SIERRA CLUB

August 25, 2020

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem, OR 97301

Re: Docket No. UE 374 Errata Sierra Club Opening Testimony

Sierra Club hereby submits the following Errata to the Opening Testimony of Jeremy Fisher for filing in the above-referenced dockets.

After discussions with PacifiCorp, both Sierra Club and the company agree, PacifiCorp over-designated certain information in its direct testimony as confidential. Accordingly, Sierra Club is submitting an updated version of the Opening Testimony of Jeremy Fisher (Sierra Club/100). PacifiCorp sent an email on June 11, 2020 to UE 374 parties formally removing certain confidential designations and additional information was publicly presented in the Reply Testimony of Dana Ralston (PAC/2600). Sections of Dr. Fisher's testimony based on the following information are now public:

- Selected details about the Hayden SCR Project made public in PAC/2600 (Sierra Club/100 at Fisher/7, Fisher/77-79, Fisher/81-82, Fisher/84, Fisher/87-88)
- $31 million fuel cost increase and $28.3 million in reclamation costs related to the Bridger Mine made public in PAC/2600 at Ralston/8
- PAC/710
- PAC/800, Teply/24:6-19

Also, in the corrected version, Sierra Club added a citation to Teply/24 in footnotes 147 and 150. Lastly, Sierra Club/106 was inadvertently mislabeled and therefore Sierra Club is submitting a correctly labeled version of that the exhibit.

If you have any questions or require any additional information, please do not hesitate to contact me.

Respectfully submitted,

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

In the Matter of PACIFICORP d/b/a PACIFIC POWER, Request for a General Rate Revision	UE 374

CERTIFICATE OF SERVICE

I hereby certify that on this 25th day of August, 2020, I have served the foregoing Errata to the Opening Testimony of Jeremy Fisher upon all party representatives on the official service list for this proceeding. The public version of this document was served upon parties via email, and the highly confidential and confidential portions of this document were served pursuant to Protective Order No. 20-040 and 20-131 respectively upon all eligible party representatives electronically via encrypted password protected ZIP folders.

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Dated this 25th day of August, 2020 at Redwood City, CA.

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BEFORE THE
OREGON PUBLIC UTILITIES COMMISSION

In the Matter of PACIFICORP d/b/a PACIFIC POWER Request for a General Rate Revision.	**UE 374**

Opening Testimony of
Jeremy Fisher, PhD

On Behalf of
Sierra Club

Public Version

June 4, 2020
Corrected August 25, 2020

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF EXHIBITS

LIST OF EXHIBITS CONT.

Sierra Club/117	PacifiCorp Response to Sierra Club Data Request 4.10 in Docket No. 13-035-184 (Utah Pub. Serv. Comm'n)
Sierra Club/118	PacifiCorp Dec. 5, 2013 Memorandum (provided as a confidential attachment to PacifiCorp Response to Sierra Club Data Request 1.4)
Sierra Club/119	Highly Confidential Exhibit B Re: Bridger EPC Contract
Sierra Club/120	Direct Testimony of Susan Arigoni in Docket No. 11A-917E (Colo. Pub. Util. Comm'n)
Sierra Club/121	Confidential Technical Workshop: Review of Existing Analysis on Craig and Hayden Environmental Investments (provided as a confidential attachment to PacifiCorp Response to Sierra Club 2.6)
Sierra Club/122	Confidential Attachment to Pacificorp Response to Sierra Club Data Request 2.6-2 (Hayden PVRR)
Sierra Club/123	Confidential Hayden SCR Recommendation Memo (provided as a confidential attachment to PacifiCorp Response to Sierra Club Data Request 2.4)
Sierra Club/124	Confidential Attachment to Pacificorp Response to Sierra Club Data Request 2.4 (Xcel Energy Projects)
Sierra Club/125	Direct Testimony of James Hill in Docket No. 10M-245E (Colo. Pub. Util. Comm’n)

1. INTRODUCTION AND QUALIFICATIONS

Q Please state your name, position, and business address.

A My name is Jeremy I. Fisher. I am a Senior Advisor for Strategic Research and Development in Sierra Club's Environmental Law Program, which is located at 2101 Webster Street, Suite 1300 in Oakland, California.

Q On whose behalf are you providing testimony in this case?

A I am providing testimony on behalf of Sierra Club.

Q Please describe your role at Sierra Club.

A Sierra Club is a national public interest group dedicated to the responsible use of ecosystems and resources with over 800,000 members. My role as an advisor is to work with the Environmental Law Program to understand and engage productively with best utility practices in energy system planning, fossil generation issues, energy efficiency and renewable energy, ratemaking and rate design, market power issues, and utility regulations.

Q Please summarize your work experience and educational background.

A Prior to joining Sierra Club in December 2017, I held the position of Principal Associate with Synapse Energy Economics in Cambridge, Massachusetts where I worked for a decade on electricity system energy planning, supporting regulators in the use and execution of environmental regulations, and helping states craft or revise resource planning rules. As a consultant, I worked with a wide variety of public sector and public interest clients, including the U.S. Environmental

Protection Agency ("EPA"), the National Association of Regulatory Utility Commissioners ("NARUC"), the National Association of State Utility Consumer Advocates ("NASUCA"), National Rural Electric Cooperative Association ("NRECA"), the energy offices and public utility commissions of Alaska, Arkansas, Michigan, and Utah, the Commonwealth of Puerto Rico, Tennessee Valley Authority Office of Inspector General ("TVA OIG"), the California Division of Ratepayer Advocates ("CADRA"), the California Energy Commission ("CEC"), the Regulatory Assistance Project ("RAP"), and multiple environmental public interest groups. In 2014 and 2015, I provided training to federal regulators on resource planning practice. I recently led an intensive statewide planning process on behalf of the Michigan Public Service Commission ("MPSC") and worked on behalf of the Puerto Rico Energy Commission ("CEPR") on the first open audit of the Commonwealth's public utility.

I have provided testimony in electricity planning and general rate case dockets in California, Georgia, Idaho, Indiana, Kansas, Kentucky, Louisiana, Mississippi, Nevada, New Mexico, Ohio, Oklahoma, Oregon, Puerto Rico, Utah, Washington, Wisconsin, and Wyoming.

I hold a doctorate in Geological Sciences from Brown University, and I received my bachelor degrees from University of Maryland in Geology and Geography.

My full curriculum vitae is attached as Exhibit Sierra Club/101.

Q **Have you previously provided comments to or testified before the Oregon Public Utility Commission previously?**

A Yes. I've submitted testimony on behalf of Sierra Club in PacifiCorp's prior rate case in 2012 (OR UE 246), and supported Sierra Club comments in multiple PacifiCorp IRP proceedings from 2013 to the present day.

Q **In general, are you familiar with PacifiCorp's system and practices?**

A Yes. Since 2010, I've reviewed PacifiCorp's long-term resource planning and short-term modeling in dockets across the Company's service territory. This includes expert testimony in rate cases (WY 20000-384-ER-10, WY 20000-446-ER-14, OR UE 246, WA UE-152253), certificates of public convenience and necessity ("CPCN") (WY 20000-418-EA-12), assessments of fuel contracts (OR UM 1712, CA A.15-09-007), and multiple integrated resource planning ("IRP") reviews in 2013 (OR LC 57, UT 13-2035-01), 2015 (OR LC-62, UT 15-035-04), 2017 (OR LC-67, UT 17-035-16), and 2019 (OR LC 70, UT 19-035-02).

Q **What is the purpose of your testimony?**

A My testimony is focused on the election of PacifiCorp d.b.a. Pacific Power ("Company") to install high-cost selective catalytic reduction ("SCR") emissions controls at the Jim Bridger units 3 & 4 and Hayden 1 & 2 coal-fired power stations. My testimony walks through the process of how PacifiCorp, or in the case of Hayden, its co-owner Public Service Company of Colorado ("PSCo"), decided to move forward with the retrofits, and the analyses that PacifiCorp employed to assess whether the retrofits were in the best interests of customers. I assess the alternatives available to the Company at each key decision-making moment, and how the Company's decisions aligned with the information it knew, or should have known at the moment.

I show that the Company understood that its election to move forward with the SCRs at Jim Bridger 3 & 4 was premature, and had degraded in value from the time the Company first proposed the projects to effectively no economic value to ratepayers at the time. Once the Company began construction, the liability of the project degraded faster than the monies the Company sank into it, meaning ratepayers would have benefited from cancelation mid-stream.

I also show that the Company failed to conduct appropriate due diligence on the Hayden SCR projects when decisions on those projects were underway by PSCo, and then failed to appropriately exercise its participation rights when it determined that the projects were not favorable to ratepayers.

2. <u>SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS</u>

Q Can you summarize your conclusions?

A Yes. With respect to the installation of SCR at Jim Bridger 3 & 4, I conclude the following:

1. PacifiCorp manufactured a compliance deadline that it understood was well ahead of EPA's requirements;

2. PacifiCorp asserted that same compliance deadline without respect to alternatives or the flexibility afforded under the Clean Air Act, at a cost to ratepayers;
3. PacifiCorp's election to move forward on the SCRs at Jim Bridger 3 & 4 on December 1, 2013 was uninformed by changes in the projected cost of coal and gas available to the Company, factors which would have shown a substantially degraded value for the projects.
4. A new mining plan in October 2013 materially changed the way that PacifiCorp would procure coal for Jim Bridger, and increased the cost of coal, and yet PacifiCorp failed to assess how that plan would impact its impending SCR decision.
5. PacifiCorp failed to assess new market price projections available to it prior to December 1, 2013 that would have revealed lower market price forwards for gas.
6. PacifiCorp's use of a shortcut "breakeven" assessment to determine whether the SCR still had economic value in September 2013 relied on modeling data over 15 months old, and was unbefitting of a project of this magnitude.
7. Prior to committing monies to the SCR projects at Jim Bridger, the Company was aware that the economic value of the projects had degraded substantially, and yet failed to conduct more extensive modeling.
8. After committing monies to the SCR projects on December 1, 2013, the Company failed to assess whether continuing with the projects was cost effective or in the best interests of customers.

9. The Company failed to terminate the SCR projects when the forward liability of continuing the projects and operating Jim Bridger 3 & 4 on coal fell below the cost of ceasing construction.

10. PacifiCorp's election to install SCRs in December 2013 and continue operating Jim Bridger 3 & 4 has resulted in excess costs to ratepayers above the cost of alternatives. Ratepayers have incurred damages more substantial than the cost of the SCRs alone.

With respect to the installation of SCRs at Hayden 1 & 2, I conclude the following:

1. The Company failed to engage successfully or meaningfully in PSCo's 2010 emission reduction plan, whereby PSCo opted to install SCRs at Hayden, committing PacifiCorp to that same course of action.

2. The Company failed to assess the joint cost of signing a new coal contract for Hayden and moving forward on the SCRs. By decoupling the SCR decision from the coal contract decision, the Company made two separate elections that should have been made jointly.

3. The Company failed to press PSCo to conduct updated cost effectiveness studies on the Hayden SCRs, and did not pursue appropriate due diligence documentation on the benefits or risks of pursuing the SCRs.

4. The Company failed to pursue an alternative retirement strategy with PSCo, instead incorrectly agreeing to—[redacted]—an unenforceable premature compliance deadline.

5. The Company's assessment of [redacted] but the Company elected to ignore this information and signaled its approval to PSCo.
6. The Company failed to assess whether the Hayden 2 SCR project was in the best interests of customers.
7. [redacted].
8. [redacted].

The Company failed to pursue arbitration to compel PSCo to close Hayden rather than install the SCR retrofits, despite a surfeit of evidence that PSCo's decision was stale and inconsistent with generally accepted practices for electric utilities.

Q What are your recommendations to this Commission?

A With respect to the SCRs at Jim Bridger, I recommend that the Commission disallow the full costs of the projects, $56.9 million on an Oregon-allocated basis.

With respect to the SCRs at Hayden, I recommend that the Commission disallow the full costs of the projects, $6.3 million on an Oregon-allocated basis.

In addition, I recommend that the Commission consider disallowing costs associated with the minimum take provision of the take-or-pay Hayden coal contract entered into in 2011.

3. THE COMPANY'S ELECTION TO INSTALL SELECTIVE CATALYTIC REDUCTION AT JIM BRIDGER IN DECEMBER 2013 WAS IMPRUDENT

Q Please describe the Jim Bridger plant.

A The Jim Bridger power plant is a 2,100 MW coal-fired plant made up of four units (Jim Bridger units 1, 2, 3, and 4). PacifiCorp owns two-thirds of each unit and Idaho Power Company owns the remaining one-third. Jim Bridger is located in southwest Wyoming and contributes to haze pollution in several national parks and wilderness areas: Yellowstone National Park, Grand Teton National Park, Rocky Mountain National Park, Teton Wilderness Area, Bridger Wilderness Area, Fitzpatrick Wilderness Area, Mt Zirkel Wilderness Area, Rawah Wilderness Area, and Washakie Wilderness Area. [1]

Jim Bridger is a mine-mouth plant, which means that it receives the bulk of its coal fuel from a mine that is adjacent to (or at least near) the plant. The majority of Jim Bridger plant ("Bridger plant") is supplied by the Bridger coal mine ("Bridger mine"). The Bridger mine is comprised of two separate operations—a surface mine and an underground mine, a distinction which will prove important.

The Bridger mine is operated by the Bridger Coal Company ("BCC"), itself a jointly-owned subsidiary of PacifiCorp and Idaho Power Company. Bridger Coal Company is one of the few remaining coal mining operations owned by a regulated utility. The costs of operating BCC are recovered both through the fuel costs of Jim Bridger plant, as well as recovered directly through rate base from

[1] Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze, 79 Fed. Reg. 5032, 5041 (Jan. 30, 2014).

PacifiCorp's customers. This intimate relationship between the mine and the plant, and the fact that both are rate-based means that PacifiCorp treats the mine as an asset for which customers maintain all liability. Similarly, factors that affect the mine impact the costs of operating the plant, and vise versa.

Q Why did PacifiCorp install SCRs at Jim Bridger 3 & 4?

A PacifiCorp installed the selective catalytic reductions ("SCR") in connection with the Regional Haze Rule under the Federal Clean Air Act. As I will discuss later, a core question for this Commission is whether PacifiCorp actually had an enforceable obligation to install the SCRs by 2015 and 2016. In Section 3.b (page 17), I assert that the Company's timeline for the installation of SCRs was a product of its own manufacture, and was not a matter of law.

Q When did PacifiCorp decide to install SCRs at Jim Bridger 3 & 4?

A The Company agreed to install SCR at Jim Bridger 3 & 4 in November 2010, as an outcome of a settlement with the Wyoming Department of Environmental Quality ("WYDEQ").[2] As I describe below in Section 3.b, the Company appears to have entered into that agreement voluntarily, even when offered the opportunity to extend its compliance deadlines by the United States Environmental Protection Agency ("EPA").

The Company's "final" decision to proceed on the SCRs came when the Company issued a full notice to proceed ("FNTP") letter to its Engineering,

[2] PAC/800 at Teply/32:1, Figure 1—Bridger SCRs Timeline.

Procurement and Construction ("EPC") contractors on December 1, 2013.[3] Prior to signing that FNTP, the Company had the option to withdraw from the project with relatively little consequence and cost. As I show, after that contract date the Company still had the option to terminate the contract, but the cost of doing so rose thereafter. The Company had an obligation to continue assessing its decision to install the SCRs up through the signing of the FNTP on December 1, 2013, and had a continuing obligation thereafter to continue assessing if the project had merit, net of costs already sunk into the project.

Q Were alternative compliance paths available to the Company?

A Yes. The Regional Haze Rule's requirements are based on both a control technology and an emissions limit at each unit. PacifiCorp could therefore have complied with the rule either by installing the required pollution controls necessary to meet that limit, or by shutting down, or by converting the Jim Bridger units to run on fossil gas. There are several examples of coal plants shutting down or switching to gas fuel as an alternative compliance path under the Regional Haze Rule,[4] and examples wherein a unit committed to a firm future shut down date in exchange for less expensive near-term controls.[5]

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[3] *Id*.

[4] Approval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans; Reconsideration 80 Fed. Reg. 19,220 (Apr. 10, 2015 (Apache Unit 2); 79 Fed. Reg. at 5045 (Naughton Unit 3, Wyoming; (Muskogee 4 & 5, Oklahoma).

[5] Approval and Promulgation of Implementation Plans; State of Oregon; Regional Haze State Implementation Plan and Interstate Transport Plan, 76 Fed. Reg. 38, 997 and 2008 Oregon Regional Haze Plan at 154-156 and) (PGE Boardman, Oregon); Transalta Centralia, Washington (Washington Department of Ecology, Order 6426, 2011)

Q Did the Company assess alternatives to the installation of the SCRs at Jim Bridger?

A Just one. The Company performed an assessment, described by Mr. Rick Link, to determine if it was more cost effective to install the SCRs, shut down or repower Jim Bridger 3 & 4 with gas.[6]

Notably, the Company had other forms of compliance that would have likely been deemed acceptable by EPA, and that the Company has since sought to exercise elsewhere. Prominent amongst these alternatives is the option to avoid costly controls like SCR by committing to a shorter plant life. That shorter plant life need not be the immediate shut down of the unit on the compliance deadline. I discuss alternative compliance with the Regional Haze Rule in Section 3.c (page 28), below.

a. Overview of PacifiCorp's Jim Bridger 3 & 4 SCR Assessment

Q Please summarize the Company's analysis process to determine if the SCRs should be built at Bridger 3 & 4.

A Since 2012, PacifiCorp has used the System Optimizer (sometimes abbreviated "SO") model, its primary forward planning and integrated resource planning platform, to determine whether large capital investments were economic at existing coal-fired units. PacifiCorp typically uses the model to assess two alternative worlds: one in which the retrofit is pursued, the other in which the plant is retired or, as in this case, repowered. The use of a system-wide model is critical because it assesses how other factors on the utility's system change in

[6] PAC/700 at Link/86: 8-11.

response to a retire/retrofit decision, and not just the costs of the power plant itself.

This methodology, like all other models, is highly sensitive to inputs and the quality of the data used in the model. Specifically, the value of pursuing a retrofit can change substantially as the market shifts, and decisions need to be evaluated using the very best information available up to the moment the decision is finalized, and even beyond.

The Company's initial filing in this case was a CPCN submitted to the Wyoming Public Service Commission on August 1, 2012, and was based on an analysis conducted using data from December 2011.[7] In that initial analysis, the Company claimed that the Bridger 3 & 4 SCRs had a value of [redacted][8] Intervenors pointed out that, amongst other flaws, PacifiCorp's initial analysis used outdated data. On rebuttal, filed March 4, 2013, the Company provided an updated analysis, populated with September 2012 data, showing a $183 million value,[9] substantially lower than the Company's initial valuation. The results of that

[7] PacifiCorp Response to Sierra Club Data Request 1.1(h) ("Yes, the CPCN application in Wyoming (Docket 20000-418-EA-12) used the December 2011 official forward price curve for the base case."). All public data responses referenced in this testimony are compiled and attached as Exhibit Sierra Club/102.

[8] Direct Testimony of Mr. Rick Link, *In The Matter of the Application of Rocky Mountain Power for Approval of a Certificate of Public Convenience and Necessity to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 And 4 Located Near Point of Rocks, Wyoming* Docket No.20000-418-EA-12 at 2:5. (Wyo. Pub. Serv. Comm'n Aug. 2012) (provided as an attachment to PacifiCorp Response to Sierra Club Data Request 1.1(g)) (attached as Exhibit Sierra Club/103).

[9] Redacted Rebuttal Testimony of Mr. Rick Link, *In The Matter of the Application of Rocky Mountain Power for Approval of a Certificate of Public Convenience and Necessity to Construct Selective Catalytic Reduction Systems on Jim Bridger Units 3 And 4 Located Near Point of Rocks, Wyoming* Docket No.20000-418-EA-12 at 1:22. (Wyo. Pub. Serv. Comm'n Mar. 2013) (attached as Exhibit Sierra Club/104). Note that value is provided publicly in PAC/700, Link/86:15.

revised September 2012 analysis are before this commission today.[10] The Wyoming Commission docket was concluded in May 2013.

The Company's "final" assessment conducted for the Wyoming CPCN rebuttal used September 2012 data, and was conducted in January 2013[11]—it would be the last time the Company ran the System Optimizer model to assess the retire/retrofit decision.

Q How did the Company assess the value of the retire/retrofit decision after January 2013?

