain their existing ones, or be lengthened.
>
> **Q. And that's just your hunch, correct?**
>
> A. There's no specific requirement, no, to shut down these facilities on those dates, but our proposal here is one to mitigate risk for customers in the future.

[10] Dalley, Exh. No. RBD-3T 8:3-4.

[11] Dalley, Exh. No. RBD-3T 1:22; *see* Dalley, Exh. No. RBD-1T, 6:1-25 (enumerating laws and regulations).

> **Q. Okay. So the answer, again, is you're just speculating?**
> A. We're—I guess we're 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.[12]

In similar fashion, when Commissioner Ann Rendahl asked Mr. Dalley at hearing whether any particular "requirement of public authorities"[13] will, in fact, shorten the useful lives of Bridger and Colstrip 4, Mr. Dalley conceded that he was unaware of a single requirement.[14] Mr. Dalley wants the Commission to act based solely on a hunch.

12 Having acknowledged the absence of any legal requirement that will necessitate early retirement, Mr. Dalley attempted to supply the Commission with an alternative rationale for accelerated depreciation:

> **Q. [Commissioner Rendahl:] So how do you reconcile that clarification you read about the consideration of requirements of public authorities when there currently isn't a requirement?**
> A. I reconcile it in that there's a variety of things that need to be considered when establishing depreciation rates, and it's not just an engineering study. . . . Considerations of public authorities is another one in the CFR, but as we've seen in prior Commission decisions here in Washington associated with our depreciation rates, the Commission ultimately has discretion over what they view is the appropriate life.[15]

Staff disagrees with Mr. Dalley's view of the Commission's discretion. Although the Commission has broad authority to select appropriate ratemaking methodologies, the

---

[12] Dalley, TR. 149:15 - 150:10.
[13] Dalley, TR. 196:20-22. The phrase "requirement of public authorities" comes from the definitions section of FERC's Uniform System of Accounts, at 18 C.F.R. § 101. The pertinent definition reads, "*Depreciation*, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and *requirements of public authorities*." 18 C.F.R. § 101 (second emphasis added). Administrative Law Judge Friedlander took official notice of this definition at the cross-examination hearing. Dalley, TR. 161:14-25.
[14] Dalley, TR. 196:25 - 197:8.
[15] Dalley, TR. 198:22-23.

Company—not the Commission—has the burden of proof. In Staff's opinion, the Company's generalized speculation about the future of coal-fired resources falls short of this burden.

3. The Company's "alignment" rationale fails to bridge the evidentiary gap.

13 The absence of evidence supporting accelerated depreciation is even more apparent considering the Company's "alignment" rationale. Lacking an updated depreciation study, the Company was forced to devise retirement dates using a non-technical source. The Company chose 2025 (Bridger) and 2032 (Colstrip 4) because those dates "align" with the dates currently approved in Oregon. Mr. Dalley acknowledges that "alignment" is "not based on a change in technical depreciation assumptions, methodologies, or calculations."[16]

14 "Alignment" is not a sufficient reason to accelerate depreciation of Bridger and Colstrip 4. As Staff witness Joanna Huang testified, "alignment" appears to be pointless:

> **Q. What is your analysis of the Company's "alignment" justification?**
>
> A. It raises questions. No state other than Oregon uses the Company's proposed Jim Bridger and Colstrip Unit 4 retirement dates. If the Commission "aligns" itself with Oregon, it will fall out of "alignment" with California, Utah, Wyoming, and Idaho (Washington is currently "aligned" with the latter states). The Company suggests it is desirable to align the "two states that account for most of the load in the west control area," but it fails to clearly explain why this is so.[17]

On cross-examination, Mr. Dalley agreed with Staff counsel that the Company's proposal actually reduces alignment on a system-wide basis:

> **Q. Isn't it true that aligning with Oregon means falling out of alignment with the other states in which the Company operates?**
>
> A. Yes, it would. Our other states are using the depreciation lives that are currently approved here in Washington. So it would deviate from those other states, but would align with Oregon that has a shorter life for those facilities.[18]

---

[16] Dalley, Exh. No. RBD-3T 7:20-21.

[17] Huang, Exh. No. JH-1T 10:4-10; *see also* Huang, Exh. No. JH-3 (listing currently-approved depreciable lives for each jurisdiction in which the Company operates).

[18] Dalley, TR. 147:24 - 148:6.

15 Mr. Dalley's testimony begs the question: What, if anything, will the Commission accomplish by aligning with Oregon? The answer is unclear. As the Company acknowledged during discovery, Washington and Oregon cannot dictate the fate of Bridger and Colstrip 4 because the Company plans on a system-wide basis without regard to alignment:

> **[Public Counsel's Data Request 60]**
> (a) Is it currently the Company's intent to stop using power from the Jim Bridger units for serving Washington Customers in 2025?
>
> **[Company's Response to Public Counsel Data Request 60]**
> (a) . . . If approved by the Washington Utilities and Transportation Commission, this proposal would align Washington's depreciable lives with those used in Oregon for the same facilities. Changing depreciable lives, however, *would not restrict the company from using generation from these resources to serve Washington customers after the end of the facilities' depreciable lives*, nor would it prevent the Commission from revisiting the depreciable lives in a future proceeding. The Company expects that parameters such as state and federal policies, regulatory compacts, as well as the then-current operating costs and benefits will ultimately dictate whether or not individual units continue to serve Washington customers after their depreciable lives are met.[19]

"Alignment" turns out to be an empty rationale.

16 Ultimately, by asking the Commission to align Washington and Oregon, the Company is advocating for blind acceptance of Oregon's depreciation timeline, including the analysis supporting that timeline. But the Company has not explained how Oregon's analysis translates into just, fair, reasonable, and sufficient *Washington* rates. The Commission should require this explanation. What works for Oregon may not work for Washington.

17 As a final note, the Company's proposal will "align" only the retirement dates and not align depreciation rates. That is because Oregon approved its current retirement dates in 2003,[20] with modifications in 2013.[21] To achieve the same retirement dates, with less time remaining,

---

[19] Huang, Exh. No. JH-6 (emphasis added).
[20] Huang, Exh. No. JH-2 (Company's response to Public Counsel's Data Request 31).
[21] Huang, Exh. No. JH-3 (Company's response to Public Counsel's Data Request 13).

Washington will need to "catch up" to Oregon by approving higher depreciation rates relative to those approved in Oregon.[22] Higher depreciation rates, in turn, will burden Washington ratepayers with more acute rate impacts relative to those felt by ratepayers in Oregon.

4. The Commission cannot simply "return" to previously-approved depreciation rates.

18 Mr. Dalley's rebuttal testimony urges the Commission to "return" Bridger and Colstrip 4 to their "pre-2008 depreciable lives."[23] The suggestion is that the Commission can simply "return" to the shorter depreciable lives approved before the Commission extended them based on the Company's 2007 depreciation study.[24] Staff is not convinced that the 2007 study can be cast aside so easily. The Company submitted no evidence in this docket suggesting that the data, assumptions, or conclusions in the 2007 study were flawed (or that the evidence relied upon prior to 2008 establishes more appropriate depreciation rates).

5. Accelerated depreciation will not eliminate the risk of intergenerational inequity.

19 Sierra Club witness Jeremy Fisher testifies, "Accelerated depreciation protects ratepayers by minimizing the risk of intertemporal cost shifting between current ratepayers who are continuing to receive power from the plant, and future ratepayers who may otherwise be required to pay off undepreciated assets after the plant has stopped providing power."[25] On this point, Mr. Fisher's logic suffers from the same flaw as Mr. Dalley's. The record contains no evidentiary basis establishing that Bridger and Colstrip 4 will, *in fact*, cease operations any

---

[22] *See* Dalley, TR. 147:12-17.
[23] Dalley, Exh. No. RBD-3T 20-21; *see also* Dalley, TR. 204:24 - 205:1 (testifying in response to a question from Chairman Dave Danner, "Yeah, I think the rational basis is we're *reverting* to lives previously approved by the Commission . . . .") (emphasis added).
[24] *See In the Matter of the Petition of PacifiCorp, for an Accounting Order Authorizing a Revision to Depreciation Rates*, Docket UE-071795, Order 01 (Apr. 10, 2008) (revising depreciation rates for accounting purposes based on the Company's 2007 depreciation study).
[25] Fisher, Exh. No. JIF-1CT 35:7-11.

earlier than their currently-approved retirement dates. Without this basis, the notion that accelerated depreciation will forestall "rate shock" is pure speculation.[26]

20 At hearing, Commissioner Dave Danner recognized that attempting to eliminate intergenerational inequity while simultaneously speculating about retirement dates amounts to little more than a guessing game.[27] Like the Company, the Commission lacks a crystal ball.

B. The Company Should Defer Its Proposal Until It Updates Its Depreciation Study

21 During discovery, Public Counsel asked the Company to "provide any analysis, evaluations and studies conducted by or for the Company in its evaluation of whether or not to seek to shorten the depreciable lives of the Bridger and Colstrip units in [the current] rate filing."[28] The Company acknowledged that it "*has not done any analysis or studies* in its evaluation of whether to shorten depreciable lives of Bridger and Colstrip."[29] This statement should give the Commission pause. Can the Commission really approve new depreciation rates when the Company admittedly performed *no analysis or studies*?

22 Staff advocates exercising caution and recommends that the Commission take up the issue of accelerated depreciation once the Company supplies an updated depreciation study. Staff witness Ms. Huang explained that an updated depreciation study will give the Commission a stronger evidentiary foundation on which to base its decision:

> **Q. What are the benefits of an updated depreciation study?**
> A. Periodic depreciation studies are an important and well established accounting practice to update depreciation rates. Depreciation studies recognize additions to investment in plants and reflect any changes in plant asset characteristics, technology, salvage, removal costs, life span estimates, and other factors. With a

---

[26] Fisher, Exh. No. JIF-1CT 35:14.
[27] Dalley, TR. 203:6-21 (emphasis added).
[28] Huang, Exh. No. JH-4 (Company's response to Public Counsel's Data Request 11).
[29] *Id.* (emphasis added).

> complete depreciation study conducted by an independent consultant, the Company's depreciation rates will be more reliable for ratemaking purposes.[30]

Mr. Dalley questions the value of an updated study, predicting at hearing that the Company's proposal "would not change" even if the Company reevaluated the proposal based on an updated study.[31] Whether that is true, the Company cannot deny the importance of an adequate evidentiary record. An updated study will allow the Commission to analyze depreciation rates based on both engineering data and any relevant policy considerations. The updated study will bolster the foundation for the Commission's ultimate decision.

23 The Company will update its depreciation study just two years from now, in 2018.[32] Staff perceives no great urgency that compels the Commission to accelerate depreciation rates now, as opposed to deciding the issue in a few years when the record is more fully developed. The Commission should reject the Company's proposal (i.e., reject Adjustment 6.4) and decline to revisit the matter until the record is sufficient to allow a reasoned analysis. In the meantime, Pacific Power will continue to recover the depreciation costs currently in rates. Under Staff's proposal, Pacific Power bears no loss of cost recovery, and ratepayers are not subjected to a revenue increase based on political speculation.

III. THE RATE PLAN

24 Staff supports Pacific Power's proposed rate plan in concept but recommends a modified proposal. A rate plan, as Mr. Ball explains in his testimony, "involve[s] two key components: a stay-out period, in which the Company agrees to not file a general rate case seeking additional

---

[30] Huang, Exh. No. JH-1T 11:16-22.
[31] Dalley, TR. 163:20.
[32] *See* Huang, Exh. No. JH-1T 7:6-9 ("The Company most recently updated its depreciation study in 2013. The Company updates its depreciation study approximately every five years. Staff expects that the Company's next update will occur in 2018."); *see also* Dalley, TR. 163:10 (testifying that the Company's updated depreciation study could support "depreciation rates effective in 2019"); *id.* 164:25 - 165:1 (testifying that the Company has the ability to update its study sooner than 2018, since "[t]here's no requirement that we have to wait five years.").

revenue, and in exchange the Company either receives a series of pre-determined rate adjustments or some other type of incentive for agreeing to the stay-out period."[33] Such a rate plan is appropriate for this case and is consistent with past Commission decisions. Staff's proposed rate plan benefits both Pacific Power and its customers by incorporating recovery of significant capital expenditures and an expiring tax credit into rates with one modest rate increase only in the latter part of the rate plan period. Given that the Company will be able to begin recovering these expenses in rates during the second period of the rate plan, the stay-out period is an important quid pro quo. Without the stay-out period, the rate plan would hold no certain benefits for parties other than the Company.

