BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 374

In the Matter of PACIFICORP, dba, PACIFIC POWER, Request for a General Rate Revision.	))))))	FIRST SUPPLEMENT TO OREGON CITIZENS' UTILITY BOARD'S CROSS-EXAMINATION STATEMENT AND EXHIBITS

Pursuant to Administrative Law Judge Lackey's August 31, 2020 Memorandum in the above-captioned proceeding, the Oregon Citizens' Utility Board (CUB) submits this supplement to its cross-examination statement, providing reference materials for its anticipated cross-examination of PacifiCorp witness James Owen. CUB intends to cross-examine Mr. Owen on information contained in his pre-filed testimony and on the information in CUB/504, PAC/2506, and PAC/4002. CUB/504 is attached to this filing.

CUB has no supplemental materials to provide for its cross-examination of PacifiCorp witness Rick Link. Cross-examination on Mr. Link will be limited to his pre-filed testimony and the information in CUB/505, as noted in CUB's prior cross-examination statement. CUB/505 is attached to this filing. CUB's believes its cross of Mr. Link can be conducted in 10 minutes.

Dated this 8th day of September, 2020.

Respectfully submitted,

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Docket No. 20000-___-EA-12
Witness: Rick T. Link

BEFORE THE WYOMING PUBLIC SERVICE
COMMISSION

ROCKY MOUNTAIN POWER

REDACTED
Direct Testimony of Rick T. Link

August 2012

Q. Please state your name, business address and position with PacifiCorp dba Rocky Mountain Power ("Company").

A. My name is Rick T. Link. My business address is 825 NE Multnomah St., Suite 600, Portland, Oregon 97232. My present position is Director, Structuring & Pricing.

Q. Please describe your education and business experience.

A. I received a Bachelor of Science degree in Environmental Science from the Ohio State University in 1996 and a Masters of Environmental Management from Duke University in 1999. I have been employed in the commercial & trading area of PacifiCorp since 2003 where I have held positions in market fundamentals, structuring, and planning. Currently, I direct the work of the market assessment group, the structuring & pricing group, and the integrated resource planning group. Prior to joining the Company, I was an energy and environmental economics consultant for ICF Consulting (now ICF International) from 1999 to 2003.

Summary

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the economic analysis used by the Company to support its application for a certificate of public convenience and necessity ("CPCN") related to the selective catalytic reduction ("SCR") investments planned for Jim Bridger Unit 3 and Jim Bridger Unit 4.

Q. Please summarize your testimony in this proceeding.

A. My testimony describes the Company's economic analysis of SCR investments at

Jim Bridger Units 3 and 4 as compared to the alternatives which includes early retirement and resource replacement or conversion to natural gas. Specifically, I will address in my testimony the following:

- Base case results from the System Optimizer model ("SO Model") showing a [redacted] present value revenue requirement differential ("PVRR(d)") favorable to the SCR and other incremental environmental investments required to continue operating Jim Bridger Units 3 and 4 as coal-fueled assets.
- Base case results from a benchmarking analysis using the GRID model showing a [redacted] PVRR(d) favorable to the SCR and other incremental environmental investments required for continued coal-fueled operation of Jim Bridger Units 3 and 4.
- A description of the methodology using the SO Model to analyze the SCR investments required to continue operating Jim Bridger Units 3 and 4 as coal-fueled facilities.
- An overview of why natural gas price and carbon dioxide ("CO_2") price assumptions are important to the analysis of the SCR investments required for Jim Bridger Units 3 and 4.
- A summary of third party natural gas and CO_2 price forecasts and how these projections were used to develop assumptions for natural gas and CO_2 price scenario analysis.
- Natural gas price and CO_2 price scenario results showing the SCR and other incremental environmental investments required for Jim Bridger

Units 3 and 4 remain favorable under base gas and high gas price assumptions when paired with base case or zero CO_2 price assumptions.

Methodology

Q. What methodology did the Company use to evaluate the SCR investments for Jim Bridger Units 3 and 4?

A. The Company used the SO Model to perform a PVRR(d) financial analysis of the Jim Bridger Unit 3 and 4 SCR investments.

Q. Please describe the SO Model and how it is used by the Company.

A. The SO Model is a capacity expansion optimization tool that is used in the Company's integrated resource plan and business planning process to produce resource portfolios in support of long-term planning. The SO Model is also used in the Company's analysis of resource acquisition opportunities and resource procurement activities. It was used to support the successful acquisition of the Chehalis combined cycle plant, to support the selection of the Lake Side 2 combined cycle resource in the most recently completed request for proposals process, and is being used to evaluate bids in the currently issued request for proposals for a 2016 resource as approved by the Public Service Commission of Utah and Oregon Public Utility Commission. The SO Model endogenously considers the tradeoffs between the operating and capital revenue requirement costs of both existing and prospective new resources while simultaneously evaluating the tradeoffs in energy value between existing and prospective new resource alternatives.

Q. Why is the SO Model an appropriate tool for analyzing incremental environmental investments required for coal resources?

A. The SO Model is the appropriate modeling tool when evaluating capital investment decisions and alternatives to those investments that might include early retirement and replacement or conversion of assets to natural gas. The SO Model is capable of simultaneously and endogenously evaluating capacity and energy tradeoffs between making incremental investments required to meet emerging environmental regulations and a broad range of alternatives including fuel conversion, early retirement and replacement with greenfield resources, market purchases, demand side management resources, and/or renewable resources. In this way, the SO Model captures the cost implications of prospective investment decisions by evaluating net power cost impacts along with the impacts those decisions might have on future resource acquisition needs, which is particularly important when resource retirement and replacement is considered to be an investment alternative.

Q. How was the SO Model used to analyze the PVRR(d) of the SCR investments required for Jim Bridger Units 3 and 4?

A. For a range of market price scenarios, which I will describe later in my testimony, two SO Model simulations were completed – an optimized simulation and a change case simulation. In the optimized simulation, the SO Model determines whether continued operation of Jim Bridger Units 3 and 4 inclusive of incremental SCR and other planned costs required to achieve compliance with emerging environmental regulations is a lower cost solution than avoiding those incremental investments through early retirement and resource replacement or through conversion to natural gas. In the change case simulation, the SO Model is forced to produce a suboptimal decision by not allowing it to make the preferred decision that was made in the optimized simulation.

In the analysis for Jim Bridger Units 3 and 4, when the optimized simulation selected continued operations with incremental SCR and other planned costs, then the change case was created by removing the SCR investment as an alternative, allowing the SO Model to select the next best alternative, which in all scenarios is conversion to natural gas. In scenarios where the optimized simulation selected conversion to natural gas, then the change case forced continued operations with incremental SCR and other planned costs to calculate the PVRR(d) of making the investment. The differences in system costs, inclusive of differences in net power costs, operating costs and capital investment costs, between the two simulations for any given market price scenario represents the PVRR(d), which establishes how favorable or unfavorable the incremental environmental capital investments planned for Jim Bridger Units 3 and 4 are in relation to the next best alternative.

Q. What incremental environmental investment costs were assumed for Jim Bridger Units 3 and 4?

A. Incremental environmental investment costs applied in the SO Model include the cost of the SCR required for Jim Bridger Units 3 and 4 along with costs required to achieve compliance with an array of known and prospective emerging environmental regulations. This includes costs to achieve compliance with the

U.S. Environmental Protection Agency's mercury and air toxics standard, and costs to achieve compliance with prospective rules on coal combustion residuals and cooling water intake structures. The incremental investment costs assumed in the SO Model for Jim Bridger Units 3 and 4 along with other coal resources in the Company's fleet are summarized in Confidential Exhibit RTL 1 to my testimony.

Q. What resource replacement alternatives were made available to the SO Model in the event SCR investments are not made for Jim Bridger Units 3 and 4?

A. In addition to brown field natural gas conversion of Jim Bridger Unit 3 and/or Jim Bridger Unit 4, the SO Model was configured with a range of resource replacement alternatives, which include:

- green field natural gas resources,
- firm market purchases,
- demand side management,
- and incremental wind resources.

With the installation of SCR required by December 31, 2015 for Jim Bridger Unit 3 and by December 31, 2016 for Jim Bridger Unit 4, resource retirement and replacement alternatives were assumed to be available beginning January 2016 and January 2017 respectively. Natural gas conversion alternatives were made available beginning March 2016 for Jim Bridger Unit 3 and March 2017 for Jim Bridger Unit 4, assuming coal-fueled operation would continue as long as possible and the work to complete the gas conversion could be accomplished over a two month period.

Q. Does the Company's SO Model analysis consider the power requirements from the SCR investments required at Jim Bridger Units 3 and 4?

A. Yes. The SCR equipment, once installed and operational, is assumed to reduce the Company's share of capacity of both Jim Bridger Unit 3 and Unit 4 by approximately 3.5 megawatts.

Q. Did the Company analyze the PVRR(d) for the SCR investments at Jim Bridger Units 3 and 4 together as well as individually?

A. Yes.

Q. Why is it important to evaluate the PVRR(d) of the SCR investments required at Jim Bridger Units 3 and 4 in this way?

A. The decision to install SCR equipment at Jim Bridger Unit 3 can be made independent of the decision to install SCR equipment at Jim Bridger Unit 4 and vice versa. However, the cost implications, and therefore the PVRR(d), associated with SCR investment decision at each individual unit, are not necessarily additive when looking at both units collectively. By evaluating both the individual and combined investments, this analytical approach ensures that the conclusions drawn from the economic analysis of each individual unit remain unchanged when both units are analyzed together.

Q. Does the Company's analysis consider how the fueling strategy for the Jim Bridger plant might be affected if one or more of the Jim Bridger units were to stop burning coal?

A. Yes. The Company's analysis considers how the Jim Bridger fueling plans would be affected in the event that Jim Bridger Unit 3 and/or Jim Bridger Unit 4 were to stop burning coal. These fueling plans include coal production from Bridger Coal Company, coal contract purchases and other coals produced in Southwest Wyoming that could be used to supplement the fuel requirements at the Jim Bridger facility. The change in cost associated with changes to the fueling plans under potential early retirement and replacement or gas conversion outcomes were factored into both the optimized and change case simulation results when formulating the PVRR(d) for each scenario.

For instance, in a simulation where Jim Bridger Unit 3 stops burning coal, either due to early retirement and replacement or due to gas conversion, whether forced or optimized by the SO Model, coal cost and mine capital adjustments were applied assuming a fueling strategy for a three-coal unit operation at the Jim Bridger plant. Similarly, in a simulation where both Jim Bridger Unit 3 and Unit 4 stop burning coal, coal cost and mine capital adjustments were applied consistent with a two-unit fueling strategy for the Jim Bridger plant.

Q. Did the Company assume coal costs at Jim Bridger are affected by its decision to convert Naughton Unit 3 to natural gas?

A. No. The economic analysis supporting the Company's decision to convert Naughton Unit 3 to natural gas included potential take-or-pay costs identified in coal supply agreements put in place to fuel the Naughton facility. That analysis assumed minimum coal contract volumes would be taken at Naughton, and approximately one million tons would be delivered to the Jim Bridger plant in 2015 and 2016. Given that the Jim Bridger fueling plan includes market based deliveries with the expiration of a third party coal supply agreement at the end of

2014, any deliveries from Naughton could be used to fill that open position. All costs inclusive of handling and transport above delivered market prices for any shipments from Naughton to Jim Bridger would be charged to the Naughton plant and not affect coal costs at Jim Bridger. Moreover, given the SCR for Jim Bridger Unit 3 must be installed prior to December 31, 2015 and the SCR at Jim Bridger Unit 4 must be installed by December 31, 2016, any deliveries from Naughton to Jim Bridger in 2015 could be made regardless of the SCR investment decision.

