BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 374

In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision.	))))))	OREGON CITIZENS' UTILITY BOARD'S CROSS-EXAMINATION STATEMENT, EXHIBITS, & ACTIVE PARTICIPANT LIST

I. CROSS EXAMINATION STATEMENT

Pursuant to Administrative Law Judge (ALJ) Alison Lackey's August 31st, 2020 Ruling, the Oregon Citizens' Utility Board (CUB) submits this notice of intent to cross-examine witnesses at the September 9-10, 2020 hearing in the above-referenced proceeding. CUB reserves the right to conduct follow-up cross examination of any witnesses that are cross-examined by other parties, or the ALJ. CUB currently wishes to cross-examine the following witnesses. Any questions posed to witnesses by CUB at the hearing will be conducted by its General Counsel, Michael P. Goetz. CUB does not intend to cross-examine witnesses on confidential information. Materials to be referenced for Mr. Link will be limited to his testimony and CUB/505. CUB will update its reference materials as necessary.

Witness	Party	Amount of Time Requested	Subject
Rick Link	PacifiCorp	20 minutes	Jim Bridger SCRs
James Owen	PacifiCorp	20 minutes	Jim Bridger SCRs

II. CROSS EXAMINATION AND ADDITIONAL EXHIBITS

CUB submits the following Cross Examination and Additional Exhibits for inclusion in the administrative record in this proceeding. These Exhibits are attached to this filing.

- CUB/500 – *Alternative Regulatory Methods and Firm Efficiency: Stochastic Frontier Evidence from the U.S. Electricity Industry* – Dr. Christopher Knittel, MIT.
- CUB/501 – PacifiCorp Response to CUB Data Request 18 – Annual Wheeling Revenue Deferral Amounts on an Oregon-Allocated Basis.
- CUB/502 – PacifiCorp Response to CUB Data Request 19 – Annual Wheeling Revenues in Base Rates on an Oregon-Allocated Basis.
- CUB/503 – Redacted Direct Testimony Regarding Operational Necessity – Installation of Selective Catalytic Reduction Systems of PacifiCorp Witness Chad A. Teply in California Public General Rate Case Proceeding, Filed April 2018.
- CUB/504 – Redacted Rebuttal Testimony Regarding Operational Necessity – Installation of Selective Catalytic Reduction Systems of PacifiCorp Witness Chad A. in California Public Utilities Commission General Rate Case Proceeding, Filed November 2018.
- CUB/505 – Redacted Direct Testimony of PacifiCorp Witness Rick T. Link in Wyoming Public Service Commission Proceeding, Filed August 2012.
- CUB/506 – Redacted Direct Testimony Regarding Economic Analysis – Installation of Selective Catalytic Reduction Systems and Wind Repowering of PacifiCorp Witness Rick T. Link in California Public Utilities Commission General Rate Case Proceeding, Filed April 2018.
- CUB/507 – Redacted Rebuttal Testimony Regarding Economic Analysis –

Installation of Selective Catalytic Reduction Systems and Wind Repowering of PacifiCorp Witness Rick T. Link in California Public Utilities Commission General Rate Case Proceeding, Filed November 2018.

- CUB/508 – Federal Register, Vol. 78, No. 111, Monday, June 10, 2013. Part III. Environmental Protection Agency, Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze; Proposed Rule. Codified at 40 CFR Part 52.

III. ACTIVE PARTICIPANT LIST

Michael P. Goetz, counsel for CUB, will be an active participant for the purpose of cross examining the PacifiCorp witnesses identified above, asking any follow-up questions of other parties' witnesses, and defending questions of CUB witness Bob Jenks. Mr. Goetz is available before 10:00AM and after 12:00PM on September 11, 2020 should additional time be needed. Mr. Goetz will be a participant in the confidential session and is qualified under the PO and MPO in this proceeding. His phone number is (630) 347-5053.

Bob Jenks, witness for CUB, will also be an active participant should another party, the ALJ, or the Commissioners reserve time to cross examine him. Mr. Jenks is also available before 10:00AM and after 12:00PM on September 11, 2020. Mr. Jenks will also be a participant in the confidential session and is qualified under the PO and MPO. His phone number is (503) 753-4190.

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Dated this 2nd day of September 2020.

Respectfully submitted,

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ALTERNATIVE REGULATORY METHODS AND FIRM EFFICIENCY: STOCHASTIC FRONTIER EVIDENCE FROM THE U.S. ELECTRICITY INDUSTRY

Christopher R. Knittel*

Abstract—The use of incentive regulation and other alternative regulatory programs in U.S. electricity markets has grown during the past two decades. Within a stochastic frontier framework, I investigate the effect of individual programs on the technical efficiency of a large set of coal and natural gas generation units. I find that those programs tied directly to generator performance and those that modify traditional fuel cost pass-through programs, to provide a greater incentive to reduce fuel costs, are associated with greater efficiency levels. Other programs have no statistical association with efficiency levels.

I. Introduction

THE method of regulating investor-owned electricity utilities (IOUs) has undergone a tremendous amount of change in recent years. Although a number of states are now moving toward a system that is centered around a competitive market for electricity generation, the vast majority of IOUs still operate under a traditional regulatory environment. Furthermore, even in a deregulated environment, certain sectors, such as the transmission and distribution of electricity, will remain regulated. Therefore, many regulators are faced with designing effective regulatory methods within the confines of traditional regulatory oversight structures. In recent years, there has been an increase in the number of options available within the traditional regulatory framework. Specifically, the use of "incentive regulation" programs and other alternatives to rate-of-return regulation in U.S. electricity markets has grown during the past two decades. Given the wide array of programs that have been used to achieve similar goals, state regulators are faced with deciding which type of program is most effective.

In this paper, I analyze the effect of alternative regulatory programs on technical efficiency at the plant and firm level for U.S. coal and natural gas generation units. Within a stochastic frontier setting, the distribution of inefficiency is allowed to be a function of the regulatory environment under which the plant operates. The results suggest that certain alternative regulatory methods, such as those directly tied to thermal efficiency and the availability of units, increase observed technical efficiency. Furthermore, I find that those programs that modify traditional fuel cost pass-through programs such that the firm is held accountable for a portion of fuel cost overruns, and at the same time is able to capture some of the rents from cost savings, are associated with higher efficiency levels relative to the more traditional fuel cost programs. Finally, those programs that allow a firm's rate of return to fluctuate inside a range, before a rate hearing is initiated, those designed to decouple revenues from profits to increase the success of demand reduction programs and price-cap programs have no statistically significant association with efficiency levels.

The remainder of the paper is organized as follows: section II provides a brief discussion of the variety of programs that have been utilized. Section III discusses the data used in the study and the econometric methodology. The results of the base case specifications are presented in section IV. Section V expands on these specifications, and section VI concludes the paper.

II. Alternative Regulatory Methods

In this section, I briefly describe the programs that either seek to, or may, alter productive efficiency.[1]

A. *Direct Efficiency Reward Programs*

A number of regulatory commissions have adopted programs that are tied directly to generator performance. Thermal efficiency programs provide the firm with an incentive to reduce the heat rate of generation facilities.[2] Often these programs set price/profits conditional on a firm-level average heat rate. Therefore, if the firm operates at a lower heat rate (implying that it operates more efficiently than the guideline), the firm retains the benefits from the heightened efficiency level. Given a fixed price, the firm has the incentive to operate at the optimal efficiency level. Similar programs have also been used for nuclear units focusing on the capacity factor.

Related to heat-rate programs are Equivalent Availability Factor (EAF) programs, which focus on increasing the percentage of the time that a plant is available to produce electricity, whether or not it is called upon to actually do so. These programs provide a disincentive for firms to keep plants offline, thereby reducing total generation costs if low-cost generators would have been held offline, as well as potentially increasing the reliability of the network. For example, availability programs have been designed such

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[1] For a more comprehensive review of alternative regulatory programs and their potential impact on productive efficiency in the electricity industry, see Joskow and Schmalensee (1986).

[2] The heat rate refers to the amount of energy wasted in the form of heat in the production process. Therefore, the lower the heat rate, the more efficient the plant.

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TABLE 1.—USE OF INCENTIVE REGULATION BY STATE THROUGH 1996

Program	States
ROR Range Program	AL, MS
EAF Program	AZ, DE, FL, MD, MA, NH, VA (via FERC)†
Heat-Rate Program	FL, HI, MA, MD, VA (via FERC)
Price-Cap/Benchmark	CA, IL, ME, NY
Modified Fuel Cost Pass-Through	CA, KS, IL, NY, OH, OR, UT, VA (via FERC), WI
Revenue-Decoupling	CA, CO, CT, FL, ME, NY, WA

† The FERC oversaw the programs for the Virginia plants.

that, if the set of plants' availability over the course of a year is above a certain threshold, the firm is rewarded for the costs savings, whereas, if it falls below a certain threshold, the firm's profits are reduced.[3]

Table 1 lists the states that have adopted heat-rate and EAF programs. As the table suggests, these two programs are typically combined. Indeed, in the data used in this study, there are no natural gas plants that operate under only an EAF or a heat program. Therefore, it is not possible to separately identify their effect on natural gas plants.