A. Pacific Power's Proposed Rate Plan

25 Pacific Power's proposed multi-year rate plan contemplates two rate increases, a stay-out period, an attestation filing to facilitate final review of the costs of the capital additions underlying the second rate increase, mid-year filings of Commission Basis Reports (CBRs),[34] and an extension of the current LIBA plan, which is discussed below in the Low Income Issues section of this brief. The first rate increase would total approximately $9 million; the second rate increase would total approximately $10.3 million and would go into effect a year after the first increase. Pursuant to its proposed stay-out period, Pacific Power commits to not file a general rate case with an effective date before June 1, 2018.[35]

26 The basis for the rate increase in the second period of the rate plan includes the expiration of production tax credits as well as the capital costs of several significant projects: overhaul of

[33] Dalley, Exh. No. RBD-3T 3:6-7 ("In exchange for the second-year rate increase, the Company agrees that it will not file another rate case with rates effective before June 1, 2018.").
[34] Dalley, RBD-1T 20:1-4.
[35] Dalley, Exh. No. RBD-1T 2:13-14. Consequently, the Commission may expect a filing on or about May 1, 2017.

and installation of selective catalytic reduction at Bridger Unit 4 by December 2016; replacement and upgrade of the Company's Supervisory Control and Data Acquisition Energy Management System (SCADA), to be in service in the Spring of 2016; and the Union Gap Substation Upgrade (Union Gap), to be in service May 2016.[36] This basis for the second rate increase in the rate plan is different from some other recent rate plans, which are based on trended or escalated levels of certain expenses.[37] The capital projects are expected to be in service before the second rate increase goes into effect.[38] Before the second rate increase effective date, Pacific Power will file an attestation, which will include the final costs of the capital projects and allow for review of those costs.[39]

B. Staff's Rate Plan Recommendations Are Sensible And Align With Ratemaking Principles

27 Staff's modified rate plan proposal adjusts the structure to fit Staff's revenue requirement as well as ensures that the rate plan accords with ratemaking principles. To support Staff review of the Company's proposed attestation filing, Staff recommends that the Commission order the Company to file the attestation on a date certain, 60 days before the second rate increase will go into effect.[40] At this time, all three projects should satisfy the used and useful requirement because they will be in service, and the costs should be known and measurable.

28 Given that not all of the projects supporting the second-period rate increase are yet in service, it is not possible to conduct a full prudence review of these projects at this time.[41] Accordingly, Staff recommends applying a two-step prudence review. The first step is to review

[36] Dalley, Exh. No. RBD-1T 16:11 - 17:14.
[37] Ball, Exh. No. JLB-1T 20:15-20.
[38] Ball, Exh. No. JLB-1T 20:20-21.
[39] *See* Dalley, Exh. No. RBD-1T 17:18-19; O'Connell, TR. 373:4-25.
[40] Ball, Exh. No. JLB-1T 24:17 - 25:2.
[41] The Commission's prudence standard is discussed in the SCR section of this brief and, with respect to the rate plan projects, is discussed in Ms. O'Connell's prefiled direct testimony.

the prudence of management's decisions and the second step is to review the prudence of the final costs of projects to be incorporated into rates during the second period of the rate plan.[42] Staff has reviewed the prudence of the Company's decisions to go forward with these projects and has provided prudence recommendations in this case. Ms. O'Connell testifies that the investment decisions with regard to SCADA and Union Gap were prudent. Mr. Twitchell testifies that the decision to install selective catalytic reduction ultimately was not prudent. Following the attestation filing, Staff will review the prudence of the final costs of the projects.[43]

29 Staff has structured its rate plan somewhat differently from the Company's based on the difference in revenue requirement recommendations. Given that Staff's recommended revenue requirement is negative for the rate year, Staff has structured its proposed rate plan to provide an incentive for Pacific Power to have a rate plan: Staff proposes that the rate plan be revenue neutral in the first rate plan period and provide an increase in the second period of the rate plan.[44] The revenue increase in the second rate plan period would be 0.19 percent,[45] subject to the results of the attestation review. If the Commission approves Staff's proposed rate plan and Pacific Power declines to accept it, Staff's revenue requirement is negative $5,330,704 for the rate year, which represents a rate decrease of 1.58 percent.

C. Given The 2016 Capital Additions And The Expiring Production Tax Credit, There Is A Sound Basis For Adopting A Rate Plan With An Automatic Rate Adjustment In This Case

30 While Pacific Power has not demonstrated that it is experiencing attrition and that attrition necessitates a rate plan,[46] there are other, sound reasons to adopt a rate plan. Rate plans

[42] Ball, Exh. No. JLB-1T 26:3-8.
[43] Ball, Exh. No. JLB-1T 26:6-8.
[44] *See* Ball, Exh. No. JLB-1T 24:8-12.
[45] Ball, Exh. No. JLB-1T 28:15-16.
[46] Ball, Exh. No. JLB-1T 22:12-22.

help mitigate regulatory lag. Staff recognizes that Pacific Power will have vital infrastructure[47] additions to its rate base and that a tax credit will be expiring in less than a year,[48] and Staff believes that the Company is sure to file another rate case.[49] Staff's proposal allows Pacific Power to recover these infrastructure investments in rates over the two-year period without filing another rate case.[50] The Commission signaled the relevance and importance of this consideration in its order approving a rate plan along with decoupling for PSE in 2013:

> The rate plan provides a degree of relative rate stability, or at least predictability, for customers for several years. The rate plan is an innovative approach that will provide incentives to PSE to cut costs in order to earn its authorized rate of return. Moreover, the lack of annual rate filings will provide the Company, Staff, and other participants in PSE's general rate proceedings with a respite from the burdens and costs of the current pattern of almost continuous rate cases with one general rate case filing following quickly after the resolution of another.[51]

31 The rate plan, as modified by Staff, fulfills the aspirations set forth above. Staff's proposed rate plan would provide greater rate stability, with fewer rate changes, than the Company's proposal. With respect to cost cutting incentives, as discussed by the Commission in the PSE case, the combination of the decoupling proposal with the rate plan provides an incentive for Pacific Power to aggressively pursue cost control. The incentive exists because the earnings test that Staff supports as part of decoupling apportions half of any excess earnings to the Company.[52] It is important to note that the lack of a rate change in the first year of the rate plan is not a corresponding lack of incentive as the Company has claimed.[53] Staff's proposal, in

---

[47] *See* O'Connell, Exh. No. ECO-1T 13: 1-9 (SCADA EMS); 20:15-21 (Union Gap).
[48] O'Connell, Exh. No. ECO-1T 5:4-6.
[49] *See* Dalley, Exh. No. RBD-1T 17:14-17.
[50] *See* Ball, Exh. No. JLB-1T 23:2-4.
[51] *In the Matter of the Petition of Puget Sound Energy and NW Energy Coalition for an Order Authorizing PSE to Implement Electric and Natural Gas Decoupling Mechanisms and to Record Accounting Entries Associated with the Mechanisms*, Dockets UE-121697 and UG-121705 (Decoupling), and *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-130137 and UG-130138 (ERF), Order 07 (June 25, 2013).
[52] Ball, Exh. No. JLB-1T 23:25 - 24:2; 29:12-14.
[53] Dalley, TR. 231:4-20.

fact, proposes no rate decrease in the first year – even though Staff's analysis justifies a significant reduction in the Company's first-year annual revenues. The lack of a rate decrease is most certainly an incentive for the Company to continue to control its costs. Cost savings benefit customers by potentially lowering future rates based on the test period in which the Company reduced costs,[54] and earnings sharing protects against allowing Pacific Power to reap a windfall at ratepayers' expense.[55] The decoupling earnings test is essential to creating an appropriate incentive for cost control; without it, Staff does not support implementing a rate plan.

32 Rate plans with periodic rate adjustments are well established at this Commission. In 2000, for example, the Commission approved a five-year rate plan for PacifiCorp.[56] The rate plan included a general rate case stay-out[57] accompanied by three percent rate increases in years one and two, a one percent rate increase in year three, and no additional rate increases for the remainder of the rate plan.[58] There was no specific basis other than the Company's filed revenue requirement for the periodic rate increases or for the amount of the increases. More recently, in 2012, the Commission approved a two-year rate plan for Avista Corporation. The approval of the rate plan was based on an attrition trending analysis, which the Commission accepted for purposes of the multi-party settlement but found to be less precise than what would be required in a fully litigated rate case.[59]

33 In 2013, the Commission approved a three-year rate plan for Puget Sound Energy, which

---

[54] Ball, Exh. No. JLB-1T 24:2-3.
[55] Ball, Exh. No. JLB-1T 29:15-16.
[56] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-991832, Third Supplemental Order (Aug. 2000) (the rate plan was ultimately interrupted by the energy crisis and did not run as planned; however, this has no relevance to this case).
[57] Docket UE-991832, Third Supplemental Order at ¶ 28.
[58] Docket UE-991832, Third Supplemental Order at ¶ 33.
[59] *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Dockets UE-120436 and UG-120437, Order 9, 27, ¶ 72 (Dec. 26, 2012).

included automatic rate adjustments based on fixed annual escalation factors.[60] In that case, the Commission concluded that using "fixed annual escalation factors to adjust PSE's rates is a viable approach to reduce the impacts of regulatory lag and attrition during a multi-year general rate case stay-out period."[61]

34 The rate plan in this case is consistent with the recent trend of Commission decisions reflecting an expectation of more precision in the basis for automatic rate adjustments. Here, the use of discrete pro forma adjustments tied directly to specific projects and expenses is more precise than using a blanket percentage increase. It is important to recognize that there may be a variety of approaches to automatic rate adjustments, which will be more or less useful depending on each particular case. In this case, basing the second period rate adjustment on costs driven by specific capital projects and the expiration of the production tax credit represents a viable and appropriate approach to achieve the purposes of a rate plan.

35 Boise White Paper argues that the rate plan is based on disfavored single-issue ratemaking and should be rejected. Single-issue ratemaking occurs regularly before this Commission—for example, in power cost proceedings. Further, the record in this case fails to implicate the traditional concern that single issue ratemaking "might cause the regulating authority to allow a company to raise rates to cover increased costs in one area without realizing that there were counterbalancing savings in another area."[62] The Commission has explained that counterbalancing savings, also known as "offsetting factors," diminish the impact of the known and measurable events and may create mismatches if disregarded.[63] Ms. O'Connell testified at

[60] Dockets UE-121697 and UG-121705 (Decoupling), and Dockets UE-130137 and UG-130138 (ERF), Order 07.
[61] *Id.* at 74, ¶ 171.
[62] 73 B C.J.S. *Public Utilities* § 21 (June 2016 update).
[63] *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Dockets UE-090134 and UG-090135, Order 10, 46, ¶ 21 (Dec. 22, 2009).

hearing that, "at this point, Staff doesn't have any reason to believe that there will be an offsetting factor" and, if there were any, they could be reviewed during the attestation process.[64]

36 Moreover, the Commission has stated that it has discretion to add capital additions to rate base between general rate cases if "the investments are shown to be prudent, the amounts are reasonable, and the plant is demonstrated to be used and useful."[65] Additional considerations include "whether there has been a very recent general rate proceeding or the Company commits to making a general rate filing soon after the additions are allowed."[66]

37 In this case, the Commission may exercise its discretion to include the discrete expense items supporting the rate plan because: (1) there will have been a recent rate case (this one) updating the relationships among revenues, expenses, and rate base; (2) Pacific Power has committed to filing mid-year CBRs during the rate plan; (3) the attestation process provides an opportunity for review of any potential offsetting factors; and (4) it is anticipated that Pacific Power will file another rate case within months of the start of the second rate plan period, which can "true up" any test period relationships that may have become mismatched.

IV. PRUDENCE OF SELECTIVE CATALYTIC REDUCTION

38 Pacific Power owes a duty to its customers to ensure that it prudently incurs costs necessary to provide safe and reliable electric service. Pacific Power failed in its duty to Washington customers by committing to install selective catalytic reduction (SCR) systems on Units 3 and 4 of the Bridger plant when converting the plant to run on natural gas would have been cheaper and less risky. Unfortunately, the window of opportunity to convert Bridger Units 3 and 4 to run on natural gas has long-since closed.

---

[64] O'Connell, TR. 373:4-12.

[65] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-060266 and UG-060267, Order 08, 19, ¶ 51 (Jan. 5, 2007).

[66] *Id.*

39 The Commission should not allow Pacific Power to make multi-million dollar decisions on the basis of obsolete, out-of-date information and then profit from the result. Fully granting the Company's request for recovery of its SCR investment would signal that the bar for evaluating continued investment in coal facilities will be set low at a time when climate change, forthcoming environmental regulations, and public sentiment dictate that the bar be higher than ever. Staff therefore recommends that the Commission disallow $42.4 million of the Company's requested $60.8 million in adjustments for SCR and related equipment at the Bridger plant.