A Mr. Link ran what he describes as a "breakeven" assessment of the retrofit.[12] Basically, the Company observed that the value of the retrofit decision appeared to have a roughly[13] linear relationship with gas prices, and assessed that if the levelized cost of gas fell below $4.86/MMBtu, it would be more economical to repower Jim Bridger with gas than install the SCRs.

Figure 1, below, shows Mr. Link's derived relationship between the value of the SCR retrofit[14] relative to the levelized cost of gas from 2016-2030. It then shows how the value of the Bridger SCR degraded from September 2012 through December 2014 as gas prices rapidly approached and then fell below PacifiCorp's own breakeven at $4.86/MMBtu.

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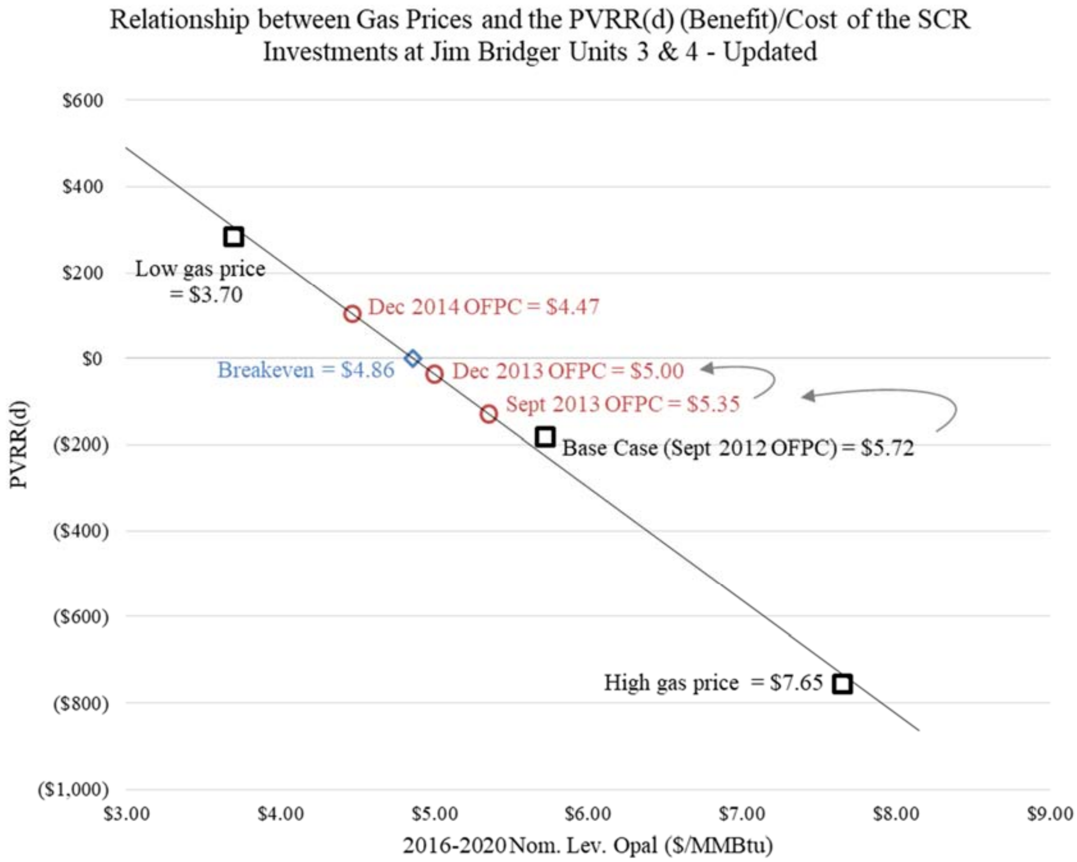
[10] PAC/700, Link/86:15, Link/98:9.
[11] Date stamps on Mr. Link's System Optimizer work papers submitted in this docket.
[12] PAC/700 at Link/106:4-21
[13] Roughly: Mr. Link's breakeven analysis relies on three data points to create a line of best fit. While the trend appears visually clear, from a statistical standpoint, the lack of additional modeling observations (i.e. degrees of freedom) actually renders this a weak relationship. At a 90% confidence interval, the projected "breakeven" could be as low as $3.71/MMBtu, or as high as $5.59/MMBtu.
[14] Negative values being a benefit to the Bridger SCR decision.

Figure 1. Relationship between levelized gas prices and the (benefit) / cost of the SCR investments at Jim Bridger 3 & 4.[15]

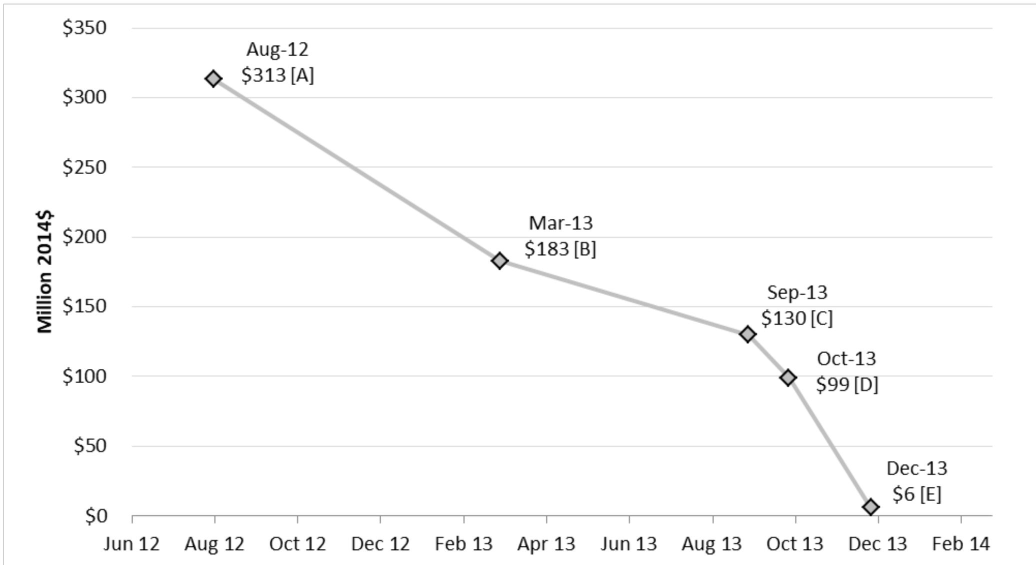


Q **How had the Company's analysis of the Bridger 3 & 4 SCRs changed from the Company's CPCN proceeding in Wyoming until the time that the SCR FNTP was signed in December 2013?**

A From the time the Company completed its rebuttal assessment in the Wyoming CPCN, the value of the decision to install SCRs continued to fall substantially up through the FNTP. Figure 2, below, shows the value of the Bridger 3 & 4 retrofit through time leading up to the FNTP.

[15] PAC/710; Attachment to PacifiCorp Response to Sierra Club Data Request "Attach Sierra Club 1.6.xlsx" [hereinafter "Attach Sierra Club 1.6.xlsx"] (additional OFPC author's calculation).

Figure 2. Benefit of SCRs at Bridger 3&4 over time, Company and Author calculations[16]



In the instant docket, Mr. Link testified that prior to executing the FNTP in December 2013, he found that the margin had shrunk another 30% to $130 million using September 2013 gas price projections in his breakeven assessment.[17]

However, Mr. Link's updated analysis is still deficient because it relied on inadequate and stale data when there was substantial evidence that the decision to install SCR continued to rapidly lose value. In fact, by the time PacifiCorp executed the FNTP on December 1, 2013, the SCR projects had effectively no value to ratepayers.

As I show in Section 3.d (page 32), PacifiCorp acknowledged that the costs of coal provided to Jim Bridger had increased in October 2013, reducing the value to

[16] [A] Ex. Sierra Club/103, Direct Testimony of Rick Link in Wyoming 20000-418-EA 12 at 2:5; [B] PAC/700 at Link/86:15; [C] PAC/700 at Link/107:13; [D] Author's calculation, see Adjustment #1; [E] Author's calculation, see Adjustment #2.
[17] PAC/700 at Link/107:13

$99 million—an adjustment neither disclosed nor discussed by Mr. Link. Below, I show that the Company critically failed to assess how a new mine operations plan for Jim Bridger would impair the decision to retrofit Jim Bridger 3 & 4.

Finally, late 2013 was the dawn of the hydraulic fracturing boom, and in the months leading up to the FNTP, analysts and PacifiCorp were projecting substantially lower forward-looking gas prices. As I describe in Section 3.e (page 44) information in the Company's hands prior to the execution of the FTNP led the Company to conclude that gas prices had fallen within cents of Mr. Link's $4.86/MMBtu breakeven,[18] and a reasonable assessment of trends leading up to that period would have concluded that there was a very real potential that the project would fail economically. In December 2013, the value of the SCR retrofit had, conservatively, fallen to $6 million—effectively a wash.

As has been made clear in the industry, the economics of maintaining coal have continued to fall drastically in the months and years since the Company finalized its decision to proceed with the SCRs, to the extent that the Company recently identified Jim Bridger 3 & 4 as candidates for early retirement in the 2019 IRP.

Finally, as I show in Section 3.f (page 58) the Company's own metric for the economics of the Bridger 3 & 4 SCRs degraded so rapidly that the losses attributed to the continued operations of the unit exceeded the termination cost of the SCR project during the construction of the SCRs. In other words, the Company erred not only in releasing contractors to build the SCRs, but it also

[18] PAC/700 at Link/101:13-17.

erred in not re-evaluating—and ceasing construction—at the Bridger SCRs, to the detriment of their ratepayers.

b. The Timeline to Install SCR at Jim Bridger by 2015 and 2016 was of the Company's Own Manufacture

Q What is the basis for the SCRs at Jim Bridger, and how is the installation connected to the Clean Air Act?

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

In 1977, Congress declared as the nation's goal, the "prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution."[19] In order to meet this goal, states are required to adopt implementation plans ("SIPs") to reduce, and ultimately eliminate, haze-causing pollution that may cause or contribute to visibility impairment for any protected Class 1 area (i.e. wilderness or national park) located within or beyond that state's boundaries.

The Clean Air Act imposes a legal obligation on both states and EPA to abate haze pollution in such Class 1 areas.[20] One of the Clean Air Act's mechanisms for achieving this goal was the requirement for certain haze-causing sources, like coal

[19] 42 U.S.C. §7491(a)(1).
[20] *Id*.

plants, to install "best available retrofit technology" ("BART").[21] Bridger units 3 & 4 were subject to BART.

Under the BART-phase of the Regional Haze Rule, states were required to assess which power plants were covered by the rule, and set emissions limits and require control technology necessary to satisfy the particular requirements of BART, including visibility monitoring and an assessment of cost. States would then include these findings into a SIP, which would be submitted to EPA for final approval. EPA had the option of approving, disapproving, or modifying state plans. If EPA disapproved a plan (or a portion of a plan), it then promulgated a federal implementation plan ("FIP") to replace the disapproved SIP.[22] Ultimately regional haze plans <u>were not enforceable</u> until after EPA acted to either approve a SIP or issue a FIP. Finally, under the Regional Haze Rule, an owner/operator was required to comply with a final BART rule within five years of rule issuance.[23]

In 2011, Wyoming Department of Environmental Quality ("WYDEQ") submitted a revised state implementation plan to EPA to comply with the BART provisions of the Regional Haze Rule. Within that SIP, the state proposed that Jim Bridger 3 & 4 be retrofit with SCRs in 2015 and 2016, respectively. After several years of back and forth, EPA disapproved several elements of Wyoming's plan, which triggered EPA's obligation to promulgate a federal implementation plan ("FIP") to replace those disapproved elements.[24]

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[21] *Id*. §§ 7491(a), (b)(2).
[22] 42 U.S.C. § 7410(c)(1)(A).
[23] 40 C.F.R. 51.308(e)(iv).
[24] 79 Fed. Reg. 5032 (Jan. 30, 2014).

EPA issued a FIP, which then became binding on Jim Bridger, on January 30, 2014[25]—nearly two months after the Company had already issued its FNTP for the SCRs at Jim Bridger. In other words, the Company made its final determination to proceed with the retrofit before the EPA had finalized the plant's BART obligations.

Q Did the Company decide to install SCRs at Jim Bridger in 2015/2016 before EPA had even finalized its requirements?

A Yes. In 2007, PacifiCorp provided data to Wyoming for Wyoming to incorporate into its regional haze SIP. Wyoming adopted that first regional haze SIP on May 22, 2008,[26] followed by a series of permit issuances from Wyoming DEQ authorizing PacifiCorp to move forward with SCRs.

On November 2, 2010, PacifiCorp settled with WYDEQ, agreeing not to appeal the SCR requirements for a number of coal units.[27] In the settlement, PacifiCorp agreed to install SCR at Jim Bridger 3 & 4 by 2015 and 2016, and install SCR at Jim Bridger 1 & 2 by 2022 and 2021, respectively. The settlement, which is briefly mentioned by Mr. Teply as the "2010 Wyoming Stipulation",[28] was signed by PacifiCorp's then Vice President of Generation, Dana Ralston.

In January 2011, WYDEQ submitted a revised SIP to EPA, including the proposed settlement terms. Importantly, EPA did not make its final BART

[25] PAC/800 at Teply/32:1, Figure 1—Bridger SCR Timeline.
[26] *Id.*
[27] Exhibit RMP_(CSW-3R) Accompanying the Rebuttal Testimony of Cathy S. Woollums, November 2010 Wyoming DEQ Bart Appeal Settlement Agreement, Docket No. 20000-418-EA-12 (Wyo. Pub. Serv. Comm' March, 2013) (attached as Exhibit Sierra Club/105).
[28] PAC/800 at Teply/28:10-11.

determination for Wyoming until January 30, 2014. In its FIP, EPA was explicit that while it was accepting Wyoming's proposed deadlines, compliance was only required "within five years of our approval of the SIP,"[29] pushing PacifiCorp's deadline out to 2019. EPA noted that it was accepting the state's deadlines because they were likely more stringent than what the EPA itself would have otherwise required:

> In our proposal, we indicated that the State had neglected to reasonably assess the costs of compliance and visibility improvement for Jim Bridger in accordance with the BART Guidelines. We nonetheless proposed to approve the State's BART and reasonable progress determinations for Units 3 and 4 because the compliance deadlines to install SCR on these units were sufficient to meet the requirements of BART.[30]

The Regional Haze rule provided up to five years to install BART retrofits.[31] In this case, however, PacifiCorp appears to have supported—or likely proposed—the 2015/2016 installation dates for Bridger 3 and 4 back in November 2010, as I describe below.

Q To date, what had been the typical EPA-mandated compliance period for installing BART retrofits?

A The Regional Haze rule expressly provides owners/operators with a five-year installation window. In this case, EPA finalized its FIP for Wyoming on January 30, 2014 with an effective date of March 3, 2014. Therefore, **the Jim Bridger 3 & 4 projects would have had a compliance deadline of March 2019**, not 2015 and 2016. EPA only affirmed Wyoming's proposed 2015/2016 compliance

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[29] 79 Fed. Reg. at 5046.
[30] *Id.*at 5048.
[31] 40 C.F.R. 51.308(e)(iv).

deadlines because PacifiCorp had agreed to or proposed those deadlines itself. In no instance did PacifiCorp complain about the expedited construction schedule.

Q Why was the Company's rush to achieve early compliance with the Regional Haze Rule a problem in this case?

A The Company's rush to achieve early compliance with an expensive environmental obligation deeply reduced the Company's optionality. By pushing forward to meet compliance well ahead of the federally mandated deadline—in this case by a number of years—the Company forfeited any opportunity to assess whether the expedited compliance schedule was economically advantageous for its customers.

Q Why did PacifiCorp support the 2015/2016 SCR installations at Jim Bridger plant?

A The record convincingly indicates that PacifiCorp viewed the installations as a way of extending investments in its coal plants, and identified from an early date the opportunity to invest $2.7 billion dollars across its entire coal fleet.

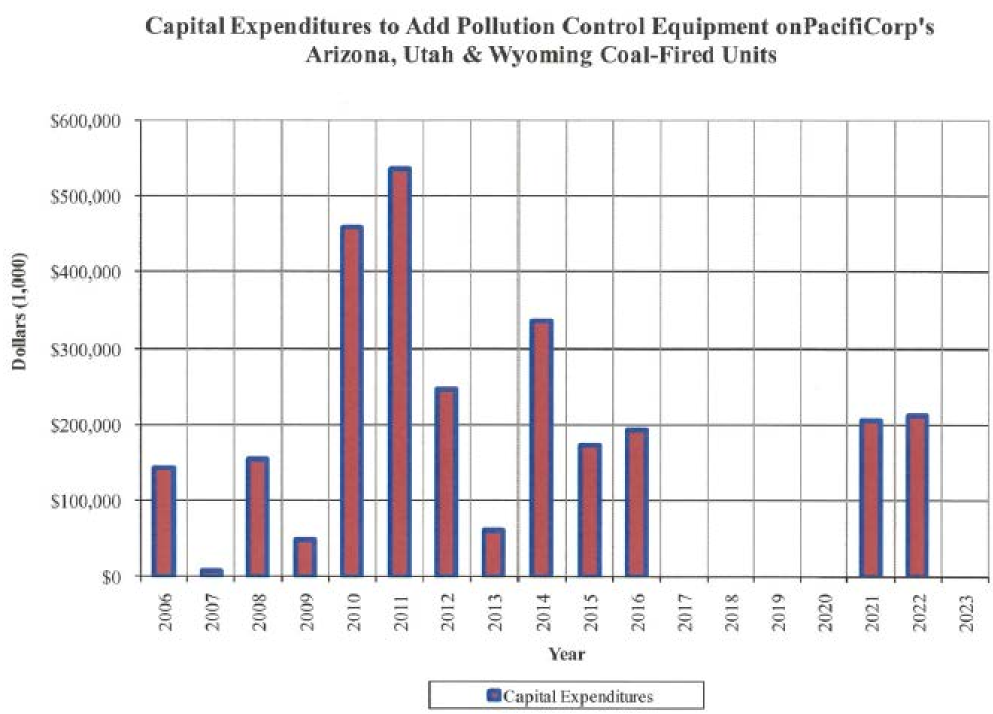
On November 2, 2010—the same day that PacifiCorp settled with WYDEQ, according to Mr. Teply's testimony[32]—PacifiCorp provided to Wyoming an Emissions Reduction Plan ("2010 Plan").[33] The 2010 Plan opened with a description of the monies PacifiCorp anticipated spending:

[32] PAC/800 at Teply/32:1, Figure 1—Bridger SCR Timeline.
[33] Exhibit A: PacifiCorp's Emission Reduction Plan (Nov. 2, 2010) (originally published as part of Regional Haze State Implementation Plan supporting materials at WYDEQ) (attached as Exhibit Sierra Club/106).

> From 2005 through 2010 PacifiCorp has spent more than $1.2 billion in capital dollars [on emission reductions]. **It is anticipated that the total costs for all projects that have been committed to will exceed $2.7 billion by the end of 2022.** The total costs (which include capital, O&M and other costs) that will have been incurred by customers to pay for these pollution control projects during the period 2005 through 2023, are expected to exceed $4.2 billion, and by 2023 the annual costs to customers for these projects will have reached $360 million per year.[34]

The 2010 Plan then showed a schedule of prior and anticipated spending, including the substantial spending for the Bridger 3 & 4 SCRs in 2015 and 2016, and the Bridger 1 & 2 SCRs in 2021 and 2022.

Figure 3. Figure from PacifiCorp 2010 Plan, showing capital expenditures anticipated at PacifiCorp's coal plants.[35]



[34] *Id*. at 1 (emphasis added).
[35] *Id*. at 5.

Q You testified above that PacifiCorp's Bridger 3 & 4 retrofit schedule was well ahead of the Regional Haze rule's regulatory compliance timetable. Was PacifiCorp aware that it was pushing for a construction schedule much faster than that required by federal regulations?

A Yes. According to Company's 2010 Plan, "PacifiCorp began implementing its emission reduction commitments in 2005. **This was well ahead of the emission reduction timelines under the regional haze rules** which require BART to be installed no later than five years following approval of the applicable Regional Haze SIP."[36] PacifiCorp was both aware that its compliance was premature and that the Regional Haze Rule itself specified a five year window **after approval of the SIP by EPA**.

In addition, in PacifiCorp's CPCN proceeding for the retrofits in Wyoming, Sierra Club motioned to stay or continue the proceeding until after EPA had made its designations final.[37]

Q What are the reasons that PacifiCorp states it was required to install the SCRs at Jim Bridger in 2015/2016?