B. *Indirect Efficiency Reward Programs*

In addition to heat-rate and EAF programs, a number of programs have been adopted that seek to correct the indirect effects of regulation. Beginning with Averch and Johnson (1962), a number of critiques have been waged against rate-of-return regulation. Averch and Johnson illustrate that, in a rate-of-return regulatory environment, because the firm's profit rate is tied to the amount of capital it employs, the firm utilizes an inefficient level of capital. A second indirect result from rate-of-return regulation is that, if regulators are active in their oversight of the firm, cost reductions may cause regulators to initiate a rate hearing, implying the end result of the cost reduction might be a lower rate of return. Price-cap regulation corrects these inefficiencies. Because price is set exogenous to the firm's behavior, the firm is the residual claimant to increases in efficiency.[4] Although price-cap regulation has been used much less in the electricity industry than in other regulated industries in the United States (such as telecommunications), public utility commissions (PUCs) have recently adopted price-cap regulation.[5]

Related to price-cap regulation are rate-of-return range programs that allow the firm's rate of return to fluctuate within a lower and upper bound before a rate hearing is prompted. Although price-cap regulation corrects these inefficiencies, if the firm's profit level becomes too high, the regulator may face pressure from consumer groups to reduce the price cap.[6] Rate-of-return range programs address this by allowing the firm's rate of return to fluctuate inside some band before a rate hearing is initiated. Therefore, as long as the firm remains within this band, the firm has an incentive to undergo efficiency increases.

In a dynamic setting, it is less clear how rate-of-return range programs will influence productive efficiency. When the actual rate of return falls to this lower bound, rates may be altered so that the firm's rate of return is increased to some intermediate level between the lower and upper bounds.[7] Therefore, the firm may have less of an incentive to produce efficiently, because the penalty from producing inefficiently is reduced. Also, the firm may choose to lower efficiency to reach this lower bound and then, once rates are increased, increase efficiency so as to earn a higher rate of return. As with price caps, rate-of-return range programs have not been extensively utilized.

Regulators have also sought to reduce the direct costs associated with rate-of-return regulation. For prices to adjust within a rate-of-return regulation framework, a rate hearing must be held. Rate hearings are a quasi-judicial process in which the firm and the regulators put forth evidence as to what the level of prices should be. These hearings can often take considerable time and resources. Therefore, during inflationary times, either firms will be forced to lose profits between rate hearings or the cost of regulation can be quite high because volatile costs require frequent rate hearings. In response to this, a number of PUCs have adopted automatic fuel cost pass-through programs that allow the firms' price to automatically adjust if input costs rise.[8]

As Joskow (1974) points out, to account for this, "virtually all" PUCs adopted automatic fuel cost pass-through programs wherein changes in fuel costs were directly passed on to the consumer without the need of a rate hearing. Although such programs are likely to reduce the need for rate hearings, the effect on efficiency may be negative because firms do not bear any of the burden from excessive fuel use.[9] To combat this disincentive, a number of PUCs

[3] EAF programs are often set at the firm level, focusing on a subset of the firm's baseload generators. In many cases, the "reward" is not tied directly to the costs savings but instead is a predetermined increase in the rate of return.

[4] Given the infrequency of rate reviews, whether the Averch and Johnson effect holds in practice is not clear. See Joskow (1974) for a more thorough discussion of this.

[5] Although only a subset of customers (for example, large manufacturing companies) are allowed to choose this benchmark rate, Illinois has also adopted benchmark regulation that produces much the same incentives as price-cap regulation. Under benchmark regulation, the firm's price is set as an average of the prices charged by firms in neighboring states. Therefore, if you are a firm in Illinois, your capital expenditures do not affect the price, and you have the incentive to produce efficiently. However, the incentives are less clear when the rates of the firms that affect your price are also dependent on your price. See Shliefer (1985) for a discussion of the theoretical issues.

[6] For price-cap regulation to be effective in correcting this disincentive, it must be credible in the sense that the regulator must be able to commit to either low or high profit draws.

[7] Typically, a rate hearing occurs if the lower bound is reached. If the regulators conclude that the increases in costs are not prudent, rates will likely remain the same.

[8] See Joskow (1974) for a more thorough discussion of these programs and their political implications.

[9] A number of authors have made this point. See, for example, Brown, Einhorn, and Vogelsang (1991).

have modified their fuel cost pass-through programs such that the firm must absorb a portion of fuel cost overruns, as well as profit from lower than expected fuel costs. For example, New York has adopted a program in which each firm's fuel costs are forecasted and 60% to 80% of any costs above those forecasted are passed through to consumers (depending on the utility). More importantly, however, if the utility's actual costs are below this forecast, the utility retains 60% to 80% of this savings.

I analyze how fuel cost pass-through programs that allow only a portion of fuel cost changes to be passed on to consumers and provide an incentive for reductions in costs affect efficiency. Given that the vast majority of PUCs have traditional fuel cost pass-through programs, the parameter estimates associated with these programs are more accurately viewed as how these programs affect efficiency relative to the traditional fuel cost pass-through programs that allow all of the fuel cost changes to be passed on to consumers rather than no fuel cost programs whatsoever.[10]

Revenue Decoupling Programs: Revenue-decoupling programs are a byproduct of regulators' desire to reduce the amount of electricity consumed. To provide an incentive for electricity users to reduce their demand, a number of PUCs have adopted rebate programs that subsidize the purchase of more-efficient appliances, such as refrigerators. In many cases, the IOUs operate these programs. However, if the marginal price paid by consumers exceeds the marginal cost of generation, then IOUs have an incentive to limit the success of rebate programs because the result of a demand reduction is lower profits. To combat this incentive, revenue-decoupling programs have been adopted. Revenue-decoupling programs are designed such that, after some level of sales, IOUs rebate the difference between the marginal price and the marginal cost to the consumers. Therefore, the IOU no longer profits from sales above this threshold.

One drawback of these programs is that, because the firm must rebate the difference between price and costs, the firm no longer has an incentive to minimize costs. As long as the firm keeps the marginal costs below the marginal price, the firm does not benefit from producing efficiently. Therefore, although revenue-decoupling programs may reduce the incentive for IOUs to resist demand-side management programs, they may also reduce efficiency.

[10] Baron and De Bondt (1979) report that all but five states have adopted fuel adjustment programs as of 1979. (They may had adopted programs after 1979.) Two of these five states utilized a modified fuel cost program in my sample. Therefore, at worst, the remaining three states (Montana, Washington, and Wyoming) are categorized as having fuel cost programs when indeed they do not. For the coal generator data set, generation in these three states account for only 0.36% of the total output. For the natural gas data set, there are no generators in these three states. Therefore, the bias in the coal plant specifications from their possible missclassification is likely to be small, and there will not be any bias for the natural gas results.

III. Empirical Investigation

The use of such a wide array of alternative programs brings up a number of questions about their effect on firm behavior. The most obvious question is whether programs designed to increase generator efficiency meet this goal. To address this question, I estimate a stochastic frontier model that allows the distribution of inefficiency to depend on the generator's regulatory environment.

Analyses of the level of inefficiency in the electricity industry are numerous. Indeed, electricity data have become somewhat of a "test case" data set for stochastic frontier and other production frontier estimation techniques.[11] However, few studies have sought to understand the sources of inefficiency. This paper is most related to Berg and Jinook (1991), which regresses the observed "managerial slack" (the error term from a least squares production frontier model) on an indicator variable that takes the value of one if the firm is regulated under some form of incentive regulation. They find that incentive regulation is associated with lower values of managerial slack.

In addition to using a different empirical methodology, this paper differs from Berg and Jinook (1991) in a number of respects. For one, the current study allows the effect of regulatory programs to differ depending on the type of programs utilized. This allows regulators to assess which programs, to date, have been most effective. Second, the paper also analyzes other alternative regulatory programs that are not specifically designed to affect efficiency, but nevertheless may have an impact (for example, fuel cost pass-through programs). Thirdly, the data used in this study cover a longer time period allowing me to analyze the effect of newer price-cap regulatory programs. Finally, this paper uses plant-level data separated by fuel type, rather than firm-level data.

This study is also related to Joskow and Schmalensee (1987), which analyzes the effect of plant attributes on coal plant thermal efficiency and availability. Estimating two different models, they regress the plant's annual thermal efficiency level and the percentage of time that the plant was available for operation on the unit's vintage, scale, operating practices (for example, if the plant is used for base-load demand), and coal quality. One use for their analysis is to use these "conditional" heat rates and availability measures in the design of regulatory programs such as those that are based on heat rates and plant availability. This differs from the present analysis in that here I am concerned with whether such programs alter firm behavior.

A. *Econometric Framework*

Estimating the effect of alternative regulatory programs on efficiency levels requires the estimation of a production frontier. Econometric estimation of production frontiers that

[11] See, for example, Greene (1990), Ray and Mukherjee (1995), and Kim (1998).

allow for the existence of inefficiency, known as *stochastic frontier analysis,* began with Aigner, Lovell, and Schmidt (1977), Meeusen and van den Broeck (1977), and Battese and Corra (1977). The technique assumes that firms must produce below some deterministic production frontier. However, because of the stochastic nature of variables such as weather, other acts of nature and the presence of unobserved variables, at times a firm may produce below or in excess of this production frontier. This implies that there will be random deviations around the deterministic frontier.

To account for this, stochastic frontier analysis assumes that, to the econometrician, there are two unknown random variables associated with the error term.[12] The first characterizes the randomness in the production process and thus takes on both positive and negative values, and the second characterizes the possibility that the firm is operating inefficiently and thus takes on only negative values. A typical specification is as follows:

$$\ln f_{it} = \ln f(x_{it}) + v_{it} + \eta_{it} \tag{1}$$

where f_{it} represents output for plant i at time t,
$f(x_{it})$ is the deterministic production frontier,
x_{it} is the vector of inputs for plant i at time t,
v_{it} is a mean zero error term and,
η_{it} is a nonpositive random variable reflecting inefficiency for plant i at time t.

This method differs from ordinary least squares by the inclusion of the second error term, η_{it}. If all firms produce efficiently, then OLS yields consistent estimates of all the production frontier parameters. However, if inefficiency is present, the OLS intercept is biased, whereas the remaining parameters are still consistent. Besides yielding an unbiased estimate of the intercept, stochastic frontier analysis has at least two advantages over OLS. First, stochastic frontier analysis allows one to obtain estimates of the mean level of inefficiency present in the data. OLS is incapable of this because a measurement of the mean level of inefficiency requires a consistent estimate of the intercept as well as the distributional properties of both the two-sided error term and the "inefficiency" error term. Second, stochastic frontier analysis allows one to obtain estimates of the variance in inefficiency, which would allow policymakers to measure the extent to which efficiency levels vary among firms.