A. Legal Standard

40 Pacific Power bears the burden to prove that the rate increase it seeks is just and reasonable.[67] To satisfy this affirmative obligation the Company must establish it prudently incurred the costs it seeks to recover. The Commission applies a reasonableness standard when reviewing prudence.[68] The Commission's prudence standard evaluates what "a reasonable board of directors and company management [would] have decided given what they knew or reasonably should have known to be true at the time they made a decision."[69] To meet this standard, the Company must establish that it adequately studied both the question of need and the appropriateness of the expenditures, using the data and methods that reasonable management would have used at the time of the decisions.[70] Importantly, the Commission requires that the Company's study use "the most currently available information" as of the time of the decision.[71]

---

[67] RCW 80.04.130(4).
[68] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket No. UE-031725, Order 12, ¶ 19 (Apr. 7, 2004).
[69] *Id.* at ¶ 19.
[70] *Id.* at ¶ 19.
[71] *Wash. Utils. & Transp. Comm'n v. Puget Sound Power & Light Co.*, Docket Nos. UE-920433, UE-920499, UE-921262, Nineteenth Supplemental Order, 2, 37, 48 (Sept. 27, 1994) (Puget 1994 Order).

41 The Commission also expects that "[p]roving the prudence of the company's conduct should be simple and straightforward."[72] The Commission and the parties "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."[73] The company thus "must keep adequate contemporaneous records of its decision process which will allow the Commission to evaluate its decision. This is the minimum standard to which a regulated utility should be held."[74]

> The Company also has an ongoing duty to prudently manage the project: Simply because the decision to begin a project is prudent does not mean the continuation or completion of the project is *ipso facto* prudent. . . . [A] company must 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.[75]

The Commission has found both abandoned projects and successfully completed projects to be imprudent. For instance, the Commission disallowed certain costs of the abandoned Skagit Nuclear project because a utility did not adequately study the likelihood that the project would not be successfully completed after the Three Mile Island incident raised national questions about nuclear plant safety.[76] The Commission also disallowed certain cost over-runs of the Kettle Falls power plant because a utility did not adequately study whether it should complete the plant once the cost over-runs were known.[77] The Commission also disallowed portions of wholesale power contracts because a utility "did not adequately study, using up-to-date information, its

[72] Puget 1994 Order at 8.
[73] *Id.* at 16.
[74] *Id.* at 2, 37, 48.
[75] *Wash. Utils. & Transp. Comm'n v. Wash. Water Power Co.*, Cause No. U-83-26, Fifth Supplemental Order, 13 (Jan. 19, 1984).
[76] Puget 1994 Order at 10, n. 12.
[77] *Id.* at 10, n. 13.

specific resource acquisition decisions."[78] In these cases the Commission found that ratepayers should be held harmless with regard to any adverse rate impacts caused by the company's imprudent actions and, therefore, adjusted the company's expenditures for ratemaking purposes to disallow the excessive costs.[79]

B. Background

1. Pacific Power must reduce Bridger's haze polluting emissions pursuant to the Clean Air Act.

42 The Jim Bridger generating plant (Bridger) is a 2,120 MW coal-fueled power plant located in Point of Rocks, Wyoming. It consists of four identically sized generating units each two-thirds owned by PacifiCorp and one-third owned by Idaho Power Company. Bridger's emissions of fine particles contribute to haze pollution.[80]

43 The Clean Air Act and regional haze rules promulgated by the Environmental Protection Agency (EPA) obligate Pacific Power to reduce the emissions from Bridger that contribute to regional haze.[81] Under the Clean Air Act, each state must develop a State Implementation Plan (SIP) to meet air quality requirements.[82]

44 Pacific Power negotiated its regional haze compliance target for Bridger with the State of Wyoming and entered into a settlement agreement on November 2, 2010.[83] The agreement specified that the Company must either: (i) install SCR; (ii) install alternative add-on NO_x control systems; or (iii) otherwise reduce NO_x emissions—by December 31, 2015, for Unit 3 and

[78] Puget 1994 Order at 14.
[79] *Id.* at 47-48.
[80] Haze pollution impairs visibility, can cause serious health effects and mortality in humans, and contributes to environmental effects such as acid deposition and eutrophication. 79 Fed. Reg. 5032, 5033–34 (Jan. 30, 2014).
[81] 79 Fed. Reg. 5032 (Jan. 30, 2014).
[82] 79 Fed. Reg. 5032, 5033 (Jan. 30, 2014).
[83] *See* Teply, Exh. No. CAT-24; Teply, Exh. No. CAT-14CT 18:9-12.

by December 31, 2016, for Unit 4.[84] The State of Wyoming incorporated these compliance options into its Regional Haze SIP, which it submitted to the EPA for approval on January 12, 2011.[85] At that time, Pacific Power immediately pursued SCR installation at Bridger. The EPA, however, did not issue final regional haze rules for Wyoming until January 30, 2014—which finally established a federally enforceable emission reduction target for Bridger.[86]

2. Pacific Power completed three SO Model analyses to justify SCR investment.

45 Despite uncertainty about its compliance targets, Pacific Power continued to pursue SCR installation. In August 2012, the Company began to develop its economic justification for installing SCR.[87] The Company used the SO Model to perform a financial analysis to support its investment decision.[88] The SO Model is a "complex model" capable of forecasting the economic value of alternative emissions compliance options.[89] The Company used the SO Model to forecast how "a multitude of dynamic variables" interact over the 2016–2030 timeframe in order to identify a least-cost compliance option and the next best alternative.[90] The cost difference between the two least-cost options represents the present value revenue requirement differential (PVRR(d)), which is the SO Model's forecast of how economically favorable the preferred compliance option is in relation to the next best alternative.[91] Like any complex model, the SO

---

[84] Teply, Exh. No. CAT-24; Teply, Exh. No. CAT-25.
[85] Teply, Exh. No. CAT-25.
[86] 79 Fed. Reg. 5032 (Jan. 30, 2014).
[87] Twitchell, Exh. No. JBT-10C at 16.
[88] Link, Exh. No. RTL-1CT 2:23-25.
[89] Link, TR. 630:8 - 631:8; *see also* Twitchell, Exh. No. JBT-10C at 17 ("[redacted]").
[90] Link, TR. 630:5-7; Link, Exh. No. RTL-1CT 4:5-5:6; *see also* Twitchell, Exh. No. JBT-10C at 17 ("[redacted]").
[91] Link, Exh. No. RTL-1CT 4:5-5:6.

Model produces a PVRR(d) forecast that is only as accurate as the long-term cost assumptions that the Company inputs into the Model.[92]

46 Three critical cost assumptions drive the SO Model's PVRR(d) forecast: long-term natural gas, coal, and CO_2 prices.[93] Pacific Power internally developed all three key cost assumptions that drive the SO Model analysis. The Company captures its natural gas price assumptions in its official forward price curve (OFPC), which it constructs quarterly after reviewing forecasts from three third-party consultants.[94] The Company captures its coal price assumptions in its Bridger fuel plan; the Company develops its Bridger fuel plan approximately every two years based on costs captured in its most-current Bridger Coal Company (BCC) Mine Plan and forecasts received from third-party coal suppliers.[95] The Company developed CO_2 price assumptions only once because it lacked better information about prospective carbon regulations.[96]

47 Ultimately, Pacific Power completed three SO Model analyses to support SCR investment as the preferred regional haze compliance option for Bridger Units 3 and 4. Pacific Power completed its first SO Model analysis of alternative regional haze compliance options for Bridger in August 2012.[97] The August 2012 analysis incorporated natural gas price assumptions from the Company's December 2011 OFPC; what coal cost assumptions the Company used is not clear.[98] The August 2012 "base case" analysis forecasted the PVRR(d) in favor of SCR

[92] Link, TR. 643:20 - 644:6.
[93] *See, e.g.,* Link, TR. 635:10-11; Exh. No. RTL-1CT 8:6-21.
[94] *See* Link, Exh. No. RTL-11CT 17:3 - 18:2; *see also* Link, TR. 688:12 - 690:16.
[95] Ralston, Exh. No. DR-1CT 3:21-23, 7:3-13 (Pacific Power owns and operates the BCC mine—it is the primary source of coal for the Bridger plant).
[96] Link, Exh. No. RTL-11CT 30:17-25.
[97] Twitchell, Exh. No. JBT-10C at 16.
[98] Twitchell, Exh. No. JBT-10C at 19 (The Company's use of its December 2011 OFPC is puzzling—if it developed OFPCs quarterly, the Company should have had two more-current OFPCs by August 2012.).

installation by [redacted], as compared to the next best alternative—converting Bridger to run on natural gas.[99] Supported by this analysis, Pacific Power filed an application for a Certificate of Public Convenience and Necessity (CPCN) with the Wyoming Public Service Commission (Wyoming PSC) on August 7, 2012; and it filed an application for pre-approval of the SCR installation with the Utah Public Service Commission (Utah PSC) on August 24, 2012.[100]

48 Pacific Power completed its second SO Model analysis in February 2013 at the behest of parties to the application proceedings in Wyoming and Utah.[101] The February 2013 analysis corrected aspects of the August 2012 analysis and incorporated the Company's more current key cost assumptions, including natural gas price assumptions from the September 2012 OFPC and coal cost assumptions from its January 2013 Bridger fuel plan.[102] The February 2013 "base case" analysis forecasted the PVRR(d) in favor of SCR by [redacted] as compared to the next best alternative—converting to natural gas.[103] Driven by falling natural gas prices and rising coal costs, the favorable value of the SCR option decreased by [redacted] million by December 2013, resulting in a net benefit of [redacted] million in favor of gas conversion.[104]

49 In addition to its base case analysis, Pacific Power conducted sensitivity analyses with the SO Model using several different combinations of price assumptions for the outcome drivers of natural gas and CO_2—but not for coal.[105] From these sensitivity analyses, the Company created

---

[99] Twitchell, Exh. No. JBT-10C at 17.
[100] Teply, Exh. No. CAT-14CT 6:1-4, 7 (Figure 1-Bridger SCRs Timeline).
[101] Twitchell, Exh. No. JBT-10C at 21; Exh. No. JBT-1CT 60:1-2.
[102] Twitchell, Exh. No. JBT-10C at 21-22 (The Company's use of its September 2012 OFPC is puzzling—if it developed OFPCs quarterly, the Company should have had a more-current OFPC by February 2013.).
[103] Link, Exh. No. RTL-1CT 13:1-9.
[104] The $274.5 million figure has three components: the impact of the September 2013 OFPC (Twitchell, Exh. No. JBT-1CT 9:1), the impact of the October 2013 BCC Mine Plan (Twitchell, Exh. No. JBT-28HCT 9:16), and the impact of the December 2013 OFPC (*see* Twitchell, Exh. No. JBT-28HCT 30:6-9).
[105] Link, Exh. No. RTL-1CT 9:1-13; Link, TR. 635:23-24.

two regression graphs—one for the natural gas cost driver and one for the CO_2 cost driver—to depict how the SO Model's forecasted PVRR(d) would change in relation to an isolated change in either one of these two independent variables.[106] For example, the natural gas regression graph depicts how the SO Model's forecasted PVRR(d) changes as natural gas price assumptions change: the favorable PVRR(d) to SCR installation decreases [redacted] for every 1 cent decrease in the assumed price of natural gas, and vice versa.[107] Pacific Power's natural gas regression graph, however, only depicts how different natural gas price assumptions affect the SCR's favorable PVRR(d) *with all other cost assumptions held constant*; if any other assumption used as an input to the SO Model changes, the regression graph would no longer accurately depict the SO Model's forecasted relationship between natural gas price and PVRR(d).[108]

50 Pacific Power completed a third SO Model analysis in April 2013 as part of its 2013 Integrated Resource Plan (IRP), which was filed and reviewed in each of the Company's jurisdictions.[109] The April 2013 IRP analysis forecasted the PVRR(d) in favor of SCR by [redacted] as compared to the next best alternative—converting to natural gas.[110] This represented a mere 0.6 percent difference in total portfolio costs between the two compliance options.[111]

51 The April 2013 IRP analysis was the first version of the SO Model analysis presented to the Commission.[112] Given the narrow 0.6 percent cost difference between the SCR and gas conversion options, the Commission requested that the Company provide two new analyses with its 2013 IRP Update: a break-even analysis that would identify the levelized forward natural gas

[106] *See* Link, Exh. No. RTL-9C; Exh. No. RTL-10C.
[107] Twitchell, Exh. No. JBT-19HCT 25:21-26:2.
[108] Link, TR. 637:24-638:7.
[109] Teply, Exh. No. CAT-14CT 6:1-6.
[110] Twitchell, Exh. No. JBT-1CT 21:13-19.
[111] Twitchell, Exh. No. JBT-1CT 21:13-19.
[112] Twitchell, Exh. No. JBT-1CT 20:10-13.

price at which gas conversion would become cost effective, and an updated analysis based on current data.[113] The Commission stated that the updated analysis was "necessary to ensure that the Company does not commit itself to investments that later prove not to be cost-effective."[114]