Q. Did the Company use any other models to evaluate the SCR investments required at Jim Bridger Units 3 and 4?

A. Yes. During the Naughton Unit 3 CPCN process, parties requested the Company perform an analysis of the environmental investments required for continued coal operation of Naughton Unit 3 using the GRID model. In response to parties' concerns raised in that proceeding, the Company has performed a GRID study to benchmark the base case SO Model results for the combined analysis of Jim Bridger Units 3 and 4.

In performing this GRID benchmarking analysis, the resource portfolios from the optimized and change case SO Model simulations were replicated in GRID, and assumptions for coal availability rates, coal costs, and variable operations and maintenance costs for natural gas resources were aligned with what were assumed in the SO Model. The difference in net power costs from the two GRID runs were then used to establish a PVRR(d) that can be compared to the SO Model results. As I will discuss later in my testimony, this benchmarking analysis performed using GRID shows a [redacted] PVRR(d) favorable to the

SCR investments required at Jim Bridger Units 3 and 4.

Natural Gas and CO_2 Price Scenarios

Q. Please explain why natural gas and CO_2 price assumptions are important when analyzing the SCR investments at Jim Bridger Units 3 and 4.

A. Alternatives to the SCR investments include early retirement and resource replacement or conversion of Jim Bridger Unit 3 and/or Jim Bridger Unit 4 to natural gas. Consequently, the assumed price for natural gas directly affects the cost for gas-fueled replacement resources in the case of an early retirement alternative or the fuel cost and replacement energy in the case of a gas conversion alternative. The price for natural gas is also a key factor in setting wholesale power prices. In this way, gas prices disproportionately affect the value of energy net of operating costs from Jim Bridger Units 3 and 4 when operating as a coal-fueled resource versus the value of energy net of operating costs from a gas-fueled resource replacement alternative. Similarly, because of the relatively high level of carbon content in coal as compared to natural gas, higher CO_2 prices disproportionately affect the prospective cost of emissions between coal resources and natural gas as an alternative to the incremental investments required to continue operating Jim Bridger Units 3 and 4 as coal-fueled assets.

Q. Has the Company evaluated different assumptions for natural gas prices and CO_2 prices in its analysis of the Jim Bridger Units 3 and 4 SCR investments?

A. Yes. In the Company's analysis of the SCR investments at Jim Bridger Units 3 and 4, six different combinations of natural gas and CO_2 price assumptions were analyzed as variations to the base case, which is tied to the December 2011 official forward price curve ("OFPC"). Table 1 below summarizes the directional changes to base case assumptions among the six scenarios, with the scenario description indicating the CO_2 price assumption for the first year that CO_2 prices are assumed. Two scenarios assume low and high natural gas prices with base case CO_2 assumptions held constant; two scenarios assume low and high CO_2 price assumptions with the underlying base case natural gas prices held constant; and two scenarios pair different combinations of natural gas price and CO_2 price assumptions to serve as bookends around the base case. In any scenario where the CO_2 assumption varies from those used in the base case, the underlying natural gas price assumption is adjusted to account for any natural gas price response from changes in electric sector natural gas demand.

Table 1
Natural Gas and CO_2 Price Scenarios

Description	Natural Gas Prices	CO_2 Prices
Base Case	December 2011 OFPC	$16/ton in 2021, escalating at 3% plus inflation
Low Gas, $16 CO_2	Low	$16/ton in 2021, escalating at 3% plus inflation
High Gas, $16 CO_2	High	$16/ton in 2021, escalating at 3% plus inflation
Base Gas, $0 CO_2	Base Case Adjusted for Price Response	No CO_2 Costs
Base Gas, $34 CO_2	Base Case Adjusted for Price Response	$34/ton in 2018, escalating at 5% plus inflation
Low Gas, $34 CO_2	Low Case Adjusted for Price Response	$34/ton in 2018, escalating at 5% plus inflation
High Gas, $0 CO_2	High Case Adjusted for Price Response	No CO_2 Costs

Q. Why are natural gas price assumptions adjusted in those scenarios where CO_2 price assumptions vary from the base case?

A. CO_2 prices disproportionately affect the prospective cost of emissions between coal resources and natural gas alternatives. This is primarily driven by the relatively high level of carbon content in coal as compared to natural gas. With rising CO_2 prices, generating resources with lower CO_2 emissions, such as natural gas-fueled resources, begin to displace coal-fueled generation, thereby increasing the demand for natural gas within the electric sector of the U.S. economy. Displacement of coal generation is also influenced by low or zero emitting renewable generation sources; however, not enough to entirely offset increased natural gas demand. Conversely, with falling CO_2 prices (or a market that is absent CO_2 prices), there is no incremental emissions-based cost advantage for natural gas or renewable generation as compared to coal, and demand for natural gas in the electric sector of the U.S. economy is slightly lower. It is assumed that any change in natural gas demand must be balanced with a change in supply such that higher natural gas demand yields an upward movement in price and lower natural gas demand yields a downward movement in price.

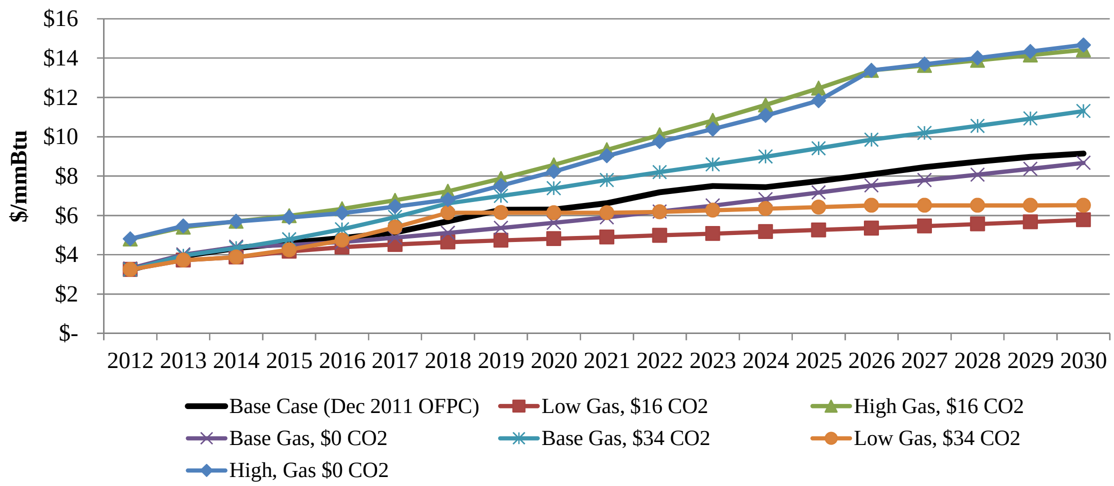
Q. How did the Company choose its natural gas and CO_2 price assumptions as used in the six market price scenarios?

A. The range of low and high price assumptions are based upon the range of current third party expert forecasts and government agency price projections. Confidential Exhibit RTL 2 to my testimony shows how the low and high price assumptions used in the Company's analysis compare to these third party forecasts.

Low natural gas price assumptions are derived from a third party low price scenario, which is characterized by strong and price resilient shale gas supply growth and stagnant exports of liquefied natural gas out of the U.S. natural gas market. The high natural gas price assumptions are based on a blend of two, third-party, price scenarios. This blending approach recognizes that the most extreme high gas price forecast reviewed is a strong outlier relative to price projections from other forecasters, and yields a high price scenario that by 2018 exceeds the highest of 47 natural gas price forecasts in the U.S. Energy Information Administration's 2011 Annual Energy Outlook.[1]

Fundamental drivers to a high price scenario would include constraints or disappointments in shale gas production, linkage to rising oil prices through substantial new demand in the transportation sector, and/or significant increases in liquefied natural gas exports out of the U.S. natural gas market. Figure 1 below shows the Henry Hub natural gas price forecast among all market price scenarios included in the analysis of SCR investments at Jim Bridger Units 3 and 4.

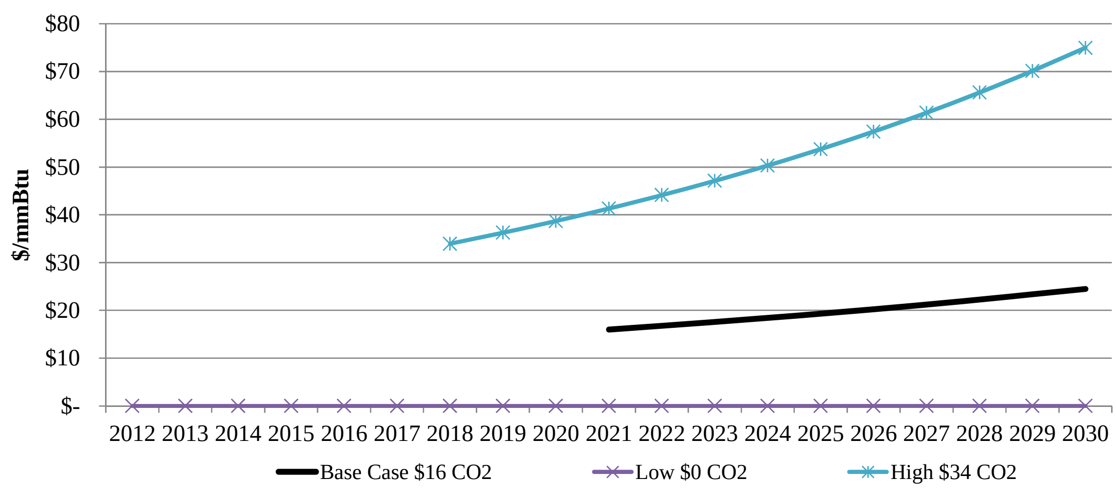
Figure 1
Henry Hub Natural Gas Prices among All Scenarios



[1] The U.S. Energy Information Administration is the statistical and analytical agency within the U.S. Department of Energy. The highest natural gas price forecast in the 2011 Annual Energy Outlook assumes that total unproved technically recoverable shale gas resources are reduced by 49 percent and that the estimated ultimate recovery per shale gas well is 50 percent lower than in their reference case.

The Company assumes a zero CO_2 price for the low scenario recognizing that there has been limited activity in the CO_2 policy arena, and policy makers remain unwilling or unable to address the greenhouse gas issue over the study period. For the high CO_2 price scenario, prices are assumed to remain consistent with the upper limit that would have been established under the American Power Act of 2010 with an assumed start date in 2018, which is higher than any of the current third party CO_2 price projections. The high CO_2 price scenario start date aligns with the earliest start date assumed by the third party price forecasts reviewed by the Company. Figure 2 below shows the three CO_2 price assumptions used in the market price scenarios in the analysis of SCR investments at Jim Bridger Units 3 and 4.

Figure 2
CO2 Prices among All Scenarios



Base Case Results

Q. Please describe the results from the base case SO Model analysis.

A. The optimized base case simulation from the SO Model selected the SCR investment at Jim Bridger Unit 3 and Jim Bridger Unit 4. The three change case simulations – one in which Jim Bridger Unit 3 was not allowed to select SCR, one in which Jim Bridger Unit 4 was not allowed to select SCR, and one in which Jim Bridger Units 3 *and* 4 were not allowed to select SCR – shows that gas conversion is the next best, albeit higher cost, alternative to the SCR investment. The PVRR(d) between the optimized simulation, as summarized in Confidential Exhibit RTL 3 to my testimony, shows that SCR is:

- [redacted] favorable to gas conversion for Jim Bridger Unit 3,
- [redacted] favorable to gas conversion for Jim Bridger Unit 4, and
- [redacted] favorable to gas conversion for Jim Bridger Units 3 *and* 4.

Q. Why do the base case results show that SCR at Jim Bridger Unit 3 is more favorable than the SCR at Jim Bridger Unit 4?