To estimate the model, parametric assumptions must be made regarding the distributions of η_{it} and v_{it}, as well as the assumed functional form of $\ln f(x_{it})$. v_{it} is assumed to be drawn from a normal distribution with mean zero and variance σ_v^2, whereas η_{it} is assumed to be drawn from a truncated (at zero) normal distribution where the nontruncated distribution is $N(\mu, \sigma_\eta)$. To test whether efficiency levels depend on the regulatory environment, I model μ as containing both a deterministic component and a component that depends on the regulatory environment under which the firm operates.[13] Formally, μ is modeled as

$$\mu = \mu_o + R_{eaf}D_{eaf} + R_{hr}D_{hr} + R_{ror}D_{ror} + R_{cap}D_{cap} + R_{fuel}D_{fuel} + R_{revdec}D_{revdec}, \tag{2}$$

where μ_o represents the mean of the untruncated distribution for plants that do not operate under any of the modeled regulatory programs, D_j is an indicator variable equal to one if the plant operates under the program j (see table 2 for their descriptions), and R_j is the parameter associated with program j. In particular, R_j measures the effect that program j has on the mean of the "inefficiency distribution" prior to truncation. If $R_j > 0$, then the estimates imply that inefficiency is reduced because, on average, the plants operating under program j produce more output given an equal amount of inputs.

Finally, I assume that $f(x_i)$ takes the form of a modified Cobb-Douglas production frontier. In their study on U.S. coal plants, Joskow and Schmalensee (1987) find that the plant's vintage significantly influence thermal efficiency and reliability, both of which would affect the production frontier of plants. Therefore, I augment the Cobb-Douglas production frontier to control for the vintage of the plant, including $g(Vintage, \gamma)$, which is defined as

$$\ln g(Vintage, \gamma) = \gamma_1 \ln Vintage + \gamma_2(\ln Vintage)^2,$$

where *Vintage* is the year in which the plant was built minus 1943 for coal plants and 1941 for gas plants (the year of the earliest plant in the data set) and γ is a vector of unknown parameters. Therefore, output is governed by

TABLE 2.—ALTERNATIVE REGULATORY PROGRAMS ANALYZED

Variable	Description
D_{eaf}	Equal to 1 if the plant operates under a program that rewards for plant availability levels.
D_{hr}	Equal to 1 if the plant operates under a program that rewards for lower heat-rate levels.
D_{ror}	Equal to 1 if the firm owning the plant operates under a program that allows the rate of return of the IOU to fluctuate inside given range.
D_{cap}	Equal to 1 if the firm owning the plant is regulated via either price caps or benchmark regulation.
D_{fuel}	Equal to 1 if the firm owning the plant operates under a program that allows only a partial pass-through of excessive fuel costs and provides incentive for reducing fuel costs.
D_{revdec}	Equal to 1 if the firm owning the plant operates under a program that, after some level of sales, decouples revenues.

[12] See Kumbhakar and Lovell (2000) for a nice discussion of stochastic frontier techniques.

[13] A number of other papers have utilized this method. See, for example, Kumbhakar, Ghosh, and McGuckin (1991), Battese and Coelli (1995), Frame and Coelli (2001), and Morrison-Paul, Johnston, and Frengley (2000). Stevenson (1980) was the first to derive the likelihood function for the case in which the distribution of inefficiency has a nonzero mean, μ. See Kumbhakar et al. (1991) and Battese and Coelli (1995) for the derivation of the likelihood function that specifies μ to be a function of the data and unknown parameters.

$$\ln y_i = \ln \beta + \alpha_K \ln K_i + \alpha_L \ln L_i + \alpha_C \ln Coal_i + \alpha_O \ln Oil_i + \gamma_1 \ln Vintage + \gamma_2(\ln Vintage)^2 + v_i + \eta_i \quad (3)$$

where K_i is the level of capital employed, L_i is the level of labor, $Coal_i$ is the quantity of coal utilized, and Oil_i is the quantity of oil used. A similar specification for natural gas plants is also made.

B. *The Data*

To estimate the effect of the regulatory environment on productive efficiency, I employ an unbalanced panel data set of generator-specific outputs and inputs taken at yearly intervals. The data are from the years 1981 to 1996 for a large subset of IOU generators and were collected as part of the Federal Energy Regulatory Commissions (FERC) Form 1 data requirements. The data track yearly total production of the generators and the quantity of inputs used in the production process, as well as a variety of plant-level characteristics.

The measurement of output used is the net megawatt hours produced by the plant in a given year.[14] Labor is measured as the number of full-time equivalent employees. Two fuels are used in the operation of both coal and gas plants. For coal plants, I include the total tonnage of coal used during the year, as well as the number of barrels of oil used in the generation process. For gas plants, both the quantity of gas used, measured in million cubic feet, and the quantity of oil used, measured in numbers of barrels, are included.[15,16]

Obtaining a suitable measurement of capital is not as straightforward. Because the data are taken at an annual interval, inefficiency can manifest itself in two ways. For one, an inefficient plant may utilize more inputs to produce the same amount of output than that of an efficient plant. Second, an inefficient plant may operate less often as an efficient plant. In addition, the nature of electricity generation implies that, during certain time periods, efficient production calls for higher marginal cost units to not operate. If we were to ignore this, these "peaking" plants would appear to be inefficient. To account for this, I focus attention on base-load plants. (Base-load plants are those that are designed to continuously generate electricity.[17]) By focusing on base-load plants, the capacity of the plant, measured as the maximum sustainable output of electricity, is an accurate measurement of the capital input. Therefore, the parameter estimates measure the effect of alternative regulatory methods on inefficiency that takes the form of excess input usage and excess generator outages.[18]

Table 3 lists the summary statistics of the variables used in the study, and the data sources are described in appendix B.[19]

TABLE 3.—SUMMARY STATISTICS

Fuel Type	Variable	Mean	Std Dev	Min	Max
Coal	Megawatt hours (1000s)	4235	3919	.221	21883
	Employees (full-time)	204	155	10	1211
	Capacity (MWs)	862.7	723.3	11	3953
	Coal (1000 tons)	2053	2027	.190	35063
	Oil (1000 barrels)	669	3749	0	11569
Regulatory	ROR Range Program	.0154	—	0	1
	EAF program	.0831	—	0	1
	Heat-rate program	.0244	—	0	1
	Price-cap/benchmark	.0152	—	0	1
	Fuel cost pass-through	.1166	—	0	1
	Revenue-decoupling	.0222	—	0	1
Gas	Megawatt hours (1000s)	1750	2037	11.17	11417
	Employees (full-time)	82.84	65.74	10	819
	Capacity (MWs)	641.0	593.4	8	2295
	Gas (10000 MCF)	1859	2019	24.73	10600
	Oil (1000 barrels)	216.0	671.1	0	8336
Regulatory	ROR range program	.0021	—	0	1
	EAF and heat-rate programs†	.0641	—	0	1
	Price cap/benchmark	.0336	—	0	1
	Fuel cost pass-through	.1830	—	0	1
	Revenue-decoupling	.1966	—	0	1

† The effects of EAF and heat-rate programs are not separately identifiable for natural gas plants.

IV. Results

A. *Coal Plants*

The results of the stochastic frontier model for coal plants are reported in table 4. The estimates imply that there exist mild economies of scale in coal generation, as the sum of the α's is 1.0644, and the sum is statistically different from one.[20] The parameter estimates with respect to plant vintage suggest that newer plants are capable of generating a greater amount of electricity given input levels. The estimates with respect to the square of vintage suggests that this effect is becoming less strong.[21]

The parameter estimate of μ_o suggests that $\mu_o > 0$, implying that the modal plant, not operating under any alternative regulatory methods, produces efficiently. Figure

[14] *Net megawatts* is defined as the amount of electricity that a plant actually transmits, which differs from the amount of electricity generated because of electricity usage at the plant.

[15] The FERC Form 1 data do not report quantity of gas used in the production process, but instead the cost of the fuel. To obtain a quantity measurement, I use the average price of natural gas paid by IOUs for each state to obtain an estimate of the volume of fuel used.

[16] For coal and natural gas generation units, oil is sometimes used as a startup fuel (for heating the plant's boilers from a cooled state). Therefore, for some units, the value for the oil variable is zero. To allow for the taking of a logarithm of this variable, one is added to the quantity of oil used for each observation.

[17] The definition of base-load used is that of FERC's Form 412 data, which is based on plant characteristics.

[18] After these restrictions, the number of observations for coal units is 5,040, and the number of observations for gas plants is 951.

[19] To control for outliers and data entry errors, plants were chosen only if they produced a positive amount of electricity, employed more than ten employees, and used a positive amount of either coal or gas.

[20] The t-statistics associated with testing the null hypothesis that the sum of the coefficients equals one is 8.23.

[21] The point estimates would imply that the vintage effect would be zero in the year 2020, well outside the timespan of the data.