52 To satisfy the Commission's request for a break-even analysis, Pacific Power presented the natural gas regression graph it developed in conjunction with the February 2013 analysis with its IRP Update.[115] Pacific Power, however, ignored the Commission's request for an updated analysis based on current data.[116] When Staff sent the Company a data request to again ask for the updated analysis, the Company refused to provide an analysis of information it had not performed.[117] Pacific Power never updated its SO Model analysis after April 2013.[118]

3. SCR and natural gas conversion compliance options each offered different cost advantages.

53 Pacific Power's SO Model analyses forecasted that the SCR option had a favorable PVRR(d) because its higher fixed costs were more than offset by its lower variable costs as compared to the natural gas conversion option.[119] Specifically focusing on the February 2013 analysis, the SCR option had higher "fixed costs associated with the capital for the SCR systems, which is approximately [redacted]/kW higher than gas conversion capital costs, and levelized annual operating and run-rate capital costs, which are approximately [redacted]/kW higher than projected gas

[113] Link, Exh. No. RTL-14CX at 2-4.
[114] Link, Exh. No. RTL-14CX at 4.
[115] Twitchell, Exh. No. JBT-1CT 23:1-17.
[116] Twitchell, Exh. No. JBT-1CT 23:6-7.
[117] Twitchell, Exh. No. JBT-1CT 25:1-7; Exh. No. JBT-11.
[118] There is no evidence in this proceeding demonstrating, or even indicating, that the Company updated its SO Model analysis after April 2013.
[119] Link, Exh. No. RTL-1CT 14:6-8 ("System variable costs include fuel, net system balancing revenue, variable O&M expenses, and CO2 emissions expenses. System fixed costs include incremental environmental controls costs, fixed O&M and run-rate capital expenses for existing and new resources, and changes to system demand-side management costs." Link, Exh. No. RTL-1CT at 14, n.3.).

conversion costs."[120] On the other hand, the SCR option had lower fuel costs and was predicted to dispatch more, which produced higher net system balancing revenues.[121] Overall, the SCR system's [redacted] million higher fixed costs offset the gas conversion option's [redacted] million higher variable costs, which produced the SCR's [redacted] million favorable PVRR(d).[122]

54 Certain differences between fixed costs and variable costs carry implications about the results of the SO analysis. First, forecasting fixed costs involves a higher degree of certainty than forecasting variable costs.[123] Second, all three of the key cost drivers of the SO Model analysis were variable costs.[124] Generally, falling natural gas prices, rising coal prices, and rising carbon expenses all serve to lower the benefit of SCR compared to the gas conversion alternative.[125] Third, regulated investor-owned utilities, such as Pacific Power, only earn a return on their capital costs, which are fixed costs; variable costs are merely passed on to the ratepayer.[126] The SCR and the natural gas compliance options, therefore, carried different implications for the Company and its customers. At the time of its third and final SO analysis, from a customer perspective, the total cost difference of the two options was relatively minor—a mere 0.6 percent.[127] However, the SCR option would have been the clear preferred choice for the Company given its significantly higher fixed costs, which would result in greater returns for shareholders.

---

[120] Link, Exh. No. RTL-1CT 14:2-6.
[121] Link, Exh. No. RTL-1CT 13:13 - 14:2.
[122] Link, Exh. No. RTL-1CT 14:6-8.
[123] Link, TR. 648:1-6.
[124] Link, TR. 649:19 - 650:7.
[125] Link, TR. 650:8 - 651:1.
[126] Link, TR. 652:5-11.
[127] Twitchell, Exh. No. JBT-1CT 21:13-19.

4. PacifiCorp management approved funding SCR installation.

55 Pacific Power contracted to install SCR on Bridger Units 3 and 4 once it received regulatory approvals in the Utah and Wyoming commissions. On May 10, 2013, the Utah PSC granted the Company's preapproval request, but cautioned: "the approval of resource decision projected costs in this Order is conditioned on the Company acting prudently when responding to potential new information and changed conditions."[128] On May 30, 2013, the Wyoming PSC granted the Company's CPCN request.[129] That same day, the CEO of PacifiCorp, Greg Abel, approved the appropriations request to fund SCR installation.[130] Mr. Abel delegated all further decisions regarding SCR installation to Michael Dunn, who was President and CEO of Rocky Mountain Power at the time.[131] On May 31, 2013, Pacific Power executed the EPC contract for the SCR installation.[132]

56 Pacific Power structured the EPC contract to contain significant flexibility for altering or abandoning the SCR installation at a minimal cost. The EPC contract contained a limited notice to proceed (LNTP), which was issued with the initial execution of the contract, and a full notice to proceed (FNTP) deadline of December 1, 2013.[133] During the LNTP phase, the contractor was limited to engineering and planning activities, and expressly forbidden from entering any procurement agreements or conducting any on-site work.[134]

57 The [redacted][135]

---

[128] Twitchell, Exh. No. JBT-1CT 61:14-17.
[129] Twitchell, Exh. No. JBT-1CT 60:7-9.
[130] Teply, Exh. No. CAT-14CT, 7 (Figure 1-Bridger SCR Timeline); Teply, TR. 469:14-24.
[131] Teply, TR. 550:14-21.
[132] Teply, Exh. No. CAT-14CT 7 (Figure 1-Bridger SCR Timeline).
[133] Twitchell, Exh. No. JBT-1CT 27:2-4.
[134] Twitchell, Exh. No. JBT-1CT 27:4-6.
[135] Teply, Exh No. CAT-21C at 7.

[redacted][136] [redacted][137]

5. **Price forecasts materially changed for two key cost drivers of the SO Model.**

58 Subsequent to issuing the LNTP, Pacific Power identified critical new information about forward natural gas and coal prices that eroded SCR's favorable PVRR(d).[138] In September 2013, the Company identified that forward natural gas price forecasts dramatically declined. The Company's September 2013 OFPC revealed that the benefits of SCR installation had decreased by approximately 30 percent since the February 2013 analysis: from [redacted] in favor of SCR to approximately [redacted].[139] The Company's natural gas regression graph shows that it understood the effect of the September 2013 OFPC on its February 2013 analysis.[140] Yet, the Company did not update its SO Model analysis with its up-to-date information on natural gas prices.

59 In October 2013, Pacific Power identified that coal costs for Bridger also materially increased. The Company developed a new BCC Mine Plan in October 2013, which accounted for major changes to the mine's operation.[141] Specifically, the October 2013 Mine Plan budgeted for BCC's underground mine to close in 2023; however, in prior BCC mine plans, the underground mine remained in operation through the long-term planning horizon.[142] This dramatic change in

---

[136] Twitchell, Exh. No. JBT-1CT 27:11-13.
[137] Twitchell, Exh. No. JBT-35HC; Twitchell, Exh. No. JBT-28HCT 30:1-14.
[138] Twitchell, Exh. No. JBT-28HCT 1:15-23.
[139] Twitchell, Exh. No. JBT-28HCT 3:20 - 4:1.
[140] Link, TR. 638:8-16.
[141] Twitchell, Exh. No. JBT-28HCT 10:17 - 11:12.
[142] Twitchell, Exh. No. JBT-28HCT 11:23-25.

strategy significantly affected the overall long-term cost of BCC coal because of the increased variable production costs associated with substituting higher-cost, miner-based production at the surface mine for lower-cost, machine-based production at the underground mine.[143] At the time, Pacific Power did not conduct an analysis of how rising coal costs identified in the October 2013 Mine Plan would affect the value of SCR. The Company acknowledges that the increased coal costs identified in the October 2013 Mine Plan further eroded SCR's favorable PVRR(d); however, the overall effect of that impact remains in dispute.[144]

6. Pacific Power issued the FNTP without using the SO Model to study the impact of the most currently available information on the value of SCR installation.

60 Despite identifying changes to two key cost assumptions, Pacific Power issued the FNTP on December 2, 2013, without ever formally reassessing the economics of SCR installation.[145] Chad Teply "reviewed all key decision factors" and recommended issuance of the FNTP.[146] Michael Dunn, President and CEO of Rocky Mountain Power at the time, made the final decision to issue the FNTP.[147] [redacted][148] [redacted][149] [redacted] because the EPA had not yet issued a final ruling on Wyoming's regional haze

[143] Twitchell, Exh. No. JBT-28HCT 12:5-9.
[144] Link TR. 650:23 - 651:1; Crane, TR. 590:18 - 591:1.
[145] Teply, TR. 470:25 - 471:10.
[146] Teply, 4:22, 5:11-12.
[147] Teply, TR. 550:14-21.
[148] Teply, Exh. No. CAT-23C.
[149] Teply, Exh. No. CAT-23C; Teply, TR. 461:16-20.

requirements—that final rule came on January 30, 2014.[150]

61 Shortly after issuing the FNTP, Pacific Power identified new natural gas price information that again materially eroded the value of SCR installation. In October and November 2013, the Company received updated forecasts from two of its three third-party consultants that reflected moderate reductions to their natural gas price forecasts.[151] On December 11, 2013, the Company received the update from the third consultant, which reflected a dramatic decrease. On December 31, 2013, when the Company constructed its December 2013 OFPC, its forward price fell from [redacted] per mmBtu to [redacted] per mmBtu.[152] Relative to the September 2013 OFPC and holding all other variables constant, including the rising coal costs identified in the October 2013 mine plan, the December 2013 OFPC created a [redacted] swing in favor of gas conversion, reducing SCR's favorable PVRR(d) to [redacted].[153] Thus, from the time the Company conducted its first SO Model analysis in August 2012 to the end of December 2013, declining natural gas prices alone decreased SCR's favorable PVRR(d) by almost 90 percent.[154] The trend of declining natural gas prices was both sustained and accelerating.[155] The Company did not avail itself of the flexibility in the EPC contract that would allow it to cancel SCR installation after issuing the FNTP.

C. Pacific Power's Decision To Install SCR Was Imprudent

62 Pacific Power presented its February 2013 analysis and its two regression graphs to support the prudence of its decision to install SCR at Bridger Units 3 and 4.[156] As Commission

---

[150] Teply, Exh. No. CAT-23C at 12.
[151] Twitchell, Exh. No. JBT-28HCT 27:5-6.
[152] Twitchell, Exh. No. JBT-28HCT 27:11-13.
[153] Twitchell, Exh. No. JBT-28HCT 28:1-3.
[154] Twitchell, Exh. No. JBT-28HCT 27:20.
[155] Twitchell, Exh. No. JBT-28HCT 28:6-7.
[156] *See* Link, Exh. No. RTL-1CT.

Staff and Sierra Club independently determined, however, it is clear that the Company imprudently issued the FNTP after it identified material changes to both its natural gas and coal cost assumptions that each eroded the value of SCR installation. Had the Company reassessed the value of SCR installation with the SO Model, it would have identified that natural gas conversion had become the clear economic choice. Moreover, the flexibility of the EPC contract would have allowed the Company to change course and capture the significant benefits for its customers—both prior to issuing the FNTP on December 1, 2013, and again in January 2014. The Company, however, claims the cost changes were not material in light of offsetting EPC cost savings, and even if it had reassessed the value of SCR installation with the SO Model, SCR installation would have remained the preferred choice. Consequently, the issue of how the SO Model would have responded to the identified cost changes is a key issue of dispute.

63 Pacific Power, Commission Staff, and Sierra Club all attempted to replicate how the SO Model analysis would have responded to the Company-identified cost changes. Each of their post hoc calculations was done outside of the SO Model because Pacific Power refused to allow the parties to access the Model and refused to rerun the Model with different assumptions.[157]

1. Pacific Power failed to establish the appropriateness of its actions using the data and methods reasonable management would use.

64 Reasonable management studies the appropriateness of its expenditures before making a decision using the most currently available information.[158] In contrast, Pacific Power never adequately studied the decision to issue the FNTP. In particular, the Company never used the SO Model to reassess the value of SCR installation after issuing the LNTP.[159] Despite acknowledging that "an undisputable reversal of project economics, new or changed

[157] Twitchell, TR. 742:13-743:13; Twitchell, Exh. No. JBT-11.
[158] Puget 1994 Order at 2, 37, 48.
[159] Teply, TR. 470:25 - 471:10; Teply, Exh. No. CAT-40-CT 4:22-5:12.

environmental compliance requirements, changes to legislative policies impacting the resource for all customers, or similar major events" all could have lead to the prudent cancelation of SCR installation in January 2014,[160] the Company contended: "there was no triggering event that caused [it] to reassess SCR versus gas conversion, other than to compare back to the tools that [it] had created [i.e., the regression graphs]."[161] The regression graphs, however, were not capable of depicting the effect of the significant changes that had occurred. The SO Model is needed to understand how changes in two or more key cost assumptions affect the PVRR(d) of the SCR option.[162] Prior to issuing the FNTP, Pacific Power needed to rerun the SO Model using the Company's most current price assumptions to adequately understand how the material changes in natural gas and coal price forecasts affected the value of SCR investment. By failing to rerun the model, Pacific Power failed its duty to adequately study the investment decision.