A. This is primarily driven by differences in assumed incremental environmental capital requirements between the two units. As described in Exhibit CAT 1 to the testimony of Company witness Mr. Chad A. Teply, there are differences in the flue gas desulfurization system at Jim Bridger Unit 4 that increase the estimated cost for the Jim Bridger Unit 4 SCR as compared to the Jim Bridger Unit 3 SCR. PacifiCorp's share of the cost for the SCR investment at Jim Bridger Unit 4 is approximately [redacted] higher than PacifiCorp's share of the estimated cost for the SCR at Jim Bridger Unit 3. The higher cost of the Jim Bridger Unit 4 SCR improves the upfront investment cost advantage of the gas conversion alternative, which reduced the PVRR(d) benefit of the SCR investment when compared to Jim Bridger Unit 3.

Q. Why does the PVRR(d) that is favorable to the SCR investments at Jim Bridger Units 3 and 4 when analyzed individually not sum to the PVRR(d) when Jim Bridger Units 3 and 4 are analyzed together?

A. As discussed earlier in my testimony, the analysis takes into consideration how the fueling plan for the Jim Bridger plant would change if Jim Bridger Unit 3 and/or Unit 4 were to stop burning coal. When analyzed individually, the PVRR(d) results for Jim Bridger Unit 3 and Jim Bridger Unit 4 reflect the cost differential between a three-unit operation and a four-unit operation fueling plan. When analyzed together, the PVRR(d) results for Jim Bridger Unit 3 *and* Jim Bridger Unit 4 reflect changes in cost between a two-unit operation and a four-unit operation fueling plan. The difference in cost between the two fueling plans gets applied to the Jim Bridger units that continue operating as coal-fueled assets.

Q. How do the fueling plans for a Jim Bridger plant three- and two-unit coal operation differ from the fueling plan for a four-unit operation?

A. As reflected in Confidential Table 2 below for the 2018 to 2030 period**,** the plant fueling requirements are supplied from Bridger Coal Company's surface and underground mining operations and from third party mines.

Confidential Table 2

Jim Bridger Plant Fueling Plan			
	Annual Production (Millions of tons)		
Production Source	Four Unit	Three Unit	Two Unit
Bridger Coal Underground	[redacted]	[redacted]	[redacted]
Bridger Coal Surface	[redacted]	[redacted]	[redacted]
Third party/Other	[redacted]	[redacted]	[redacted]
Total Bridger Plant	[redacted]	[redacted]	[redacted]

Under a fueling plan for either a three unit or two unit coal operation at the Jim Bridger plant, coal production from the Bridger Coal Company's surface operation ceases and the draglines used to uncover coal are instead dedicated to final reclamation of the surface mine. Under such a scenario, final reclamation would need to be completed by 2021 to achieve Wyoming Department of Environmental Quality requirements. Because funding for final reclamation expenditures is currently amortized and recovered over the life of the surface operation, advancement of final reclamation activities from post 2037, which is Jim Bridger plant's current depreciable life, to 2021 results in higher final reclamation amortization costs through 2021, which increases coal costs on a dollar per mmBtu basis.

Additionally, to meet the reduced coal requirements in the two-unit operation, production from the Bridger Coal underground operation would be curtailed and third party coal supplies would be terminated.

Q. Please identify the differences in coal costs between the SCR investments at Jim Bridger Units 3 and 4 when analyzed individually and when Jim Bridger Units 3 and 4 are analyzed together.

A. The coal costs incorporated in the SCR investment analysis for Jim Bridger Units 3 and 4 on an individual basis and Jim Bridger Units 3 and 4 collectively are included in Confidential Exhibit RTL 4. As reflected in the change case simulation where Jim Bridger Unit 3 or Jim Bridger Unit 4 individually convert to natural gas, the 2017 coal cost associated with a three-unit coal operation is approximately [redacted] per mmBtu higher than the coal cost for a four-unit coal operation. This equates to approximately [redacted] in incremental fuel cost for the three Jim Bridger units that continue operating as coal-fueled assets in the year 2017.

In the change case simulation where Jim Bridger Unit 3 and Jim Bridger Unit 4 both convert to natural gas, the 2017 coal cost associated with a two-unit coal operation is approximately [redacted] per mmBtu higher than the coal cost for a four-unit coal operation. This equates to just over [redacted] in incremental fuel costs for the two Jim Bridger units that continue operating as coal-fueled assets. Simply adding the [redacted] coal cost impact in the case where Jim Bridger Unit 3 converts to natural gas to the [redacted] coal cost impact in the case where Jim Bridger Unit 4 converts to natural gas does not sum to the [redacted] cost impact when both Jim Bridger Unit 3 and Unit 4 are converted to natural gas.

Q. Did the Company perform a similar base case analysis of environmental upgrades required at its Naughton Unit 3 coal facility?

A. Yes. The Company performed a similar base case analysis of SCR and bag house investments that would be required to continue operating Naughton Unit 3 as a coal-fueled facility. In contrast to the Jim Bridger Unit 3 and Unit 4 analysis discussed above, this base case analysis produced a PVRR(d) that favored converting Naughton Unit 3 to a natural gas-fueled facility.

Q. Why would gas conversion be favorable for Naughton Unit 3, but not favorable for Jim Bridger Units 3 and 4?

A. In the case of Naughton Unit 3, one of the primary drivers favoring gas conversion is the difference between the up-front environmental investment cost that would have been required to continue operating Naughton Unit 3 as a coal fueled facility beyond 2015 as compared to the up-front investment cost for gas conversion. For Naughton Unit 3, the upfront investment cost for gas conversion was approximately [redacted] than the up-front investment cost, inclusive of bag house and SCR costs, required for continued coal operation. In the case of Jim Bridger Units 3 and 4, the upfront investment cost for gas conversion is [redacted] than the up-front investment cost, inclusive of SCR costs, but absent the cost for bag houses, required for continued coal operation. Combined, the up-front investment cost savings for the gas conversion alternative for Jim Bridger Units 3 and 4 is [redacted] of the up-front investment cost savings for gas conversion at Naughton Unit 3.

Q. How do run-rate capital and ongoing operating cost differences between investment in coal and investment in gas conversion at Naughton Unit 3 compare to run-rate capital and ongoing operating cost tradeoffs in the Jim Bridger Units 3 and 4 analysis?

A. Given expectations for lower dispatch from coal units that are converted to burn natural gas, annual operating costs and run-rate capital costs for units converted to burn natural gas would be lower than operating costs and run-rate capital costs for coal-fueled facilities. Given differences in the expected operating and run-rate capital costs between Naughton Unit 3 and Jim Bridger Units 3 and 4 as coal-fueled facilities, the Naughton Unit 3 realizes proportionately greater operating and run-rate capital cost benefits when converted to natural gas than would be expected for a gas conversion alternative at Jim Bridger Units 3 and 4.

On a levelized basis, the forecasted annual operating and run-rate capital cost of Naughton Unit 3 as a coal fueled facility is approximately [redacted]. When Naughton Unit 3 converts to natural gas, levelized annual operating and run-rate capital costs are expected to be [redacted], which equates to annual levelized cost savings of approximately [redacted]. In the case of Jim Bridger Units 3 and 4, levelized annual operating and run-rate capital costs expected for continue coal-fueled operation is [redacted]. If converted to natural gas, levelized annual operating and run-rate capital costs for Jim Bridger Units 3 and 4 would be [redacted]. While there would be levelized operating and run-rate capital costs savings for a gas conversion at Jim Bridger Units 3 and 4, equating to approximately [redacted] per year on a levelized basis, the potential cost savings are approximately 21 percent less than the cost savings achieved by converting Naughton Unit 3 to a natural gas-fueled asset.

The SO Model evaluates the cost advantages of gas conversion, and other available resource options, for each of the coal units against the value of system energy, capacity and balancing needs to identify the most economic resource option for the Company. In the case of Naughton Unit 3, the SO Model analysis support gas conversion, whereas, the SO Model analysis supports making the incremental environmental investments required to continue operating Jim Bridger Units 3 and 4 as coal-fueled assets.

Q. Please describe how the GRID benchmarking analysis compares to the base case SO Model results.

A. As I noted earlier, the base case SO Model results for the combined Jim Bridger Unit 3 and Unit 4 analysis yields a PVRR(d) of [redacted] favorable to the required SCR investments. The GRID benchmarking analysis yields a PVRR(d) that is [redacted] favorable to the SCR investments required at Jim Bridger Units 3 and 4. The results of the PVRR(d) analysis from GRID and the SO Model are compared in Confidential Exhibit RTL 5 to my testimony.

Q. Please explain what differentiates GRID from the SO Model.

A. While there are similarities between the GRID and the SO Model, in that they are both production dispatch models, the two models are simply designed to perform different tasks. GRID is primarily used to simulate the Company's operations and project net power costs with a given resource portfolio for rate setting purposes, and therefore, models the characteristics and operations of the resources, as well as obligations, at a more granular level than is done in the SO Model. The SO Model has been used to evaluate resource acquisition opportunities and is used in resource procurement activities, consistent with its use in the Company's integrated resource plan, due to its ability to endogenously select new resources and to develop a least cost resource expansion plan. In order for the SO Model to solve for a resource expansion plan that takes into consideration potential resource retirement alternatives while simultaneously dispatching resources to meet load obligations, the SO Model relies on a less granular, yet reasonable representation of system dispatch. This is a tradeoff that is required to achieve reasonable model performance and simulation run times.

Q. How do these differences influence the PVRR(d) results between the two models?

A. Differences in the models contribute to differences in how system resources are dispatched in GRID as compared to the SO Model. Variations in system dispatch between the two models affects net power costs, which accounts for the difference in the PVRR(d) reported by GRID and the SO Model.

The difference in net power costs between a simulation in which Jim Bridger Units 3 and 4 continue operating as coal-fired units and a simulation where they are converted to burn natural gas is representative of the net power cost benefits of these two coal units. Defining net power costs for purposes of this analysis as including emissions and variable operations and maintenance costs, in addition to fuel costs, wheeling expenses, and wholesale purchase expenses net of wholesale revenues, the GRID model shows the present value net power cost benefit of Jim Bridger Units 3 and 4 as coal-fueled facilities over the period 2016 through 2030 is approximately [redacted]. The present value of net power cost benefits of Jim Bridger Units 3 and 4 over the same period as calculated in the SO Model is [redacted], which is within [redacted] or approximately eight percent of the value reported by GRID. On a levelized basis over the period 2016 through 2030, the net power cost difference between the two models equates to approximately $11 million per year.

Q. What do you conclude from the GRID benchmarking analysis?

A. Consistent with the SO Model, the GRID model shows a PVRR(d) that is favorable to the SCR investments required to continue operating Jim Bridger Units 3 and 4 as coal-fueled assets. Moreover, on a net power cost basis, both GRID and the SO Model show similar value for Jim Bridger Units 3 and 4 as coal-fueled facilities. Based upon these findings, I believe that the GRID benchmarking analysis supports the Company's use of the SO Model in the evaluation of the SCR investments required at Jim Bridger Units 3 and 4.

Natural Gas and CO_2 Price Scenario Results

Q. Please describe the results from the natural gas and CO_2 price scenarios in the Company's SO Model analysis.

A. The optimized simulations from the SO Model selected the SCR investment at Jim Bridger Unit 3 and Jim Bridger Unit 4 in all scenarios except the low gas price and high CO_2 price scenarios. In the low gas price scenario, the nominal levelized price of natural gas at Opal over the period 2016 to 2030 is $4.51 per mmBtu and the PVRR(d) is [redacted] to the SCR investments required at Jim Bridger Units 3 and 4. In the high CO_2 price scenario, CO_2 prices start at $33.94 per ton in 2018 and climb to $74.96 per ton by 2030, and the nominal levelized price of natural gas at Opal over the period 2016 to 2030 is $7.25 per mmBtu. In this high CO_2 price scenario, the PVRR(d) is [redacted] to the SCR investments.