TABLE 4.—BASE CASE COAL PLANT RESULTS

Parameter	SF Estimates: Estimate	SF Estimates: Implied $\frac{\Delta E[\ln y]}{\Delta R_j}$	OLS Estimates: Estimate
$\ln \beta$	3.235***		2.471***
	(0.0711)		(0.0884)
α_K	0.4311***		0.4022***
	(0.0080)		(0.0092)
α_L	0.0216***		0.0290***
	(0.0075)		(0.0089)
α_C	0.6480*		0.7049***
	(0.0066)		(0.0070)
α_O	0.0069***		0.0062***
	(0.0005)		(0.0007)
ln *Vintage*	0.0674***		0.1328***
	(0.0028)		(0.0403)
(ln *Vintage*)^2	0.0278***		0.0457***
	(0.0049)		(0.0069)
μ_o	1.699***	—	—
	(0.1474)		
R_{eaf}	3.210***	0.1051	0.0577***
	(0.1377)		(0.0135)
R_{hr}	2.578***	0.0953	0.1659***
	(0.3480)		(0.0240)
R_{ror}	0.6601***	0.0397	0.1321***
	(0.7238)		(0.0259)
R_{cap}	1.542	0.2476	0.0200
	(1.336)		(0.0257)
R_{fuel}	2.476***	0.0935	0.1322***
	(0.1896)		(0.0100)
R_{revdec}	1.448	0.2199	0.1880
	(3.286)		(0.1250)
σ_v	0.1196***		—
	(0.0198)		
σ_η	0.6632***		—
	(0.0465)		

N 5,040. Asymptotic standard errors in parentheses.
*** denotes significant at the 99% confidence level.

1 plots the implied distribution of inefficiency for these firms.[22] The modal value of inefficiency is one measurement of the level of inefficiency present in the industry, but perhaps a better gauge is the mean level of inefficiency. The estimates imply that the mean of the inefficiency distribution is 0.1757. This implies that, for firms that do not operate under alternative regulatory methods, the inefficiency present reduces output, on average, by 17.57%. To get a sense of the potential savings in the industry, I compare this to the average yearly cost of a coal plant in this data set. The average reported total yearly cost for the plants in this data set is $301 million (including labor, fuel costs, and estimated land costs). An average inefficiency level of 17.57% implies that, on average, firms could reduce the level of inputs by 16.51% (17.57/1.0644) by producing efficiently. Therefore, the estimates imply an average waste of $49.70 million per plant.

This interpretation also gives a clearer picture of the impact of the alternative regulatory methods. Again, the point estimate of γ_j measures the amount that the mean of the untruncated distribution shifts with the regulatory environment; however, for many of the γ_j's, the modal value remains zero. Therefore, I also calculate the implied change in expected output from the alternative regulatory program, $\frac{\Delta E[\ln y]}{\Delta R_j}$, because this is more comparable to what one would obtain from a simple OLS regression that included the regulatory dummies on the right-hand side.[23]

The results with respect to the specific performance-based regulation programs suggest that EAF, heat-rate, and rate-of-return range are associated with an increase in efficiency. Specifically, the results suggest that, for plants that operate under EAF programs, the mode of the inefficiency distribution, prior to truncation, shifts by 3.21 (obviously remaining zero). The estimates imply that the change in expected output when moving from no program to an EAF program is 10.51%.

The modal firm that operates under heat-rate programs also produces efficiently. In addition, heat-rate programs are associated with a 9.53% increase in expected output, and rate-of-return range programs are associated with a 3.97% increase in expected output.

The results with respect to the "modified" fuel pass-through programs imply that providing some incentive to keep fuel costs below expectations increases efficiency. Again, the suitable base-line is traditional fuel cost pass-through programs. Thus, these results imply that these traditional programs reduce efficiency levels. Therefore, although fuel pass-through programs may reduce the need for costly rate hearings, they may also create an indifference to efficient use of inputs for the firm. In particular, plants that operate under "modified" fuel pass-through programs are associated with 9.35% more output for a given amount of inputs.

Finally, price-cap/benchmark and revenue-decoupling programs do not appear to have a statistically significant effect on efficiency. It was postulated that revenue-decoupling programs may reduce the incentives for cost minimization because firms are required to rebate any cost savings to the consumer. However, because revenue-decoupling programs are used in conjunction with demand-reduction programs, they take effect only after some level of demand. Because we have analyzed base-load units here, these units may not be affected, as the results indicate.

Figure 1 plots the implied distribution of inefficiency under the programs that have a statistically significant effect on efficiency. For programs that increase efficiency, we see that the distributions drop off more rapidly.

Comparison with OLS Estimates: Table 4 also reports the results from estimating the following equation via OLS:

[22] Recall for the truncated normal to integrate to one, it must be reweighted by the cumulative distribution of the associated untruncated normal distribution.

[23] Because the distribution is not symmetric, an assumption must be made regarding what other alternative programs the plant operates under. I make the simple assumption that the plant operates only under the program in question.

$$\ln y_i = \ln \beta + \alpha_K \ln K_i + \alpha_L \ln L_i + \alpha_C \ln Coal_i + \alpha_O \ln Oil_i + \gamma_1 \ln Vintage + \gamma_2 (\ln Vintage)^2 + R_{eaf} D_{eaf} + R_{hr} D_{hr} + R_{ror} D_{ror} + R_{cap} D_{cap} + R_{fuel} D_{fuel} + R_{revdec} D_{revdec} + e_i. \quad (4)$$

The OLS estimates for the production frontier are similar to those of the stochastic frontier model except for the intercept, which appears to be biased downward. This is what we would expect because OLS yields consistent estimates of all parameters but the intercept. Under the OLS model, the R_j's estimate the percentage change in expected output for firms that operate under the alternative regulatory program, j.

Comparing these to the implied $\frac{\Delta E[\ln y]}{\Delta R_j}$ suggests that the SF and OLS estimates largely agree on the sign and statistical significance of the regulatory programs. It is difficult to determine whether the OLS estimates show a systematic bias compared to the $\frac{\Delta E[\ln y]}{\Delta R_j}$ estimates because, when determining $\frac{\Delta E[\ln y]}{\Delta R_j}$, we are forced to make certain assumptions regarding what other regulatory programs the plant operates under. The mean difference between the absolute value of $\frac{\Delta E[\ln y]}{\Delta R_j}$ and the OLS coefficient is 0.0175; however, this is not likely to be statistically significant. To determine whether there is a systematic difference, I simulated a number of Monte Carlo experiments to estimate the bias. The results, under a variety of specifications, could not reject that the OLS coefficients were unbiased.[24]

B. Gas Plants

The results for the natural gas plants are listed in table 5. The estimates are similar in nature to those of the coal plants. In the case of natural gas plants, the estimates imply that there exist constant returns to scale, as the sum of the α's is 1.0063 and is not statistically different from one. Interestingly, the results suggest that the plant's vintage does not have as important an effect on the production frontier as for coal plants.

As with the coal plants, the modal value of inefficiency is zero for plants not operating under alternative regulatory programs. Unlike the coal plants, however, the gas plant results suggest that little inefficiency is present, with the mean level of inefficiency for firms not operating under alternative regulatory programs being 5.37%, far lower than that for coal plants. One potential reason for this is that the degree of environmental regulation for coal plants is much more heterogeneous across states. Therefore, the coal plant results may be capturing this heterogeneity and making some plants appear inefficient.[25]

TABLE 5.—BASE CASE GAS PLANT RESULTS

Parameter	SF Estimates: Estimate	SF Estimates: Implied $\frac{\Delta E[\ln y]}{\Delta R_j}$	OLS Estimates: Estimate
$\ln \beta$	2.341***		2.190***
	(0.0621)		(0.0027)
α_K	0.4092***		0.4126***
	(0.0260)		(0.0269)
α_L	0.0861***		0.0846***
	(0.0128)		(0.0276)
α_G	0.5267***		0.5254***
	(0.0079)		(0.0223)
α_O	0.0048		0.0052**
	(0.0029)		(0.0026)
ln *Vintage*	0.1188		0.1139
	(0.1904)		(0.0782)
(ln *Vintage*)^2	0.0040		0.0028
	(0.0036)		(0.0179)
μ_o	0.0396***	—	—
	(0.0089)		
R_{eaf} & R_{hr}	0.0928**	0.0185	0.1173***
	(0.0512)		(0.0314)
R_{ror}	0.3931*	0.3000	0.3382*
	(0.2340)		(0.2076)
R_{cap}	0.1971	0.1095	0.1680
	(0.1852)		(0.1462)
R_{fuel}	0.0667*	0.0144	0.0357***
	(0.0404)		(0.0120)
R_{revdec}	0.1869***	0.1007	0.1178***
	(0.0546)		(0.0319)
σ_v	0.3023***		—
	(0.0201)		
σ_η	0.0829***		—
	(0.0387)		

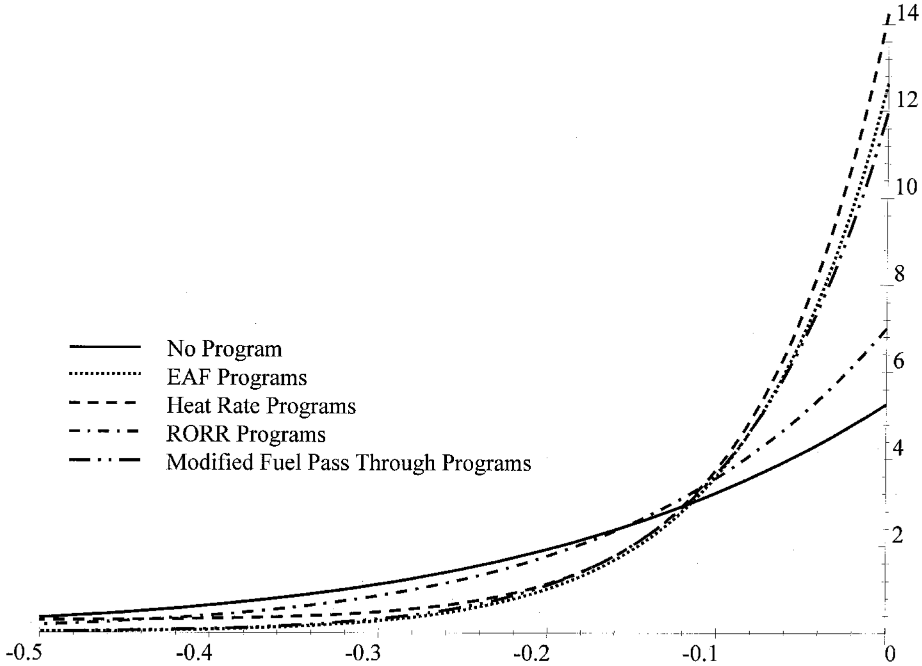
N 951. Asymptotic standard errors in parentheses.
*** denotes significant at the 99% confidence level.
** denotes significant at the 95% confidence level.
* denotes significant at the 90% confidence level.