65 Reasonable management also keeps contemporaneous records of its decision process to facilitate the Commission's review: "This is the minimum standard to which a regulated utility should be held."[163] Pacific Power did not clear this hurdle either. The Company alleged that before issuing the FNTP it had "reviewed all key decision factors," including: (1) its September 2013 OFPC; (2) the October 2013 Mine Plan; and (3) a $28 million cost reduction it had negotiated in the EPC contract.[164] The Company, however, did not provide any evidence to substantiate that such a review ever took place or that the Company identified the $28 million cost reduction prior to issuing the FNTP.[165] At hearing, Mr. Teply testified that his review

[160] Teply, Exh. No. CAT-40CT 6:21 - 7:2.
[161] Teply, TR. 471:4-10; 79 Fed. Reg. 5032 (Jan. 30, 2014).
[162] Link, TR. 641:19 - 642:1.
[163] Puget 1994 Order at 2, 37, 48.
[164] Teply, Exh. No. CAT-40CT 4:22 - 5:3.
[165] Twitchell, TR. 750:22 - 752:19.

involved "literally sitting down at a desk, looking at the screen, 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."[166] Mr. Teply further asserted that he had engaged in "daily phone calls with Mr. Link [and] almost daily phone calls with [the Company's] fuels group" to get comfortable with the numbers before recommending to Mr. Dunn to issue the FNTP.[167] Mr. Teply, however, admitted that there is "very little documentation" to demonstrate that such a review ever took place because it was accomplished mostly by "verbal communications" and that it was not captured in the FNTP memo.[168] Ultimately, the Company produced no evidence to support its witnesses' claims that the Company ever reassessed the value of SCR installation after issuing the LNTP. Pacific Power thus failed to meet the minimum standard to which a regulated utility should be held.

2. Pacific Power's post hoc calculation of increased coal costs is not credible.

66 The parties' corrections to the Company's February 2013 analysis primarily concern the effect of the coal cost increases identified in the October 2013 BCC Mine Plan. BCC mine plans have been the subject of much confusion and controversy in this case. Pacific Power was not forthright with information about its mine plans in discovery and repeatedly added new layers of complication about their purpose and function only after Staff took a position based on the information the Company provided.

67 Pacific Power seeks to diminish the importance of the October 2013 Mine Plan by distinguishing it from a long-term fuel plan for Bridger. The Company claims that "the nature of the data provided in the two types of plans is different, and different analytical rigor is applied in

166 Teply, TR. 465:2-6.
167 Teply, TR. 554:7-25.
168 Teply, TR. 554:19 - 555:9; *see also* Teply, Exh. No. CAT-23C; Teply, TR. 461:16-20.

developing the long-term data included in the [two] plans."[169] Specifically, Ms. Crane testified that BCC mine plans are 10-year budgets that only identify BCC coal costs, which is only one of the two mines that supply coal to Bridger.[170] In contrast, Bridger fueling plans forecast over a longer term all costs to Bridger, including the coal price forecasts from the third-party supplier.[171] Ms. Crane accused Staff of "mistakenly [assuming] that the long-term data in a mine plan is comparable to the long-term data in the October 2013 Mine Plan (data for the period 2023 through 2030)."[172] But at hearing, Ms. Crane *for the first time* provided an added layer of complication: there are also two different types of BCC mine plans, regular mine plans, which apply less analytical rigger to the forecasted expenses in the years beyond the 10-year budget horizon, and Life of Mine Plans, which incorporate greater analytical rigor in the years beyond the 10-year budget horizon and which are used to develop the Bridger fuel plan.[173] The October 2013 BCC Mine Plan, however, is much more important than the Company let on.

68 The October 2013 Mine Plan is critically important for three reasons. First, BCC mine plans are the most important component of Bridger fuel plans.[174] The plant and mine do not operate independently: "the mine is captive to the Jim Bridger plant."[175] The majority of Bridger's fuel comes from the BCC mine.[176] The BCC's underground mine is also the largest and cheapest single source of coal for Bridger.[177] In October 2013, "BCC accounted for 85 percent of Bridger's fuel and [a third-party supplier] provided the remaining 15 percent."[178]

[169] Crane, Exh. No. CAC-1CT 3:20-22.
[170] Crane, Exh. No. CAC-1CT 3:12-13.
[171] *See* Crane Exh. No. CAC-1CT 3:16-19; Ralston, Exh. No. DR-1CT 3:21-23.
[172] Crane, Exh. No. CAT-1CT 5:18 - 6:1.
[173] *See* Crane, TR. 581:10 - 589:13.
[174] Ralston, Exh. No. DR-1CT 14:15-16.
[175] Ralston, Exh. No. DR-1CT 14:7-13.
[176] Crane, TR. 579:13-16.
[177] Crane, TR. 590:11-17.
[178] Twitchell, Exh. No. JBT-28HCT 18:18-5.

Second, as already discussed, the October 2013 Mine Plan accounted for major changes to the mine's operation, which significantly increased the overall long-term cost of BCC coal.[179] Third, as Ms. Crane admits, the October 2013 Mine Plan represented the most currently available information about Bridger coal costs available to the Company.[180] As Staff succinctly stated: "The October 2013 Mine Plan rendered the January 2013 long-term fuel plan obsolete."[181]

69 Pacific Power's post hoc calculation of increased coal costs is riddled with errors that each serve to undervalue the impact of the October 2013 Mine Plan. The Company claims that the SCR's favorable PVRR(d) would have only decreased by [redacted] million had it accounted for the October 2013 Mine Plan.[182] The Company's calculation, however, was based on the ten-year time frame between 2014 and 2023; whereas the Company's SCR analysis and Staff both used the 15-year time frame from 2016 to 2030.[183] By limiting its calculations to the 2014 to 2023 time frame, the Company's calculations did not account for the higher BCC coal costs that result from the underground mine's closure after 2023, thereby materially understating the impact of the October 2013 Mine Plan.[184] Moreover, the Company's coal cost calculation inappropriately divided the net present value of costs by the net present value of mmBtus, a nonsensical calculation that again served to materially understate the impact of the October 2013 Mine Plan.[185] Ms. Crane asserts that this approach is necessary to account for annual fluctuations in BCC production volumes.[186] Aside from the Company's obvious misunderstanding of the purpose of discounting, the Company's argument fails to address the fact that Staff's analysis

---

[179] Twitchell, Exh. No. JBT-28HCT 10:17 - 1 2:9.
[180] Crane, TR. 578:14-19.
[181] Twitchell, Exh. No. JBT-28HCT 6:12-13.
[182] Crane, Exh. No. CAC-1CT 4:19-20.
[183] Crane, TR. 591:11-18.
[184] Crane, TR. 593:20 - 594:2.
[185] Crane, Exh. No. CAC-11CX.
[186] Crane, TR. 594:24-596:10.

explicitly considered and accounted for the varying production volumes and associated costs for each year of the mine plan.[187] Pacific Power's post hoc calculation of increased coal costs is inaccurate, self-serving, and ultimately not credible.

70 In contrast, Staff calculated coal costs transparently, using the information and raw data provided by the Company. Careful to avoid hindsight review, Staff openly acknowledged when a lack of available information limited its ability to determine how the October 2013 Mine Plan affected the gas conversion option given the information available.[188] Sierra Club used reasonable proxies to fill the information gap, which drew objections from the Company.[189] The Commission, however, has found that "[t]he responsibility for the dearth of contemporaneous information rests squarely with [the company]," and that "[i]t is difficult to construct an adjustment, using information that was, or should have been available to [the company] at the time . . . ."[190] In such circumstances, the Commission has rejected the company's contention that "the offered proxies should be discarded because they are not perfect."[191] Ultimately, Staff and Sierra Club's calculations corroborate each other by independently arriving at similar conclusions about the impact of the October 2013 Mine Plan on Bridger's coal costs. Their calculations are more credible than those of Pacific Power.

D. The Commission Should Disallow Pacific Power's Imprudent Costs

71 Pacific Power has not demonstrated that its decision to install SCR rather than convert to natural gas was prudent. Ratepayers should be held harmless for the Company's imprudent decision to proceed with SCR. In recognition that installing emissions control measures would

---

[187] Twitchell, Exh. No. JBT-31C.
[188] Twitchell, Exh. No. JBT-28HCT 20:9 - 21:21.
[189] Fisher, Exh. No. JIF-24CT 12:10 - 17:14.
[190] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy & Light Co.*, Docket Nos. UE-920433, UE-920499, UE-921262, Nineteenth Supplemental Order, 31 (Sept. 27, 1994).
[191] *Id.*

ultimately be necessary at Bridger, Staff recommends only a partial disallowance. As the Company itself recognizes, the Commission has discretion to order a partial disallowance of an investment that it finds to have been imprudent.[192]

72 In this case, Staff has shown that gas conversion would have been the more economic option for ratepayers. It is appropriate, therefore, to allow the equivalent costs of gas conversion to be recovered in rates and disallow the difference in cost between gas conversion and the installation of SCR. The difference, which is Staff's recommended disallowance, is [redacted].[193]

V. OTHER ADJUSTMENTS

A. Transmission Asset Allocations

73 Pacific Power attempts to pad Washington ratepayer bills with expenses for facilities that the Company may only use to serve Washington under certain contingencies, if at all. Without more concrete information on the costs and on how certain transmission assets will actually benefit Washington ratepayers, these assets should not be included in rates. State law authorizes the Commission to determine the value of property, which is used and useful, for inclusion in rates.[194] Because Pacific Power has not demonstrated that all of the transmission assets in its Adjustment 8.13 are used and useful, the Commission should not include all of these rate base additions in rates. Staff's recommended adjustment regarding these transmission assets meets the used and useful standard. The Staff adjustment represents an increase to revenue requirement of

[192] Dalley, TR. 446:16-22.
[193] Twitchell, JBT-1T 54:9-14. Mr. Twitchell provides a table on p. 55 of his testimony summarizing his calculations of Staff's recommended disallowance.
[194] RCW 80.04.250; *People's Organization for Washington Energy Resources (POWER) v. Wash. Utils. & Transp. Comm'n*, 101 Wn.2d 425, 430 (1984) ("RCW 80.04.250 empowers the Commission to determine, for rate making purposes, the fair value of property which is employed for service in Washington *and* capable of being put to use for service in Washington") (emphasis included).

approximately one million dollars, which is approximately half a million dollars lower than the Company's proposed adjustment.[195]

74 Last Fall, the Commission approved a petition by Pacific Power for approval of an exchange of certain transmission assets with Idaho Power Company.[196] Pacific Power now seeks to add to its rate base certain transmission assets that the Company mostly associates with the exchange. Staff has analyzed the assets and has placed them into in three categories: (1) the transmission assets Pacific Power received in the exchange; (2) other assets that the Company claims are now, as a result of the exchange, used and useful for service to Washington ratepayers; and (3) assets that should already have been assigned to the West Control Area (WCA). Staff refers to these assets, respectively, as the "Exchange Assets," the "Reassignment Assets," and the "Correction Assets."[197] The WCA includes the California, Oregon and Washington loads and resources.[198] Staff does not dispute inclusion of the Correction Assets in rate base, because they are part of the primary transmission path for the Wyoming Bridger plant, which serves Washington loads.[199] Costs associated with assets that are located outside the WCA may be assigned to the WCA and allocated to Washington if the assets are used to serve Washington.

75 Staff recommends excluding the Exchange Assets and the Reassignment Assets from the WCA because the Company has not shown that they are used and useful in Washington. Staff's proposed adjustment is consistent with the Commission's guidance on allocating costs to Pacific

[195] Ball, Exh. No. JLB-1T 74:19-23.
[196] *In Re Petition of Pacific Power & Light Co. for an Order Approving the Exchange of Certain Transmission Assets with Idaho Power Company*, Docket UE-144136, Order 01 (Sept. 24, 2015) (Asset Exchange Order).
[197] Ball, Exh. No. JLB-1T 61:1-16.
[198] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-061546, Order 08, 13, ¶ 44 (June 21, 2007) (in which the Commission approved the West Control Area interjurisdictional cost-allocation methodology for Washington).
[199] *See* Ball, Exh. No. JLB-1T 74:4-9.