A PacifiCorp generates a list of reasons, none of which are the federally enforceable deadline—which was issued after the Company made its firm commitment to its EPC contractors.

Mr. Teply testified that the Company filed an application requesting CPCN at the Wyoming Commission "in compliance" with the 2010 Wyoming Stipulation with

[36] *Id*. at 4 (emphasis added).
[37] Docket No. 20000-418-EA-12, Sierra Club Motion for a Stay or Continuance Pending Final EPA Action (Wyo. Pub. Serv. Comm'n Dec. 21, 2012) [hereinafter "WY PSC, SC Motion for Stay"].

WYDEQ.[38] As I'll describe, the SCRs are regulated—and enforced—under the federal Clean Air Act. There is no record of how PacifiCorp made the determination with WYDEQ that SCRs at Jim Bridger were reasonable, or should be achieved by 2015-2016.

Mr. Teply also testified that the timeline was required by a "Best Available Retrofit Technology (BART) permit issued by the state of Wyoming"[39] in December 2010.[40] That permit was issued as an outcome of 2010 Wyoming Stipulation. As I understand these permits, they allow for the stated modification in a particular timeframe, but are not the records that establish an enforceable deadline.

Q Finally, Mr. Teply testified that "the Company was required to comply with the timelines set in Wyoming's SIP."[41] The SIP was, until EPA's finalization, simply a draft plan. Mr. Teply testified that "the Company was required to comply with the timelines set in Wyoming's SIP,"[42] and provided a letter from the Wyoming DEQ[43] which he claimed verified the enforceability of the Wyoming claim. Was he correct?

A No. Mr. Teply's fundamental assertion that the Wyoming DEQ was able to enforce the specific deadlines in its SIP prior to EPA's affirmation of the SIP was, in my lay understanding, incorrect. As I understand the requirements under the

[38] PAC/800 at Teply/26:22-23, 28:9-13.
[39] PAC/800 at Teply/26:22.
[40] PAC/800 at Teply/32, Figure 1—Bridger SCRs Timeline.
[41] PAC/800 at Teply/36:15.
[42] PAC/800 at Teply/36:15.
[43] PAC/830.

rule, Wyoming DEQ had neither state nor federal authority to require compliance with its draft SIP under the federal Regional Haze Rule.

PacifiCorp's letter to Wyoming DEQ (dated March 5, 2013)[44] was sent the day after the Company submitted rebuttal in the Wyoming CPCN (March 4, 2013),[45] and was generated for the purposes of rebutting Sierra Club's assertion that the Company did not have an enforceable deadline. The proper course of action by PacifiCorp would have been to inform Wyoming that it understood its deadline to be contingent on EPA's review and finalization, and that its deadlines would be no earlier than five years after EPA's final approval.

Q What options were open to the Company other than rushing SCR construction ahead of the federally mandated deadlines?

A First, the Company should not have entered into a decade-long compliance schedule with WYDEQ in the 2010 Wyoming Stipulation. Secondly, Regional Haze falls under the federal Clean Air Act, and as the years wore on, and expensive retrofits became less economically viable, the Company should have used the opportunity to adjust its plans through the appropriate channels with EPA. Again, EPA's final Regional Haze FIP was not issued until January 30, 2014. [46] Tellingly, PacifiCorp sued EPA for its SCR requirements under the Wyoming FIP for its other units in Wyoming, but <u>not</u> for Bridger. The Company

[44] PAC/829.
[45] WY PSC, SC Motion for Stay.
[46] Even after it issued the FNTP, the Company still could have terminated the project with minimal costs. I discuss the termination provisions of the EPC contract in Section 3 f (starting page 58).

successfully obtained a stay of the FIP with respect to those other units, [47] but it did not challenge or seek a stay of the EPA's decision to require the Jim Bridger SCRs. As of today, construction deadlines for those other units are still pending.

Q Did the Company have the opportunity to ask EPA to make its deadlines for Jim Bridger 3 & 4 later than 2015 / 2016?

A Yes. In fact, the Company submitted comment to EPA while the agency was analyzing these very deadlines, in August of 2013. But rather than contest Wyoming's Bridger deadlines as inconsistent with Clean Air Act requirements, the Company instead cited the fact that "engineering and permitting is underway for the installation of SCR" at Jim Bridger,[48] and even referenced the recent CPCN process that it had gone through before the Wyoming Public Service Commission ("WPSC") seeking approval to install these retrofits.[49]

It cannot be understated just how backwards, PacifiCorp's process was here. In comments to EPA, the regulatory agency that would ultimately determine what its compliance obligations would be, PacifiCorp instead elaborated on its intent—and actions—to reach a presumptive form of compliance. Any form of urgency to meet a 2015/2016 deadline was of PacifiCorp's own manufacture, and not a

[47] *See PacifiCorp v.EPA*, No. 14-9534 (10th Cir.)(filed Mar. 31, 2014) (PacifiCorp's motion to stay implementation of the FIP granted September 9, 2014 and implementation of the FIP remains stayed as of this writing).
[48] PacifiCorp Comments on Wyoming's Regional Haze Plan, ID EPA-R08-OAR-2012-0026-0149 at 7 (Aug. 26, 2013) (excerpts attached as Exhibit Sierra Club/107).
[49] *Id.* at 35.

product of the federally enforceable requirements of the federal Regional Haze Rule.[50]

Q What are your conclusions with respect to the Company's timeline to install the SCRs at Jim Bridger 3 & 4?

A I conclude that the Company manufactured a compliance deadline that it understood was well ahead of EPA's requirements, and continued to assert that compliance deadline without respect to alternatives or flexibility afforded under the Clean Air Act, and at cost to its ratepayers.

Rather than a 2015/2016 deadline, PacifiCorp had an enforceable 2019 deadline. The additional four to five years of compliance would have afforded PacifiCorp the opportunity to assess additional alternatives, and continue to assess the need to retrofit Jim Bridger 3 & 4, as opposed to either retiring or repowering the units. And as I'll show in Section 3.e (page 44) and Section 3.f (page 58) that additional timeline would have revealed unequivocally that the Company's election to move forward on the retrofits was not in the interests of ratepayers.

The Company's failure to ask EPA for a federally enforceable deadline commensurate with the five-year requirements under the Regional Haze Rule was imprudent.

[50] 40 C.F.R. 51.308(e)(iv).

c. THE COMPANY'S ASSESSED ALTERNATIVES TO CONSTRUCTING SCRS AT JIM BRIDGER WAS FUNDAMENTALLY FAULTY

Q You testified that the Company had alternative compliance options available to it other than the immediate shut down or repowering of the coal-fired unit in order to meet regional haze obligations. What kinds of alternatives were available to states and generators under the Regional Haze Rule?

A EPA worked with states to propose alternative compliance pathways that achieved the same or better cumulative emissions reductions, what is known as "better than BART." For example, in the recent approval of an alternative compliance pathway for PacifiCorp's Naughton 3 coal-fired station, EPA was clear that its guidance on alternative compliance extended back to 2006, stating:

> In 2006, the EPA finalized regulations that govern alternatives to source-specific BART determinations such as that contemplated in the Wyoming SIP revision for Naughton Unit 3. These regulations "make clear that the emissions reductions that could be achieved through implementation of the BART provisions at § 51.308(e)(1) [for source-by-source BART] serve as the benchmark against which States can compare an alternative program." In turn, the emissions reductions that could be achieved through source-by-source BART are calculated in accordance with the Guidelines for BART Determinations Under the Regional Haze Rule.[51]

Q Is the Company today aware of the alternative compliance options available to it under the Regional Haze Rule?

A Yes, very much so. In fact, much of the 2017 Integrated Resource Plan ("IRP") focused on alternative regional haze compliance options, including unit retirements and conversions to gas; pathways that the Company believed would

[51] 84 Fed. Reg. 55, 10433 (Mar. 21, 2019) (internal citations omitted).

provide potentially lower cost options for compliance than installation of pollution controls.[52]

Q Should the Company have been aware in 2013 that there were alternative compliance options available to it rather than the five year compliance window under the Regional Haze Rule?

A Yes. On July 5, 2011, EPA approved Oregon's Regional Haze SIP, which amongst other items, proposed to shut Portland General Electric's ("PGE") Boardman coal-fired power plant by December 2020, well after the five-year compliance deadline under the Regional Haze Rule.[53] In proposing to accept the alternative approach, EPA cited a specific process conducted by PGE and the Oregon Department of Environmental Quality ("ODEQ"):

> In a letter from PGE to ODEQ dated October 22, 2010, PGE requested that ODEQ reopen the Regional Haze BART rulemaking to consider an alternative BART approach for PGE Boardman. This alternative approach would allow PGE Boardman to commit to cease burning coal by December 31, 2020, and in the interim operate with less expensive control technology.[54]

EPA approved this process and finding, an outcome that would have—or should have—been clear to PacifiCorp. And in fact, organizations such as the Citizens' Utility Board ("CUB") of Oregon strove to make it quite clear to PacifiCorp that this type of alternative compliance should be reviewed by the Company. In both

[52] PacifiCorp, 2017 Integrated Resource Plan, at 21 (April 4, 2017), *available at* https://www.pacificorp.com/energy/integrated-resource-plan html ("Compliance associated with Regional Haze requirements continued to be a key area of focus for the 2017 IRP. PacifiCorp developed resource portfolios among seven potential Regional Haze scenarios (including a reference case), assessing how different inter-temporal and fleet-tradeoff compliance outcomes might influence new resource needs and system costs.").
[53] 76 Fed. Reg. 38997.
[54] 76 Fed. Reg. 12651, 12660 (Mar. 8, 2011).

opening comments, and then reiterated in final comments on PacifiCorp's 2011 IRP, CUB explicitly raised this alternative compliance opportunity, stating:

> To the degree that the clean air costs are associated with Regional Haze (BART) SIPs, the range of options that the Company has considered must also be disclosed, since BART contains a fair amount of flexibility tied to the lifetime of the plant. This flexibility allows for a utility to shorten the life of a plant rather than prolong it by adding additional clean air investments, as the total amount of pollution emitted from a plant is greatly reduced by early closure. As such, if a plant is closed early, the shorter life will mean that less pollution control investment is cost-effective and the utility can move towards finding a more efficient replacement resource.[55]

Inexplicably, PacifiCorp ignored CUB's recommendation. Instead, PacifiCorp affirmatively chose not to assess any alternative compliance options for Jim Bridger 3 & 4. It is entirely feasible that a commitment to retire Jim Bridger at a later date, like 2020 or 2022, would have resulted in lower costs in a forward-looking assessment.

Q **Has the Commission previously recognized that the Regional Haze Rule provides utilities with flexibility in its timing?**

A Yes. In December 2012, this Commission ruled on PacifiCorp's implementation of retrofits at the (still operating) Naughton 1 & 2 coal-fired power plants, finding that the Company's decision and process to build emission controls was analytically and structurally flawed.[56] Specifically, the Commission noted that the inherent flexibility in the Regional Haze Rule as afforded to PGE should have

[55] Opening Comments of the Citizens' Utility Board of Oregon, *In the Matter of PacifiCorp dba Pacific Power 2011 Integrated Resource Plan*, Docket No. LC 52, at 7-9 (Aug. 25, 2011).
[56] Order No. 12-493, *In the Matter of PacifiCorp, dba Pacific Power Request for a General Rate Revision*, Docket No. UE 246, at 29 (Dec. 20, 2012) [hereinafter "Order No. 12-493"].

been employed by PacifiCorp in contemplating those retrofits, to the benefit of ratepayers:

> In addition, if Pacific Power had properly explored the potential flexibility in the timing of its options under the RHR, as we believe it had the opportunity to do, the utility and ratepayers would have benefited from additional information that could have been incorporated into cost-effectiveness analyses. That additional information, at a minimum, could have supported later potential shut down dates for use in the PVRR(d) analysis as suggested by CUB and Sierra Club. Indeed, had Pacific Power planned to delay investments at some of its plants, then the utility would have been clearly aware of the "phase-out" analysis conducted by PGE for its Boardman plant and prompted to evaluate the economics of a similar phase-out. As noted by CUB, that analysis permitted PGE to consider a phase-out of its Boardman plant geared toward shutting the plant in 2020, rather than investing in more costly upgrades necessary to allow the plant to operate past that date.[57]

Q What are your conclusions with respect to the alternatives that were available to the Company under the Regional Haze Rule?

A I conclude that the Company failed to assess any alternatives towards lower cost compliance as authorized under the Regional Haze Rule, as conducted by PGE for the Boardman plant, and as recommended by CUB in 2011. These alternatives would have allowed the Company to seek a later firm retirement date for Jim Bridger 3 & 4 rather than install the SCRs. This pause would have ultimately resulted in substantial savings for customers, as I show in Section 3.f (page 58).

The Company's failure to assess alternative options under the Regional Haze Rule was imprudent.

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[57] *Id*. at 30.

d. Costs and Operations at the Bridger Mine Changed Materially in the Months Prior to the FNTP

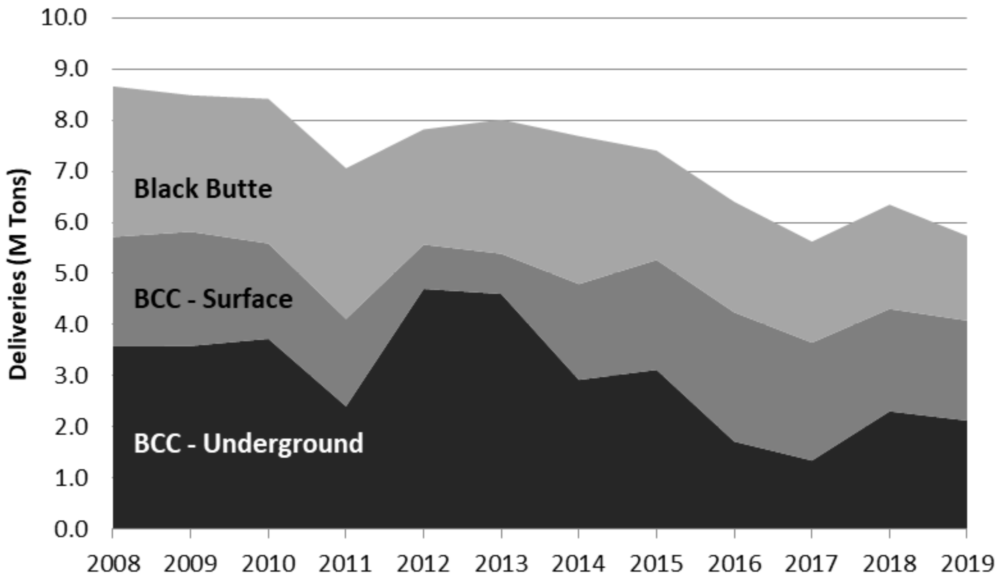
Q How does the Bridger coal plant receive fuel, and how is that relevant to this case?

A The Jim Bridger coal plant receives coal both from the Bridger Coal Company ("BCC"), a mine and company jointly owned by PacifiCorp and Idaho Power Company; and the Black Butte Mine, a commercial coal producer. BCC exclusively serves Jim Bridger plant, while Black Butte mine also serves a small amount of coal to Idaho Power Company's North Valmy station.

Over the last decade, Jim Bridger has received about 2/3rds of its coal supply from BCC, with the remainder coming from Black Butte. My testimony focuses on the Bridger Coal Company mine, and material changes that occurred in mining operations between the time that Mr. Link ran his September 2013 "breakeven" assessment and the signing of the FNTP.

The BCC mine is divided into a surface and underground operation. Over the last decade, the underground mine has contributed around 60 percent of the coal from BCC to Bridger (see Figure 4, below).

Figure 4. Deliveries of coal to Jim Bridger plant (M tons).[58]



The BCC underground mine was opened in 2004, and was meant to extend the longevity of the Bridger mine at a lower cost than the surface.

When doing long-term planning, PacifiCorp constructs what it terms "long-term fueling forecasts," ("fuel forecast") and for the Jim Bridger plant, those forecasts seek to account for the costs of procuring coal from the surface mine, the underground mine, and from Black Butte over a period of decades. For the Bridger SCR assessment, the Company used a fuel forecast from January 2013 (the "January 2013 Fuel Plan").[59]

However in the period between January 2013 and October 2013—i.e. preceding the FNTP date of December 1, 2013—the Company's plan for acquiring fuel at

[58] EIA Form 923, *available at* https://www.eia.gov/electricity/data/eia923/.
[59] *See* Exhibit No. DR-1CT, Confidential Rebuttal Testimony of Dana Ralston, *Washington Utilities and Transportation Commission, Complainant, v. Pacific Power & Light Company, Respondent*, Docket No. UE-155253, at 2:14-16 (Wash. Util. Transp. & Comm'n Apr. 2016) [hereinafter "UTC Ralston Rebuttal Testimony"] (provided as an attachment to PacifiCorp Response to Sierra Club Data Request 1.8(c) (attached as Exhibit Sierra Club/108).

Jim Bridger was thrown into disarray, ultimately causing the Company to come up with a completely different fueling plan for the plant and a very different outlook for the Bridger Mine. The Company admits that as an outcome of this new fueling plan, the costs of maintaining Jim Bridger as a four-unit coal-fired plant increased by $31 million.[60] This increased cost materially devalued the SCR retrofit project, and was not accounted for by the Company at all in its re-assessment of the SCR project prior to executing the FNTP.

Below I explain the basis of the Company's adjustment.

Q How did the Company assess the cost of coal for the Jim Bridger SCR assessment?

A First, it's notable that the fuel costs for Jim Bridger are actually reflected in two different places in the Company's modeling. Because PacifiCorp partially owned the mine, the Company actually incorporated capital costs[61] through a completely different avenue than what it referred to as the "cash costs," which are reflected in the per MMBtu cost of coal.[62] For clarity, I refer to the all-in cost of coal (i.e. including capital) as the "full cost" of coal, while I use the Company's term for the variable cost, the "cash cost."

In assessing both the cash cost as well as the full cost of coal at Bridger for the SCR analysis, the Company developed two completely different fuel forecasts. The first forecast assessed how coal would be procured if all four Jim Bridger units were to run until 2037 (the "four-unit scenario"). The second forecast

[60] *See id* at 8:15.
[61] *See* PAC/707;
[62] *See* PAC/705;

assessed the cost of coal if only two units ran through 2037 (the "two-unit scenario").[63]

Mr. Link briefly described that under a two-unit scenario, the Company had a different set of assumptions for the Bridger coal mine, and requisite costs.[64] He also showed some of the differences between the resulting costs in his accompanying exhibits.[65]

What Mr. Link failed to describe was that under a two-unit scenario, the Company assumed that it would close the surface mine in 2017,[66] relying instead on the underground mine for the remainder of the plant's life, through 2037. The Company assumed that the expedient closure of the surface mine (in the two-unit scenario) would result in the acceleration of the mine reclamation costs.[67] Critically, that acceleration of mine reclamation costs (shown by Mr. Link in Exhibit PAC/706) [redacted] between 2013 and 2018, the period when all four Bridger units are still operating.[68]

In contrast, the four-unit scenario assumed that both the surface and underground mine would persist through 2037.[69]

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[63] In its initial CPCN the Company also developed a three-unit scenario assessment that it dismissed as a higher cost alternative.
[64] PAC/700 at Link/91:20-93:3.
[65] *See* PAC/705; PAC/706; PAC/707.
[66] *See* Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 1.8(b).
[67] *See* Exhibit No. CAC-1CT, Redacted Supplemental Rebuttal Testimony of Cindy Crane, *Washington Utilities and Transportation Commission, Complainant, v. Pacific Power & Light Company, Respondent*, Docket No. UE-152253, at 11:18- 12:1 (Wash. Util. & Transp. Comm'n May 2016) [hereinafter "UTC Crane Supplemental Rebuttal"] (attached as Exhibit Sierra Club/109).
[68] Author's calculation from Exhibit PAC/705.
[69] *See* Sierra Club/102, PacifiCorp Response to Sierra Club 1.8(b).

Paradoxically, in the Company's view, it is more expensive to operate the Bridger Coal Company (in absolute terms) when it is producing less coal. These incremental costs were not imposed on the four-unit scenario.

Q What was the total incremental cost that was imposed in the two-unit scenario for assumed accelerated reclamation at the Bridger mine?