As with the coal plant specification, the results suggest that, although certain programs provide a heightened incentive to produce efficiently, others may reduce this incentive. Because the maximum benefit from alternative regulatory methods is 5.37%, the marginal impact of alternative regulatory programs will be smaller than those implied by the coal plant estimates. The parameter estimates associated with five programs are statistically significant at conventional levels. Specifically, the results suggest that plants operating under heat-rate and EAF programs are statistically significantly more efficient than those that do not, on average, producing 1.85% more output. As with the coal

[24] I simulated six different models each with one independent variable and one determinant of inefficiency (an indicator variable), so that explicit assumptions regarding the level of other factors were not needed. I specified two values of μ_o (−0.08 and 0.08) and specified μ_1 as −0.1, 0, 0.1. I drew 1,000 samples of 300 observations. In each specification, I could not reject that the coefficient from the OLS specification equaled $\frac{\Delta E[\ln y]}{\Delta R}$.

[25] One possible consequence of this outcome is that, if the incidence of environmental regulation is correlated with alternative regulation programs, then the results with respect to alternative regulatory programs would be biased. However, because the parameters associated with the individual programs in the natural gas specification mirror those of the coal plant results, and the effect of environmental regulation on natural gas plants is more homogenous, this does not appear to be the case.

FIGURE 1.—IMPLIED DISTRIBUTIONS OF INEFFICIENCY FOR COAL PLANTS



specification, the parameter estimate associated with modified fuel pass-through programs suggest that traditional programs reduce efficiency. The implied percentage change in output from adopting a fuel cost pass-through program that provides some incentive to reduce fuel costs is 1.44%. Revenue-decoupling programs are associated with a reduction in output of 10.07%. In addition, the estimates suggest that the modal firm operating under revenue-decoupling programs operates inefficiently. Rate-of-return range programs are associated with a reduction in output, estimated at 30%; however, the standard error is quite large, and the parameter is only marginally significant.

Comparing the gas plants estimates to those of the coal plants, their signs and level of statistical significance agree on all but rate-of-return range programs. In the coal plant specification, rate-of-return range programs are associated with a statistically significant increase in output, whereas in the gas plant specification the point estimate is negative and insignificant. With this in mind, caution should be taken when attempting to derive policy implications with respect to rate-of-return range programs. The comparisons with respect to the OLS estimates are similar to those of the coal plant specifications. The SF and OLS, for the most part, agree on sign and level of significance.

Figures 1 and 2 emphasis that coal plants appear to be operated less efficiently than natural gas plants. Focusing on the implied distribution of inefficiency for firms not operating under alternative regulatory programs, the coal plant distribution places much more weight on values below -0.2, suggesting that a considerable portion of plants operate at below 80% of their potential.

V. Alternative Specifications

A. *Firm Level Results*

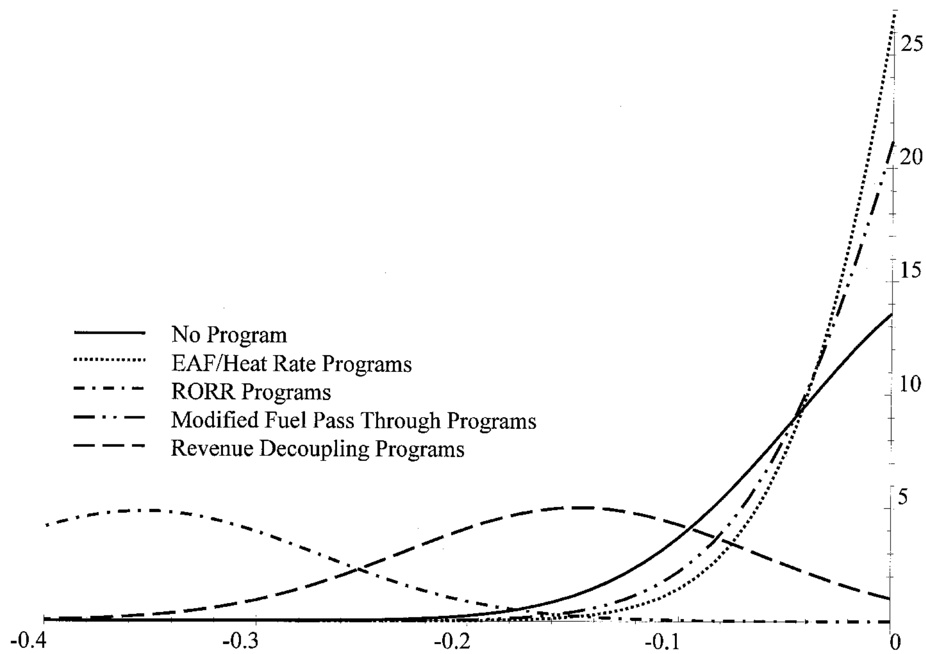
The previous specifications make the assumption that each plant-level observation is an independent observation. However, it is likely that plants operated by the same firm have similar efficiency levels. In addition, because alternative regulatory programs are adopted at the firm level, their affect on plants owned by the same firm are likely to be strongly correlated. This correlation would suggest that estimating efficiency at the plant level and treating each observation as independent would tend to understate the standard errors. To account for this, I also estimate the preceding specification using firm-level data. Specifically, I sum the level of output and inputs for each plant-level observation for a given firm and year to create a firm-level observation for each year. I then use these data to estimate the preceding stochastic frontier model.

The estimates for the coal and natural gas plants are reported in table 6, and the conclusions from above are robust to the firm-level specification.

B. *Dynamic Impact of Regimes*

The previous specifications established a correlation between alternative regulatory programs and plant- and firm-level efficiency. However, often, if not always, alternative regulatory programs are adopted to alter the behavior of the firm. If this is the case, we would expect alternative regulatory programs to be more frequently used with firms that operate inefficiently. This would imply that the preceding

FIGURE 2.—IMPLIED DISTRIBUTIONS OF INEFFICIENCY FOR GAS PLANTS



results might be biased against finding that alternative regulatory programs improve efficiency.[26]

If alternative regulatory programs are adopted as a response to inefficient production, one can still ask how the programs influence changes in efficiency without the same endogeneity issues—because the efficiency level has been "differenced" out.[27] In this section, I estimate how the regulatory environment affects the change in a firm's efficiency.

As before, let the production frontier for coal plants be (and the analogous production frontier for gas plants)

$$\begin{aligned} \ln y_t = \ln \beta &+ \alpha_K \ln K_t + \alpha_L \ln L_t + \alpha_C \ln Coal_t \\ &+ \alpha_O \ln Oil_t + \gamma_1 \ln Vintage \\ &+ \gamma_2 (\ln Vintage)^2 + \eta_t + v_t. \end{aligned} \tag{5}$$

This implies that the change in the output from one year to the next is governed by

$$\begin{aligned} \Delta \ln y_t = \alpha_K \Delta \ln K_t &+ \alpha_L \Delta \ln L_t + \alpha_C \Delta \ln Coal_t \\ &+ \alpha_O \Delta \ln Oil_t + \Delta \eta_t + \Delta v_t. \end{aligned} \tag{6}$$

As before, I assume that v_t are i.i.d. normally distributed with mean zero and standard deviation, σ_v, implying that Δv_t is mean zero with standard deviation $\sigma_{\Delta v}$. We are interested in whether $\Delta \eta_t$ is dependent on the regulatory environment the plant operates under. Unlike previous specifications, however, $\Delta \eta_t$ is no longer constrained to be nonpositive because a firm's change in efficiency may be positive or negative. Therefore, I specify $\Delta \eta_t$ as being independent of v_t (with mean $\rho_t D_t$, where D_t is the vector of alternative regulatory programs variables described previously and ρ is the associated vector of parameters) and standard deviation, $\sigma_{\Delta \eta}$.[28,29]

Table 7 reports the results from the dynamic specification. The parameter estimates with respect to the production frontier are similar to those obtained from the previous specifications. Not surprisingly, the coefficient associated with the respective fuel source are larger in the dynamic specification because the majority of output fluctuations are due to changes in fuel quantities.

The parameter estimates associated with the alternative regulatory program variables are largely consistent with the previous specifications. With respect to both coal and natural gas plants, the statistical insignificance of m_o suggests that there is no yearly change in efficiency for firms that are not operating under any alternative regulatory programs. For both coal and natural gas plants, the estimates of ρ_{eaf}

[26] If the decision to operate efficiently were a short-term one, there would not be a biased present. If this were the case, current regulatory status would not be correlated with the error term. However, if there exist frictions to becoming more efficient, the error term would be serially correlated and, because past efficiency levels would likely have an influence on current regulatory status, the current error term would be correlated with the current regulatory status, thereby biasing the coefficients.

[27] If regulatory programs are passed based on expected improvements in efficiency (not caused by the regulatory program itself), the regulatory variables would still be biased. Therefore, differencing controls for only the "levels" bias.

[28] Note that we are interested in how the current regulatory structure impacts efficiency, that is, D_{it}, and not the change in the regulatory structure, ΔD_{it}.

[29] One additional advantage to this specification is that, if the error term v_{it} contains a fixed-firm effect, it will be differenced out.