The market price scenario results also show that the investment in SCR at Jim Bridger Unit 3 and Jim Bridger Unit 4 remains favorable to gas conversion under all base and high natural gas price scenarios that are paired with either base case CO_2 or zero CO_2 price assumptions. The PVRR(d) between the optimized simulations and the change case simulations are summarized alongside the base case results in Confidential Exhibit RTL 3 to my testimony.

Q. How do the PVRR(d) results trend among the different natural gas price assumptions?

A. The market price scenario results show that there is a strong trend between natural gas price assumptions and the PVRR(d) benefit/cost associated with the incremental pollution control investments required for continued operation of Jim Bridger Units 3 and 4 as a coal-fueled assets. With higher natural gas price assumptions, the incremental SCR investments become more favorable to the Jim Bridger Unit 3 and Unit 4 gas conversion alternatives. Conversely, lower natural gas prices improve the PVRR(d) results in favor of the gas conversion alternative. This relationship is intuitive given that lower natural gas prices lower the fuel cost of the gas conversion alternative, lowers the fuel cost of the other natural gas-fueled system resources that partially offset the generation lost from the coal-fueled Jim Bridger units, and lowers the opportunity cost of reduced off system sales when Jim Bridger Units 3 and/or 4 operate as a gas-fueled generation assets.

Q. Can you infer from this trend how far natural gas prices would need to fall for gas conversion to become favorable to making the incremental environmental investments in Jim Bridger Units 3 and 4?

A. Yes. Confidential Exhibit RTL 6 to my testimony graphically displays the relationship between the nominal levelized natural gas price at the Opal market hub over the period 2016 through 2030 and the PVRR(d) benefit/cost of the incremental investments required for continued coal operation of Jim Bridger Unit 3, Jim Bridger Unit 4, and Jim Bridger Units 3 and 4 combined. To isolate the effects of CO_2 prices, which as I described earlier are assumed to elicit a natural gas price response due to changes in demand for natural gas in the electric sector, the natural gas price relationship with PVRR(d) results is shown for the natural gas price scenarios in which the base case $16 per ton CO_2 price assumption is used.

The figures in Confidential Exhibit RTL 6 show a very strong linear relationship between the nominal levelized price of Opal natural gas prices and the PVRR(d) benefit/cost of the incremental environmental investments required at Jim Bridger Units 3 and 4. Based upon this trend, levelized natural gas prices over the period 2016 through 2030 would need to decrease by 19 percent, from $6.18 per mmBtu to $4.99 per mmBtu, to achieve a breakeven PVRR(d) for Jim Bridger Unit 3. Break even economics would require levelized gas prices to drop to $5.12 per mmBtu over the period 2016 to 2030, which is more than 17 percent below base case natural gas prices, for Jim Bridger Unit 4. When analyzed together, levelized gas prices would need to fall to $4.99 per mmBtu, or 19 percent below the base case, to achieve a breakeven PVRR(d).

Q. Has the Company's natural gas price curve for Opal changed since December 2011?

A. Yes. The nominal levelized natural gas price at Opal from the Company's June 2012 official forward price is $5.65 per mmBtu, which is approximately nine percent lower than the base case. Based upon the relationship above, the predicted PVRR(d) with the most recent gas prices would be [redacted] and remain favorable to the SCR investments required at Jim Bridger Units 3 and 4.

Q. How do the PVRR(d) results trend among the different CO_2 price assumptions?

A. Higher CO_2 price assumptions improve the PVRR(d) in favor of the gas conversion alternative, and lower CO_2 prices improve the economics of the investments required to continue operating Jim Bridger Units 3 and 4 as coal-fueled assets. As with the trend described in the relationship between natural gas prices and the PVRR(d) results, the relationship between CO_2 prices and the PVRR(d) benefit/cost of the incremental environmental investments at Jim Bridger Units 3 and 4 is intuitive. Because the CO_2 content of coal is nearly double the CO_2 content of natural gas, higher CO_2 prices reduces the cost of emissions for the gas conversion alternative and lowers the fuel cost of other natural gas-fueled system resources used to offset any generation lost from the coal-fueled Jim Bridger Units 3 and 4 assets.

Q. What CO_2 price is required to change the PVRR(d) results in favor of converting Jim Bridger Units 3 and 4 to natural gas?

A. Confidential Exhibit RTL 7 to my testimony includes a graphical representation of the relationship between the nominal levelized CO_2 price over the period 2016 to 2030 and the PVRR(d) benefit/cost of the incremental investments required for continued coal operation of Jim Bridger Units 3 and 4. To isolate the effects of fundamental shifts in the natural gas price assumptions, the CO_2 price relationship with the PVRR(d) results is shown for the two CO_2 price scenarios that are paired with the same underlying base case natural gas price assumption.

The figure in Confidential Exhibit RTL 7 shows a strong relationship between the nominal levelized CO_2 price and the PVRR(d) benefit/cost of the incremental environmental investments required at Jim Bridger Units 3 and 4. The relationship is not as linear as the relationship between natural gas prices and the PVRR(d) results because of the natural gas price response that is assumed when CO_2 price assumptions are changed. For instance, the PVRR(d) results from the base gas \$0 CO_2 scenario reflect the removal of CO_2 costs, which directionally favors investment in coal, and a nine percent reduction in natural gas prices, which directionally favors the gas conversion alternative to the investment in coal. Similarly, the base gas \$34 CO_2 scenario results reflect higher CO_2 prices that occur sooner relative to the base case, which favors the gas conversion alternative, and a 16 percent increase in natural gas prices, which directionally favors the incremental investments required for Jim Bridger Units 3 and 4 to continue operating as coal-fueled facilities. Nonetheless, the trends in the figure indicate that among the scenarios studied, the effect of the CO_2 price assumption tends to outweigh the effect of the natural gas price response.

Based upon the trends shown in the figures within Confidential Exhibit RTL 7, levelized CO_2 prices over the period 2016 through 2030 would need to exceed \$35 per ton, more than three times the base case nominal levelized CO_2 price assumption, to achieve a breakeven PVRR(d) for Jim Bridger Unit 3 SCR investment. Break even economics would require a levelized CO_2 price of \$34 per ton over the period 2016 to 2030, which is 220 percent higher than base case CO_2 prices, for Jim Bridger Unit 4 SCR investment. When the SCR investments for both Jim Bridger Unit 3 and Unit 4 are analyzed together, nominal levelized CO_2 prices would need to be in excess of \$36 per ton, or 239 percent above the base case, to achieve a breakeven PVRR(d).

Q. Please describe the results from the remaining two scenarios included in the Company's scenario analysis.

A. Two additional scenarios were included in the Company's analysis to see how combinations of natural gas price and CO_2 price assumptions that have amplifying upside and downside effects would affect the PVRR(d) results. These two scenarios include the low gas \$34 CO_2 price scenario, where both the natural gas price assumptions and the CO_2 price assumptions directionally favor alternatives to incremental investment in coal, and the high gas zero CO_2 price scenario, where both the natural gas price assumptions and the CO_2 price assumptions favor the incremental investments required at Jim Bridger Units 3 and 4 for continued coal-fueled operation. In effect, these two scenarios establish the more extreme combinations of assumptions that serve as bookends to those assumptions used in the base case analysis.

When low natural gas prices are paired with high CO_2 price assumptions, the PVRR(d) is [redacted] favorable to the gas conversion alternative at Jim Bridger Unit 3, [redacted] favorable to the gas conversion alternative at Jim Bridger Unit 4, and [redacted] favorable to the gas conversion alternatives at Jim Bridger Units 3 *and* 4 when analyzed together. When high natural gas prices are paired with zero CO_2 price assumptions, the PVRR(d) is [redacted] favorable to making the incremental SCR and other planned environmental investments at Jim Bridger Unit 3, [redacted] favorable to the incremental environmental investments required for Jim Bridger Unit 4, and [redacted] favorable to the incremental environmental investments at Jim Bridger Units 3 *and* 4 when analyzed together. The difference in the PVRR(d) between these two scenarios is greater than [redacted] dollars when Jim Bridger Unit 3 and 4 are analyzed together, highlighting the significance of the natural gas price and CO_2 price assumptions in the analysis.

Conclusions

Q. What do you conclude from the results of the Company's analysis?

A. The base case results show a PVRR(d) of [redacted] favorable to the SCR and other environmental investments required to continue operating Jim Bridger Units 3 and 4 as coal-fueled assets when compared to a gas conversion alternative. Additional scenario analysis, including a broad range of natural gas price and CO_2 price assumptions further support the base case results except when levelized CO_2

prices are more than three times those assumed in the base case and/or when long-term natural gas prices are assumed to fall by more than 19 percent below the base case forecast or nearly 12 percent below the most recent forward curve. Under the low gas scenario, long-term natural gas prices at the Opal market hub remain well below $5 per mmBtu through 2030, a scenario that would require continued strong and price resilient shale gas supply growth and stagnant exports of liquefied natural gas and/or limited growth in demand for natural gas across the U.S. economy. With consideration given to all of the scenarios, accounting for both upside and downside natural gas and CO_2 price risk, the SCR investment required to continue operating Jim Bridger Units 3 and 4 as coal-fueled assets is in customers best interest.

Q. Does this conclude your testimony?

A. Yes.

Application No. 18-04-002
Exhibit PAC/1600
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP

REDACTED

Rebuttal Testimony of Chad A. Teply

Operational Necessity

Installation of Selective Catalytic Reduction Systems

November 2018

TABLE OF CONTENTS

ATTACHED EXHIBITS

Q. Are you the same Chad A. Teply who submitted direct testimony in this case on behalf of PacifiCorp, d/b/a Pacific Power (PacifiCorp)?

A. Yes.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to Sierra Club's testimony challenging the prudence of the company's investments in selective catalytic reduction systems (SCRs) and other necessary capital additions at the company's coal plants. Sierra Club's testimony was submitted by Dr. Jeremy I. Fisher.

Q. Please identify the specific issues you address and the related issues addressed by other PacifiCorp witnesses.

A. In my role at PacifiCorp, I was directly responsible for the development, evaluation, and implementation of the SCRs at Jim Bridger Units 3 and 4 (Jim Bridger SCRs). I also oversaw the environmental compliance investments at Naughton, Craig, and Hayden that are challenged by Sierra Club. I summarize the reasons why Sierra Club is wrong in claiming that the company acted imprudently with respect to any of these investments.

In particular, I address criticism of the company's process for evaluation, review, and approval of the Jim Bridger SCRs, and Sierra Club's challenges on the timing and legal basis of the company's compliance requirements underlying the company's investment in the Jim Bridger SCRs. I respond to Sierra Club's claim that the Naughton Unit 1 flue gas desulfurization (FGD) and low-NO_X burners, which have been in rates since 2012, are imprudent. Finally, I address Sierra Club's claim that the company was imprudent for not suing its co-owners, as plant operators, over the installation of SCRs at the Hayden and Craig plants, even though the ownership agreements leave it highly unlikely that PacifiCorp could have stopped the projects and avoided paying for its share of those investments.

Mr. Rick T. Link responds to the specific adjustments Sierra Club proposed to the company's analysis supporting the Jim Bridger SCRs. These adjustments are based on updates for alleged material decreases in natural gas prices and increases in coal costs. Mr. Link demonstrates the significant errors in each of these adjustments and shows that none of the adjustments, when properly calculated, fundamentally change the company's supporting analysis. Mr. Dana M. Ralston rebuts testimony of Sierra Club regarding alleged material increases in coal costs in 2013.

Mr. Link also responds to Sierra Club's proposal to disallow capital costs in certain coal units on a going-forward basis based on allegations relating to the company's resource planning process.

II. SUMMARY OF TESTIMONY

Q. Please summarize your rebuttal testimony.

A. In my rebuttal testimony, I make the following key points:

- PacifiCorp's capital investments in its coal fleet are supported by a reasonable planning process and comprehensive economic analysis, designed to ensure the prudence of all such investments.
- Contrary to Sierra Club's assertions, the company prudently and reasonably developed, assessed, and approved the Jim Bridger SCRs through a robust, multi-year process. During the multi-year review period, the company refined

and updated its economic analysis. The company diligently studied the costs and benefits of installing the Jim Bridger SCRs for several years before executing and finalizing the engineering, procurement, and construction services (EPC) contract for the projects.