A The accelerated reclamation cost was actually imposed as a contribution to a "sinking fund,"[70] or a pool of cash the Company allocates for the use of eventual mine closure. The Company collects an amount every year, determined as the amount necessary, after growth through interest, to fund closure activities at the end of the mine's life. In the four-unit scenario, the Company is able to simply collect $[redacted] per year,[71] while in the two-unit scenario the Company requires contributions of [redacted] per year through 2018 to fund the closure of the surface mine.[72]

Overall, the acceleration of remediation in the two-unit scenario drove up the present value of closure by $[redacted] (present value, 2014$) relative to the four-unit scenario.[73]

Effectively, the Company *had* assumed through 2013 that it would continue collecting sufficient revenue through 2037[74] sufficient to fund the massive closure in 2037. Specifically, the Company assumed that compounding interest—and [redacted]—would generate

[70] *See* Sierra Club/109, UTC Crane Supplemental Rebuttal at 6:3-5.
[71] *See* Exhibit PAC/706.
[72] *Id.*
[73] Author's calculation from Exhibit PAC/706
[74] *See* PAC/700 at Link/92:15-18

enough to fund [redacted] of reclamation activities, the bulk of which would [redacted]. This assumption that the Company could effectively self-bond its own closure was interrupted by the two-unit scenario, where the Company's requirement for cash was suddenly accelerated. And while the overall closure cost was much lower – at only [redacted],[76] the impact on the cost of coal increased dramatically.

Q You stated that between January 2013 and October 2013, prior to the completion of the FNTP, circumstances changed dramatically at the Bridger coal mine. How so?

A In March/April of 2013, Bridger Coal Company conducted drilling that resulted in a finding that a panel in the underground mine had excessive ash content,[77] a finding that led to a substantial change in mining operations and ultimately contributed to a rate increase request before the Utah Public Service Commission. That January 2014 Utah rate case presented new costs associated with the Bridger mine. [78] The mine plan supporting those costs was developed in October 2013, two months before the FNTP. [79]

[75] PacifiCorp 2/3 share. Sum nominal 2013-[redacted] Author's calculation from Confidential Attachment "BCC Production-Operating Cost Schedules.xlsx" to PacifiCorp Response to Sierra Club Data Request 1.7/Two DL Rev [hereinafter "1.7 Attach_Two DL Rev,_CONF BCC Production-Operating Cost Schedules"].

[76] Author's calculation from Confidential Attachment "BCC Production-Operating Cost Schedules CONF.xslx" to PacifiCorp response to Sierra Club Data Request 1.7/Two Unit Rev2. [hereinafter "1.7 Attach_Two Unit Rev 2_ CONF BCC Production-Operating Cost Schedules"].

[77] *See* Docket No. 13-035-184, PacifiCorp Response to Sierra Club Data Request 4.9(b) (Utah Pub. Serv. Comm'n Apr. 15, 2014) (attached as Exhibit Sierra Club/110).

[78] *See In the Matter of the Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations*, Docket No. 13-035-184 (Utah Pub. Serv. Comm'n filed Jan. 3, 2014).

[79] *See* Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 1.8(a).

The October 2013 four-unit mine plan ("October 2013 mine plan") shows that the Company had significantly changed its expectations for the Bridger mine since January of 2013. While the January 2013 fuel plan (for four-unit operation) assumed that both the surface and underground mines would be utilized through 2037, [80] the October 2013 mine plan indicated that the Bridger underground mine would cease operations in 2022,[81] and only utilize surface operations through 2037.[82]

Q Why was the change in closure dates for the underground mine in the October 2013 mine plan significant?

A The January 2013 fuel plan had assumed that the surface mine would close in 2017 in a two-unit scenario, requiring an immediate—and costly—remediation. By October 2013, the Company clearly no longer believed that the underground mine had the capacity to provide cost-effective coal through the end of the analysis period. Therefore, it is highly unlikely that the Company would have developed or continued to use a two-unit mine plan that relied on the underground mine, and the acceleration of surface remediation would not have been featured in that two-unit scenario.

[80] *See id.* at 1.8(b).
[81] *See id.*
[82] *See id.*

Q Was the October 2013 mine plan significant?

A Yes, the October 2013 mine plan was the basis for a new business plan at the mine.[83] In a Washington UTC docket on this same issue, the Company verified that "[t]here is no doubt that the October 2013 mine plan reflects changes in the relationship between the surface and underground mining operations at BCC."[84]

The change in disposition of the underground mine in October 2013 was a substantial shift with respect to the Bridger Coal mine. In late March 2013—before the coal ash problems were discovered at the underground mine—Cindy Crane, then CEO of Interwest Mining Company, the PacifiCorp subsidiary which partially owns and operates the Bridger Coal Company, verified that if two units were to shut down the Company would assuredly rely on the underground mine in perpetuity.[85]

By October 2013, the Company was projecting that it would shutter the underground mine by 2022,[86] and that assumption persists. In fact, the Company's recent 2019 IRP verified that in its preferred scenario the underground mine

[83] Docket No. 13-035-184, Redacted Rebuttal Testimony of Cindy A. Crane on Behalf of PacifiCorp dba Rocky Mountain Power , at 11: 193-197 (Utah Pub. Serv. Comm'n June 4, 2014) ("In this test period, based on drilling in March/April 2013, Bridger Coal personnel spent several months re-engineering the mine plan to bypass the 12th right longwall panel. This re-engineered plan is the basis of the 2014 Bridger Coal Business Plan produced in October 2013.").
[84] Sierra Club/108, UTC Ralston Rebuttal Testimony at 8: 5-6.
[85] *See* Docket No. 20000-418-EA-12, Hearing Transcript of Ms. Cindy Crane, at 130:6-16 (Wyo. Pub. Serv. Comm'n Mar. 26, 2013) [hereinafter "WY Crane Hearing Transcript"] (attached as Exhibit Sierra Club/111).
[86] Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 1.8(b).

would close in 2022,[87] and a recent article quoted the Company as projecting a December 2021 closure.[88]

Q What was the impact of the new mining plan on the Bridger SCR assessment?

A The surface mine is a high cost operation.[89] In the Company's January 2013 fuel plan, the Company assessed that the total cost of the surface mine is [redacted], as shown in Confidential Figure 5, below. On a levelized cost basis (2016-2030), the surface mine is [redacted].[90]

Confidential Figure 5. Baseline total cost of coal at Bridger Coal Company surface and underground mines from January 2013, four unit scenario ($/MMBtu)

[redacted]

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[87] *See* Docket No. LC 70, Attachment "Attach Sierra Club 3.27" to PacifiCorp Response to Sierra Club Data Request 3.27 (Ore. Pub. Util. Comm'n Nov. 27, 2019) (attached as Exhibit Sierra Club/112).
[88] Andrew Graham, *Life beneath the earth in Wyo's only underground coal mine,* WyoFile (Sept. 3 2019 *available at* https://www.wyofile.com/life-beneath-the-earth-in-wyos-only-underground-coal-mine/ (attached as Exhibit Sierra Club/113.
[89] *See* Sierra Club/111, WY Crane Hearing Transcript at 125: 3-11.
[90] Author's calculation from 1.7 Attach_Two DL Rev_CONF BCC Production-Operating Cost Schedules. Levelized cost of the surface mine is [redacted]. The levelized cost of the underground mine is [redacted]

Therefore, when the Company elected to close the underground mine early, and then shift to the surface mine, it was electing to use a higher cost of coal in the four-unit scenario—a circumstance that would disadvantage the decision to retrofit Jim Bridger with SCR.

Q Did the Company re-assess the value of pursuing the SCR retrofit in light of the need for a new and revised mining plan?

A No. There is no evidence that the Company reviewed, assessed, or even discussed the new mining plan.

Ironically, Ms. Crane had testified just months before that in assessing the value of the SCR the Company strove to use the most up-to-date data, stating:

> In addition, the company has been very diligent in its mine planning to ensure that we have included in the analysis in this proceeding the absolute most current detailed mine planning data available for the decision relating to the SCR installations.[91]

While that may have been true when the Company sought a CPCN in 2012, it was not the case when the Company actually committed customer funds and signed the FNTP.

Q What was the monetary impact of the new October 2013 mining plan on the Bridger SCR decision?

A An independent assessment of the monetary impact is almost impossible from a third-party perspective. The Company did not translate the new mine plan into a comprehensive "fueling plan" until November 2014, in preparation for the 2015

[91] Sierra Club/111, WY Crane Hearing Transcript at 125:19-23.

IRP,[92] and the Company never created a two-unit scenario with the new October 2013 mining plan.[93]

While both UTC Staff[94] and I[95] have previously attempted to create an estimated four- and two-unit coal cost scenarios in the past, the Company's source workbooks for Bridger fuel costs are a warren of broken links,[96] circular references,[97] inscrutable structures,[98] and the Company's characterization of costs as either "cash costs" or that flow to capital are both ill-defined and changing.[99]

In its Washington presentation of this case, the Company rebutted my assessment of the impact of the new mining plan, but affirmed that the new mine plan represented "changes in the relationship between the surface and underground mining operations at BCC."[100] Company witness Dana Ralston, Vice President of Thermal Generation at PacifiCorp, provided a revision to my assessment, and estimated that the new October 2013 mine plan had resulted in an increased cost

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[92] *See* Sierra Club/108, UTC Ralston Rebuttal Testimony at 10:2-3.
[93] *Id*. at 10:19-20.
[94] UE-152253, Supplemental Testimony of Jeremy B. Twitchell on Behalf of UTC Staff (Exhibit JBT-19HCT), at 9-15 (Wash. Util. & Transp. Comm'n May 6, 2016) (attached as Exhibit Sierra Club/114).
[95] UE-152253, Direct Testimony Jeremy Fisher on Behalf of Sierra Club, at 20:22-21:19 (Wash. Util. & Transp. Comm'n Mar. 17, 2016).
[96] Opening the Company's fuel plan workbook entitled "BRIDGER Rev 1-18-13 CONF. xlsx" (provided as a confidential attachment to PacifiCorp Response to Sierra Club Data Request 1.7) produces an unreadable content flag, and flags a number of broken links.
[97] Opening the Company's Bridger Coal Company core workbook "BCC Production-Operating Cost Schedules. xlsx" produces a circular reference warning. *See* 1.7 Attach_Two DL Rev_CONF BCC Production-Operating Cost Schedules.
[98] For example, in the Bridger mine workbook, [redacted] *See* 1.7 Attach_Two DL Rev_CONF BCC Production-Operating Cost Schedules.
[99] *See* Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 1.7(f) (listing line items included in "cash costs" and noting that "reclamation contributions were included in cash costs in these scenarios, however, they are not included in the 2019 Integrated Resource Plan cash cost.").
[100] Sierra Club/108, UTC Ralston Rebuttal Testimony at 8:5-6.

of $31 million to the Bridger SCR retrofit decision[101]—thereby degrading the value of the SCR by $31 million.

Notably, Mr. Ralston's assessment was conducted *post hoc*. He calculated his adjustment to the value of the SCR projects using work papers that I had constructed to assess the potential change in value. There was no affirmative Company assessment or adjustment conducted between October 2013 and the signing of the FNTP in December 2013.

Layered on top of Mr. Link's re-assessment using September 2013 gas prices, the value of the SCR retrofit would have fallen by another 24%, to $99 million.

Q Is it your opinion that Mr. Ralston's estimate of the cost increase associated with the shift to surface mining may have been a lowball estimate?

Yes. As I noted earlier, the Company's two-unit scenario assumed that the surface mine would need to be remediated immediately, requiring an increase in reclamation payments of $28.3 million (present value, 2014$) relative to the four-unit scenario.[102] Once the surface mine was the exclusive source of coal, there was relatively little difference between the timing of the closure obligation for the two-unit scenario and the four-unit scenario. In addition, the two-unit scenario would presumably have disturbed less landscape, requiring less reclamation. Mr. Ralston did not factor in the lack of accelerated reclamation nor the reduction in total reclamation associated with a surface-based two-unit scenario. Accounting for these changes would have increased the discrepancy between the two-unit and

[101] *See id.* at 8:14-15.
[102] Author's calculation from Exhibit PAC/706.

four-unit scenarios by potentially $59.3 million,[103] to the detriment of the Bridger SCR projects.

Q What are your conclusions with respect to the new mine plan at Bridger mine in October 2013?

A I conclude that the Company failed to properly or timely assess the impact that its new October 2013 mining plan would have on the value of the Bridger SCR decision. That new plan resulted in a degradation of value by anywhere from $31 to $59.3 million, but the Company ignored this information in the run-up to signing the FNTP.

The Company acted imprudently in failing to account for the new mine plan, available prior to the December 1, 2013 FNTP.

e. <u>Gas Prices Fell Rapidly in the Months Leading Up to the FNTP</u>

Q You earlier testified that in the months leading up to the FNTP, industry analysts and PacifiCorp were projecting substantially lower forward-looking gas prices which PacifiCorp ignored when assessing the value of Jim Bridger when the Company executed the FNTP. Please explain.

A PacifiCorp's records at the time show that when it signed the FNTP, it understood that gas prices would likely become—and remain—depressed on a going-forward basis. This was new information that was not represented in the Company's analyses preceding the FNTP.

[103] Addition of the Ralston's $31 million mine plan adjustment and an incremental $28.3 million adjustment to account for the lesser near-term reclamation costs.

Mr. Link described that the Company elected to move forward on the Bridger SCR retrofits on the basis of his "breakeven" assessment, in which he assessed that the levelized cost of local gas prices from 2016 to 2030 would have to drop below $4.86/MMBtu[104]in order for the Company to re-assess its retrofit decision. In constructing that assessment, Mr. Link described that he used a September 2013 gas price forecast, which still projected gas prices at $5.35/MMbtu,[105] above his breakeven. Mr. Link testified that at this price point, the SCRs benefited customers by approximately $130 million.[106]

It is notable that from a statistical standpoint, the $5.35/MMBtu gas price was <u>not</u> a robust indicator that the retrofit was cost effective, even relying on Mr. Link's shortcut breakeven assessment. In fact, at a 90 percent confidence interval, the SCRs either continued to be a benefit to consumers, or were already a liability. And since gas prices are inherently uncertain,[107] there was a distinct potential—particularly if gas prices trended downward—that the SCRs would pose a liability to consumers.

The Company did not conduct any further analysis with respect to gas prices and did not conduct further modeling on the value of pursuing the retrofit.

The "September 2013" gas price forecast that Mr. Link relied on is the Company's own internal "Official Forward Price Curve" ("OFPC"), a quarterly 30-year projection compiled by Mr. Link and for which Mr. Link bears

[104] PAC/700 at Link/101:13-17; Link/106:4-21.
[105] *Id.* at Link/107:6-9.
[106] *Id.* at Link/107:6-13.
[107] *Id.* at Link/107:15.

responsibility.[108] As far as I can discern, Mr. Link develops the OFPC gas price forecast by consulting forecasts from three private vendors,[109] the Energy Information administration, and forwards on commodity exchanges.

When Mr. Link produced the Company's December 2013 OFPC on December 31, 2013, the levelized price of gas at Opal had dropped to $5.00/MMBtu.[110] According to Mr. Link's "breakeven" assessment, that would have left the value of the Bridger SCRs at just $36.7 million—or a drop of 80% from Mr. Link's "base case" of $186 million.[111]

Below, I show why assessing the cost of gas using a projection that theoretically wasn't available until December 31, 2013 is consistent with the information available to the Company at December 1, 2013.

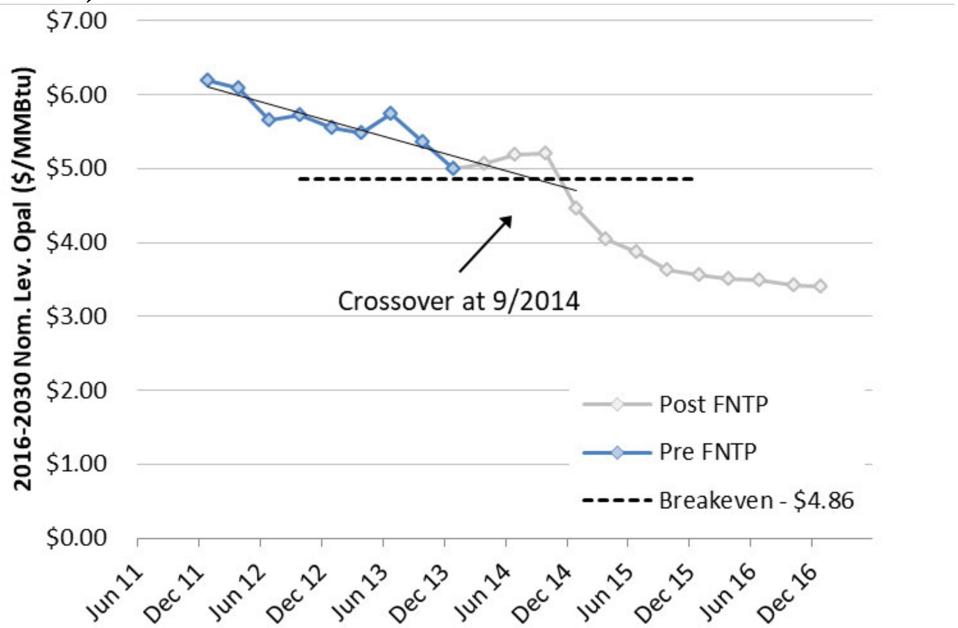
Q Mr. Link testified that "PacifiCorp also considered that . . . natural-gas prices cannot trend downward indefinitely."[112] To what trend is Mr. Link referring?

A Mr. Link was referring to the fact that from the time of the Company's August of 2012 CPCN application before the Wyoming PSC, which relied on a gas price forecast from December 2011,[113] the Company's projection of future gas prices had fallen steadily, dropping by $1.18/MMBtu by December 2013. In fact, just projecting forward from the Company's own projections of prices at the Opal hub

[108] *See* Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 1.6(a)-(b).
[109] *See* Sierra Club/102. PacifiCorp Response to Sierra Club Data Request 1.5(b) (Vendors are PIRA, CERA, and Woods Mackenzie.).
[110] Authors calculation from data provided in Attach Sierra Club 1.6.xlsx .
[111] PAC/700 at Link/86:15-17.
[112] *Id.*at 107:14-16.
[113] Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 1.1(h).

would have showed that the project would cross Mr. Link's notional "breakeven" of $4.86/MMbtu in September 2014 (see Figure 6).

Figure 6. PacifiCorp projections of Opal gas prices Dec 2011- Dec 2013 (blue) and 2014-2016)[114]



As I discuss below, while gas prices did not trend down "indefinitely," they absolutely continued to fall through the execution of the SCR project. And as I show in Section 2.g (page 62), below, gas prices in fact fell faster than the Company's termination provisions from the contract, meaning that it could have exited the contract mid-project and still provided customer benefits.

[114] Author's calculation from, Attach Sierra Club 1.6.xlsx, using Link formulation for real levelized cost.

Q The Company signed the FNTP on December 1st, 2013, but you testify that the Company's lower projection wasn't produced until December 31st. Did the Company have sufficient information by December 1st to know that prices were falling?

A Yes. It is notable that the OFPC is produced internally from information that the Company had on hand. On December 1, 2013, PacifiCorp had the following new information:

- Two new forecasts from third-party vendors, CERA (accessed November 21, 2013) and Wood-Mackenzie (accessed October 22, 2013).[115] Relative to prior forecasts (in [redacted] and [redacted], respectively[116]), both vendors were projecting [redacted] across the 2016-2030 analysis window ([redacted], respectively).
- Commodity trading forwards for natural gas. A retrieval for Henry Hub prices, a heavily traded gas hub, indicates that between the 2nd and 3rd quarters of 2013, gas price forwards for January 2018 fell by 6-10%, from between $4.6-$5.1/MMBtu in July-September to $4.3-4.5/MMBtu in September to December. This sustained projected price fall, repeated for every year 2014-2020, would have been apparent to PacifiCorp.

[115] Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 1.5(b).
[116] *See* Confidential Attachments1.5-2 to PacifiCorp Response to Sierra Club Data Request 1.5 (attached as Exhibit Sierra Club/115.

Figure 7. NYMEX Futures for 2018 HH, 2012-2016, indicating fall in forecast during 2013. [117]

- The Energy Information Administration's ("EIA") Short Term Energy Outlook ("STEO") does not extend beyond a year, and would have served limited value for this analysis. Nonetheless, the November STEO (Nov 13, 2013)[118] projected prices about three percent lower in 2014 than had been projected in the August STEO (August 6, 2013).[119]

The next Annual Energy Outlook ("AEO") "early release" product was not available until December 16, 2013.

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[117] CME Group, January 2018 Henry Hub gas futures with one-week average open, high, low, close (accessed Mar. 15, 2016.).
[118] EIA Short Term Energy Outlook, November 2013, *available at* https://www.eia.gov/outlooks/steo/archives/nov13.pdf.
[119] EIA Short Term Energy Outlook, August 2013, available at https://www.eia.gov/outlooks/steo/archives/aug13.pdf.