TABLE 6.—FIRM-LEVEL RESULTS

Parameter	Coal Plants Estimate		Natural Gas Plants Estimate
$\ln \beta$	4.146***		0.1119
	(0.0953)		(0.3758)
α_K	0.4636***		0.3901***
	(0.0146)		(0.0370)
α_L	0.0273***		0.1547***
	(0.0115)		(0.0287)
α_C/α_G	0.5475***		0.7647***
	(0.0161)		(0.0344)
α_O	0.0016**		0.0003
	(0.0008)		(0.0029)
μ_o	2.123		2.411***
	(0.1437)		(1.066)
R_{eaf}	0.7735***		
	(0.0946)	R_{eaf} & R_{hr}	0.7671***
R_{hr}	3.351***		(.0746)
	(0.3455)		
R_{ror}	1.043***		1.904
	(0.3825)		(0.4332)
R_{cap}	1.444		0.3418
	(1.447)		(0.5997)
R_{fuel}	0.2561***		0.1218**
	(0.0703)		(0.0563)
R_{revdec}	2.291		0.5800
	(1.800)		(0.3655)
σ_v	0.1125***		0.1725***
	(0.0201)		(0.0403)
σ_η	0.7598***		0.5556***
	(0.0380)		(0.0201)
	$N = 2{,}401$		$N = 402$

Asymptotic standard errors in parentheses.
*** denotes significant at the 99% confidence level.
** denotes significant at the 95% confidence level.
* denotes significant at the 90% confidence level.

TABLE 7.—DYNAMIC MODEL RESULTS FOR COAL AND GAS PLANTS

	OLS Estimates		
Parameter	Coal Results		Gas Results
α_K	0.1738***		0.4106***
	(0.0214)		(0.0557)
α_L	0.0192		0.0315
	(0.0195)		(0.0832)
α_C/α_G	0.8024***		0.5923***
	(0.0091)		(0.0371)
α_O	0.0049		0.0107**
	(0.0161)		(0.0050)
m_o	0.0003		0.0107***
	(0.0026)		(0.0029)
ρ_{eaf}	0.0081**		
	(0.0041)	ρ_{eaf} & ρ_{hr}	0.0222**
ρ_{hr}	0.240**		(0.0090)
	(0.0101)		
ρ_{ror}	0.0041		0.0170
	(0.0181)		(0.0244)
ρ_{cap}	0.0038		0.1164
	(0.0183)		(0.1091)
ρ_{fuel}	0.0080**		0.0094*
	(0.0039)		(0.0053)
ρ_{revdec}	0.0316		0.0976
	(0.0475)		(0.0626)
	$N = 4{,}977$		$N = 333$

Standard errors in parentheses.
*** denotes significant at the 99% confidence level.
** denotes significant at the 95% confidence level.
* denotes significant at the 90% confidence level.

suggest that firms regulated under EAF programs are associated with improvements in efficiency. For the coal plant specification, the estimates suggest that plants operating under EAF programs increase their efficiency by 0.81% per year, and the estimates for the natural gas plants suggest that EAF and heat-rate programs increase efficiency by 2.22% per year. For the coal specification, the estimates suggest that coal plants operating under heat-rate programs are associated with a 2.4% yearly increase in efficiency. This, too, is consistent with the previous results that plants and firms operating under heat-rate programs have higher efficiency levels. Also consistent with the previous results, the dynamic specification suggests that modified fuel pass-through programs lead to higher efficiency levels, leading to a yearly increase in efficiency of 0.80% for coal plants and 0.94% for gas plants.

The estimates suggest that the previous results are robust to controlling for the potential endogeneity of regulation created if alternative regulatory programs are adopted as a result of low efficiency levels.[30] As with the previous specification, the dynamic models suggest that EAF, heat-rate, and modified pass-through programs tend to increase generator efficiency.

C. *Summary of Results*

Given the number of specifications estimated, I summarize the results in table 8. For each program/specification, the sign of the coefficient is presented in the table with the level of significance. It is evident from the table that strong evidence exists showing that heat-rate and EAF programs increase the efficiency of electricity production. In addition, there is strong evidence to suggest that modified fuel pass-through programs have a positive influence relative to traditional pass-through programs.

TABLE 8.—SUMMARY OF RESULTS

	Specification					
	Plant Level		Firm Level		Dynamic	
Program	Coal	Gas	Coal	Gas	Coal	Gas
EAF	+***	+***	+***	+***	+**	+**
Heat-rate†	+***	+***	+***	+***	+**	+**
Rate-of-return	+***	*	+***		+	
Price cap			+	+	+	
Fuel pass-through	+***	+*	+***	+**	+**	+*
Revenue-decoupling		***	+	+		+

† Recall that, for the natural gas specifications, the EAF and H-R impacts are not separately identifiable.
*** denotes significant at the 99% confidence level.
** denotes significant at the 95% confidence level.
* denotes significant at the 90% confidence level.

[30] This specification constrains the effect on changes in efficiency to be independent of the time that the program has been in place. It should be noted that, in practice, it is likely that programs have the largest effect earlier in their lives as firms move toward the new "steady-state" efficiency level.

No other program appears to have a consistent pattern, and, therefore, caution should be taken when forming policy implications with respect to these programs.

VI. Conclusions

Despite the recent expansion of competitive markets for electricity generation, more-traditional regulatory practices are likely to continue in at least some facets of the industry. Therefore, the issue of whether alternative regulatory programs provide firms with the incentive to increase efficiency will continue to be of importance to policymakers and market analysts. In this paper, I investigate whether a variety of regulatory programs influence plant-level efficiency and the change in plant-level efficiency. The empirical results imply that heat-rate and availability programs likely increase plant-level efficiency. In addition, modifying fuel cost pass-through programs such that there is both some accountability for the firm for fuel cost overruns and some incentive mechanism that allows the firm to capture a portion of the rents from keeping costs in check is superior to retaining traditional fuel cost programs.

The policy implications of this study are clear. Regulators must be aware of the indirect effects of regulatory programs (such as traditional fuel cost programs) and design them appropriately. As they have an obligation to their shareholders, IOUs are profit-maximizing entities, and changes in the regulatory environment that are designed for specific goals will affect the incentives of IOUs in other facets of business. The results suggest that programs that are based directly on generator performance outperform those that seek to provide indirect incentives for producing efficiently.

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APPENDIX A: DATA SOURCES

Data on the level of output and inputs for each plant were taken from FERC Form 1 data. Output is the net megawatt hours produced from the plant during the previous year. The level of capital is the capacity rating of the plant, and the level of labor is the average number of full-time employees working at the plant during the given year. For coal plants, there are two types of fuel used in the production process: coal (measured as total tons of coal utilized) and oil (measured as the number of barrels of oil used). Data on the average natural gas price paid by IOUs were collected from the Energy Information Administration's *Natural Gas Monthly* for their respective years. The bulk of the data on the status of the regulatory environment were collected from *Incentive Regulation in the Electric Utility Industry*. These data were supplemented with listings in Joskow and Schmalensee (1986) and Comnes, Greene, and Hill (1995). The data on the average price for natural gas were obtained from the Energy Information Administration's *Historical Natural Gas Annual 1930 through 1997,* and collected from their Web site.

UE 374/PacifiCorp
August 31, 2020
CUB Data Request 18

CUB Data Request 18

Please provide the total amount, on an Oregon allocated basis, that was booked to the Company's Wheeling Revenue deferral for each year since PacifiCorp's last Oregon general rate case.

Response to CUB Data Request 18

Please refer to the table below for Oregon-allocated wheeling revenue deferrals (excluding interest and amortization) recorded for calendar years 2013 through 2019.

Calendar Year	Wheeling Revenue OR Allocated
2013	$ (2,220,862.58)
2014	(3,442,128.71)
2015	(5,114,028.97)
2016	(7,093,959.86)
2017	(8,083,494.87)
2018	(8,436,372.39)
2019	(7,488,200.48)
Total	$ (41,879,047.86)

UE 374/PacifiCorp
August 31, 2020
CUB Data Request 19

CUB Data Request 19

Please provide the amount of Wheeling Revenue currently placed in base rates annually on an Oregon allocated basis.

Response to CUB Data Request 19

The Wheeling Revenue incorporated in base rates in the Company's last general rate case (GRC), docket UE 263, was $19,021,281 Oregon allocated. The Wheeling Revenue incorporated in base rates in the current GRC, docket UE 374, is $32,327,764 Oregon allocated.

Application No. 18-04-___
Exhibit PAC/400
Witness: Chad A. Teply

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP

REDACTED

Direct Testimony of Chad A. Teply

Operational Necessity

Installation of Selective Catalytic Reduction Systems

April 2018

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ATTACHED EXHIBITS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp).

A. My name is Chad A. Teply. My business address is 1407 West North Temple Street, Suite 310, Salt Lake City, Utah 84116. My present position is Senior Vice President of Strategy and Development.

I. QUALIFICATIONS

Q. Please describe your education and professional experience.

A. I have a Bachelor of Science degree in mechanical engineering from South Dakota State University. I have held positions of increasing responsibility within various Berkshire Hathaway Energy companies since November 1999. I joined PacifiCorp in February 2009 as the Vice President of Resource Development and Construction. My current responsibilities include the development and implementation of PacifiCorp's major generation resource additions, major transmission and distribution project delivery, major environmental compliance retrofit projects, and to a lesser extent generation fleet repair and replacement projects. My organization also supports the activities of PacifiCorp's integrated resource planning team.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony supports the prudence and necessity of certain major capital projects and associated costs incurred on coal-fired generation resources within the PacifiCorp generation portfolio. In particular, my testimony supports the selective catalytic reduction (SCR) systems retrofitted on Jim Bridger Units 3 and 4, Craig Unit 2, and Hayden Units 1 and 2 included in this case, all of which were installed in accordance with state and federal environmental compliance requirements for the individual units. The analysis of these projects began in 2012 to meet applicable environmental requirements in place at the time. The SCR systems reduced emissions at these units, in compliance with those requirements. The Jim Bridger Units 3 and 4 SCR system projects were placed in service in November 2015 and November 2016, the Craig Unit 2 SCR system project was placed in service in December 2017, and the Hayden Units 1 and 2 SCR system projects were placed in service in May 2015 and August 2016.