Power's service territory in Washington. The Commission has interpreted the phrase "used and useful for service in this state" to mean "benefits to ratepayers in Washington,"[200] and has established that "the test for including a resource in rates is . . . whether it provides quantifiable direct or indirect benefits to Washington commensurate with its cost."[201] In the Commission's order approving the WCA cost allocation methodology, the Commission confirmed such articulations of the "used and useful" standard.[202] Under the WCA methodology, assets within the WCA are presumed to be used to serve Washington.[203] Resources outside the WCA can be assigned to the WCA and costs can be allocated to Washington if adequate transmission is available for these resources to provide delivery to Washington customers.[204] However, as the Commission elaborated on reconsideration of its final order rejecting the Company's Revised Protocol allocation methodology, such resources or assets must actually be used and useful in Washington:

> Both common sense and hornbook utility law support our conclusion that RCW 80.04.250 requires a resource to be "employed in accomplishing something … beneficial" for Washington ratepayers ("in this state"), before they can be required to pay for it. Our Order allows these benefits to be direct or indirect, tangible or intangible, as long as they are reasonably quantifiable and commensurate with their costs.[205]

76 Pacific Power has not established that the Exchange Assets and the Reassignment Assets provide quantifiable benefits to Washington commensurate with their costs. The Company's

[200] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-050684, Order 04, 21, ¶ 50 (Apr. 17, 2006).
[201] *Id.* at 27-28, ¶ 68.
[202] *See* Docket UE-061546, Order 08 at 16, ¶ 57. ("We find the WCA cost-allocation for Washington, modified by our adoption of Staff's adjustments 5.4 and 5.5, produces results that are consistent with the requirements for an allocation methodology that we have discussed in prior orders, particularly our Final Order in PacifiCorp's 2005 Rate Case").
[203] *See* Docket UE-061546, Order 08 at 7, ¶ 11.
[204] *See* Docket UE-061546, Order 08 at 13, ¶ 44.
[205] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-050684, Order 06, 19, ¶ 27 (July 14, 2006), *citing* Goodman, *The Process of Ratemaking* (1998) at 800; 73 C.J.S. *Public Utilities* § 46 (2005).

presentation of the costs of these assets is incomplete, in significant part because it does not reflect the additional net power costs resulting from the exchange.[206] This rate case does not include updated power costs, and so there simply is no information in the record about whether the exchange may result in higher net power costs, lower net power costs, or in no change to net power costs.[207]

77 Because this case does not include updated power costs, there is also an incomplete record on the level of benefits of the transaction. For example, the Company's case does not include or quantify benefits associated with increased flexibility in resource dispatch and wheeling across the PACW and PACE systems.[208] This is appropriate for this case because updating power costs to reflect the transmission asset exchange necessarily involves changing the baseline power cost rate, which would change the PCAM before it has had a chance to operate. Even though the Company's PCAM has a comparison to actuals, with various sharing bands, the baseline power cost rate is the only *rate* where such costs or benefits will materialize. We will only be able to evaluate the PCAM if the baseline remains the same and the mechanism can run for at least one cycle. Therefore, Staff does not support changing the PCAM base rate in this rate case.[209] Not updating baseline power costs, however, necessarily makes it premature to evaluate the benefits of the asset exchange. And this is an independent reason that the Commission should not incorporate the Exchange Assets and the Reassignment Assets into rates at this time.

[206] Ball, Exh. No. JLB-1T 72:1-3.
[207] *See* Ball, TR. 342:12-25.
[208] Ball, Exh. No. JLB-1T 71:13-16.
[209] Ball, Exh. No. JLB-1T 71:19-20; 12:4-19.

78 Staff's recommendation, to exclude the Exchange Assets and the Reassignment Assets from rates at this time, is unlikely to affect Pacific Power's PCAM. The PCAM baseline is an estimate of net power costs.[210] Pacific Power has not demonstrated in this case how, if at all, the asset exchange affects net power costs. Under the PCAM, *actual* power costs that are $4 million greater or less than the net power cost baseline on a Washington basis are subject to sharing 50/50 among the Company and its ratepayers.[211] As Mr. Ball testified, however, it is very unlikely that more than $4 million in variable power cost benefits on a Washington basis will materialize from the asset exchange.[212] At any rate, Pacific Power has not made any such showing and, if such a showing could be made, Staff would have expected the Company to include power costs in this rate proceeding.[213] Accordingly, the asset exchange does not require an immediate reevaluation of the PCAM baseline as it is unlikely that any benefits from the transaction would reach beyond the dead band of the PCAM mechanism.

79 The putative benefits that are in the record appear to be the increased dynamic overlay, which is being used for the Energy Imbalance Market (EIM), and increased efficiency in administering transmission agreements between Pacific Power and Idaho Power.[214] As a threshold matter, any benefits accruing through the EIM are necessarily not reflected in this case because they affect power costs. And power costs are not part of this case.

80 With regard to benefits in general, Pacific Power has not demonstrated that any benefits accrue to Washington ratepayers, either directly or indirectly. Washington rate payers appear to

---

[210] *See Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.*, Docket UE-140762, Order 09, 9, ¶ 24 (May 26, 2015).
[211] *Id.* at 11, ¶ 30.
[212] Ball, TR. 346:8-23.
[213] *See* Ball, TR. 346:18-22.
[214] Ball, Exh. No. JLB-1T 71:7-11.

be receiving the same service they received before the exchange, without any proven improvement.[215] The same amount of power is flowing to Washington.[216] And even though Pacific Power now has an ownership interest in a third path out of Bridger, which it did not have before the exchange, it is not at all clear how this would actually benefit Washington because the Goshen line sends power to the eastern balancing area and not the WCA.[217] As Mr. Ball correctly points out, these transmission assets cannot be allocated to the WCA "simply because they are connected to Jim Bridger."[218] They must actually benefit Washington, indirectly if not directly, and this the Company has not shown. Moreover, the Company appears to have been able to maintain service before the transaction,[219] so it is not clear that service to Washington or elsewhere in the WCA will actually be more reliable now with Pacific Power's part ownership of the Goshen line. Accordingly, the Commission should not allow Pacific Power to collect half a million dollars more in rates every year from Washington ratepayers without demonstrating actual benefits, quantifying them, and showing that they are commensurate with the costs the Company wants ratepayers to pay.

81 Pacific Power likely will argue that one of the benefits of the asset exchange is that the conversion to tariff service for transmission service through Idaho provides new flexibility in the Hurricane and La Grande areas.[220] These two cities are in the WCA.[221] The "flexibility" that the Company touts presumably relates to reliability. While it may be true that increased flexibility in transmission provides an intangible benefit to areas in the WCA, the putative benefit is unquantified and there is no change to how the system is being operated; therefore, the costs of

---

[215] Ball, Exh. No. JLB-1T 72:7-24.
[216] Ball, Exh. No. JLB-1T 72:7-9.
[217] Ball, Exh. No. JLB-1T 74:4-15.
[218] Ball, Exh. No. JLB-1T 73:15-20.
[219] *See* Vail, TR. 289:7-18.
[220] *See* Ball, TR. 340:8-13; JLB-10CX.
[221] Ball, TR. 340:16-19.

this asset should not be assigned to the WCA. Essentially, Pacific Power wants to assign costs to the WCA but no quantified benefits. Most importantly, however, it does not follow that this "flexibility" benefits Washington ratepayers at all. The assets must benefit Washington ratepayers in order to be used and useful for Washington ratemaking purposes, and the Company has not made that showing.

82 At the time the Commission approved the Company's Idaho asset exchange petition, Pacific Power made representations about the costs and benefits.[222] Before the assets are incorporated into Washington rate base, however, Pacific Power must show actual costs and quantified benefits so that the Commission can determine whether the benefits are commensurate with the cost. These costs and benefits are as yet unknown. Until Pacific Power presents a complete picture of how the asset exchange affects net power costs and demonstrates that the assets benefit Washington, the Commission should not include the costs of the exchange assets and the reassignment assets in rates.

B. Non-Major Environmental Remediation Expense

83 Pacific Power currently allocates non-major environmental remediation expense under the WCA methodology using the System Overhead (SO) allocation factor.[223] Staff recommends that the Commission reject this arrangement and instead adopt Staff's Adjustment 8.2, which requires the Company to allocate non-major environmental remediation expense for purposes of Washington rates using situs allocation.[224] These costs are state-specific. As discussed below, the principle of cost causation directs that Washington ratepayers should pay for in-state non-major

---

[222] Twitchell, Exh. No. 7-CX, p. 3.
[223] McCoy, Exh. No. SEM-6T 15:7-8. The SO allocation factor is calculated "by dividing the gross plant (excluding SO allocated plant) allocated to Washington by total Company gross plant." *Wash. Utils. & Transp. Comm'n v. PacifiCorp,* Docket UE-061546, Order 08, 63 (June 21, 2007).
[224] O'Connell, Exh. No. ECO-1T 33:19-20.

remediation costs but should not pay for out-of-state costs that provide no demonstrated benefit to Washington ratepayers and over which Washington ratepayers have no control.

84 In 2005, Pacific Power petitioned for deferral of environmental remediation expenses.[225] The Commission decided that "major projects" would be eligible for deferral and defined "major projects" as those environmental remediation projects expected to involve a total, system-wide Company expenditure of more than $3 million.[226] The Commission directed the Company to expense non-major projects and stated that such costs could be considered for recovery in rates in a general rate proceeding.[227] At the time, the Commission had yet to approve the WCA methodology.[228] The Commission anticipated, however, that it would determine an inter-jurisdictional methodology in the Company's next general rate case[229] and ordered as follows: "The level of environmental remediation costs allocable to Washington and subject to this accounting treatment shall be consistent with the inter-jurisdictional cost allocation methodology then in effect for the Company."[230]

85 One of the principles animating the subsequently-approved WCA methodology is that costs should be allocated based on causation.[231] Situs allocation is consistent with this principle because it "insulate[s] states from policy decisions made by other states."[232] Here, Staff proposes situs allocation of non-major environmental remediation costs because those costs are state-specific. Situs allocation ensures that Washington ratepayers will not absorb the costs associated with out-of-state environmental remediation projects initiated in response to policies over which

---

225 *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.*, Docket UE-031658, Order 01 (Apr. 27, 2005).
226 *Id.* at 5, ¶ 12.
227 *Id.* at 5, ¶ 12.
228 *See id.* at 6, ¶ 17.
229 *Id.* at 7, ¶ 17.
230 *Id.* at 7, ¶ 19.
231 *See Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-130043, Order 05, 39, ¶ 94 (Dec. 4, 2013).
232 *Id.* at 43, ¶ 143.

Washington ratepayers have no control. (Washington ratepayers will, however, pay for the costs associated with in-state projects initiated in response to in-state regulations or policies).

86 Pacific Power's current SO allocation is inconsistent with the principle of cost causation. Other expenses allocated using the SO factor are payroll and general office expenses.[233] Non-major environmental remediation costs are not system-wide overhead expenses like payroll. They are state-specific costs that should be allocated to the jurisdiction that (a) caused the costs and (b) enjoys the benefits associated with the costs. As Staff witness Ms. O'Connell testified, the use of the SO allocation factor here "is at fundamental odds" with the WCA methodology.[234]

C. End-Of-Period Rate Base

87 Staff supports the Company's proposal to measure electric-plant-in-service using end-of-period (EOP) balances rather than average-of-monthly-averages (AMA) balances (Adjustments 6.1–6.1.3 and 8.11–8.11.5).[235] Staff believes that EOP rate base is one tool that may reduce the impact of regulatory lag.[236] This reduction, in turn, may slow the frequency of rate filings. Further, it is especially appropriate in this case given the rate plan, because EOP treatment brings forward the plant balances to a time period that is more consistent with the two rate periods.

88 EOP rate base "is an appropriate regulatory tool under one or more of the following conditions: (a) Abnormal growth in plant; (b) Inflation and/or attrition; (c) As a means to mitigate regulatory lag; or (d) Failure of utility to earn its authorized rate of return over an historical period."[237] Staff acknowledges that the record reflects no abnormal growth in plant,

---

233 *See PacifiCorp*, Docket UE-130043, Order 05 at 37, ¶ 88 (Dec. 4, 2013) ("The SO allocation factor is used to allocate general and intangible plant and general A&G expenses that cannot be directly assigned.").
234 O'Connell, Exh. No. ECO-1T 33:14-16.
235 *See* Dalley, Exh. No. RBD-1T 8:3-18.
236 Huang, Exh. No. JH-1T 4:12-13 ("Staff believes using EOP plant in service balances will reduce the impacts of regulatory lag, thereby enhancing the Company's ability to earn its authorized return.").
237 *Wash. Utils. & Transp. Comm'n v. Pacific Power & Light Co.*, Docket UE-140762, Order 08, 62-63, ¶ 145 (March 25, 2015) (Pacific Power 2015 GRC Order).

inflation and/or attrition, or historical failure to earn the authorized rate of return. But under the Commission's four-factor test, EOP rate base may be appropriate based on a single factor.