The new information available to PacifiCorp between September 2013 and December 1, 2013 all indicated a downward trend in forward gas prices. This trend was ultimately reflected in the Company's December OFPC, and should have been reflected at the start of that month, had the Company sought to consult its standard data sources.

Q How stale was the data PacifiCorp used to inform the September 2013 OFPC?

A PacifiCorp doesn't provide insight into its black box process of developing OFPCs, but it did provide the two prior vendor forecasts presumably used in the September 2013 OFPC. While CERA is dated [redacted], Wood-Mackenzie is dated [redacted]. This means that if these vendor forecasts were a substantial part of the OFPC, elements of the OFPC were [redacted] old by the time PacifiCorp finalized the FNTP.

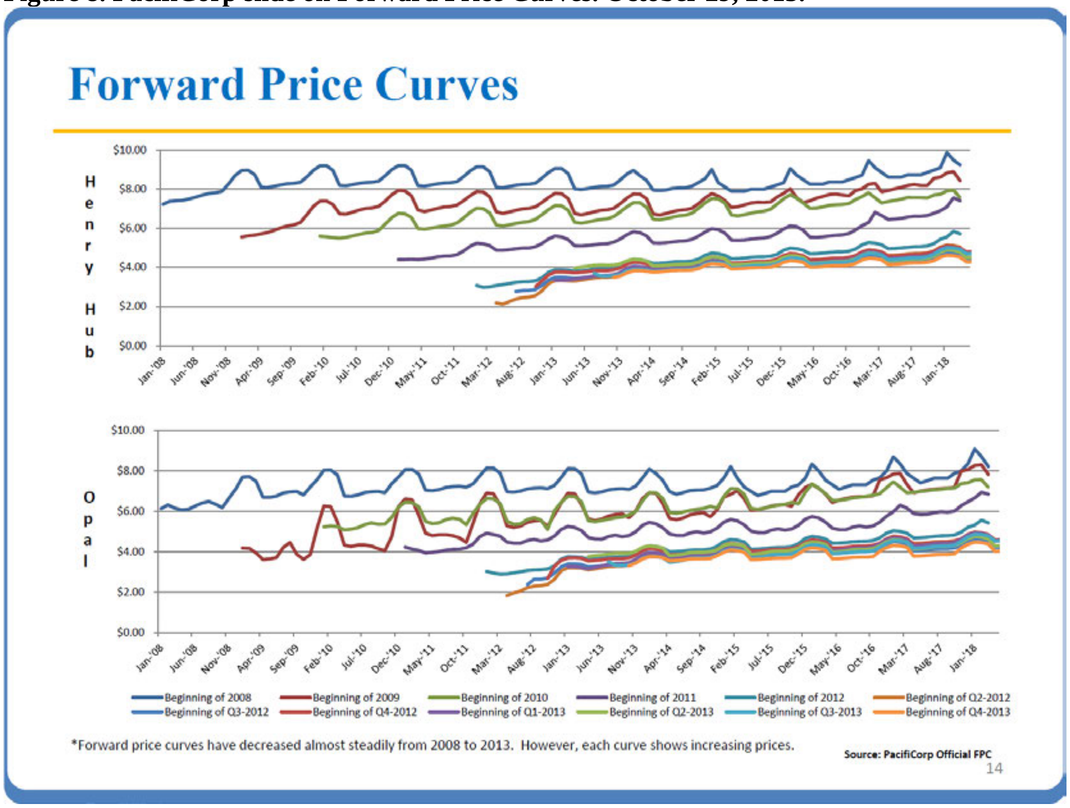
Q Did PacifiCorp recognize that gas prices were dropping rapidly through 2013?

A Yes. In an October 29, 2013 workshop on a natural gas RFP process, PacifiCorp developed a slide with a series of then-recent OFPCs, dropping from 2008 through the September 2013 OFPC.[120] That slide, shown below in Figure 8, indicated that "forward price curves have decreased almost steadily from 2008 to

[120] PacifiCorp,*2012 Natural Gas Request for Proposals Workshop* (Oct. 29, 2013)(also provided in UTC docket UE-152253 as Exhibit No. JIF-8) (attached as Exhibit Sierra Club/116).

2013."[121] The curves show that the Company, in fact, had revised gas price futures downwards in recent OFPCs as well, and was therefore aware of the trend.

Figure 8. PacifiCorp slide on Forward Price Curves. October 29, 2013.



In addition, the Company produced two short-term OFPC, dated October 31, 2013 and November 8, 2013.[122] These forecasts only extended through December 2016, and are thus of limited value, but provide a sense of directionality. In October, 2013 PacifiCorp projected that gas prices would be nearly 3 percent lower through 2016 than the September 2013 OFPC, and in November 2013, PacifiCorp was already projecting that gas prices would be nearly 5 percent lower through 2016 than the September 2013 OFPC.

[121] *Id.* at 14.
[122] *See* Attach Sierra Club 1.6. xlsx at tab "11-08-2013" and tab "10-31-2013".

PacifiCorp clearly understood that forward gas prices were falling after the September 2013 OFPC. Nonetheless, PacifiCorp failed to construct a new assessment of forward gas prices or uncertainty in those prices, failed to conduct new or additional modeling, and failed to convey internally or externally that the economics of the Bridger SCR had degraded.

Q Is the fact that the Company only produces long-run OFPCs on a quarterly basis relevant?

A No. The Company's election to create OFPC on a quarterly basis is useful, but arbitrary. There are no specific pieces of information that are only available to the Company on a quarterly basis—the Company simply elects to finalize its OFPC on that schedule.

The information driving the lower gas prices projected in PacifiCorp's December 2013 OFPC would have been available to PacifiCorp on and before December 1, 2013. A reassessment using the Company's own mechanism and own projection of levelized gas prices (2016-2030) at $5.00/MMBtu would have revealed that—according to a gas price adjustment alone—the benefit would have dropped to $36.7 million,[123] or a reduction of $146 million from the Company's assessed $183 million "Base Case" in the instant docket.[124]

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[123] Based on Mr. Link's linear relationship between the levelized cost of gas and the SCR benefit, B_{SCR}= [redacted] * P_{NG} [redacted], where B_{SCR} is the benefit of SCR decision (PVRR(d)) in millions of 2014 dollars, and P_{NG} is the levelized cost of gas at Opal hub from 2016-2030 at a 7.15% discount rate.

[124] PAC/700 Link/86:15-17.

Q Mr. Link testified that "[b]efore issuing the FNTP PacifiCorp was aware that EPC costs for the Jim Bridger SCR emission control systems had been reduced by [redacted] . . ." which resulted in "[redacted] in additional benefits to the SCR compliance alternative."[125] How does this factor into your assessment?

A Even taking into account the incremental benefit of [redacted], the final overall value of the projects were not substantial going into the FNTP. Layered on top of the Company's own admitted change in coal prices received from the Bridger mine, which had already reduced the benefit of the SCRs to $99 million,[126] the Bridger SCRs were reduced to basically a wash—from the perspective of a system the size of PacifiCorp's— with a benefit of only [redacted] by December 1, 2013. In other words, when the Company signed the FNTP, the SCRs presented no ratepayer benefit.

Q Mr. Link also testified that "there was a reasonable possibility that actual natural-gas prices could be higher than then-current base-case projections."[128] Do you have a response?

A Yes. It is true that gas prices could have trended higher than the Company's then-current base-case projections. And gas prices could also have trended lower than the Company's then-current base-case projections, which is the value proposition

[125] *Id.* at Link/108:3-6.
[126] Company's September 2013 breakeven assessment value of $130 million less Ralston's $31 million October 2013 coal price adjustment = $99 million.
[127] Company's breakeven assessment applied to Company's December 2013 OFPC, resulting in $36.7 million benefit for the SCR, less Ralston's $31 million October 2013 coal price adjustment, plus Mr. Link's [redacted] SCR cost reduction = [redacted].
[128] PAC/700 at Link/107:16-18.

behind sensitivities and characterizing risk. But the risk bands that Mr. Link discussed in his testimony,[129] shown graphically in Figure 14, are from September 2012 and were 15 months stale—and moot—by the time the Company signed the FNTP. The Company did not produce risk bands associated with its September 2013 OFPC.

Q Given the marginal outcome for the Bridger SCR project in December 2013, what action should the Company have taken?

A The rapidly declining benefit of the Bridger SCR project should have galvanized the Company to perform a far more rigorous assessment of the benefits or costs of continuing with the SCR projects. It should have paused the execution of the FNTP, if necessary, in order to conduct a final rigorous analysis.

Q What are your conclusions with respect to falling gas price leading up to the FNTP?

A I have several conclusions:

1. The Company failed to assess new market price projections available to it prior to December 1, 2013 that would have revealed lower market price forwards for gas.
2. The Company's use of a shortcut "breakeven" assessment, which relied on modeling data more than 15 months old at the time of the FNTP was unbefitting for a project of this scale and magnitude.

[129] PAC/700 at Link/102:18-105:

3. The Company was aware that the margin for the Bridger SCRs was tightening, and failed to conduct more extensive or intensive modeling to determine if the decision was still in the best interests of ratepayers prior to the signing of the FNTP.

In sum, the Company acted imprudently by failing to produce an adequate assessment prior to signing the FNTP, and the Company acted imprudently in failing to assess up-to-date gas price forwards at the time it made the decision to move forward with SCR construction.

Q **Did the Company re-assess the value of the Bridger SCR on the basis of falling gas prices or increasing coal costs?**

A No. The Company conducted no modeling on the benefit of the Bridger 3 & 4 SCRs after January 2013,[130] and did not re-assess the value of the Bridger SCR after September 2013 through any mechanism.

[130] Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 1.4(d).

Q The Company now claims that before issuing the FNTP, "PacifiCorp reviewed 10-year budget projections based on the October 2013 mine plan showing that Jim Bridger coal costs were not expected to increase significantly,"[131] and claims that "[Mr]. Teply personally performed the review of these factors, in regular consultation with Mr. Link and members of PacifiCorp's fuels group."[132] What is your opinion of these assertions?

A The Company has not provided **any** evidence that it actually reviewed these projections. Sierra Club requested that the Company provide evidence indicating that the coal and changed gas prices had been considered. The Company objected that it had no obligation to provide contemporaneous documentation of any its decisions.[133] When asked to provide notes or emails discussing these changes, the Company responded that all such records would have been erased.[134]

In fact, in its Washington presentation of this case, Mr. Teply—no longer employed by PacifiCorp, but responsible for the SCR installation—stated that any such reviews would have been informal, testifying:

> [T]he reviews that we would have completed here prior to issuing full notice to proceed would have been literally sitting down at a desk, looking at the screen, looking at the actual data, and making a decision as to whether there was any material change there that would have then triggered a reason to go back and reassess compliance approaches. In this instance there were none […]

[131] *Id.* at 1.4(b).
[132] *Id.*
[133] *Id.*
[134] Sierra Club/102, PacifiCorp Response to Sierra Club Data Request SC 4.3(a)-(b).("Internal emails are not routinely saved but are automatically deleted in the normal course of business after 90 days unless deliberately saved by a user. PacifiCorp is conducting an internal review of responsive emails. None have been identified to date.").

> There would be no memo documenting these three particular decision points in one place, no.[135]

There is additional evidence showing that the Company **did not** consult up-to-date gas prices or the new fueling plan.

1. In the spring of 2014, Sierra Club was engaged in PacifiCorp's general rate case in Utah, and asked if the changed coal costs from October 2013 had been assessed with respect to the Jim Bridger SCRs. The Company responded that:

   > A comparison of [2014] test period [coal] costs to the CPCN approval docket for the Bridger 3 & 4 SCR **has not been completed**. Since the CPCN analysis, Bridger Coal Company mine costs and quality have been updated as part of the annual mine planning process.[136]

2. The Company provided an internal memorandum written December 5, 2013 explaining the Company's decision to ultimately sign the FNTP. The memorandum, [redacted] but made no mention of either gas or fuel price changes, or even Mr. Link's economic analysis supporting the decision to move forward.[137]

3. In its Washington presentation of this same case, the Company rebutted my assertion that the coal price differential between the two- and four-unit scenarios had increased, using a *post* hoc analysis, as I described on page 43, above. The fact that the Company's analysis, performed by Mr. Ralston, was

[135] Order 12, *Washington Utilities and Transportation Commission, Complainant, v. Pacific Power & Light Company, a Division of PacifiCorp, Respondent*, Docket No. UE-152253, at ¶92 (Wash. Util. & Transp. Comm'n Sept. 1, 2016) [hereinafter "Order 12"].
[136] Docket No. 13-035-184, PacifiCorp Response to Sierra Club Data Request 4.10(d) (Utah Pub. Serv. Comm'n) (emphasis added) (attached as Exhibit Sierra Club/117).
[137] PacifiCorp, December 5, 2013 Memorandum (provided as confidential attachment "Attach Sierra Club 1.4-3 CONF.pdf" to PacifiCorp Response to Sierra Club Data Request 1.4, (attached as Sierra Club/118).

conducted as a modification to my already heavily modified work papers, and was not provided as an assessment conducted by the Company at the time clearly indicates that the Company had not assessed the coal price differential at the time.

From the evidence here, I conclude the Company never actually reviewed the changes in gas or coal prices after September 2013, and prior to signing the FNTP on December 1, 2013.

f. THE LIABILITY OF THE JIM BRIDGER SCRS EXCEEDED THE COST OF CONTRACT TERMINATION WELL BEFORE THE PROJECT REACHED COMPLETION

Q Was the drop in gas prices and reduction in value of the Bridger SCRs a temporary downturn restricted to December 2013, or did lower gas prices persist?

A With the exception of a three-quarter excursion in mid-2014, the Company's projected gas prices continued to fall after the execution of the FNTP (see Figure 6, page 47). By December 2014, the Company projected that the forward cost of gas at the Opal hub had fallen to $4.47/MMBtu (2016-2030), or $0.39/MMBtu **below** Mr. Link's breakeven. Had the Company assessed the SCRs as a new project in December 2014, it would have made the determination that the SCRs were a deep liability. On the basis of gas prices alone and using Mr. Link's 2012 gas/benefit relationship,[138] the Company would have assessed a liability of over -$100 million for pursuing the SCRs. Of course the SCRs were already under

[138] *See* PAC/700 at Link/107:9-10.

contract by late 2014—but the value proposition kept plunging as gas prices sank further and further.

Just three months later, in March 2015, Mr. Link's breakeven assessment would have shown a liability of -$215 million. Accounting for the now-solidified Bridger fueling plan (which assumed the near-term closure of the underground mine) and the assessed slightly lower cost of the SCR projects, a contemporaneous assessment would have shown an SCR liability of [redacted].

Q Even if the Company had already spent a large fraction of the Bridger SCR budget, was there a point in the construction process where it still would have been prudent to terminate the project prior to completion?

A Yes. The Company's obligation under a prudence standard is not only to make a rational and competitive decision on the basis of the most up-to-date information at its disposal at the time that it makes a commitment, but to continuously assess whether its decisions are serving the best interests of ratepayers. The Company's contract with the SCR construction firm included "termination rights and an associated cancellation schedule,"[139] [redacted][140] [redacted] At any point when the liability of continuing to pursue the project exceeded the cost of terminating the contract, the Company should have scrutinized the value of ceasing the project.

[139] Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 1.3(d).
[140] *See* Highly Confidential Attachment 1.4-3, "Exh B to EPC Contract" to PacifiCorp Response to Sierra Club 1.3(e) (attached as Exhibit Sierra Club/119).

This inflection point occurred between January 2015 and April 2015. By April 2015, the liability of the Bridger SCRs at [redacted] exceeded the contractor's [redacted].[142] From this rough assessment, terminating in April 2015 would have saved ratepayers [redacted]. Highly Confidential Figure 9, below, shows the [redacted] against the value of the Bridger SCR projects.

Highly Confidential Figure 9. SCR contractor associated cancelation schedule (i.e. [redacted]) versus the value of the Bridger SCR projects from December 2013 (including adjustment for coal and SCR cost savings) through the completion of the project.[143]

[redacted]

The [redacted] subject to change on the basis of the actual project costs. It is possible that termination could have been invoked earlier in a cost effective manner, as well.

[141] Author's calculation from OFPC provided in Attach Sierra Club 1.6.xlsx, tab "0314"
[142] *Id.*
[143] Author's calculation, and Sierra Club/119, "Exh B to EPC Contract" to PacifiCorp Response to Sierra Club 1.3(e).

To continue with a failed project is to succumb to the sunk cost fallacy. Not only should the project not have commenced, it should never have been completed.

Q Did the Company provide detailed modeling or assessment of the Jim Bridger SCRs after they commenced?

A No. Sierra Club asked the Company if it re-assessed the Bridger SCRs using the System Optimizer model at any time after February 2013, and the Company confirmed that it did not.[144]

The Company did not include any assessments of Jim Bridger 3& 4 in its contemporaneous IRP either. On March 31, 2015 the Company submitted its 2015 IRP. Each and every assessed case included an assumption that Jim Bridger 3 & 4 would be retrofit with SCR and run through 2037.[145]

Q What conclusions do you draw about the Company's assessment of the Bridger SCRs after the FNTP?

A After signing the FNTP, the Company failed to assess whether continuing with the Bridger SCRs was cost effective and in the best interests of customers. My analysis demonstrates that customers would have benefited by [redacted] had the Company elected to terminate the projects—and the units—in early 2015.

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[144] *See* Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 1.4(d).
[145] PacifiCorp, *2015 Integrated Resource Plan*, Vol. II, at 148, Figure 7.2 (Mar. 31, 2015), *available at* https://www.pacificorp.com/energy/integrated-resource-plan html ("Common to all scenarios: Carbon 1&2 shut down 2015; Colstrip 3&4 SCR 2023/2022, respectively; Craig 1&2 SCR 2021/2018, respectively; Hayden 1&2 SCR 2015/2016, respectively; Naughton 1&2 shut down 2029; Naughton 3 gas conversion 2018, shutdown 2029; Hunter 1&3 SCR 2021/2024, respectively; and Bridger 3&4 SCR 2015/2016, respectively").

The Company acted imprudently by failing to terminate the SCR projects, once the forward liability of continuing the projects and operating Jim Bridger 3 & 4 on coal fell below the cost of ceasing construction.

g. THE CONTINUED OPERATIONS OF JIM BRIDGER HAVE IMPOSED SUBSTANTIAL AND CONTINUING HARM ON PACIFICORP'S RATEPAYERS

Q Have ratepayers continued to be harmed by Jim Bridger 3 & 4 and the Company's election to install SCR at these units?

A Yes. I estimate that, using Mr. Link's "breakeven" assessment, adjusting for coal and SCR costs, ratepayers would have benefited by $353 million by December 2015 if the Company had retired Jim Bridger 3 & 4 in 2015/2016, rather than installing SCRs. This value is remarkably close to a damage value derived from the Company's most recent IRP, and then accounting for the costs of the SCRs. In October 2019, the Company submitted its 2019 IRP, which assessed the economics of specific coal units, and for the first time assessed the value of maintaining coal units not facing large new capital expenditures. The IRP showed a ratepayer benefit of $141million (present value 2019$) if the Company sought the retirement of Jim Bridger 3 & 4,[146] with the SCRs already a sunk cost. Adding the total cost of those SCRs,[147] at $235.44 (inflated from 2015$ to 2019$) amounts to $376 million (2019$) in savings allocated to customers if the Bridger SCRs had been avoided.

[146] PacifiCorp, 2019 Integrated Resource Plan, Volume II, Appendix M, at 274 -275 (Oct. 18, 2019), *available at* https://www.pacificorp.com/energy/integrated-resource-plan html (Comparing case P-35 ("Jim Bridger 3&4 Retirement 2022") at $21,732 million and "parent" case P-11 ("Cholla 4 Retirement 2020") at $21,873 million.).

[147] PAC/800 at Teply/24:7, 33:22 ($102.8 million for the Jim Bridger 3 SCR); PAC/800 at Teply/24:9, 35:17 () ($115.8 million for Jim Bridger 4 SCR).

Q Does this Commission have an established standard for disallowing imprudent expenditures?

A Yes. In 2012, the Commission ruled that "[b]ecause the purpose of a prudence review is to hold ratepayers harmless from any amount imprudently invested, a disallowance should equal the amount of the unreasonable investment."[148]

Here, the "amount imprudently invested" was the totality of the SCRs at Jim Bridger 3 & 4, and subsequent capital and operating expenses that continue to harm ratepayers relative to the Company's alternative options.