Q. Please provide a general description of the SCR system retrofits and the benefits gained from the projects.

A. The SCR system projects included in this case and described further in testimony below were required to comply with environmental laws, namely the Clean Air Act Regional Haze Rules, established by the U.S. Environmental Protection Agency (EPA) and administered by the respective state agencies in which the units reside. The SCR system results in the reduction of oxides of nitrogen (NO_X) emissions.

Q. Please provide a summary of PacifiCorp's cost to complete the SCR system retrofits.

A. The cost of the Jim Bridger Unit 3 SCR system included in this proceeding is [redacted] on a total-company basis, or approximately [redacted] on a California-allocated basis, and the cost of the Jim Bridger Unit 4 SCR system included in this proceeding is [redacted] on a total-company basis, or approximately [redacted] on a California-allocated basis. The cost of the Craig Unit 2 SCR system included in this proceeding is [redacted] on a total-company basis, or approximately [redacted] on a California-allocated basis. The cost of the Hayden Unit 1 SCR system included in this proceeding is [redacted] on a total-company basis, or approximately [redacted] on a California-allocated basis, and the cost of the Hayden Unit 2 SCR system included in this proceeding is [redacted] on a total-company basis, or approximately [redacted] on a California-allocated basis.

Q. Which other witnesses in this proceeding provide testimony regarding the prudence of the Jim Bridger SCR systems?

A. Mr. Rick T. Link (Exhibit PAC/500)provides testimony explaining the economic analysis used by PacifiCorp to support its decision to proceed with installation of the Jim Bridger Units 3 and 4 SCR systems. These capital additions are included in the existing rate base reflected in the revenue requirement incorporated in the exhibits of Ms. Shelley E. McCoy (Exhibits PAC/1100 through Exhibits PAC/1104).

III. SCR SYSTEM INVESTMENTS

Jim Bridger Units 3 and 4 SCR Systems

Q. Please describe the Jim Bridger facility.

A. The Jim Bridger facility is a 2,111 MW, four-unit mine-mouth coal-fired electrical generating facility located in Sweetwater County, Wyoming. All four units are jointly-owned by PacifiCorp and Idaho Power Company. PacifiCorp's ownership share is two-thirds of the power plant. PacifiCorp operates the Jim Bridger facility.

Q. Please provide a general description of the Jim Bridger Units 3 and 4 SCR systems.

A. The Jim Bridger Units 3 and 4 SCR systems and associated ancillary equipment for each unit serve to control oxides of nitrogen emissions. Each SCR system is comprised of: two separate reactors, with multiple catalyst levels; inlet and outlet ductwork; a shared ammonia reagent system; an economizer upgrade; structural reinforcement of the boiler, air preheater, and flue gas path ductwork and equipment; power distribution and electrical infrastructure installation and integration with the existing plant; and an extension of the existing plant-wide distributed control system. An induced draft fan upgrade and a corresponding auxiliary power system variable frequency drive insertion was also required for Unit 4 only.

Q. What was the required timeline for PacifiCorp to install the SCR systems at Jim Bridger Units 3 and 4?

A. The Clean Air Act Regional Haze Rules, the Jim Bridger facility Best Available Retrofit Technology (BART) permit issued by the state of Wyoming, a BART appeal settlement agreement with the state of Wyoming, and the Wyoming Regional Haze State Implementation Plan (SIP) required the installation of the SCR systems on Unit 3 by the end of 2015, and on Unit 4 by the end of 2016.

Q. Did EPA approve the state of Wyoming's Regional Haze SIP 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 subsequently 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 made these emissions reduction compliance requirements at Jim Bridger Units 3 and 4 federally enforceable, in addition to being enforceable under state law.

Q. How did PacifiCorp assess the benefits associated with the Jim Bridger SCR system projects described?

A. PacifiCorp began its detailed economic assessment of the projects in 2012 to support its Wyoming Certificate of Public Convenience and Necessity (CPCN) filings and its Utah Voluntary Resource Procurement Decision filings for the projects. PacifiCorp used the same analysis methodology and results to support its 2013 Integrated Resource Plan (2013 IRP) filings and updates across its service territory states. The proceedings associated with these various filings provided stakeholders an opportunity for rigorous review of the projects prior to their implementation in the 2013 through 2016 timeframe, as facilitated by the statutes available and procedural schedules used by the public utility commissions in each state. PacifiCorp's economic analyses are detailed in the testimony of Mr. Link. The economic analyses completed demonstrate that both of these projects were prudent, necessary, and in the best interests of our customers.

Q. Do the SCR systems at Jim Bridger Units 3 and 4 have the same general purpose and scope?

A. Yes. For this reason, my testimony references the SCR systems at both Jim Bridger Units 3 and 4.

Q. Did PacifiCorp file an application for a CPCN for the Jim Bridger Units 3 and 4 SCR systems in the state of Wyoming, where the projects are constructed?

A. Yes. On August 7, 2012, PacifiCorp filed its application requesting a CPCN[1] with the Wyoming Public Service Commission, in compliance with the Stipulation and

[1] Wyoming Public Service Commission Docket No. 20000-418-EA-12.

Agreement (2010 Wyoming Stipulation) approved in Wyoming Docket No. 20000-384-ER-10 (2010 Wyoming Rate Case), to construct two major environmental projects as provided in paragraph 13.b. of the 2010 Wyoming Stipulation. The projects entailed the addition of SCR systems to Units 3 and 4 of the Jim Bridger electric generating plant.

Q. Did PacifiCorp file a Voluntary Request for Approval of Resource Decision to Construct the Jim Bridger Units 3 and 4 SCR systems in the state of Utah?

A. Yes. On August 24, 2012, PacifiCorp filed its application requesting the Public Service Commission of Utah review and approve in advance of construction the Jim Bridger SCR system projects.[2]

Q. Did PacifiCorp include analysis of the Jim Bridger Units 3 and 4 SCR systems in the company's 2013 IRP?

A. Yes. PacifiCorp filed Confidential Volume III of the 2013 IRP on April 30, 2013.[3] Confidential Volume III included detailed analysis of the Jim Bridger Units 3 and 4 SCR systems.

Q. Have others in the industry recognized the high quality of PacifiCorp's resource planning and modeling?

A. Yes. In 2013, the Regulatory Assistance Project (RAP)[4] co-authored a paper with the consulting firm Synapse Energy Economics, Inc. (Synapse) on electric utility resource planning. RAP and Synapse wrote that PacifiCorp's integrated resource

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[2] Public Service Commission of Utah Docket No. 12-035-92.
[3] Confidential Volume III of the 2013 IRP was filed in Idaho, Oregon, Utah, Washington, and Wyoming (available at http://www.pacificorp.com/es/irp.html).
[4] "The Regulatory Assistance Project (RAP) is an independent, non-partisan, non-governmental organization dedicated to accelerating the transition to a clean, reliable, and efficient energy future." http://www.raponline.org/about/.

planning uses "progressive methodologies and contain[s] modern elements that contribute to the production of high-quality plans that are useful examples of superior resource planning efforts."[5] The publication further describes PacifiCorp's System Optimizer Model, which was used to evaluate the SCR systems, as the "most comprehensive" model RAP and Synapse examined for the report.[6]

Q. How did the Jim Bridger Units 3 and 4 SCR systems project cost information incorporated into PacifiCorp's Wyoming CPCN and Utah Resource Decision applications compare to the company's 2013 IRP analysis of the project?

A. PacifiCorp used the same project cost information as the baseline for the Wyoming CPCN and Utah Resource Decision applications, as well as for the company's 2013 IRP.

Q. Did the Public Service Commission of Utah approve PacifiCorp's request for a Resource Decision?

A. Yes. On May 10, 2013, the Public Service Commission of Utah approved the company's request for a Resource Decision to add SCR systems on Jim Bridger Units 3 and 4.

Q. Did the Wyoming Public Service Commission approve PacifiCorp's request for a CPCN?

A. Yes. On May 29, 2013, the Wyoming Public Service Commission approved PacifiCorp's request for a CPCN to add SCR systems on Jim Bridger Units 3 and 4.

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[5] Exhibit PAC/401 Best Practices in Electric Utility Integrated Resource Planning, Page 3.
[6] *Id.* at page 23.

Q. Before executing the engineering and procurement contract (EPC), did PacifiCorp engage in a multi-year process to develop, study, review, and obtain initial regulatory approvals for the Bridger SCR systems?

A. Yes. This process began with the issuance of Wyoming's SIP in 2008, which led to a lengthy environmental permitting process. In August 2012, PacifiCorp initiated a CPCN proceeding in Wyoming and a pre-approval proceeding in Utah, resulting in highly scrutinized and publicized regulatory reviews that lasted until May 2013. In April 2013, PacifiCorp completed its 2013 IRP, which contained a comprehensive review of the Bridger SCR systems.

Q. Did PacifiCorp receive prior approval or acknowledgement of the Bridger SCR system projects from all states?

A. PacifiCorp received prior approval in Utah and Wyoming issued a CPCN determining that the investment was necessary. The Public Utility Commission of Oregon declined to acknowledge the Bridger SCR system installations in the 2013 IRP, but understood that PacifiCorp would complete the investments and agreed to undertake a thorough and fair review of the prudence in a future rate case proceeding.[7] In Washington, PacifiCorp's 2013 IRP Update responded to the Washington Utilities and Transportation Commission's 2013 IRP acknowledgement letter, which asked the company to review the natural gas and carbon price assumptions in its SCR analysis. PacifiCorp reported the results of its review to the Commission in a separate appendix to its 2013 IRP Update.