89 Staff focuses on the third factor, mitigation of regulatory lag. EOP rate base will not eliminate regulatory lag, but it will reduce its impacts by moving rate base balances forward. Mitigation of regulatory lag is particularly important in the present case, since the Company has proposed a two-year rate plan. If the Commission approves the rate plan, the Company's next rate filing will not take effect until June 1, 2018, at the earliest.[238]

D. Memberships And Subscriptions

90 Staff's Adjustment 4.9, Memberships and Subscriptions, removes $23,025 of expenses that should not be included in rates. Pacific Power accepts Staff's adjustments with respect to the expenses associated with tax advocacy in Utah and Wyoming.[239] However, treatment of the Company's expenses related to the Yakima Valley Development Association (Development Association) remain in dispute. Specifically, the Company's "pledge" of $7,500 and the "Challenge Grant" in the amount of $4,500[240] provided to the Development Association represent charitable contributions and, as Staff witness Ms. Van Meter testified, the purpose of these contributions "is not part of the core business of providing electric service."[241]

91 Under law, utilities must provide safe, adequate and efficient service,[242] and this is the core business of an electric utility. Long-standing Washington State Supreme Court precedent, the *Jewell* decision, prohibits utilities from including charitable contributions in rates.[243] The

---

238 Dalley, Exh. No. RBD-3T 3:6-7.
239 McCoy, Exh. No. SEM-6T 12:2-5.
240 Van Meter, Exh. No. TMV-1T 4:16 - 5:3.
241 Van Meter, Exh. No. TMV-1T 5:9-14.
242 RCW 80.28.010; *see* RCW 80.36.080.
243 *Jewell v. Wash. Utils. & Transp. Comm'n*, 90 Wn.2d 775 (1978).

Jewell court recognized this core business of utilities and concluded that being a good corporate neighbor and improving the utility's corporate image did not augment the utility's service.[244] The *Jewell* decision explained the tensions of funding charitable causes as follows:

> Those orders are premised upon the idea that utility contributions are expected and desirable. We agree. The question is who pays for them. They can be paid for by the investors who own the utility and are interested in its corporate image and its community responsibilities, or they can be paid for by the unwitting telephone subscribers who just want to be able to use their telephones.[245]

92 In this rate case, the expenses at issue are charitable contributions to an organization that works to encourage economic development. While the contributions represent laudable support for the community in Pacific Power's service territory, they are not expenses that further the Company's provision of safe, adequate and efficient service. Pacific Power testified that these expenses indirectly promote customer growth and therefore make the electric system more efficient.[246] It is apparent, though, that the contributions support the central mission of the recipient organization, which is economic development, and have little or no effect on Pacific Power's provision of electric service. Any indirect benefit of the organization's successes to Pacific Power's electric system is merely fortuitous and too attenuated to justify rate payer funding.

VI. COST OF CAPITAL

93 Staff proposes a reasonable rate of return that is updated to incorporate the Company's actual cost of debt and appropriately reflects the Company's low risk profile as well as current capital market conditions. Pacific Power requests the same rate of return that the Commission authorized in the Company's last general rate case (GRC). While Staff disputes little of the

---

[244] 90 Wn.2d at 777.
[245] *Id.* at 778.
[246] McCoy, TR. 299:11 - 300:14.

Company's cost of capital case, and the Company's positions are very close to Staff's cost of capital recommendations, the Commission should set the rate of return based on the more current cost of capital case that Staff presents. No other party presented testimony on cost of capital.

A. Legal Standard

94 The Commission should evaluate the cost of capital in this case as it does in any general rate case. Although Pacific Power intended its rate filing to be an "expedited rate filing" (ERF) and decided not to request the higher rate of return the Company indicates it could propose if it chose, the Company also chose to add additional complexities to the rate filing including a decoupling proposal and a rate plan. The Commission expressly declined to treat this case as anything other than a general rate case, stating in the prehearing conference order, "The Commission does not recognize this filing as an ERF."[247] Accordingly, Staff has presented a full cost of capital case. Staff's testimony together with Pacific Power's testimony constitute a sufficiently robust record for decision on the Company's appropriate rate of return.

95 The Commission calculates a company's overall rate of return by summing the rates the company pays for equity and for debt, weighted proportionally to the company's capital structure. In setting the components of a company's authorized rate of return, the Commission follows the U.S. Supreme Court's foundational decisions in *Hope*[248] and *Bluefield*[249] and their progeny.[250] These decisions require rates that can provide enough revenue to cover a public service company's capital costs, which include service on the debt and a return on equity.[251] The

---

[247] Prehearing Conference Order; Notice of Hearing, 4, ¶ 14 (Dec. 29, 2015).
[248] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 64 S. Ct. 281, 88 L. Ed. 333 (1944).
[249] *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679, 43 S. Ct. 675, 67 L. Ed. 1176 (1923).
[250] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy*, Dockets UE-121697 and UG-121705, Order 15, 62-63, ¶¶ 142-43 (June 29, 2015).
[251] *Hope*, 320 U.S. at 603; *Bluefield*, 262 U.S. at 693.

equity return should be commensurate with the equity returns of other companies with similar risks, and should be sufficient for the company to maintain its credit and attract capital.[252] The appropriate rate of return, however, is subject to change. While one rate of return may be reasonable at one time, it may become too high or too low when there are changes in investment opportunities, in capital markets, and in business conditions generally.[253]

96 Under the just and reasonable ratemaking standard, the Commission has discretion to select a rate of return within a "zone of reasonableness."[254] A company's projected cost of equity, unlike debt, cannot be precisely quantified,[255] and parties generally present ranges of recommended equity returns. Staff presents a range of equity returns recommended by its cost of capital witness, Mr. David Parcell. The positions of Staff and Pacific Power are close on the cost of equity because the equity return that the Company requests falls within Staff's range.

B Pacific Power's Currently Authorized Rate Of Return

97 The Commission last authorized a rate of return for Pacific Power of 7.30 percent in Pacific Power's last general rate case, decided in 2015.[256] In the Pacific Power 2015 GRC Order, the Commission decided not to rehear the issue of cost of capital, which had been fully heard in the Company's 2013 GRC. Pacific Power appealed the Commission's order in the Company's 2013 general rate case, and just last month the Court of Appeals affirmed the Commission's 2013 decision.[257] In the Pacific Power 2015 GRC Order, the Commission stated that it would "await any direction the Court of Appeals [might] give on capital structure before revisiting the

[252] *Hope* at 603; *Bluefield* at 692-93.
[253] *Bluefield* at 693.
[254] *Permian Basin Area Rate Cases*, 390 U.S. 747, 770, 88 S. Ct. 1344, 20 L. Ed. 2d 312 (1968).
[255] Parcell, Exh. No. DCP-1T 21:16-19.
[256] Pacific Power 2015 GRC Order at 118, ¶ 297.
[257] *PacifiCorp,* No. 46009-2-II, Slip. Op.

related issue of cost of equity."[258] Accordingly, the Commission left in place the return on equity and the capital structure authorized in 2013 in Docket UE-130043.[259] The Commission updated the cost of debt, however, to then-current levels. The components of the rate of return authorized in 2013, which Pacific Power advocates keeping in place, include a hypothetical capital structure containing 49.10 percent equity and a 9.5 percent return on equity. Pacific Power also proposes not to change the cost of long-term debt of 5.19 percent or short-term debt of 1.73 percent that the Commission approved in the Pacific Power 2015 GRC Order. The Court of Appeals decision firmly upheld the Commission's use of a hypothetical capital structure, and in this case the capital structure is not in dispute; nor is the cost of preferred stock.

98 Although Pacific Power appears to believe that the Commission should not consider a full cost of capital analysis and advocates for no change in any component of its return,[260] Pacific Power ignores the Commission's clear statement that this proceeding is not an ERF but a regular rate filing. Moreover, the appellate decision affirming the Commission's 2013 PacifiCorp decision removes the uncertainty that the Commission referenced in the Pacific Power 2015 GRC Order and clears the path for the Commission to examine any or all of the components of the cost of capital.

C. Cost Of Debt

99 Staff recommends that the Commission update the Company's cost of debt to current rates. The update changes the cost of long-term debt from 5.18 percent to 5.21 percent,[261] and

[258] Pacific Power 2015 GRC Order at 77, ¶ 182.
[259] *PacifiCorp*, Docket UE-130043, Order 05.
[260] Strunk, Exh. No. KGS-19T 2:5-15.
[261] Williams, Exh. No. BNW-1T 3:4-7.

changes the cost of short-term debt from 1.73 percent to 2.15 percent.[262] Both updates are too minimal to have an effect on the overall rate of return.[263]

D. Cost Of Equity

100 Staff recommends a range for Pacific Power's cost of equity of 9.0 to 9.5 percent, which is reasonable in light of current capital market conditions. Pacific Power requests 9.5 percent, which is within this range, albeit at the upper end. The Company's cost of equity witness, Mr. Strunk, maintains, however, that 10 percent represents a fair equity return,[264] even though interest rates remain at historically low levels[265] and utility ROEs have continued to decline.[266] Given current market conditions, the evidence in this case does not support an ROE above the 9.5 percent currently authorized for Pacific Power. Rather, the record supports an ROE between 9.0 and 9.5 percent.

101 Mr. Parcell employs several methods of analysis, including discounted cash flow (DCF), capital asset pricing model (CAPM), and comparable earnings (CE), to develop his cost of equity recommendations. Specifically, he uses the midpoint of 9.0 percent from his DCF results and the midpoint of 9.5 percent from his CE results to establish his range of 9.0 to 9.5 percent.[267] He does not use his CAPM results to develop his range[268] as they are significantly lower than his other results; however, he explains that the low CAPM results do reflect investor expectations as

---

[262] Williams, Exh. No. BNW-1T, p. 5, Table 1.
[263] *See* Parcell, Exh. No. DCP-3, showing that the weighted cost of short-term debt is zero percent.
[264] Strunk, Exh. No. KGS-19T 13:11-12.
[265] Strunk, Exh. No. KGS-1T 11:19-21 ("The fact is that long-term interest rates—those relied upon by financial analysts to model investor return expectations—remain near all-time lows"); Parcell, Exh. No. DCP-1T 13:4-5.
[266] Parcell, Exh. No. DCP-1T 14:13-20.
[267] Parcell, Exh. No. DCP-1T 34:18-20.
[268] Both Mr. Parcell and Mr. Strunk agreed with Commissioner Jones at hearing that they "largely discount the use of CAPM in today's environment." Parcell and Strunk, TR. 257:12-16.

well as the recent and continuing decline in utility cost of capital and should, accordingly, be considered as one factor in determining the cost of equity.[269]

102 Mr. Strunk asserts that the imputation of a hypothetical equity level that is below a utility's actual equity ratio must be accompanied by an upward adjustment to ROE,[270] yet, Mr. Strunk makes no such adjustment. According to Mr. Strunk, Mr. Parcell should have selected an ROE of 9.5 percent rather than the midpoint of 9.25 percent to "appropriately account for the hypothetical capital structure in his recommendation to lower the Company's ROE."[271] Yet Mr. Strunk does not discuss similarly adjusting his recommendation. To Staff's knowledge, the Commission has not ever made such an adjustment to Pacific Power's ROE, at least not in the last decade of rate cases. Mr. Parcell also does not make such an adjustment, or indeed any adjustment, to his ROE recommendation.

103 Mr. Parcell recommends using the midpoint of the range of returns that the Commission finds appropriate.[272] The midpoint of Mr. Parcell's range is 9.25 percent. Mr. Strunk contends that Mr. Parcell is "limiting" his ROE recommendation to the midpoint of the zone of reasonableness based on decoupling, that there is no evidence for this, and that any effect of decoupling would already be baked into the proxy group.[273] Mr. Parcell, however, has not used decoupling as a single factor to effect any particular ROE decrement or increment, and he discusses the evidence underlying his consideration of decoupling as one of the various aspects of PacifiCorp's financial profile indicating that the Company remains relatively low risk.

[269] Parcell, Exh. No. DCP-1T 34:22 - 35:19.
[270] Strunk, Exh. No. KGS-19T 12:14-17.
[271] Strunk, Exh. No. KGS-19T 10:16-18,
[272] Parcell, Exh. No. DCP-1T 36:19 - 37:2.
[273] Strunk, Exh. No. KGS-19T 15:1 - 16:2.

104 In recommending the midpoint of the range that the Commission finds to be reasonable, Mr. Parcell is not making any adjustment or differentiating Pacific Power from the proxy group based on the Company's decoupling proposal. He has not recommended selecting the low end of his range, although that could be justified given Pacific Power's low risk profile;[274] and Mr. Parcell has not recommended selecting the high end of his range, although the evidence in this case also would support that selection. Rather, Mr. Parcell recognizes that decoupling and the rate plan are "positive factors for PacifiCorp from a financial standpoint," which considered in concert with market conditions indicate that the ROE should be no greater than the midpoint of the range.[275] Mr. Parcell testified that the rating agencies obviously attach a benefit to regulatory mechanisms such as decoupling because in January of 2014 one of the rating agencies raised the long-term credit rating of virtually every gas and electric utility in this country based primarily on the various regulatory mechanisms available to them.[276] Accordingly, decoupling as well as the rate plan comprise some of the factors that place Pacific Power at the mid-point of Mr. Parcell's proxy group. As Mr. Parcell explained at hearing: "If every one of my proxy group companies had decoupling, then the mid-point of the range represents their cost of capital, and that's what I'm recommending here."[277]

105 Market conditions do not support an ROE higher than Pacific Power's current ROE. It is noteworthy, Mr. Parcell points out, that even though federal short-term interest rates were recently increased, the already low long-term interest rates have actually declined.[278] Mr.