Q Do you have a recommendation as to how the Commission should assess damages associated with the implementation of the Bridger SCRs?

A Yes. The Company has provided sufficient evidence to show that customers will incur harm well above the cost of the SCRs themselves. In December 2015, that total harm was $353 million (as shown above), while a rough estimate in 2019 is that the total harm is roughly $376 million.

One portion of the estimated harm are the costs already incurred through the Company's election to construct the Bridger SCRs; namely, the cost of the SCRs and the excessive cost of operating Jim Bridger from 2015/2016 to the present day. Another portion of that harm is the costs incurred should the Company continue to operate Jim Bridger 3 & 4 through 2037 with the SCRs in place. The costs that are avoidable through the further operation of Jim Bridger 3 & 4 are

[148] Order No. 12-493 at 31.

still avoidable. Those costs are not yet ratepayer harm, but will be should the Company continue to operate these units above the cost of cheaper alternatives.

The costs the Commission should assess for disallowance are the totality of costs incurred to date (including both SCR and other capital) against the Company's alternative to either have converted the units to gas, or invoking an alternative under the Regional Haze Rule. The harm that will incurred by ratepayers through the continued use of Jim Bridger is still avoidable through the cessation of operations at Jim Bridger 3 & 4.[149]

We do not have a ready mechanism for assessing which costs make up the difference between the Company's chosen course of action and the lower cost option from 2015 through today at realized fuel, gas, and market prices. Therefore, I offer two alternatives:

1. The Commission could require the Company to assess the costs of having converted to gas in 2015/2016 or having delayed retirement or repowering until 2019, and assess damages as the difference between actual and theoretical capital plus operational costs incurred from 2013 to the present day; or

[149] The Commission, however, should consider any harms pressed upon ratepayers by the Company's inability or unwillingness to retire the Jim Bridger 3 & 4 units in a timely fashion if such inability or unwillingness was otherwise avoidable through the conversion or retirement of these units at an earlier date.

2. The Commission could elect to identify the costs of the SCRs, $218.6 million, or $56.9 million on an Oregon-allocated basis,[150] as the imprudent investment, and disallow the costs of the SCRs in full.

In my opinion, based on the 2019 IRP results, the avoidable forward-looking damages associated with continuing to run Jim Bridger 3 & 4 are the same order of magnitude as the SCR costs, and therefore the damages resulting from options 1 and 2 are probably proximate. In addition, because option 1 relies on a hypothetical, option 2 may be the simpler option. Therefore, I recommend that the Commission disallow the full costs of the SCRs.

Q You stated earlier that the Company made a similar presentation of this case before the Washington Utilities and Transport Commission ("WUTC") in 2016. What was the finding of the WUTC?

A The WUTC found that PacifiCorp failed to show that it had taken new information about gas and coal prices into account when making its decision to proceed with the FNTP,[151] specifically citing the substantial change in coal mining plans,[152] falling gas prices,[153] and the Company's lack of a rigorous modeling approach given the important changes afoot.[154] As a result, WUTC elected to disallow the return on investment for both the Bridger 3 and 4 SCRs.[155]

[150] PAC/800at Teply/24:7, 33:22 ($26.8 million for the Jim Bridger 3 SCR on an Oregon-allocated basis); PAC/800 at Teply/24:10, 35:17 ($30.1 million for Jim Bridger 4 SCR on an Oregon-allocated basis).
[151] Order 12.
[152] *Id*. ¶ 104.
[153] *Id*. ¶ 105.
[154] *Id*. ¶ 102.
[155] *Id*. ¶ 116.

The evidence shows that a broader disallowance including the cost of the SCRs themselves is warranted to make whole Oregon ratepayers.

4. PACIFICORP'S ELECTION TO ALLOW ENVIRONMENTAL RETROFITS AT HAYDEN WAS INCONSISTENT WITH ITS OWN ASSESSMENTS

Q Please provide background on the environmental retrofits at the Hayden power plant.

A Mr. Teply briefly described two selective catalytic converter ("SCR") projects installed at Hayden units 1 & 2, in Colorado,[156] with a cost to PacifiCorp ratepayers of $24.2 million, or $6.3 million on an Oregon-allocated basis.[157] For a number of reasons, it is notable that PacifiCorp is a minority owner at Hayden, with a 24.5 percent ownership fraction at Hayden 1 (or 44 MW) and a 12.6 percent ownership fraction at Hayden 2 (or 13 MW).[158] The units are majority owned and operated by Public Service Company of Colorado ("PSCo"). For perspective, at these fractions, the total SCR projects at Hayden 1 and 2 were large-scale projects, at $59.2 million and $77 million, respectively.[159]

While the SCRs are ultimately a requirement under the Regional Haze Rule, the Regional Haze rule requirement post-dates a series of fleet-wide decisions made by PSCo, in which PacifiCorp simply followed PSCo's elections. In my opinion, this passive role was unjustifiable given the magnitude of the SCR retrofits, and lies in stark contrast with an evaluation of the project conducted by PacifiCorp.

[156] PAC/800 at Teply/48:4-51:14.
[157] *Id.* at Teply/24:15-19 ($14.5 million for SCR at Hayden 1, and $9.7 million for SCR at Hayden 2).
[158] *Id.* at Teply/50:10.
[159] Author's calculation. PacifiCorp project cost divided by ownership fraction.

Mr. Teply provided a few key dates of the Hayden project, but like all Regional Haze projects, timelines are important in understanding drivers and opportunities for alternative decisions. In addition, several of Mr. Teply's dates were incorrect. Below, I compile a more complete and corrected timeline of the Hayden SCR project.

Table 1. Timeline and milestones for Hayden Unit 1 and 2 SCR decisions and installation

Date	Milestone
April 19, 2010	Colorado Clean Air Clean Jobs Act is passed (HB 10-1365)
April 21, 2010	Colorado PUC opens Emission Reduction Plan docket, 10M-245E
August 13, 2010	PSCo submits Emissions Reduction Plan to Colorado PUC, including a proposal to install SCR at Hayden by the end of 2016.[160]
December 9, 2010	Colorado PUC determines a need for SCR at Hayden (Colorado PUC Order C10-1328)[161]
November 14, 2011	PSCo applies for CPCN in Colorado (Colorado PUC docket 11A-917E) PSCo announces that it has signed a new long-term coal contract[162] with Peabody coal. Contract is [redacted][163] for sixteen-years, expiring December 1, 2027[164]
July 18, 2012	Colorado PUC approves PSCo CPCN for SCR at Hayden (Colo PUC Order C12-0843)
November 18, 2012	PacifiCorp runs internal analysis [redacted] in retrofitting Hayden 1.[165] No explicit analysis of Hayden 2.
November 29, 2012	[redacted][166]
November 30, 2012	[redacted]
December 31, 2012	EPA's approval of Colorado Regional Haze SIP[168]
January 30, 2013	Effective date for EPA's approval of Colo. SIP
June 1, 2013	[redacted][169]
May, 2015	Unit 1 in-service
August, 2015	Unit 2 in-service

160 Public Service Company of Colorado's Notice of Filing, *In the Matter of Commission Consideration of Public Service Company of Colorado Plan In Compliance With House Bill 10-1365, "Clean Air - Clean Jobs Act."*, Docket No. 10M-245E, at 4 (Colo. Pub. Util. Comm'n Aug. 13, 2010).

161 Corrects Mr. Teply's date of January 26, 2011. PAC/800 at Teply/49:14.

162 Direct Testimony of Susan Arigoni on Behalf of PSCo, *In the Matter of the Application of Public Service Company of Colorado for a Certificate Of Public Convenience and Necessity for the Hayden Emissions Control Project*, Docket No. 11A-917E at 12: 12-14 (Colo. Pub. Util. Comm'n Nov. 14, 2011) [hereinafter "Arigoni Direct Testimony"] (attached as Exhibit Sierra Club/120).

163 *See* PacifiCorp, [redacted] at 4 (Aug. 5, 2014) (provided as a confidential attachment to PacifiCorp Response to Sierra Club 2.6 [hereinafter "Hayden/Craig Confidential Workshop"] (attached as Exhibit Sierra Club/121).

164 EIA Form 923, fuel receipts, EIA Form 923, *available at* https://www.eia.gov/electricity/data/eia923/.

165 *See* Confidential Attachment "[redacted]" to PacifiCorp Response to Sierra Club Data Request 2.6(b) (summary A and B attached as Exhibit Sierra Club/ 122).

166 *See* Confidential Attachment "[redacted]" to PacifiCorp Response to Sierra Club Data Request 2.4 [hereinafter "Confidential Hayden SCR Memo" (attached as Exhibit Sierra Club/123).

167 *Id.*

168 Approval and Promulgation of Implementation Plans; State of Colorado; Regional Haze State Implementation Plan, 77 Fed. Reg. 76871 (Dec. 31, 2012) (Corrects Mr. Teply's date of December 31, 2012.).

169 *See* Confidential Attachment to PacifiCorp Response to Sierra Club Data Request Sierra Club 2.4 CONF/Hayden 1, [redacted] (attached as Exhibit Sierra Club/124).

Q What's the relevance of the Colorado Clean Air Clean Jobs Act ("CACJA")?

A The CACJA was a unique Colorado state program to encourage the state's utilities to reduce air pollution through a combination of unit retirements and retrofits. The bill contemplated the state's need to propose an implementation plan for EPA's regional haze rule, and proposed that a "coordinated" approach to emissions reductions would be superior for the state, rather than a piecemeal approach.[170]

Importantly, CACJA did not mandate specific controls or emissions reductions at specific units. Rather it identified that the two investor-owned utilities, Black Hills and PSCo, should submit plans to the Colorado Public Utilities Commission ("PUC") proposing emissions reductions across their entire fleets. If the plans were pre-approved by the Colorado PUC, the utilities would be legislatively entitled to earn a return on any investments, or costs stranded through unit retirement.

The incentive is described by a PSCo witness in that utility's subsequent CPCN.

> The CACJA pushed two investor owned utilities (Black Hills and Public Service) to invest significant capital and retire existing plants for the greater good of the people of Colorado. In exchange, the companies were assured that they would recover their prudently incurred costs.[171]

The Colorado legislature set up a mechanism to provide an incentive to achieve rapid emissions reductions from Colorado's utilities through retrofits or retirements. While the plans required the approval of Colorado's utility

[170] Colo. Rev. Code § 40-3.2-202.
[171] Docket No. 11A-917E, Direct Testimony of Karen T. Hyde on Behalf of PSCo, at 15:1-5 (Colo Pub. Util. Comm'n Nov. 14, 2011).

commission, there were relatively few guardrails. And the incentive—an assurance of recovery—was not granted to the Colorado utilities' partners at co-owned power plants, like PacifiCorp at Hayden.

In other words, while PSCo was encouraged to create a comprehensive emissions reduction plan, of which Hayden was simply a small segment, these same incentives were not extended or even applicable to PacifiCorp.

Q Did PSCo's emissions reduction plan explicitly assess the value of installing retrofits at Hayden versus retiring the plant?

A No. In its 2010 application before the Colorado PUC, PSCo reviewed nine different scenarios. None of those scenarios assessed the retirement of Hayden. Rather, the scenarios baked in the assumption that the Hayden units would be retrofitted with SCRs. PSCo's assessed alternatives are shown below in Figure 10. When PSCo submitted supplemental testimony to the Colorado PUC in October 2010, it maintained the same assumptions with respect to Hayden.

Figure 10. Table from PSCo Emission Reduction Plan scenarios before the CoPUC, showing the assumption that Hayden would be retrofit with SCR in each scenario.[172]

Table JFH-2

	Scenarios								
Plant	**Benchmark 1**	**Benchmark 1.1**	**2**	**3**	**4**	**5**	**6**	**6.1**	**7**
Cherokee 1	SNCR 2014	SNCR 2014	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011
Cherokee 2	SNCR 2014	SNCR 2014	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011	Shutdown 2011
Cherokee 3	SCR 2017	SCR 2017	SCR 2017	Shutdown 2017	SCR 2017	Shutdown 2017	Shutdown 2015	Shutdown 2017	Fuel Switch 2014 Shutdown 2015
Cherokee 4	SCR 2016	SCR 2016	SCR 2016	SCR 2016	SCR 2016	SCR 2016	**Shutdown 2018**	SNCR 2012 **Shutdown 2022**	Fuel Switch 2014 **Shutdown 2018**
Valmont 5	SCR 2015	SCR 2015	SCR 2015	SCR 2015	Shutdown 2017	Shutdown 2017	Shutdown 2017	Shutdown 2017	Fuel Switch 2013 Shutdown 2017
Pawnee [1]	SCR 2014	---	SCR 2014	SCR 2014	SCR 2014	SCR 2014	SCR 2014	SCR 2014	SCR 2014
Hayden 1 [1]	SCR 2015	---	SCR 2015	SCR 2015	SCR 2015	SCR 2015	SCR 2015	SCR 2015	SCR 2015
Hayden 2 [1]	SCR 2016	---	SCR 2016	SCR 2016	SCR 2016	SCR 2016	SCR 2016	SCR 2016	SCR 2016
Retired MW	0	0	213	365	399	551	903	903	903
Controlled MW	1645	903	1432	1280	1246	1094	742	742	742
Total MW	**1645**	**903**	**1645**	**1645**	**1645**	**1645**	**1645**	**1645**	**1645**
% NOx reduction 2018[3]	72%	70%	81%	83%	83%	85%	69%	76%	84%
% Nox reduction when all actions complete[3]	72%	70%	81%	83%	83%	85%	89%	89%	89%
End of Year Convention => Action occurs at end of year listed									

Notes:
(1) Analyses also performed with no emission controls on Pawnee or Hayden
(2) Actions in Bold font occur beyond December 31, 2017
(3) Low NOx burner upgrades on Cherokee 2 and 4, Hayden 1 and 2, Pawnee 1 and Valmont 5 are included in the NOx reductions.

Q **Did PacifiCorp have a choice in the matter with respect to PSCo's emission reduction plan under the CACJA?**

A Yes. Arguably, PSCo's interest in creating an approvable plan for its own Commission should have been substantially negotiated with PacifiCorp, and subject to PacifiCorp's approval at the time that PSCo was seeking to make a commitment. PacifiCorp bore a due diligence responsibility at every turn with respect to its ownership share of Hayden.

[172] Docket No. 10M-245E, Direct Testimony of James Hill on Behalf of PSCo, at 6. Figure JFH-2 (Colo. Pub. Util. Comm'n Aug. 13, 2010) (attached as Exhibit Sierra Club/125).

Q Is there evidence that PacifiCorp sought to negotiate with PSCo with respect to its decision to retrofit Hayden with SCRs as part of its CACJA emissions reduction plan?

A No. Sierra Club asked PacifiCorp to identify and then "provide any analyses, assessments, presentations, memoranda, communications or the like provided by PSCo to PacifiCorp regarding its assessment that the installation of SCR at Hayden Units 1-2 were in the best interests of customers."[173] The only information PacifiCorp provided was a series of invoices and change orders for the actual SCR projects, devoid of any meaningful information aside from incurred or projected costs.[174] PacifiCorp neither identified nor produced any documents prior to May 2, 2011.

Q Do the documents from PSCo provide any basis for the retrofits?

A No. These documents simply provide a description stating that they are consistent with Xcel Energy's (a.k.a PSCo's) emission reduction plan under the CACJA.[175]

[173] Sierra Club/102, Sierra Club Data Request to PacifiCorp 2.4(d).
[174] *See* Confidential Attachments to PacifiCorp Response to Sierra Club Data Request 2.4.
[175] Specifically, each document bears only the following description, if a description is provided: "On December 15, 2010 the Colorado Public Utilities Commission issued a formal written ruling of the commission's decision on Xcel Energy's emissions-reduction plan to meet Colorado's Clean Air-Clean Jobs Act. The plan proposed to retrofit about 450 MW of coal-fired generation at the Hayden power plants with additional emission control technology. The objective of this proposal is to install SCR controls at Hayden Unit 1 [2] for emission reduction purposes."

Q **Do the documents from PSCo provide any justification, benefits, or risk assessments for the retrofits?**

A No. The section of the forms that would otherwise be used to describe justification, benefits, and risks are either blank or state "meet environmental compliance requirements."

Q **Do the documents from PSCo provide any discussion of alternatives?**

A No. The section of the forms that would otherwise be used to describe alternatives are blank.

Q **Does PacifiCorp's correspondence with PSCo indicate any inquiry on the value, benefit, or risks of the projects?**

A No. While PacifiCorp provided a set of email correspondence between PSCo and PacifiCorp, the entire correspondence is dedicated to obtaining signatures on work orders.

Q **Mr. Teply testified that "[o]n January 26, 2011, the Colorado Public Utilities Commission approved the installation of SCR systems on Hayden Units 1-2."[176] Did that order establish an enforceable deadline for the SCRs?**

A No. The order, dated December 9, 2010, simply approved the elements of PSCo's emissions reduction plan, providing a cost recovery assurance for PSCo under the Clean Air-Clean Jobs act. It did not establish an enforceable deadline or requirement.

[176] PAC/800 at Teply/49:14-17.

Q You noted that on November 11, 2014 PSCo's application for a CPCN before the CoPUC, stated that it had signed a new coal contract for Hayden, and that the contract extended to 2027. What's the relationship between the CPCN application and this coal contract?

A The signing of a major long-term fuel contract is paramount to a capital commitment, requiring its own in-depth assessment. While this is not an assessment of Colorado's process, I find it extraordinary (a) that PSCo decoupled its decision to sign a new long-term coal contract from the CPCN, and (b) that PSCo elected to sign a coal contract in advance of the Colorado commission's approval of its SCR CPCN. Assessing the value of the coal contract and the SCR separately, and without respect to each other—after all, both the SCR and the contract would have been avoidable if the plant were to have shut down—is inappropriate and inconsistent with reasonable utility practice.

It is further remarkable that the PSCo witness describing the newly-signed contract admitted that it would be 24 percent more expensive (on a levelized cost basis, 2012-2018) than anticipated when the Company put together its emissions reduction plan.[177] And yet neither the cost increase nor the decoupling of the coal contract from the PSCo decision seem to have been of concern PacifiCorp.

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[177] Sierra Club/120, Arigoni Direct Testimony at 12:1. Author's calculation, based on notional 7% nominal discount rate.

Q Did PacifiCorp have a role in evaluating or negotiating that new fuel contract in November 2011?

A According to PSCo, yes. In Arigoni's testimony before the Colorado PUC in the CPCN, PSCo's witness on the fuel cost increase testified that the decision on both the SCR and the coal contract were made in consultation with PacifiCorp:

> Public Service jointly owns Hayden with two other utilities: PacifiCorp and Salt River Project Agricultural and Irrigation and Power District ("SRP"). Although Public Service is the Operating Agent for Hayden, major decisions, like coal supply and the installation of emissions controls have been jointly made by the participants. Therefore, Public Service has worked with SRP and PacifiCorp to negotiate the coal-supply arrangements for Hayden.[178]

Q Was the Colorado PUC's approval of PSCo's CPCN in July 2012 the final point at which a decision was irrevocable?

A Not at all. PSCo's CPCN was simply an indication that PSCo had a reasonable chance of receiving cost recovery if it elected to move forward with the SCRs under the Regional Haze rule. It did not eliminate the need for ongoing diligence by the operator, or ongoing scrutiny by PacifiCorp.

Q Mr. Teply testified that "the Hayden Units 1-2 SCRs were required by the State of Colorado's Regional Haze SIP to be installed no later than December 31, 2016."[179] Is he correct?

A No. While Colorado's Regional Haze SIP identified emission limits for Hayden consistent with SCR, it did not identify a specific deadline of December 31, 2016. That deadline was established by PSCo as a target in its Emissions Reduction

[178] Sierra Club/120, Arigoni Direct Testimony at 2:19 -3:2.
[179] PAC/800 at Teply/48:18-19.

Plan, but was not specifically enforceable as a deadline under the federal Clean Air Act.

Q Did EPA's final approval of Colorado's Regional Haze SIP identify an enforceable deadline of December 31, 2016?

A No. EPA issued both a proposed and final regional haze rule for Colorado. In both instances EPA was clear that the facilities under consideration would have a five year deadline to retrofit coal units.[180] EPA's approval of Colorado's Regional Haze SIP had an effective date of January 30, 2013.[181] Therefore, the binding installation date was January 30, 2018—more than a year after PSCo's internally-driven date.

Q Did PacifiCorp conduct an independent assessment of the Hayden SCR decision after the CPCN was issued to PSCo?