- The company did not ignore new information available before the company released the Full Notice to Proceed (FNTP) for the Jim Bridger SCRs. In fact, the company's negotiation and use of the EPC contract's Limited Notice to Proceed (LNTP) provision is evidence of the company's prudence. This provision allowed the company to limit outlay of costs while pursuing parallel path regulatory reviews and permitting and allowed assessment of market conditions and the project's economics up to the last feasible point in time, December 2013, while still meeting the company's regional haze compliance deadlines.
- Sierra Club attempts to support its challenge to the Jim Bridger SCRs by pointing to an analysis it submitted in 2016 to the Washington Utilities and Transportation Commission (Washington commission). Sierra Club has not, however, submitted this analysis or any other in this case. Sierra Club's Washington commission analysis was improperly based on forward price curves and coal costs that post-date the company's execution of the EPC contract and the FNTP. And, as Mr. Link and Mr. Ralston demonstrate, Sierra Club's Washington commission analysis was incomplete and inaccurate. When corrected, Sierra Club's Washington commission analysis supports the company's decision to move forward with the Jim Bridger SCRs. In addition,

my testimony demonstrates that Sierra Club's Washington commission analysis did not take into account significant reductions in project costs that increase the benefits to customers associated with the Jim Bridger SCRs. The evidence in this case demonstrates that—at all points relevant to this prudence review—the Jim Bridger SCRs were the most cost-effective compliance option for customers.

- The emission control investments at Naughton Unit 1 were required by applicable state and federal environmental regulations and have been included in California rates since August 25, 2012, through Commission approval of the company's 2012 Post Test-year Adjustment Mechanism (PTAM) advice letter filing.[1] Sierra Club had the opportunity to protest this advice letter filing at the time and did not. The FGD system on Naughton Unit 1 is very similar to that on Naughton Unit 2, and is supported by the same business case. The Naughton Unit 2 FGD system has been in the company's California rates since the company's 2011 general rate case.
- The SCR investments at Hayden Units 1 and 2 were required by applicable state and federal environmental regulations. The company reasonably assessed its legal position and concluded that it was highly unlikely to be successful if it attempted litigation against its plant partner and operator to stop the SCR investment. Based on this assessment, the company concluded that a reasonable utility would not incur the cost, resource deployment, and negative impacts on long-term co-owner relationships to sue an operating

[1] *See* PacifiCorp AL 476-E.

partner when lacking a sound basis for such action.

- The SCR investment at Craig Unit 2 was also required by applicable federal and state environmental regulations. Similar to the SCRs at the Hayden plant, according to the terms of its ownership agreement with the plant's co-owners, PacifiCorp alone could not stop the installation of SCRs without successfully suing its co-owners. The company reasonably assessed the low likelihood of success in such a lawsuit and concluded that there was little chance it could stop the SCR investment. Thus, the company concluded that a reasonable utility would not unnecessarily sue its plant partners.

III. POLICY RESPONSE TO SIERRA CLUB'S OVERALL RECOMMENDATIONS

Q. Sierra Club proposes disallowing all capital costs associated with the plants over the last five years, as well as capital costs for the 2019 test year.[2] How do you respond to this recommendation?

A. First, Sierra Club's overall recommendation lacks evidentiary support in the record. As described by Mr. Link and Mr. Ralston, Sierra Club has not demonstrated that any of the company's specific emission control investments were imprudent or that the company's resource planning has any systemic flaws related to the ongoing assessment of the company's coal resources.

Second, PacifiCorp's ongoing capital investments in its coal plants have been and continue to be reasonable and prudent because they allow the resources to continue to operate and provide customer benefits by, for example, lowering overall

[2] Direct Testimony of Jeremy Fisher, PhD on Behalf of Sierra Club at 4-5 (hereinafter Fisher Direct).

net power costs for PacifiCorp's customers. Contrary to Sierra Club's claims, the company has not blindly invested in its coal fleet without regard to the benefits of the resources. For example, during the same time period that Sierra Club claims the company failed to assess the economics of its coal fleet, the company agreed to and followed through with the shutdown of one coal plant (Carbon Units 1 and 2), agreed to a firm end of life on another (Dave Johnston Unit 3), and negotiated the ability to convert yet another to natural gas (Naughton Unit 3).

Q. Does PacifiCorp have a strategy for assessing the ongoing economic viability of its coal fleet?

A. Yes. The company is committed to assessing the economic viability of its coal fleet, and all other resources required to reliably and cost-effectively serve its customers, through its resource planning process. As described in more detail by Mr. Link, the biennial resource planning process includes robust public participation and is designed to address the big picture, long-term economic questions Sierra Club poses in this case. A rate case, on the other hand, is ill-suited to address such resource planning concerns.

Q. Sierra Club claims that the company has ignored national trends that favor early closure of coal-fired resources.[3] Do you agree?

A. No. On the contrary, the company's most recent Integrated Resource Plan (IRP) shows that by the end of the planning horizon, PacifiCorp assumes 3,650 MW of existing coal capacity will be retired. The 2017 IRP specifically calls for the early retirement or removal from coal-fueled service of Naughton Unit 3, Cholla Unit 4,

[3] Fisher Direct at 6-7.

Craig Unit 1, and Jim Bridger Units 1 and 2 as the assessed least-cost, least-risk planning outcome for those resources. In addition, the company already retired its Carbon Units 1 and 2 in 2015 after assessing the economics and viability of environmental compliance options for those facilities. The company does not currently anticipate extending the lives of any of its existing coal units and, in anticipation of the potential for additional early retirements, the company's case here includes accelerated depreciation of coal units to mitigate the rate impact of early closures. The company is committed to rigorous economic analysis of its existing coal resources, consistent with its prior practice and consistent with the current regulatory and economic environment.

Q. Is it prudent to simply stop investing any capital in existing coal resources, as Sierra Club recommends?

A. No. Unless and until a particular unit is deemed uneconomic and scheduled for shut down, it will continue to operate and provide customer benefits. The ongoing capital investments Sierra Club opposes are required to allow that ongoing operation until the unit is retired. Sierra Club's recommended blanket disallowance ignores the reality of operating a coal fleet and incorrectly assumes that many of the company's coal units were uneconomic years ago—despite the fact they continue to economically and reliably dispatch to lower customers' net power costs.

Sierra Club's approach to analyzing the company's coal fleet is unreasonably outcome driven. Sierra Club has made no secret of its desire to shut down coal units, regardless of whether a shutdown is economic. Indeed, in this case, Sierra Club recommends that the company commit today to retiring certain units by 2023, without acknowledging that both economic and regulatory circumstances could change a great deal between today and 2023 and without having assessed system reliability impacts that could be realized with such an aggregated retirements approach. Sierra Club's objective is to shutdown coal plants, regardless of the impact to customers or the company's ability to reliably serve customer load needs. Such a position is fundamentally at odds with prudent utility management.

Q. Setting aside Sierra Club's recommendation that the company commit to shutdowns today without regard for future circumstances, is there any basis for Sierra Club's claim that certain units are economic to retire in 2023 based on what is known today?

A. No. As described in more detail in Mr. Link's testimony, Sierra Club relies on flawed and incomplete studies to claim that several coal units should be retired in 2023. Most importantly, Sierra Club's studies make stand-alone unit economic assumptions and then recommend that multiple units be retired in parallel without having assessed the aggregated system impacts of such a recommendation. Sierra Club fails to produce *any evidence* that retiring multiple units in 2023 is economic.

Q. Sierra Club is also critical of the company's overall integrated resource planning, and particularly faults the company for quoting from a June 2013 report from the Regulatory Assistance Project (RAP) stating that PacifiCorp's resource planning was "superior."[4] How do you respond?

A. Sierra Club's attempt to discredit this statement from the RAP report is unpersuasive, particularly considering that, during that same time frame, Dr. Fisher himself has

[4] Fisher Direct at 9–10.

referenced PacifiCorp's IRP as a model to be followed by utilities in other jurisdictions.[5] For example, in 2014, Dr. Fisher pointed to PacifiCorp's carbon modeling when testifying how an Oklahoma utility should model future costs associated with environmental regulation.[6]

IV. RESPONSE TO SIERRA CLUB'S CHALLENGE TO JIM BRIDGER SCR INVESTMENTS

Company Process for Review of SCR Investments

Q. Please summarize the evidence supporting the prudence of the Jim Bridger SCRs.

A. In assessing the prudence of the Jim Bridger SCRs, the Commission must review whether the company made a reasonable business decision in light of the facts and circumstances known or reasonably knowable to the company in May 2013, subject to reassessment for major changes through December 1, 2013. Viewed objectively and holistically, the evidence shows that the company acted reasonably. In fact, it would have been difficult for the company to justify the prudence of any decision other than installing the Jim Bridger SCRs, because the economic analysis *at all times* favored this investment over other options.

In 2012, the company was facing fast-approaching regional haze compliance deadlines for Jim Bridger Units 3 and 4. These units are critical to providing reliable and affordable electric services to California customers. The analysis showed that early retirement of these units was never a viable economic option. The company had two regional haze compliance options: invest in the Jim Bridger SCRs, or propose

[5] Exhibit No. PAC/1601 at 2–3 (2013 comments from Dr. Fisher in another utility's IRP points to PacifiCorp's robust scenario modeling).
[6] Exhibit No. PAC/1602.

conversion of the units to natural gas.

Using its System Optimizer model, the company developed economic analysis to compare these options under a range of scenarios using different natural gas curves and carbon prices. The analysis showed that the SCRs investment was the most cost-effective compliance option for customers by several hundred million dollars. Based on this analysis, in August 2012, the company filed for a certificate of public convenience and necessity (CPCN) in Wyoming and for voluntary SCR investment pre-approval in Utah. In February 2013, the company comprehensively updated and refined its SCR analysis in these cases using its September 2012 official forward price curve (OFPC) and its January 2013 long-term fueling plan for the Jim Bridger plant. The results again decisively favored the Jim Bridger SCRs, this time by approximately $183 million.

The company incorporated its updated SCR analysis from February 2013 into its 2013 IRP, filed in March 2013, with minor updates that increased the benefits of the Jim Bridger SCRs.

The company's SCR analysis was fully litigated by the Utah and Wyoming commissions. In May 2013, both commissions concluded that the SCR investment was the least-cost, least-risk compliance option available to the company. Sierra Club participated in both cases, unsuccessfully raising many issues similar to issues it has raised in this case.

After the Utah and Wyoming commissions approved the Jim Bridger SCRs, the company conducted another review to support its decision to execute the EPC contract. In late May 2013, the company's President and Chief Executive Officer authorized the Jim Bridger SCRs based on this analysis, in accordance with the company's governance policies.

To minimize the risks of the Jim Bridger SCRs for customers, the company negotiated an innovative EPC contract that allowed the company to delay significant investment in the Jim Bridger SCRs to the last possible date, December 1, 2013, while still ensuring that the company could cost-effectively meet its compliance deadlines. The EPC contract allowed the company to withdraw if material changes before December 1, 2013, impacted the economics or the company's ability to implement the SCR projects.

Before issuing the FNTP, the company reviewed all key decision factors, including: (1) its most recent OFPC (dated September 2013), which remained well above the SCR's break-even point; (2) 10-year budget projections that showed that Jim Bridger coal costs were not projected to increase significantly; and (3) a [redacted] cost reduction the company negotiated in the EPC contract. The company also verified that none of its third-party forecast providers had projected increases in carbon costs in response to President Obama's June 2013 Presidential Memorandum regarding carbon emissions.