---

274 "PacifiCorp's ratings are above the most common rating categories of most electric utilities . . . [which] is indicative of a lower financial risk." Parcell, Exh. No. DCP-1T 17:1-6.
275 Parcell, Exh. No. DCP-1T 36:7 - 37:2; Parcell, TR. 273:6-13.
276 Parcell, TR. 280:17 - 281:1.
277 Parcell, TR, 281:3-5.
278 Parcell, Exh. No. DCP-1T 14:9-11.

Parcell's Economic Indicators exhibit shows that, since Pacific Power filed this case, the interest rate on 10-year U.S. treasury bonds has declined from 2.26 percent in November 2015 to 1.78 percent in February 2016.[279] Although the data show a few other low points over the last few years, regardless of which point is selected, none of these rates has been lower than the rate in February 2016, the last full month before Staff filed responsive testimony. Further, since November 2014, when the last round of testimony was filed in Pacific Power's last GRC, these interest rates continued a downward trend, from 2.33 percent in November 2014 to the February 2016 rate of 1.78 percent. The yields on Single A-rated utility bonds also reflect a recent decline, from 4.40 percent in November 2015 to 4.16 percent as of March 2016.[280] Finally, even though federal short-term interest rates are expected to eventually rise in the future, this is not projected to happen quickly, and expectations for lower interest rates will continue, potentially beyond the rate plan period.[281] There simply is no plausible argument to be made that equity investors would rationally expect a higher equity return for Pacific Power (if it were publicly traded) than the currently authorized ROE of 9.5 percent.

E. Capital Structure

106 Although capital structure is not in dispute, it is important to note that the record supports maintaining the existing hypothetical capital structure for Pacific Power. Further, the record evidence is consistent with the type of evidence that the Court of Appeals recently determined was substantial when it upheld the Commission's 2013 decision to set a hypothetical capital structure for PacifiCorp.[282] Primarily this evidence indicated that the capital structure the

---

[279] Parcell, Exh. No. DCP-4, p. 4.
[280] Parcell, TR. 261:19-23.
[281] *See* Parcell, TR. 263:10 - 264:13.
[282] *PacifiCorp*, No. 46009-2-II, Slip. Op. at 36-37.

Commission approved would continue to support PacifiCorp's current credit rating[283] and would appropriately balance economy with safety.[284] "Safety" refers to the ability of a company to maintain investment quality credit ratings and access to capital, while "economy" corresponds to the lowest overall cost to attract and maintain capital.[285] An appropriate capital structure strikes a balance between investors' interest in safety and ratepayers' interest in economy.

107 PacifiCorp has maintained "Single A" credit ratings with all three rating agencies since at least 2010.[286] Since the Commission's Pacific Power 2015 GRC Order, in which the Commission left in place a hypothetical capital structure with an equity ratio of 49.10 percent for PacifiCorp, PacifiCorp has not only *maintained* Single A credit ratings but was *upgraded* a notch by Fitch Ratings.[287] It is clear that the equity ratio of 49.10 percent represents "safety" for PacifiCorp, allowing the Company to not only maintain but improve its excellent credit rating.

108 Further, although Pacific Power's cost of long-term debt has increased slightly, there is no evidence that this slight change has diminished in any way Pacific Power's access to capital at reasonable rates. Mr. Williams himself did not claim that the Company could not currently attract reasonably priced capital; rather, he described the current cost of long-term debt as "substantially similar to the currently approved cost of long-term debt." PacifiCorp's actual capital structure contains approximately 51.03 percent common equity.[288] Accordingly, imputing

---

[283] *PacifiCorp,* No. 46009-2-II, Slip. Op. at 36-37; at 41 ("The Commission found, 'The record in this case demonstrates that this capital structure will continue to support PacifiCorp's current credit rating, and provide sufficient cash flows to support the financial metrics analyzed by the credit rating agencies'").
[284] *PacifiCorp,* No. 46009-2-II, Slip. Op. at 37.
[285] *Wash. Utils. & Transp. Comm'n v. PacifiCorp*, Docket UE-050684, Order 04, Order Rejecting Tariffs as Filed; Rejecting Stipulation on Net Power Costs; Rejecting, in Part, and Accepting, in Part, Stipulation on Temperature Normalization Adjustment; Determining Cost of Capital, p. 82, ¶ 230 (April 17, 2006).
[286] Parcell, Exh. No. DPC-1T 16:16-17.
[287] Williams, Exh. No. BNW-1T 6:9-14.
[288] Equity percentage is projected for July 1, 2016. Williams, Exh. No. BNW-1T 6, Table 2.

a hypothetical equity ratio of 49.10 percent represents economy and appropriately balances the interests of investors and ratepayers.

VII. DECOUPLING

109 Pacific Power has proposed a full decoupling mechanism modeled on the mechanisms of Avista and PSE.[289] Staff undertook a comprehensive review of the proposal[290] and supports it with the addition of certain conditions. These conditions are described in the testimony of Mr. Ball,[291] and Pacific Power has, for the most part, accepted them.[292] Staff believes that only two of Staff's recommended conditions remain at issue.

A. The Commission Should Implement A Deferral Trigger And Adjust The Rate Cap To Avoid Unnecessary Frequent Rate Increases

110 Under Pacific Power's decoupling proposal, the Company plans to file a rate adjustment (surcharge or surcredit) by December 1 of each year. Any such rate increase will be limited to three percent of annual revenues, but there is no "cap" for surcredits.[293] The decoupling rate adjustment would be in addition to any other rate increase or decrease during the year, such as a rate change following a general rate case or from a PCAM filing. This arrangement has the potential to subject ratepayers to multiple frequent rate changes during a single year.

111 To ameliorate this issue, Staff proposes setting a "trigger," or threshold amount that must accumulate in the deferral account before the Company makes a rate adjustment.[294] If the balance in the deferral account at the end of each annual decoupling period did not exceed the threshold, then no rate adjustment would occur.[295] Staff believes that a threshold or trigger of

[289] Steward, Exh. No. JRS-1T 10:16-17.
[290] Ball, Exh. No. JLB-1T 36:5 - 45:4.
[291] Ball, Exh. No. JLB-1T 45:8 - 58:19.
[292] Steward, Exh. No. JRS-9T 2:4-17.
[293] Steward, Exh. No. JRS-9T 8:8-16; TR. 327:5-19.
[294] Ball, Exh. No. JLB-1T 49:13-18.
[295] Ball, Exh. No. JLB-1T 51:9-15.

approximately 2.5 percent of allowed decoupled revenue for each class will avoid unnecessary frequent rate increases and will ensure that customers will not face significant changes in rates due to a deferral balance that becomes too high or too low.[296] Staff also recommends changing the three percent decoupling rate cap to five percent of annual revenues to avoid any conflict between the trigger mechanism and a bloated deferral balance.[297]

112 Pacific Power objects to the 2.5 percent trigger and the 5 percent rate cap, and counter proposes a 0.5 percent trigger.[298] The Company's concerns about smoothing its revenues out more quickly are not as important as helping its ratepayers avoid frequent rate changes during a single year. The largest trigger, for residential customers, would be plus or minus $2 million, which is a meaningful trigger.[299] One fifth of that, or a 0.5 percent trigger, as the Company proposes implementing, would not be effective to curb unnecessary rate changes. While the Company's concern that a five percent rate cap could result in a larger rate change than under a three percent cap is legitimate, Staff does not believe that the five percent rate cap will result in rate shock. Moving the cap to five percent is prudent given Staff's proposed trigger, and Staff's proposed trigger better serves rate stability and certainty for ratepayers.

B. The Implementation Of Decoupling Requires An Increase In Funding For Conservation Programs Assisting Low Income Customers

113 Pacific Power has not made an adequate showing under the Commission's policy statement on decoupling[300] regarding low-income conservation and should be required to commit at least $50,000 in shareholder funding to conservation programs specifically targeted at low-

---

[296] *See* Ball, Exh. No. JLB-1T 50:5-12.
[297] Ball, Exh. No. JLB-1T 52:1-6.
[298] Steward, Exh. No. JRS-9T 9:4-18.
[299] *See* Ball, Exh. No. JLB-1T 50:5-9.
[300] *In the Matter of the Wash. Utils. & Transp. Comm'n'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).

income customers. Pursuant to the Decoupling Policy Statement's low-income criterion, "[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 comparable to that achieved by other ratepayers, so long as such programs are feasible within cost-effectiveness standards."[301] While Pacific Power currently offers a low-income weatherization program, this program accounted for only 21 percent of its residential efficiency program costs in 2014.[302] So, the Company appears to be spending only about one fifth of its weatherization budget on its low-income program. Furthermore, this is well under the 47 percent that Avista was achieving when it requested a decoupling mechanism.[303] In order to provide more comparable weatherization benefits to low-income customers, Pacific Power should be required to increase its funding for low-income weatherization.

114 The Company has not presented a study analyzing the impact of a two-year rate plan and decoupling mechanism on its low-income customers.[304] Moreover, Pacific Power has not otherwise shown that its weatherization program is successfully meeting the conservation needs of its low-income customers.[305] According to the Company, its low-income conservation funding of $1 million has never been fully used and, thus, additional funding is not required.[306] Ms. Steward's testimony indicates, however, that 2015 program costs totaled approximately $850,000. This is not far from $1 million. Further, the Company's bare claims of program

[301] Decoupling Policy Statement at 18.
[302] Ball, Exh. No. JLB-1T 42:19-21.
[303] Ball, Exh. No. JLB-1T 48:20-21.
[304] Ball, Exh. No. JLB-1T 48:22-26.
[305] Ball, Exh. No. JLB-1T 49:5-8.
[306] Steward, Exh. No. JRS-9T 6:2-6.

success based on weatherizing 98 low-income homes in 2015 through partner organizations provides insufficient information to determine whether or not its program is actually meeting the low-income weatherization need. In this circumstance, it is prudent to protect low-income customers and conservation efforts now from the adverse effects of decoupling by increasing funding for low-income conservation in the amount of $50,000, and to make any necessary funding adjustments in a future rate filing based on demonstrated facts. Further it is appropriate to require shareholder funding to demonstrate the Company's commitment to conservation and in recognition of the benefits the Company will receive by implementing decoupling.

VIII. LOW INCOME BILL ASSISTANCE

115 Pacific Power's five-year Low Income Bill Assistance (LIBA) plan concludes in April 2017, which falls close to the end of the rate year and before the beginning of the second rate period under the Company's proposed rate plan. Accordingly, planning to extend LIBA should occur promptly. Pacific Power has proposed to convene a stakeholder group to discuss the future LIBA program and intends that any changes would be effective at the start of the 2017-2018 heating season.[307] Staff supports this proposal.

IX. ADDITIONAL RECOMMENDATIONS

A. Cost Of Service Study And Rate Design Collaborative

116 Staff proposes that Pacific Power collaborate with interested parties to review the Company's cost of service and rate design and to present the results of the collaborative in the Company's next general rate case.[308] This proposal represents a change in position for Staff. In responsive testimony, Staff stated that it intended the collaborative to be concluded in time to

[307] Steward, JRS-1T 9:2-4.
[308] *See* Van Meter, Exh. No. TVM-1T 8:11-21.

incorporate the results into the rates for the second rate period of the rate plan.[309] Staff now believes that allowing more time for the collaborative will greatly assist the parties in arriving at a resolution. None of the parties oppose convening a collaborative.

B. Decommissioning And Remediation Reporting

117 The Commission should require Pacific Power to report its decommissioning and remediation (D & R) expenses and revenues in its future commission basis reports.[310] The report should contain certain details, as set forth in the testimony of Mr. Ball. [311] No party opposes this proposal.

X. CONCLUSION

118 For the reasons discussed above, the Commission should reject accelerated depreciation, incorporate only a portion of the SCR costs into rates, approve a rate plan with only a small increase in the second rate plan period, approve the Company's appropriately designed decoupling proposal, including Staff's additional recommendations, and accept Staff's proposals for other adjustments and collaborative efforts.

DATED this 22nd day of June 2016.

Respectfully submitted,

ROBERT W. FERGUSON
Attorney General

JENNIFER CAMERON-RULKOWSKI
Assistant Attorney General
Counsel for Washington Utilities and
Transportation Commission Staff

---

[309] Van Meter, Exh. No. TVM-1T 8:21 - 9:2.
[310] Ball, Exh. No. JLB-1T 48:26-27.
[311] Ball, Exh. No. JLB-1T 58:29 - 59:6.