A Yes. While Mr. Teply described PacifiCorp's the independent analysis on the Craig SCRs, his testimony did not include details of a PacifiCorp analysis of the Hayden SCR projects. In response to discovery, PacifiCorp stated:

> PacifiCorp independently assessed and analyzed its options under the participation agreement for the Hayden Unit 1 and Hayden Unit 2 SCR system projects. The analysis contains commercially sensitive and highly confidential information. The analysis ultimately had no bearing on the Company's Hayden Unit 1 and Hayden Unit 2 SCR systems installation assessment, with the equipment being installed to comply with the Colorado Clean Air-

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[180] Approval and Promulgation of Implementation Plans; State of Colorado; Regional Haze State Implementation Plan. Proposed Rule, 77 Fed. Reg. 18052, 18056 (Mar. 26, 2012) ("Once a state has made its BART determination, the BART controls must be installed and in operation as expeditiously as practicable, but no later than five years *after the date of EPA approval of the RH SIP*.") (Emphasis added).
[181] 77 Fed. Reg.76871.

Clean Jobs Act under the purview of the Colorado Public Utilities Commission.[182]

[redacted]

Q What was the outcome of PacifiCorp's assessment?

A At a core level, PacifiCorp assessed that retiring, rather than retrofitting, Hayden 1 would provide a benefit of [redacted] to ratepayers.[183] In other words, PacifiCorp assessed a [redacted] liability associated with its $24.2 million share of the Hayden SCR.

[redacted]

[182] Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 2.4(e).
[183] *See* Sierra Club/122, Confidential Hayden 1 PVRR Study.

[redacted]

Q What actions did PacifiCorp take as a result of these findings?

A PacifiCorp took no actions at all. According to the Company's response to discovery, "the analysis ultimately had no bearing on the Company's Hayden Unit 1 and Hayden Unit 2 SCR systems installation assessment."[185] [redacted] In my opinion, this was an error.

Q Did the Company's Hayden analysis independently assess the value of retrofitting Hayden 2?

A No. While the analysis looked at the value of retiring Hayden 2 in conjunction with Hayden 1 [redacted] the assessment did not review the independent economics of retrofitting Hayden 2.

Q Why did the Company not act on its findings that the SCR at Hayden 1 was not in the best interests of ratepayers?

A The Company has provided two different rationales, as I discuss below.

- First, the Company assessed that it had no leverage to prevent PSCo from moving forward with the retrofits.

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[184] *See id.,* [redacted].
[185] Sierra Club/102, PacifiCorp Response to Sierra Club Data Request 2.4(e).

- Secondly, the Company assessed that the costs of the take-or-pay contract signed in November 2011 could overwhelm the value of shutting down Hayden.

Both of these rationales were flawed, and showed a lack of oversight, rather than a carefully considered analysis of ratepayer impacts. I address them in reverse order.

a. PacifiCorp's Flawed Assessment of the Take-or-Pay Coal Contract at Hayden

Q How did you learn that the Company had assessed the costs of the take-or-pay coal contract at Hayden and had decided it degraded the value of retiring Hayden 1?

A In August, 2014 the Company conducted a confidential workshop to review its existing analysis on the planned Craig and Hayden environmental investments.[186] [redacted]

[186] *See* PacifiCorp, *2015 Integrated Resource Plan*, Vol. II, App. B at 29 (filed Mar. 31, 2015), *available at* https://www.pacificorp.com/energy/integrated-resource-plan html. A redacted form of the presentation is available in Docket No. LC 57 as PacifiCorp's Response to a Ruling Requiring Redesignation of the Workshop Presentation, (Oct. 23, 2014), *available at* https://edocs.puc.state.or.us/efdocs/HAC/lc57hac124711.pdf.
[187] Sierra Club/121, Hayden/Craig Confidential Workshop at 8.
[188] *Id.*

[redacted]

Q **To whom was this presentation directed?**

A The presentation on the Craig and Hayden analyses was directed to this Commission, and intervenors in the Company's 2013 IRP subject to confidentiality provisions.

Q **Did the Company present this Commission with all of the facts concerning the value of closing Hayden?**

A No. [redacted]

In addition, in that workshop and accompanying materials, the Company failed to disclose to the Commission that the Hayden coal contract had been signed in late 2011, with PacifiCorp's consent—just a year before the PacifiCorp acquiesced to the retrofits.

Again, it is remarkable that the Company so readily signed a coal contract to extend the life of the Hayden units through at least 2027 [redacted]

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189 *Id*. at 4.
190 *Id*. at 8.
191 *See* Sierra Club/122, Confidential Hayden 1 PVRR Study [redacted]

[redacted]. As far as I'm aware, there was no time at which the Company assessed—or had assessed by PSCo—whether the plan to both extend the coal contract and retrofit Hayden with SCR was better than seeking a retirement of the unit.

Q Was the Company clear on whether the coal contract could be terminated through a "change in law" provision?

A No. The Company speculated that this termination provision could be exercised, but failed to verify this point.

Overall, PacifiCorp's explanation that the restrictive coal contract rendered the SCRs a [redacted] ratepayer outcome was incomplete at best, and potentially incorrect.

In that same presentation to this Commission, the Company claimed [redacted][192] I address this next.

b. <u>PACIFICORP'S FLAWED ASSESSMENT OF ITS ARBITRATION POTENTIAL FOR THE SCRS AT HAYDEN</u>

Q How did you learn that the Company had concluded [redacted] moving forward with the retrofits?

A [redacted]

[192] *See* Sierra Club/121, Hayden/Craig Confidential Workshop at 5.
[193] In 2012, Michael Dunn was President and CEO of PacifiCorp. Today he is the CEO of Williams, an oil production company. PacifiCorp witness Mr. Teply is now also at Williams.

[redacted][194]

[redacted]

[redacted]

Q **Do you agree that PacifiCorp** [redacted]

A No. PSCo's move to install SCR at Hayden was not consistent with generally accepted practices for electric utilities. There are several ways in which the PSCo's decision was demonstrably inconsistent, [redacted]

- PSCo should have identified the latest possible compliance date available under the law, and sought to maximize optionality by assessing the high

[194] Sierra Club/123, Confidential Hayden SCR Memo.
[195] *Id*.

cost retrofits as late as feasible. Instead, PSCo moved forward to sign a contract to install the SCRs with Hitachi before EPA had even finalized the SIP (refer to Table 1, above), establishing an installation deadline inconsistent with federal law.

- PSCo's election to install SCR at Hayden was not a cost-effectiveness decision. As shown in Figure 10, PSCo did not assess alternative scenarios in which Hayden was retired when it created its 2010 emissions reduction plan. When PSCo applied for CPCN in 2011, it did not conduct a cost effectiveness assessment at all.
- Any assessments conducted by PSCo in 2010 or 2011 would have been woefully out of date by the time PSCo was seeking to move forward on the retrofit [redacted]. As shown in the Jim Bridger section of my testimony, forward gas prices were consistently falling through 2011 and 2012. [redacted]
- A December 2016 installation date for SCRs at Hayden was not required under the Regional Haze SIP, especially because EPA had not yet approved the state plan.. Like at Jim Bridger, PSCo had alternative options to comply with the Regional Haze rule, including retirement rather than installation, or a commitment to retire at a later date, the effect of which would have shown the SCRs to not be cost-effective under the Regional Haze Rule. PSCo examined neither option.

- The SCR retrofits at Hayden were not specifically required under the Clean Air Clean Jobs Act, which instead sought a system-wide approach to achieving emissions reductions. Such reductions could have either been achieved at other facilities or through unit retirements.

Overall, I believe that PacifiCorp had a number of options at its disposal to effectively contest PSCo's decision to move forward with the SCRs, and succeed in appealing that decision as inconsistent with generally accepted practices for electric utilities.

Q Are there any other reasons to think that PacifiCorp should have pressed forward with arbitration to contest the SCR decision at Hayden?

A Yes. The costs of arbitration would have certainly paled in comparison to the costs—and negative valuation—of the SCRs.

Q Do you have any other opinions on PacifiCorp's November 2012 assessment concerning the Hayden SCRs?

A Yes, I have several.

- First, the Company's assessment failed to review the independent value, or cost, of retrofitting Hayden 2, but focused instead on Hayden 1 only.[196]
- Second, the Company's assessment failed to review the joint value, or cost, of retrofitting or retiring both Hayden 1 and Hayden 2[redacted]

[196] *See* public version of workshop presentation, available in Docket No. LC 57 as PacifiCorp's Response to a Ruling Requiring Redesignation of the Workshop Presentation (Oct. 23, 2014), *available at* https://edocs.puc.state.or.us/efdocs/HAC/lc57hac124711.pdf.

[redacted]

- Third, the Company's analysis contained a critical formula error [redacted]

Q Please explain this formula error, and what it portends for the Company's analysis of the Hayden and Craig retrofits.

A [redacted][197]

[redacted]

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[197] [redacted]

Confidential Figure 11. November 2012 Assessment of Hayden and Craig value, as conducted by PacifiCorp,[198] and as corrected.

[redacted]

Q Please summarize your findings with respect to the Company's decisions for the Hayden SCR retrofits.

A Overall, the Company failed to intervene effectively or meaningfully with respect to its participation and co-ownership of Hayden for either the SCRs or the election to move forward on a long-term fuel contract.

4. The Company failed to engage successfully or meaningfully in PSCo's 2010 emission reduction plan, whereby PSCo opted to install SCRs at Hayden, committing PacifiCorp to that same course of action.
5. The Company failed to assess the joint cost of signing a new coal contract for Hayden and moving forward on the SCRs. By decoupling the SCR decision from the coal contract decision, the Company made two separate elections that should have been made jointly.

[198] Sierra Club/122, Confidential Hayden 1 PVRR Study, line "[redacted]".

6. The Company failed to press PSCo to conduct updated cost effectiveness studies on the Hayden SCRs, and did not pursue appropriate due diligence documentation on the benefits or risks of pursuing the SCRs.
7. The Company failed to pursue an alternative retirement strategy with PSCo, instead incorrectly agreeing to—[redacted]—an unenforceable premature compliance deadline.
8. The Company's assessment of [redacted] but the Company elected to ignore this outcome and signaled its approval to PSCo.
9. The Company failed to assess whether the Hayden 2 SCR project was in the best interests of customers.
10. [redacted].
11. [redacted].
12. [redacted]

The Company acted imprudently by failing to take action to prevent the installation of the SCRs at Hayden 1 & 2. Because the cost of alternatives has fallen substantially since PacifiCorp make this decision, ratepayers have experienced losses greater than the cost of the retrofits themselves. I recommend that the Commission disallow the costs of the Hayden retrofits on an Oregon allocation basis, or $6.3 million. In addition, I recommend that the Commission consider disallowing costs associated with the minimum take provision of the take-or-pay Hayden coal contract entered into in 2011.

Q Does this conclude your testimony?

It does.

Docket No. UE 374
Exhibit Sierra Club/106
Witness: Jeremy Fisher

PUBLIC UTILITY COMMISSION OF OREGON

UE 374

ERRATA SIERRA CLUB EXHIBIT 106

Exhibits Accompanying the Opening Testimony of Jeremy Fisher

PacifiCorp Emission Reduction Plan

November 2, 2010

Exhibit A

PacifiCorp's Emissions Reductions Plan

In connection with its Best Available Retrofit Technology ("BART") determinations and its other regional haze planning activities, the Wyoming Department of Environmental Quality, Air Quality Division ("AQD") asked PacifiCorp to provide additional information about its overall emission reduction plans through 2023. The purpose is to more fully address the costs of compliance on both a unit and system-wide basis. PacifiCorp is committed to reduce emissions in a reasonable, systematic, economically sustainable and environmentally sound manner while meeting applicable legal requirements. These legal requirements include complying with the regional haze rules which encompass a national goal to achieve natural visibility conditions in Class 1 areas by 2064

Summary

PacifiCorp owns and operates 19 coal-fueled generating units in Utah and Wyoming, and owns 100% of Cholla Unit 4, which is a coal-fueled generating unit located in Arizona. PacifiCorp is in the process of implementing an emission reduction program that has reduced, and will continue to significantly reduce emissions at its existing coal-fueled generation units over the next several years. From 2005 through 2010 PacifiCorp has spent more than \$1.2 billion in capital dollars. It is anticipated that the total costs for all projects that have been committed to will exceed \$2.7 billion by the end of 2022. The total costs (which include capital, O&M and other costs) that will have been incurred by customers to pay for these pollution control projects during the period 2005 through 2023, are expected to exceed \$4.2 billion, and by 2023 the annual costs to customers for these projects will have reached \$360 million per year.

Environmental benefits, including visibility improvements will flow from these planned emission reductions. PacifiCorp believes that the emission reduction projects and their timing appropriately balance the need for emission reductions over time with the cost and other concerns of our customers, our state utility regulatory commissions, and other stakeholders. PacifiCorp believes this plan is complementary to and consistent with the state's BART and regional haze planning requirements, and that it is a reasonable approach to achieving emission reductions in Wyoming and other states.

PacifiCorp's Long-Term Emission Reduction Commitment

Table 1 below identifies the emission reduction projects and related construction schedules as currently included in PacifiCorp's reduction plan.

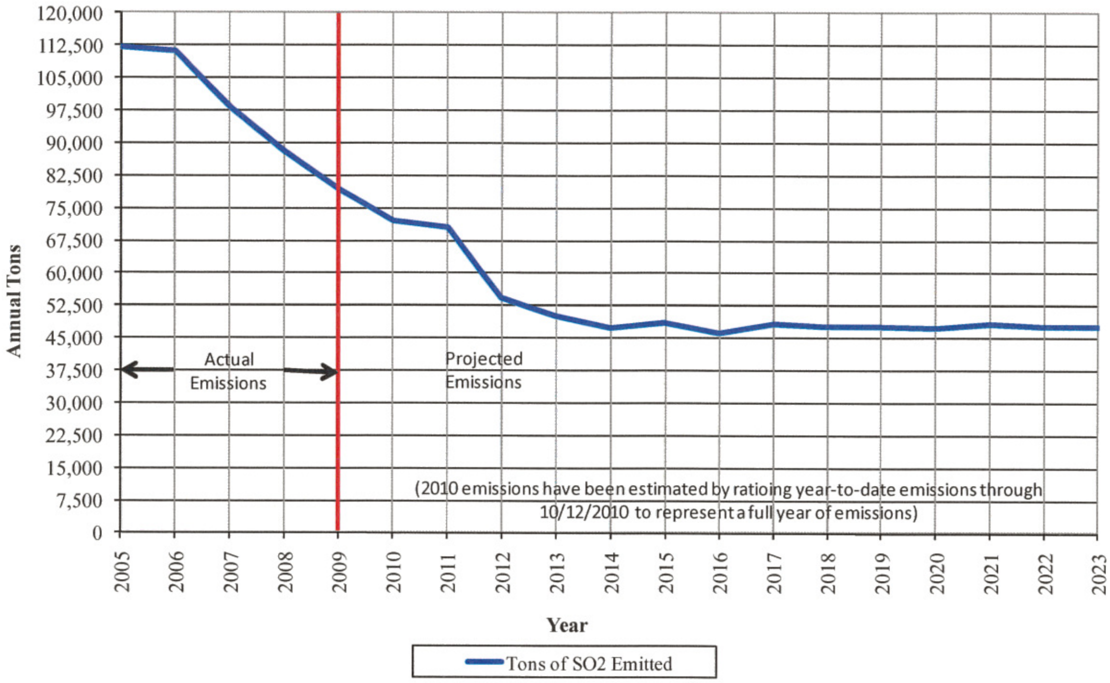
Table 1: Long-Term Reduction Plan

Plant Name	SO2 Scrubbers Installation - I Upgrades - U	Low NOx Burner Installations	Baghouse Installations	Status of SO2 / LNB / Baghouse Permitting	Selective Catalytic Reduction
Hunter 1	2014 - U	2014	2014	Permitted	
Hunter 2	2011 - U	2011	2011	Under Construction	
Hunter 3	Existing	2008	Existing	Completed	
Huntington 1	2010 - U	2010	2010	Under Construction	
Huntington 2	2007 - I	2007	2007	Completed	
Dave Johnston 3	2010 - I	2010	2010	Completed	
Dave Johnston 4	2012 - I	2009	2012	Under Construction	
Jim Bridger 1	2010 - U	2010		Completed	2022
Jim Bridger 2	2009 - U	2005		Completed	2021
Jim Bridger 3	2011 - U	2007		Permitted	2015
Jim Bridger 4	2008 - U	2008		Completed	2016
Naughton 1	2012 - I	2012		Under Construction	
Naughton 2	2011 - I	2011		Under Construction	
Naughton 3	2014 - U	2014	2014	Baghouse Permitted	2014
Wyodak	2011 - U	2011	2011	Under Construction	
Cholla 4	2008 - U	2008	2008	Completed	

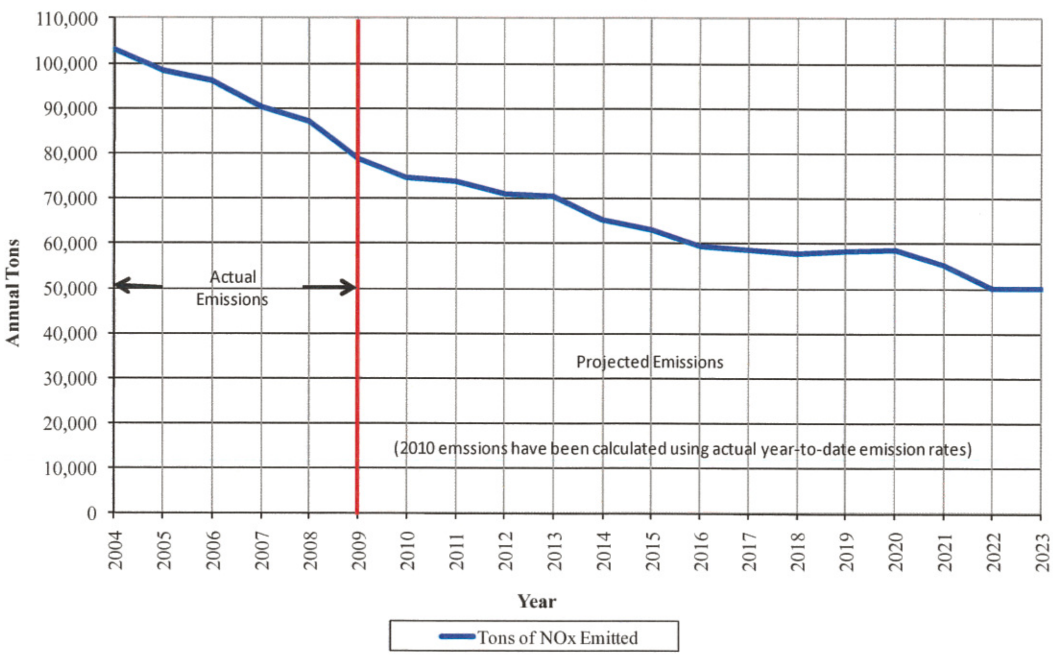
The following charts represent the reductions in emissions that will occur at units owned by PacifiCorp in Utah, Wyoming and Arizona[1]. It is significant to note that permitting has been completed for all but the SCR projects; permitting for the SCR projects will be completed as needed in advance of project construction. The emission estimates shown in these charts have been calculated using projected unit generation and heat rate data in conjunction with each unit's permitted emission rate. In those cases were the units do not have emissions controls the estimates have been based on projections of the future coal quality. All projections used are from PacifiCorp's ten-year business plan. Actual future emissions will be less than those estimated in these charts since the units will operate below their permitted rates.

[1] PacifiCorp is also a joint owner of coal-fueled facilities in Colorado and Montana that are subject to regional haze planning requirements and for which PacifiCorp will incur associated costs of emissions controls.