I personally conducted this review of the Jim Bridger SCR investment and recommended issuance of the FNTP. I would not have recommended issuance of the FNTP without considering all material factors and determining that the SCR investment remained the best compliance choice for customers. During the same timeframe, the company elected to close other coal plants or pursue conversion to natural gas. In each case, the company's decision was based on the economics of the compliance option for customers, not a predetermined preference or investment agenda.

The company carefully managed the Jim Bridger SCR EPC contract and ensured that the Jim Bridger Unit 3 SCR was completed on time and under budget. The SCR at Jim Bridger Unit 4 was also completed on time and under budget. Neither unit would currently be serving customers but for the SCR investment in compliance with the Environmental Protection Agency's (EPA) approved Wyoming Regional Haze State Implementation Plan.

Q. Throughout this process, did the company use the models and analytical approaches developed and applied in its IRP to evaluate the Jim Bridger SCRs?

A. Yes. Mr. Link's direct testimony describes the sophisticated modeling the company used in its economic analysis.

Q. Does the company agree that December 1, 2013, is the correct time for evaluating the prudence of the Jim Bridger SCRs?

A. No, not in isolation. The normal timing for evaluating the prudence of utility decision-making is when the project is approved to proceed and contracts are executed. For the Jim Bridger SCRs, this was May 2013. In this case, however, the company prudently and effectively negotiated an additional commercial structure to the EPC contract that provided risk mitigation and facilitated timely decision-making on a number of fronts that could have impacted the projects both positively and negatively through the December 2013 timeframe. While it is relevant to consider how the company managed the first stage of the EPC contract from the LNTP in May 2013 to the FNTP in December 2013, this consideration should not be blind to the company's significant review process in May 2013, nor to the fact that the structure of the EPC contract itself is evidence of the company's prudence.

Q. Did the company consider additional information before providing the FNTP to the EPC contractor in December 2013?

A. Yes. As noted in my direct testimony, the company considered all key decision factors, including the most recent OFPC, projected coal costs, and updated EPC costs. The company's assessment of the economic merits of the Jim Bridger SCRs before release of the FNTP to the EPC contractor continued to support the projects. A detailed overview of other information considered by the company before releasing the FNTP is provided in Confidential Exhibit No. PAC/1603, dated December 5, 2013.

Q. Sierra Club argues that, by December 2013, the Jim Bridger SCRs had become uneconomic as compared to natural gas conversion, so the company should not have released the FNTP.[7] Please respond.

A. Without evidentiary support, Sierra Club paints an inaccurate and incomplete picture of the relative economics of the Jim Bridger SCRs at the FNTP stage. First, as Mr. Link and Mr. Ralston explain in their rebuttal testimonies, the updated forward market price curves and coal cost information available to the company when releasing the FNTP continued to support the SCRs as the least expensive option for customers. To argue otherwise, Sierra Club relies on an aggressive position that cannot withstand analytic scrutiny.

Second, as noted in my direct testimony, at the time the company evaluated

[7] Fisher Direct at 26.

the FNTP, the company was aware of a significant reduction in the final negotiated and executed EPC contract costs, as compared to the EPC contract cost estimates used in the company's base-case analyses. The EPC cost was approximately [redacted] less for PacifiCorp's share as joint owner than originally estimated. This tangible adjustment supported execution of the FNTP.

Third, if the company changed course in December 2013 with less than two years before the initial compliance deadline at Jim Bridger Unit 3, the costs and risks of natural gas conversion would have been higher than was projected in the SCR analysis, which assumed normal permitting and construction timelines. I address these changes below.

Cancelling a major environmental compliance project mid-stream is much more than just a paper exercise, as Sierra Club would lead the Commission to believe. Prudent management of a complex multi-year, multi-jurisdictional project like the Jim Bridger SCRs included parallel path environmental agency permitting, regulatory reviews, and major commercial negotiations. For these reasons, cancelling the SCRs in December 2013 would have been imprudent absent an undisputable reversal of project economics, new or changed environmental compliance requirements, changes to legislative policies impacting the resource for all customers, or similar major events. None of those things occurred.

To summarize, the company's analysis showed over [redacted] in benefits as of December 1, 2013, based on September 2013 OFPC and EPC contract savings. Reducing this by [redacted] to account for changes in coal costs based on the

October 2013 mine plan decreases the SCR benefits to [redacted].[8] Even reducing these benefits again based on the after-the-fact December OFPC, as Sierra Club improperly recommends, still results in [redacted] in favor of the SCRs.[9] Based on [redacted] in PVRR(d) benefits favoring SCRs, coupled with the company's additional risk and scenario analysis, a reasonable utility would not have terminated the EPC contract for the SCRs and switched to natural gas conversion.

Q. Please explain why the costs of natural gas conversion would have been higher than assumed in the company's SCR analysis if the company cancelled the EPC contract on December 1, 2013.

A. The natural gas conversion costs included in the SCR analysis assumed normal project permitting, review, and construction schedules, which would have begun in 2012 and would have resulted in in-service dates for the natural gas conversions shortly after the prescribed compliance deadlines for the units and before the 2016 and 2017 peak capacity seasons, respectively. But if the company chose to pursue natural gas conversion on December 1, 2013, as Sierra Club suggests, the permitting, procurement, and construction schedules for the natural gas conversion projects would have required significant compression to attempt completion of the projects before the 2016 and 2017 summer peak capacity seasons, if that were possible at all. Before beginning construction, the company would have needed to secure necessary

[8] As discussed in Mr. Ralston's testimony, this [redacted] million figure assumes a conservative [redacted] overall increase in coal costs, which is a rough approximation based on the October 2013 Mine Plan and 2015 IRP analysis Sierra Club used in its analysis in front of the Washington commission.

[9] Mr. Link's testimony describes the impact of using the December OFPC. To summarize, Sierra Club claims that the December OFPC decreased the February 2013 benefits from $183 million to $37 million. Fisher Direct at 26. And the February benefits were $53 million higher than the September benefits.

permits and environmental agency approvals, rescind and resubmit necessary regulatory filings including those affecting a CPCN from the Wyoming commission, and procure and execute a new EPC contract. Based on the company's experience with regional haze permit and state implementation plan amendments in the state of Wyoming, this process could have conservatively taken 24 months to complete for conversion of Jim Bridger Units 3 and 4. Applying this timeframe to a decision in December 2013, the company would have been approved to proceed by the environmental agencies by year-end 2015, leaving an impracticable six months to receive regulatory approvals and implement the Jim Bridger Unit 3 project before the 2016 summer peak season. Such a timeline would necessarily increase the analyzed costs of the gas conversion scenario, either because the project would need to be expedited or because the unit would need to be shuttered for noncompliance pending completion of the retrofit, or both. See Exhibit No. PAC/1604 for a representative timeline of the activities required to convert Jim Bridger Units 3 and 4 to natural gas under this hypothetical. As indicated on that timeline, had the company switched course in December 2013, Unit 3 would be off-line from January 1, 2016, through mid-year 2017, and Unit 4 would be off-line from January 1, 2017, through mid-year 2017. Losing Unit 3 for 18 months and losing Unit 4 for six months would cause the company to incur significant replacement power costs and reduce its system reliability, increasing both the costs and risks of natural gas conversion.

In addition, by December 2013, based on information from the competitive market bids for the Naughton Unit 3 natural gas conversion EPC contract, the company knew that implementation costs for that project were significantly higher—

on an order of magnitude of [redacted]—than originally anticipated. Correlating that information to an assessment of natural gas conversion for Jim Bridger Units 3 and 4 in December 2013, the company would have understood that its original cost projections for this alternative were understated. This would have negatively impacted the competitiveness of the natural gas conversion alternative in the company's assessment and associated decision-making.

Q. Has the company effectively and prudently managed the risks associated with the Jim Bridger SCRs?

A. Yes. As described above and in my direct testimony, the company engaged on several fronts to effectively and prudently manage the risks associated with the Jim Bridger SCRs. On the regulatory front, the company engaged its stakeholders and regulators in rigorous reviews of the projects before committing to the major expenditures that the projects entailed. In parallel to those regulatory reviews, the company negotiated the LNTP concept into the EPC contract for the projects to allow as much time as possible for reviews in other regulatory dockets to proceed, federal action on the state of Wyoming's regional haze compliance requirements to progress, the company's joint owner to get regulatory approval of a CPCN for its share of the project, and potential scope and schedule changes that could have resulted from those processes to be considered and integrated into project plans before releasing FNTP to the EPC contractor. At the same time, the company committed to deliver the projects within the cost structures agreed to in the regulatory proceedings in Utah and Wyoming, while knowing that it would be held accountable in subsequent prudence reviews of the company's management of the projects.

Project Timing and Legal Basis

Q. Does Sierra Club mischaracterize the flexibility of regional haze compliance deadlines for the Jim Bridger SCRs?

A. Yes. Sierra Club asserts that the company had no legal obligation to begin planning for the SCR systems until January 2014, when EPA issued its final decision.[10] This statement is patently untrue and unsupportable.

Q Is Sierra Club aware the company was under a legally enforceable obligation to the state of Wyoming to meet compliance deadlines despite any lack of ruling by the EPA?

A. Yes. Sierra Club's witness in this proceeding, Dr. Fisher, has also been a witness for Sierra Club in several dockets where this issue was previously litigated, so he is well aware that the company was under a legally enforceable obligation to complete the Jim Bridger SCRs or otherwise meet the associated unit-specific emission limits on Jim Bridger Units 3 and 4 if the company was going to lawfully continue to operate these units, with or without an EPA ruling. These legal obligations were established in the Wyoming Best Available Retrofit Technology (BART) assessment and permit, the Wyoming State Implementation Plan (SIP), and the regional haze appeal settlement agreement[11] between the state of Wyoming and the company.

Q. Have Wyoming regulators confirmed that the company had a legal obligation to install SCRs on Jim Bridger Units 3 and 4?

A. Yes. Wyoming has been clear—its SCR requirement at Units 3 and 4 in 2015 and 2016 were independent of any action taken by EPA. In early 2013, the company

[10] Fisher Direct at 20, 22.
[11] *See* Exhibit No. PAC/1605.

specifically sought an extension of the compliance obligation based on EPA's delay in issuing its final order.[12] Wyoming reaffirmed the company's compliance obligation and denied the extension.[13]

Moreover, in response to Sierra Club's argument that the company had no compliance obligation until January 2014, the Public Service Commission of Wyoming (Wyoming commission) made an explicit finding that the company "ha[d] a legal obligation under the BART Settlement Agreement with [Wyoming Department of Environmental Quality (DEQ)] to complete the work on Jim Bridger Units 3 and 4 by December 31, 2015, and December 31, 2016, respectively."[14] The Wyoming commission continued: "This obligation is independent of EPA actions."[15] The Public Service Commission of Utah (Utah commission) and the Washington commission have also both rejected Sierra Club's argument that the company had no legal obligation to act until January 2014.[16]

A reasonable utility would not have delayed action pending EPA's approval because delay would have harmed customers. The Wyoming and Utah commissions made this finding explicitly, and the Washington commission found that the company was prudent to execute the EPC contract in May 2013.[17]

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[12] Exhibit No. PAC/402.
[13] Exhibit No. PAC/403.
[14] *In the Matter of the Application of Rocky Mountain Power for Approval of 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*, WPSC Docket No. 20000-418-EA-12 (Record No. 13314), Order Denying Motion for a Stay or Continuance Pending Final EPA Action, ¶ 14 (Feb. 4, 2013) (Wyoming Stay Order).
[15] Wyoming Stay Order ¶ 14.
[16] *Voluntary Request of Rocky Mountain Power for Approval of Resource Decision to Construct SCRs on Jim Bridger Units 3 and 4*, Docket 12-035-92, Report and Order at 9 (May 10, 2013) ("Utah Pre-Approval Order"); *Wash. Utils. and Transp. Comm'n v. PacifiCorp*, Docket No. UE-152253, Order 12 ¶¶ 96 (Sept. 1, 2016). Order 12 is included in the record here as Exhibit JIF-13.
[17] Wyoming Stay Order ¶ 14; Utah Pre-Approval Order at 9; Order 12 ¶ 97.