2005 - 2009 Actual and 2010 - 2023 Projected SO2 Emissions
PacifiCorp's Arizona, Utah & Wyoming Coal-Fired Units



2004 - 2009 Actual and 2010 - 2023 Projected NOx Emissions
PacifiCorp's Arizona, Utah & Wyoming Coal-Fired Units



Project Installation Schedule

Emission reduction projects of the number and size described above take many years to engineer, plan and build. When considering a fleet the size of PacifiCorp's, there is a practical limitation on available construction resources and labor. There is also a limit on the number of units that may be taken out of service at any given time as well as the level of construction activities that can be supported by the local infrastructures at and around these facilities. Such limitations directly impact both the overall timing of these projects as well as their timing in relation to each other. Additional cost and construction timing limitations include the loss of large generating resources during some parts of construction and the associated impact on the reliability of PacifiCorp's electrical system during these extended outages. In other words, it is not practical, and it is unduly expensive, to expect to build these emission reduction projects all at once or even in a compressed time period. The pressure on emission reduction equipment and skilled labor is likely to be exacerbated by the significant emission reduction requirements necessitated by the Environmental Protection Agency's Clean Air Transport Rule which requires emission reductions in 31 Eastern states and the District of Columbia beginning in 2012 and 2014. The Environmental Protection Agency has indicated that a second Transport Rule is likely to be issued in 2011, requiring additional reductions in the Eastern U.S. beyond those effective in 2014. The balancing of these concerns is reflected in the timing of PacifiCorp's emission reduction commitments.

Priority of Emission Reductions

PacifiCorp's initial focus has been on installing controls to reduce SO_2 emissions which are the most significant contributors to regional haze in the western US. In addition, PacifiCorp continues to rely on the rapid installation of low NO_x burners to significantly reduce NOx emissions. Also, the installation of five SCRs (or similar NOx-reducing technologies) will be completed by 2023 and reduce NOx emissions even further. PacifiCorp's commitment also includes the installation of several baghouses to control particulate matter emissions. For those units which utilize dry scrubbers, baghouses have the added benefit of improving SO2 removal. Baghouses also significantly reduce mercury emissions.

In addition to reducing emissions at existing facilities, PacifiCorp has avoided increasing emissions by adding more than 1,400 megawatts of renewable generation between 2006 and 2010. In order to meet growing demand for electricity, PacifiCorp added non-emitting wind generation to its portfolio at a cost of over $2 billion and has dismissed further consideration of a new coal-fueled unit.

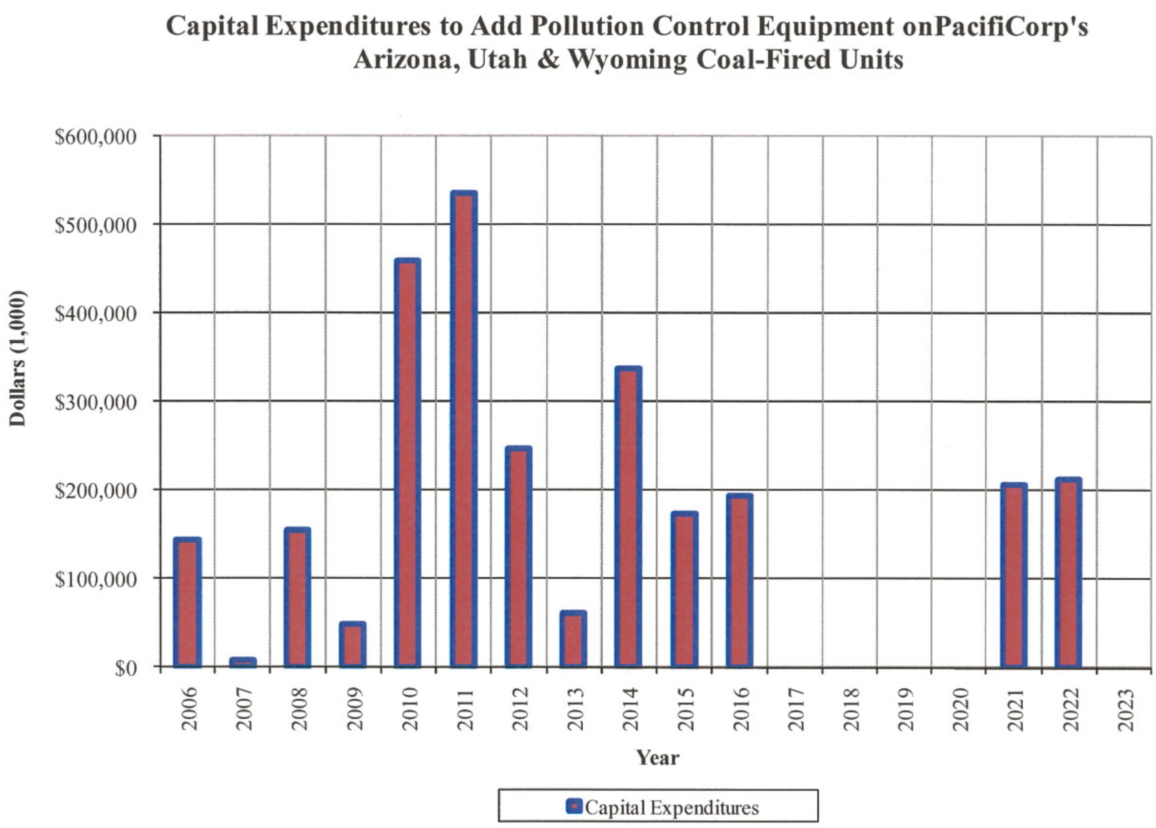
Emission Reductions and BART Deadlines

As depicted in the table and charts above, PacifiCorp began implementing its emission reduction commitments in 2005. This was well ahead of the emission reduction timelines under the regional haze rules which require BART to be installed no later than five years following approval of the applicable Regional Haze SIP. This also provides a graphic demonstration of the construction schedule and other limitations described above, as PacifiCorp was required to begin installing emission control projects at some units earlier in order to complete projects at other units within the five years after SIP approval. The table above demonstrates that most of the projects to be built between 2010 and 2014, likewise, will be installed in advance of the required completion date under BART requirements.

Customer Impacts

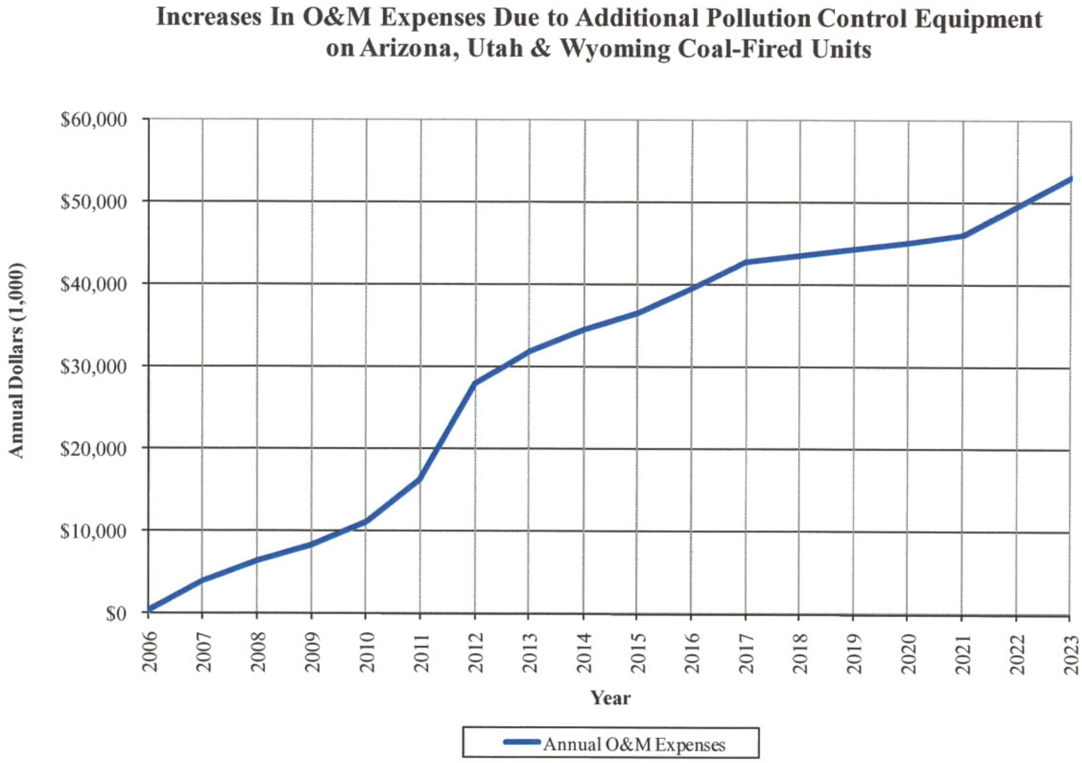
The following charts identify the timing and magnitude of the capital and O&M expenses that will be incurred due to the projects identified in Table 1. The charts identify:

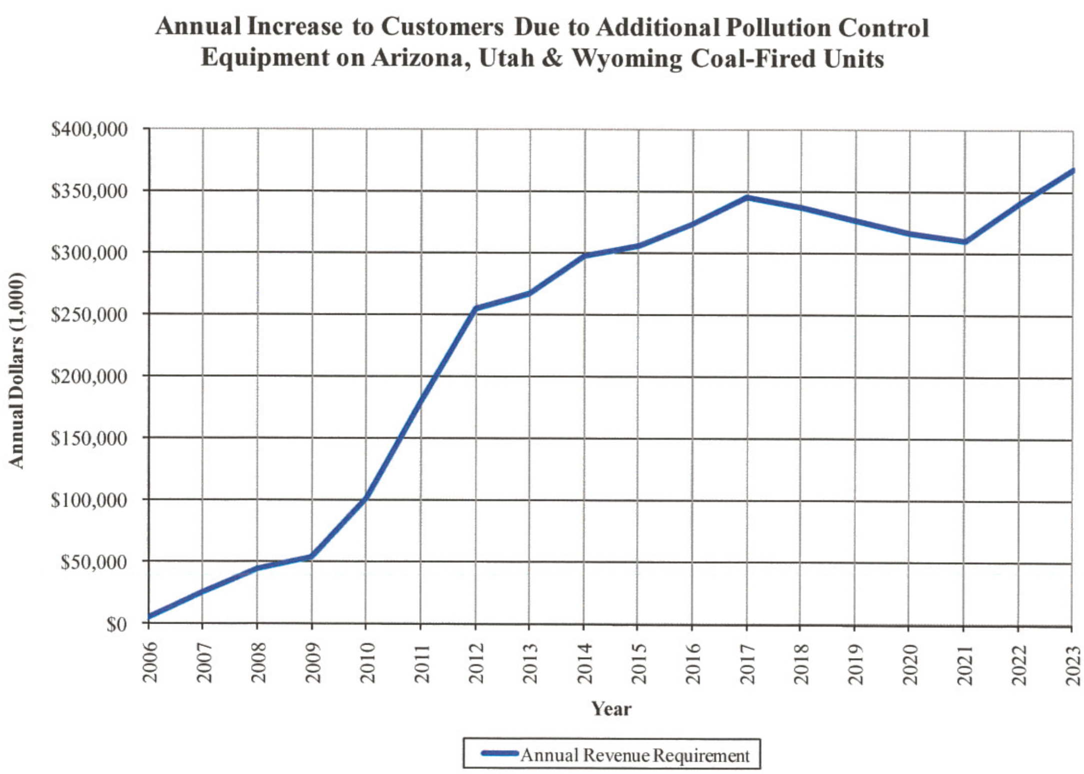
1. The timing and magnitude of the capital costs.
2. The O&M expenses that will be incurred due to these projects.
3. The expected annual costs[2] through 2023 that customers will be incur as a result of these specific pollution control projects.



[2] PacifiCorp has made every attempt to provide an accurate estimate of the anticipated increase in annual revenue requirements that will ultimately be translated to increases in customers' electricity rates. However, there are several variables such as interest rates, inflation rates, discount rates, depreciation lives, and final construction costs and operating and maintenance expenses that will be considered at the time these projects actually go into rate base and will influence the actual revenue requirements associated with these capital projects.

Exhibit A - PacifiCorp's Emissions Reduction Plan
November 2, 2010
Page 6 of 10





As can be seen from the previous charts, the rate increases for PacifiCorp customers associated with PacifiCorp's emission reduction strategy alone will be significant. In the event that PacifiCorp is required to accelerate or add to the planned emission reduction projects, the cost impacts to our customers can be expected to increase incrementally, particularly as plant outage schedules are extended and the need for skilled labor and material increases in the near term.

Of particular note, the projected costs reflect only the installation of the noted emission reduction equipment. These cost increases do not include other costs expected to be incurred in the future to meet further emission reduction measures or address other environmental initiatives, including but not limited to (see Attachment 1):

1. Implementation of Utah's Long Term Strategy for meeting regional haze requirements during the 2018-2023 time period.

2. The addition of mercury control equipment under the requirements of the upcoming mercury MACT provisions. PacifiCorp estimates that $68 million in capital will be incurred by 2015 and annual operating expenses will increase by $21million per year to comply with mercury reduction requirements. In addition, anticipated regulation to address non-mercury hazardous air pollutant (HAPs) emissions may require significant additional reductions of SO_2, as a precursor to sulfuric acid mist, from non-BART units that currently do not have specific controls to reduce SO_2 emissions.

3. Mitigating and controlling CO_2 emissions. While Congress has not yet passed comprehensive climate change legislation, in December 2009, the Administrator of the Environmental Protection Agency made a finding that greenhouse gases in the atmosphere threaten the public health and welfare of current and future generations. Having made the so-called "endangerment finding," EPA issued the final greenhouse gas tailoring rule, effective January 2, 2011, which will require greenhouse gas emissions to be addressed under PSD and Title V permits[3]. Likewise, mandatory reporting of greenhouse gas emissions to the Environmental Protection Agency commenced beginning in January 2010.

4. In addition, there are a number of regional regulatory initiatives, including the Western Climate Initiative that may ultimately impact PacifiCorp's coal-fueled facilities. PacifiCorp's generating units are utilized to serve customers in six states – Wyoming, Idaho, Utah, Washington, Oregon and California. California, Washington and Oregon are participants in the Western Climate Initiative, a comprehensive regional effort to reduce greenhouse gas emissions by 15% below 2005 levels by 2020 through a cap-and-trade program that includes the electricity sector; each state has implemented state-level emissions reduction goals. California, Washington and Oregon have also adopted greenhouse gas emissions performance standards for base load electrical generating resources under which emissions must not exceed 1,100 pounds of CO_2 per megawatt

[3] The Environmental Protection Agency has not yet published its proposed guidance on what constitutes Best Available Control Technology for greenhouses gases.

hour. The emissions performance standards generally prohibit electric utilities from entering into long-term financial commitments (e.g., new ownership investments, upgrades, or new or renewed contracts with a term of 5 or more years) unless the base load generation supplied under long-term financial commitments comply with the greenhouse gas emissions performance standards. While these requirements have not been implemented in Wyoming, due to the treatment of PacifiCorp's generation on a system-wide basis (i.e., electricity generated in Wyoming may be deemed to be consumed in California based on a multi-state protocol), PacifiCorp's facilities may be subject to out-of-state requirements.

5. Regulations associated with coal combustion byproducts. In June 2010, the Environmental Protection Agency published a proposal to regulate the disposal of coal combustion byproducts under the Resource Conservation and Recovery Act's Subtitle C or D. Under either regulatory scenario, regulated entities, including PacifiCorp, would be required, at a minimum; to retrofit/upgrade or discontinue utilization of existing surface impoundments within five years after the Environmental Protection Agency issues a final rule and state adoption of the appropriate controlling regulations. It is anticipated that the requirements under the final rule will impose significant costs on PacifiCorp's coal-fueled facilities within the next eight to ten years.

6. The installation of significant amounts of new generation, including gas-fueled generation and renewable resources.

7. The addition of major transmission lines to support the renewable resources and other added generation.

8. Increasing escalation rates on fuel costs and other commodities

BART and Regional Haze Compliance

PacifiCorp firmly believes that the commitments described above meet the letter and intent of the regional haze rules, including the guidance provided by the EPA known as "Appendix Y." The regional haze program is a long-term effort with long-term goals ending in 2064. It must be approached from that perspective. It was never intended to require SCR on BART-eligible units within the first five years of the program. Rather, it calls for a transition to lower emissions exactly as PacifiCorp has implemented to date and as it has proposed going forward through 2023.

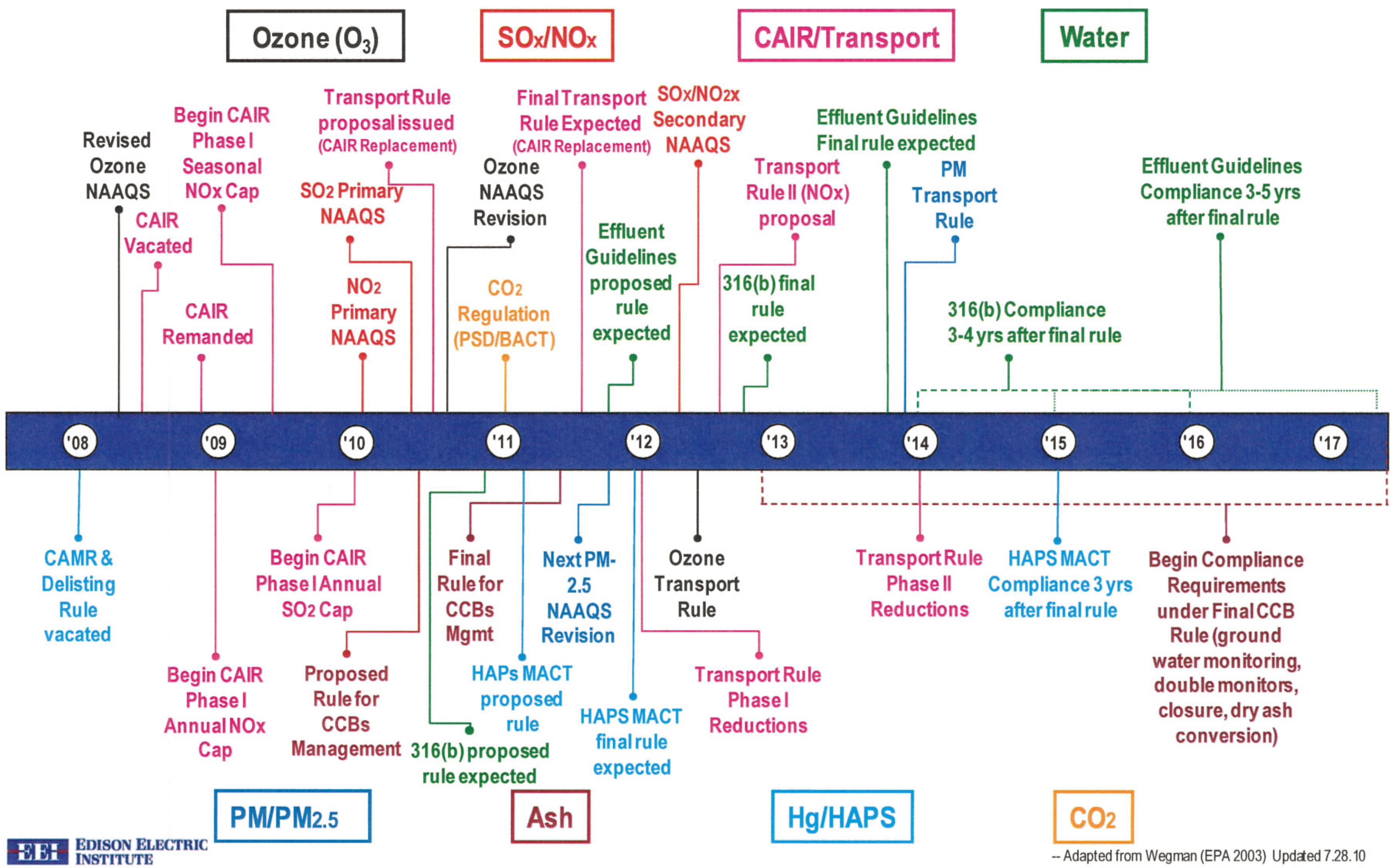
In its evaluation of emission reductions for regional haze purposes, the state should also consider several other variables which will significantly affect emissions and costs over the next ten years. These include such things as the development of new emission control technology, anticipated new emission reduction legislation and rules, the new ozone standard, the one hour SO_2 and NO_2 standards, the $PM_{2.5}$ standard, potential CO_2 regulation and costs, an aging fleet, and changing economic conditions. All of these variables matter and will affect the long-term viability of each PacifiCorp coal unit and will contribute to the reduction of regional haze in the course of the implementation of these programs. This, in turn, will affect the controls, costs and future operational expectations associated with these generating resources.

Conclusion

PacifiCorp has made a significant, long-term commitment to reducing emissions from its coal-fueled facilities and requests that the AQD consider this commitment as a reasonable approach to achieving emission reductions in Wyoming.

November 2, 2010

Attachment 1 Possible Timeline for Environmental Regulatory Requirements for the Utility Industry



-- Adapted from Wegman (EPA 2003) Updated 7.28.10