Dr. Fisher's credibility on this point is undermined not only by the fact it has been rejected by every commission that has heard it, but his predictions regarding EPA's actions also turned out to be wrong. During the Wyoming commission CPCN proceeding, in support of his claim that the company should delay action on the SCRs, Dr. Fisher testified that the 2015 and 2016 compliance deadlines would "certainly not materialize."[18] This, of course, turned out to be wrong.

Q. Is Dr. Fisher's assertion regarding timelines for the Jim Bridger SCRs also contrary to positions that Sierra Club has taken in comments filed with the EPA in the Wyoming regional haze docket?

A. Yes. Dr. Fisher's position that the company could have deferred the start of planning for the SCRs until after the EPA's final action in January 2014 is contrary to the position taken previously by Sierra Club in comments filed with the EPA on the Wyoming SIP regarding the Jim Bridger SCRs 2015 and 2016 compliance deadlines. Sierra Club's comments state in pertinent part:

> EPA's proposal would require installation of SCR plus low-NOx burners/SOFA by 2015 at Unit 3 and 2016 at Unit 4. 77 Fed. Reg. at 33035. However, EPA also is seeking comment on an alternative that would allow PacifiCorp to install SCR at Jim Bridger Units 3 and 4 within 5 years from the date of EPA's final action. *Id.* at 33053. EPA's reasoning is that this alternative would allow PacifiCorp the flexibility to determine the implementation schedule for BART controls on all four Jim Bridger units. Because EPA's initial proposal

[18] Washington Rate Case Tr. 787:7-789:11.

> to require BART installation by 2016 best complies with the statutory requirement that BART be installed and operated —as expeditiously as practicable, 42 U.S.C. § 7491(b)(2)(A), we support EPA's proposal over the alternative for Jim Bridger Units 3 and 4.[19]

In other words, in the EPA docket to review the Wyoming SIP, Sierra Club filed comments on August 2012 advocating that the company be held to the 2015 and 2016 compliance deadlines for the Jim Bridger units. Sierra Club's position in this case and in the EPA proceeding are not reconcilable—it would be impossible to meet the 2015 and 2016 deadlines if PacifiCorp had waited to act until after issuance of the EPA's decision in January 2014. Sierra Club's testimony here does not acknowledge its shifting positions on this issue, which appear to be driven by competing desired outcomes in related regulatory processes.

Q. To be clear, has EPA approved the state of Wyoming's Regional Haze compliance requirements for Jim Bridger Units 3 and 4?

A. Yes. EPA approved these requirements in its final Regional Haze Federal Implementation Plan (FIP) for Wyoming published in the *Federal Register* on June 4, 2012. EPA reiterated its approval of these requirements in its updated Regional Haze FIP for Wyoming published in the *Federal Register* on January 30, 2014. EPA's final approval makes these emissions reduction compliance requirements at Jim Bridger Units 3 and 4 federally enforceable, in addition to being enforceable under state law.

[19] See comments at: http://www.regulations.gov/#!documentDetail;D=EPA-R08-OAR-2012-0026-0056 at pages 23–24.

Sierra Club's Improper Reliance on Washington commission Order

Q. Please respond to Sierra Club's reliance on the order from the company's 2015 Washington rate case to support its proposed Jim Bridger SCR adjustment.

A. Instead of producing evidence in this case to support its allegation that the company's economic analysis overstated the benefits of the Jim Bridger SCRs, Sierra Club points to the Washington commission's high-level summary of Sierra Club's evidence in the Washington commission order. But neither Sierra Club's testimony here nor the Washington commission order provide sufficient detail to substantiate or even explain Sierra Club's proposed adjustment in this case. Sierra Club's approach has left the company in the untenable position of trying to respond to analytical evidence that is not even in this record.

Q. Did the Washington commission rely on Sierra Club's evidence in support of its decision?

A. Not according to the language of the order. The Washington commission specifically gave "no weight" to evidence based on facts after December 1, 2013.[20] Both Sierra Club's natural gas and coal adjustment explicitly rely on post-December 1, 2013, evidence, meaning that the Washington commission gave it "no weight."[21] The Washington commission also rejected Sierra Club's proposed disallowance because Sierra Club's analysis was "problematic" hindsight review.[22] Tellingly, Sierra Club does not rely on the Washington commission's findings, and instead cites to the

[20] Order 12 n. 158.
[21] Order 12 n. 116 (stating Sierra Club's coal analysis relied on 2015 IRP data); Order 12 ¶ 80 (Sierra Club gas adjustment based on December 2013 OFPC).
[22] Order 12 ¶ 111.

sections of the Washington commission order where that commission simply describes Sierra Club's evidence.

Q. How do you respond to Sierra Club's claim that the Washington commission found that "PacifiCorp acted imprudently?"[23]

A. To be clear, the Washington commission found that PacifiCorp "failed to meet its burden of demonstrating that its final decision to continue with the SCR installations on Units 3 and 4 was prudent."[24] It is my understanding, based on the language of the Washington commission order, that finding that the company failed to meet its evidentiary burden is not the same as finding that the company was imprudent.[25] A further reading of the Washington commission order indicates that the company's failure to meet its evidentiary burden was tied largely to the lack of "contemporaneous *documentation*" of the company's decision-making.[26] This finding appears to have been particularly important to the Washington commission because certain *documentation* is required by the Washington commission's prudence standard, as that standard is described in the order.[27] Indeed, the Washington commission noted that my explanation of the continuous re-assessment of the SCR economics before issuing the FNPT was "helpful," but it was not sufficient to meet the *documentation* element of prudence standard because there were insufficient written materials describing what had occurred.[28] Notably, neither the Utah nor the

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[23] Fisher Direct at 32.
[24] Order 12 ¶ 108.
[25] *See, e.g.*, Order 12 ¶ 110 (distinguishing between "cases of imprudence or failure to meet the prudence burden").
[26] *See, e.g.*, Order 12 ¶¶ 98, 100, 102, 103.
[27] Order 12 ¶ 107.
[28] Order 12 ¶ 107.

Wyoming commissions imposed this heightened requirement for documentation, relying instead on the company's testimony regarding its review process.

Q. Did the Washington commission disallow recovery of the SCRs in Washington rates?

A. No. The Washington commission found that "it is reasonable to allow Pacific Power recovery of the SCR capital expenditures."[29] The Washington commission found that PacifiCorp faced a "regulatory obligation with both the Wyoming DEQ and federal EPA to reduce emissions and meet the regional haze requirements, and that the installation of SCRs on Units 3 and 4 was one means to achieve this goal."[30] Based on the FNTP documentation issue, the Commission disallowed the return on the Bridger SCRs, but also accelerated the depreciation of the Jim Bridger plant to 2025, minimizing the overall impact of that disallowance.[31]

Q. Does Sierra Club's testimony acknowledge the numerous other regulatory commissions that approved the Jim Bridger SCRs?

A. No. As I previously testified, in May 2013, both the Wyoming and Utah commissions approved the Jim Bridger SCRs—over Sierra Club's objections in both cases. The Wyoming commission found that SCRs were the "most preferable option," "in the public interest," and that "it is inescapable that the company's course of action, taken in the context of increased ratepayer costs associated with delay, is reasonable."[32] The Utah commission found that the company's economic analysis

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[29] Order 12 ¶ 116.
[30] Order 12 ¶ 114.
[31] Order 12 ¶ 57.
[32] *Application of Rocky Mountain Power*, Docket 20000-418-EA-12 (Record No. 13314), Memorandum Opinion ¶¶55, 62, 85 (May 29, 2013).

"not only demonstrates the Project is favored in six of nine cases, but substantially so;" and, in rejecting Sierra Club's claims, concluded that there was "no compelling evidence, arguments, or analysis shifting the economics to favor an alternative strategy to comply with the Wyoming SIP requirements."[33]

In addition, the Idaho Public Utilities Commission (Idaho commission) approved the Jim Bridger SCRs based on an application submitted by the plant's co-owner, Idaho Power Company. In December 2013, the Idaho commission found that the "the future public convenience and necessity requires" the SCRs because Jim Bridger "is a source of low-cost and dispatchable baseload energy that provides reliable capacity during peak customer demand."[34] The Idaho commission rejected the claim that "renewable resources and energy efficiency could somehow replace Jim Bridger's ability to reliably provide energy and capacity" because that claim was "simply not realistic in the near term."[35] In finding that the Jim Bridger SCRs were in the public interest, the Idaho commission also concluded that the plant was "critical to the reliable operation of the high voltage transmission system in that [it] provide[s] voltage and frequency support."[36]

Sierra Club argues that this Commission should defer to the only commission that has disallowed return on the Jim Bridger SCR investment, without acknowledging that every other commission that has looked at the issue found that the investment was prudent and in the public interest.

[33] Utah Pre-Approval Order at 32.
[34] *In the Matter of Idaho Power Company's Application for a Certificate of Public Convenience and Necessity for the Investment in Selective Catalytic Reduction Controls on Jim Bridger Units 3 and 4*, IPUC Case No. IPC-E-13-16, Order No. 32929 at 10 (Dec. 2, 2013).
[35] *Id.*
[36] *Id.*

V. RESPONSE TO SIERRA CLUB'S CHALLENGE TO NAUGHTON EMISSION CONTROL INVESTMENTS

Q. Sierra Club also claims that the regional haze compliance investments at Naughton Unit 1 were imprudent.[37] How do you respond?

A. I understand that the emissions control equipment at Naughton Unit 1 has been in California rates since 2012.[38] Similar investments made at Naughton Unit 2 were found prudent and included in California rates through the company's last general rate case in 2011. Both investments were required by the same environmental regulations, and the company relied on the same analysis to support the emission control investments at both Naughton Units 1 and 2. Sierra Club did not challenge the prudence of the Naughton emissions control equipment in either of the aforementioned California cases, but is now pursuing a retroactive ratemaking adjustment to investments that have been in rates for many years.

Q. Did Sierra Club provide any evidence that the Naughton Unit 1 investment was imprudent?

A. No. Sierra Club relies instead on a decision by the Public Utility Commission of Oregon (Oregon commission) to support its claim that the emission control investments at Naughton Unit 1 were imprudent,[39] but that decision is at odds with this Commission's inclusion of the Naughton Unit 2 investments in California rates.

Sierra Club also misrepresents the Oregon commission decision when it testified that the "Naughton retrofits were not allowed into Oregon rates."[40] In fact,

[37] Fisher Direct page 12.
[38] *See* PacifiCorp AL 476-E.
[39] Fisher Direct page 17.
[40] Fisher Direct page 16.

the Oregon commission allowed 90 percent of the retrofit costs in Oregon rates. The Oregon commission explicitly rejected the total disallowance Sierra Club recommends here because of the "difficulty of excluding from rate base investments that enable the affected plants to continue to operate and provide service to customers."[41] The Oregon commission also recognized that "significant investments in [PacifiCorp's] coal fleet were necessary."[42] Again, this finding is at odds with Sierra Club's position in this case.

VI. RESPONSE TO SIERRA CLUB'S CHALLENGE TO HAYDEN SCR INVESTMENTS

Q. Sierra Club argues that the company was imprudent for supporting the decision of its co-owner and plant operator, Public Service Company of Colorado (PSCo), to install SCRs at Hayden Units 1 and 2.[43] Did the company appropriately assess its options regarding participation in the Hayden SCR projects?

A. Yes. Based on the company's economic and legal analysis, it was prudent to allow installation of SCRs at the Hayden plant.

Q. What are the primary ownership agreement considerations regarding the company's participation in the Hayden SCR projects?

A. As described in my direct testimony, the Participation Agreement common to both Hayden Units 1 and 2 requires the facilities to be operated in compliance with all applicable laws. The Participation Agreement also places an independent obligation on PSCo, as the Operating Agent, to operate the Hayden units in accordance with all environmental laws. Considerations under the agreement fall into two primary

[41] Fisher Exhibit No. JIF-10 (Order No. 12-493 at 31).
[42] *Id*.
[43] Fisher Direct at 38–43.

classes. First, PacifiCorp must consider the applicable law (e.g., the Colorado Regional Haze SIP and the Colorado Clean Air Clean Jobs Act). Second, PacifiCorp must consider its contractual rights and obligations under the Participation Agreement with regard to the applicable law. I have included relevant sections of the Participation Agreement as Confidential Exhibit No. PAC/1606.

Q. Following its assessment of applicable law and its rights and obligations under the Participation Agreement for Hayden Units 1 and 2, what position did the company take with respect to the SCR additions for the units?

A. Following its assessment of applicable law and its rights and obligations under the Participation Agreement, the company concluded that it was reasonable to support the SCR additions for Hayden Units 1 and 2 because: (1) they were required by applicable law; and (2) Hayden Units 1 and 2 are required to be operated in accordance with applicable law.

Q. Please summarize the law applicable to the Hayden Units 1 and 2 SCRs.

A. The state of Colorado promulgated, and the EPA approved, a Regional Haze SIP for the state of Colorado requiring SCRs for the units. Failure to comply with the requirements of a state and EPA approved SIP would likely result in state and/or federal enforcement action, substantial penalties, and a requirement to cease operation of a unit until it is brought into compliance.

Further, the state of Colorado adopted the Clean Air Clean Jobs Act that required PSCo to submit a plan to reduce NO_X emissions by 70 to 80 percent by 2017. PSCo's NO_X reduction plan, reviewed and approved by the Colorado Public Utilities Commission (Colorado commission), includes installation of SCR retrofits on Hayden Units 1 and 2. To comply with the Colorado Regional Haze SIP and PSCo's approved Clean Air Clean Jobs Act NO_X reduction plan, PSCo as Operating Agent for the Hayden facility, installed SCRs on Hayden Units 1 and 2.

Q. What would have happened if the company had not agreed to the installation of SCRs at Hayden?

A. The Participation Agreement requires the unanimous consent of all owners to proceed with a capital improvement. If the Operating Agent proposes a capital improvement (e.g. the installation of SCR equipment) to meet applicable law, as occurred at Hayden Units 1 and 2, a non-consenting owner has the option to assert that the Operating Agent (and other owners) are in default under the Participation Agreement if it cannot be demonstrated that applicable law requires the addition. In that case, whether or not a default has occurred will be decided by arbitration.

Q. Did the Hayden Operating Agent and joint owner, PSCo, and the state of Colorado determine that installation of SCRs on Units 1 and 2 was in the best interests of customers?

A. Yes. As I described in my direct testimony, PSCo found the installation of SCR on Units 1 and 2 to be in the best interests of customers and received approval of CPCNs from the Colorado commission for the projects.

Q. Considering the terms and conditions of the Hayden Units 1 and 2 Participation Agreement, did the company pursue arbitration of the Hayden Units 1 and 2 SCRs capital addition decisions?

A. No, because there was no dispute that applicable law required the installation of SCRs. The company concluded that it had no sound basis to challenge PSCo's decision, and therefore the company chose to not pursue litigation against its co-owner. The company does not take litigation against its partners lightly and would not, in the case of Hayden, have pursued litigation at any cost and without sound basis, which is effectively what Sierra Club claims a reasonable utility would have done.

Q. Did the terms and conditions of the Hayden Units 1 and 2 Participation Agreement drive the company to take a different approach in responding the Hayden SCRs installation when compared to the company's response to the Craig Unit 2 SCR installation?

A. Yes. While the Hayden Participation Agreement includes a unanimous approval provision, the company assessed the provisions of the Participation Agreement to allow the Operating Agent to proceed with the SCR projects even over the company's objection, especially with no dispute that applicable law required the installation of SCRs. The agreement also does not grant the company a unilateral right to decide an alternate route, such as retirement or natural gas conversion. The Craig Participation Agreement, on the other hand, provides the company the option of voting against capital project budget items in connection with at least a 50 percent participation share of other owners. The company voted against the Craig Unit 2 SCR project utilizing this available provision, but was unsuccessful in obtaining 50 percent participation share of votes against the SCR project.

Q. Sierra Club claims that the company's own analysis demonstrated that it was uneconomic to install SCRs at Hayden Unit 1.[44] Do you agree?

A. No. PacifiCorp did not analyze a scenario where "it transferred all its rights and obligations to co-owner" versus "the other in which it withdrew unilaterally and incurred contract termination costs."[45] The scenarios that were analyzed were reflective of a "hypothetical" early retirement in 2015 of Hayden Unit 1 versus an SCR retrofit, looking at both with and without take-or-pay coal contract termination costs for each scenario. In the case where coal contract termination costs applies, the installation of the SCR was more beneficial to customers by [redacted]. In the case where coal contract termination costs did not apply, the results showed a [redacted] dollar benefit if Hayden Unit 1 is assumed to hypothetically retire in 2015 versus making the SCR investment.

Q. Would coal contract termination costs have applied for Hayden Unit 1's early retirement in 2015?

A. Yes, coal contract termination costs would have applied because PacifiCorp would have been trying to avoid the capital investment for the SCR as a joint owner due to economics; the other joint owner had already decided to make the SCR investment and PacifiCorp would not have been able to utilize the "change-in-law termination provisions" in the coal contract to avoid the take-or-pay early termination provision.

Q. Did the company's economic assessment provide definitive conclusions in all applicable assessment scenarios, as Sierra Club implies?

A. No. Notwithstanding the fact that the company's analysis of its rights and obligations

[44] Fisher Direct at 40-41; Confidential Exhibit No. JIF-18 at 8.
[45] Fisher Direct at 40.

under the Hayden Participation Agreement supports the company's participation in the Hayden Units 1 and 2 SCR projects, the company's economic analysis of the Hayden Unit 1 SCR did not provide definitive conclusions in all applicable assessment scenarios, and furthermore could only reasonably be construed to compare an alternate compliance option (i.e. unit shutdown) that is unequivocally available to the company only through divestment.

Q. Did the company pursue the option of selling its interest in Hayden Units 1 and 2 as an alternative incremental environmental compliance costs?

A. Yes. To ensure that all reasonable alternate compliance approaches were pursued on behalf of PacifiCorp's customers, in March of 2014 the company initiated an open-ended Request for Expressions of Interest in Hayden Units 1 and 2, with a requested response date of April 18, 2014. To date, no expressions of interest have been received.

Q. Could PacifiCorp have transferred its full ownership rights and coal contract obligations at zero cost to PSCo as Sierra Club alleges?[46]

A. No.

Q. Sierra Club also claims that the company never considered the economics of the SCR installation at Hayden Unit 2.[47] Is this true?

A. No. The company considered the same factors for SCR installation at both Hayden units. Given the similarity of the Hayden Units 1 and 2 SCR projects and the overarching limitations of the Participation Agreement, a separate economic analysis of the Hayden Unit 2 SCR project was unnecessary.

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[46] Fisher Direct at 42.
[47] Fisher Direct at 42.

Q. Has any other commission addressed Sierra Club's arguments related to the prudence of the Hayden Unit 1 SCR investment?

A. Yes. Sierra Club raised these same arguments before the Wyoming commission. The Wyoming commission rejected Sierra Club's argument that the company "should have either immediately divested itself of its share of Hayden Unit 1 rather than participate in the costs, or contested the installation of SCR through arbitration."[48] The Wyoming commission noted, among other things, that the company "pursued selling its interest in Hayden Unit 1 as an alternative to incurring environmental compliance costs, including an open-ended Request for Expressions of Interest in Hayden Units 1 and 2" but that the company "did not receive any responses to the Request for Expressions of Interest."[49] The commission found my testimony in that case, which is substantively the same as here, persuasive and concluded that the Hayden investment was prudent.[50]

Q. What is your conclusion regarding the Hayden Units 1 and 2 SCR projects included for review in this docket?

A. The company prudently reviewed and pursued its obligations, rights, and options under the Participation Agreement for this partially owned coal-fueled resource as they pertain to the subject environmental compliance projects. The terms, conditions, and remedies of the Participation Agreement ultimately dictated the company's

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[48] *In the Matter of Rocky Mountain Power Company Request for Approval of a General Rate Increase*, WYPSC Docket No. 20000-446-ER-14 (Record No. 13816), Findings of Fact, Conclusions of Law, Decision, and Order at ¶ 82 (Dec. 30, 2014).
[49] *Id.* at ¶ 80.
[50] *Id.* at ¶ 182.

participation in the Hayden Units 1 and 2 SCR projects, which were necessary to maintain compliance of these resources with legally enforceable requirements.

VII. RESPONSE TO SIERRA CLUB'S CHALLENGE TO CRAIG SCR INVESTMENT

Q. Sierra Club claims that the company was imprudent for not doing more to stop the installation of SCRs at Craig Unit 2.[51] How do you respond?

A. I disagree. As I described in my direct testimony, the company is a minority owner in the plant and therefore could not, on its own, stop installation of the SCRs. Once the decision was made by the majority of the owners, the company's only real option was to litigate. The company does not, however, take lightly the decision to sue its co-owners. Therefore, the company would have resorted to litigation only if there was a reasonable likelihood of success. As I described in my direct testimony, the company's analysis concluded that litigation would not have prevented the installation of the SCRs. The company concluded that a reasonable utility would not unnecessarily sue its plant partners to simply make a statement.

Q. Why was the early retirement scenario for Craig Unit 2 SCR analysis referred to as a "hypothetical" analysis in your direct testimony?

A. Based on the Participation Agreement, PacifiCorp cannot unilaterally change any decisions that other joint owners have voted to support if they make up the majority vote. Thus, for the Craig Unit 2 SCR analysis that was performed, the early retirement assumption was for analysis purposes only, and was a "hypothetical" scenario because of the limitations under the Participation Agreement. I have included relevant sections of the Participation Agreement as Confidential Exhibit No.

[51] Fisher Direct at 36.

PAC/1607.

Q. Sierra Club claims that the company never assessed Tri-State's economic analysis of the SCR project.[52] Did PacifiCorp have the ability or obligation to assess Tri-State's Craig Unit 2 SCR customer benefit analysis?

A. No. Tri-State's analysis is confidential to Tri-State and PacifiCorp has no legal right to receive and review Tri-State or other companies' proprietary analysis.

Q. Does PacifiCorp maintain its responsibility to customers for generation resources where PacifiCorp has a minority share?

A. Yes. With respect the Craig Units 1 and 2 in particular, PacifiCorp has maintained and exercised its responsibility by working to ensure that the co-owners fully consider the positions of all co-owners when voting on major capital expenditures under the Participation Agreement. While the company was not able to persuade the co-owners to support its position on the Craig Unit 2 SCR, the 2016 decision by the co-owners to pursue an alternative compliance path for Craig Unit 1 incorporating retirement by December 31, 2025, or conversion to a gas-fueled unit in lieu of SCR installation resulted in a successful outcome for all parties. The Craig Unit 1 settlement was recently approved by the EPA effective August 6, 2018.[53]

Q. Sierra Club also claims that PacifiCorp could have simply withdrawn from the Participation Agreement once the other co-owners chose to install SCRs.[54] Was that a viable option?

A. No. The Participation Agreement for the Craig units does not permit PacifiCorp to

[52] Fisher Direct at 36. Tri-State is a co-owner and the operating agent of Craig Units 1 and 2.
[53] Federal Register July 5, 2015 https://www.gpo.gov/fdsys/pkg/FR-2018-07-05/pdf/2018-14387.pdf.
[54] Fisher Direct at 36.

unilaterally withdraw.

Q. Does this conclude your rebuttal testimony?

A. Yes.