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[7] *In the matter of PacifiCorp, dba Pacific Power 2013 Integrated Resource Plan*, Docket No. LC 57, Order No. 14-252 at 8-9 (July 08, 2014)(available at: http://apps.puc.state.or.us/edockets/orders.asp?OrderNumber=14-252).

Q. Did the detailed evaluation of the Bridger SCR systems that occurred as part of this multi-year process inform PacifiCorp's decision to move forward with this investment?

A. Yes. The Bridger SCR systems were fully vetted in numerous different processes, helping to confirm that they were the best compliance option for customers.

Q. Have you prepared a timeline of the Bridger SCR system projects from the draft Wyoming SIP to the final completion date?

A. Yes. Table 1 below provides a list of the major milestones for the Bridger SCR projects.

Table 1—Bridger SCR System Projects Timeline

Date	Milestone
May 22, 2008	Wyoming Regional Haze SIP (revised)
December 31, 2009	Jim Bridger BART Permit
February 26, 2010	PacifiCorp Appeal of BART Permit
November 2, 2010	Wyoming BART Appeal Settlement (Bridger SCR Requirement)
December 23, 2010	Jim Bridger BART Permit Amendment
January 7, 2011	Wyoming Regional Haze SIP (revised)
June 4, 2012	EPA Wyoming FIP Proposal
August 7, 2012	Wyoming CPCN Application
August 24, 2012	Utah Pre-approval Application
April 30, 2013	PacifiCorp 2013 IRP Confidential Volume III Filed
May 10, 2013	Utah Pre-approval Order
May 30, 2013	Wyoming CPCN Approval Order
May 31, 2013	EPC LNTP
June 28, 2013	Idaho Power Company's Wyoming CPCN Application
December 1, 2013	EPC FNTP
December 2, 2013	Idaho Power Company's Wyoming CPCN Approval Order
January 30, 2014	EPA Wyoming FIP Final Action
March 31, 2014	PacifiCorp 2013 IRP Update Confidential Exhibit F Filed
November, 2015	Jim Bridger 3 SCR system in service
December 31, 2015	Jim Bridger 3 SCR Compliance Deadline
November, 2016	Jim Bridger 4 SCR system in service
December 31, 2016	Jim Bridger 4 SCR Compliance Deadline

Q. Why did PacifiCorp not defer the start of planning for the SCR systems until after the EPA's final action in January 2014?

A. PacifiCorp was required to comply with the timelines set in Wyoming's SIP. Considering the complexity of the Bridger SCR systems and the lengthy project timeline described in Table 1, the Public Service Commission of Utah and the Wyoming Public Service Commission found the timing of PacifiCorp's investment was appropriate.

Q. Did PacifiCorp query the state of Wyoming regarding the enforceability and applicability of its obligations under the SIP?

A. Yes. The state of Wyoming responded that PacifiCorp was required to comply with the deadlines set in the Wyoming SIP. PacifiCorp's request and the state's response are attached as Exhibit PAC/402 and Exhibit PAC/403, respectively.

Q. When was the EPC contract executed and the contractor released to begin work?

A. The Jim Bridger Units 3 and 4 SCR EPC contract was executed by the parties on May 31, 2013. The EPC contract included a limited notice to proceed (LNTP) provision that initially released the selected EPC contractor to begin scheduled critical activities only for a period of time while parallel path permitting and regulatory proceedings (e.g., environmental agency Regional Haze activities and integrated resource planning reviews) continued. PacifiCorp gave full notice to proceed (FNTP) to the EPC contractor effective on December 1, 2013, under negotiated EPC contract provisions that were established to maintain project cost and schedule certainty. The EPC contractor's construction site mobilization began in December 2013.

Q. Prior to issuing full notice to proceed, did PacifiCorp confirm current market conditions and economics?

A. Before issuing the FNTP, PacifiCorp reviewed all key decision factors, including: (1) its September 2013 official forward price curve (the most recent at the time of issuing the FNTP), which remained well above the SCR system's break-even point; (2) 10-year projected Jim Bridger fuel costs were not projected to increase significantly; and (3) a [redacted] cost reduction PacifiCorp negotiated in the EPC contract. PacifiCorp 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 systems 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 systems investment remained the best compliance choice for customers. During the same timeframe, PacifiCorp elected to close other coal plants or pursue conversion to natural gas. In each case, PacifiCorp's decision was based on the economics of the compliance option for customers, not a predetermined preference or investment agenda.

Q. Did PacifiCorp update its original 2013 IRP Confidential Volume III analysis of the Jim Bridger Units 3 and 4 SCR systems?

A. Yes. PacifiCorp included its updated analysis of the Jim Bridger Units 3 and 4 SCR system projects in Confidential Appendix F in its 2013 IRP Update completed on March 31, 2014, which specifically addressed potential changes in carbon regulation and natural gas market cost impacts.

Q. What was the status of the Jim Bridger Units 3 and 4 at this point in time?

A. At the time of the Confidential Appendix F filing, the EPC contractor had been issued FNTP and was in the process of detailed engineering and procurement of materials for the SCR system projects.

Q. Did PacifiCorp's updated review of potential carbon regulation and natural gas forward price curves in its 2013 IRP Update, finalized March 31, 2014, result in changes to its earlier economic analysis of the Jim Bridger Units 3 and 4 SCR systems?

A. No. The forecast proxy costs for carbon regulations and natural gas included in the 2013 IRP Update remained within the ranges initially assessed.

Q. What was PacifiCorp's cost to complete the Jim Bridger Unit 3 SCR system?

A. The cost of the Jim Bridger Unit 3 SCR system included in this proceeding is [redacted] on a total-company basis, or approximately [redacted] on a California-allocated basis. The total-company cost to complete the Jim Bridger Unit 3 SCR system was approximately [redacted] less than the corresponding cost originally assessed in the Wyoming CPCN and Utah Resource Decision applications, as well as in the 2013 IRP. A cost comparison is shown in Confidential Exhibit PAC/404.

Q. Did PacifiCorp prudently manage the implementation of the Jim Bridger Unit 3 SCR system?

A. Yes. Beyond management of project costs as mentioned above, PacifiCorp's project team prudently implemented and maintained an appropriate procurement strategy, project controls, and status reporting to ensure compliance with contract safety program implementation, technical specification requirements, scope of work definition, critical path schedules, quality assurance, commissioning plans, and turnover to operations plans, among other things.

Q. What is the major maintenance overhaul cycle interval for Jim Bridger Units 3 and 4?

A. Jim Bridger Units 3 and 4 are maintained on a four-year maintenance outage cycle based on PacifiCorp's operating experience with the Jim Bridger units. The outage cycle has been established to optimize unit reliability and availability, while maintaining an appropriate balance of major maintenance outage scope and costs. The implementation schedules of the Jim Bridger SCR system projects were aligned with the established major maintenance overhaul cycles for the individual units.

Q. What is the current status of the Jim Bridger Unit 3 SCR system?

A. The Jim Bridger Unit 3 SCR system was placed in service in November 2015, following the planned major maintenance overhaul for Unit 3. PacifiCorp's environmental compliance deadline as established by the governing permits, implementation plans, and agreements described earlier in this testimony was December 31, 2015, for Unit 3. Completion of the Jim Bridger Unit 3 SCR system satisfied the compliance deadlines established for the unit, as well as the prescribed emissions reductions.

Q. Please confirm that the drivers, general description, and rationale for the Jim Bridger Unit 4 SCR system was consistent with that provided above for the Jim Bridger Unit 3 SCR system.

A. The drivers, general description, and rationale for the Jim Bridger Unit 4 SCR system all mirror the information provided above for the Jim Bridger Unit 3 SCR system.

Q. When was the Unit 4 SCR EPC contract executed and the contractor released to begin work?

A. A single EPC contract was executed for the Jim Bridger Units 3 and 4 SCR systems, the timeline of which is described above.

Q. What was PacifiCorp's cost to complete the Jim Bridger Unit 4 SCR system?

A. The cost of the Jim Bridger Unit 4 SCR system included in this proceeding is [redacted] on a total-company basis, or approximately [redacted] on a California-allocated basis. PacifiCorp's total-company cost to complete the Jim Bridger Unit 4 SCR system was approximately [redacted] less than the corresponding cost originally assessed in the Wyoming CPCN and Utah Resource Decision applications, as well as in the 2013 IRP. A cost comparison is shown in Confidential Exhibit No. PAC/405.

Q. Did PacifiCorp prudently manage implementation of the Jim Bridger Unit 4 SCR system?

A. Yes. The testimony I provided above relating to the prudent management of the Jim Bridger Unit 3 SCR system is also applicable to the Jim Bridger Unit 4 SCR system.

Q. What is the current status of the Jim Bridger Unit 4 SCR system?

A. The Jim Bridger Unit 4 SCR system was placed in service in mid-November 2016, following the planned major maintenance overhaul for Unit 4. PacifiCorp's environmental compliance deadline as established by the governing permits, implementation plans, and agreements described earlier in this testimony was December 31, 2016, for Unit 4. Completion of the Jim Bridger Unit 4 SCR system satisfied the compliance deadlines established for the unit, as well as the prescribed emissions reductions.

Craig Unit 2 SCR System

Q. Please describe the Craig facility.

A. The Craig facility is a three-unit coal-fired electrical generating facility located in Routt County, Colorado. Units 1 and 2 (855 MW), are jointly owned by Tri-State Generation and Transmission Association, Inc. (Tri-State), Salt River Project, Platte River Power Authority, Public Service Company of Colorado, and PacifiCorp (PacifiCorp owns 19.28 percent of the units). Unit 3 is solely owned by Tri-State. Tri-State operates all units at the facility.

Q. Please provide a general description of the Craig Unit 2 SCR system.

A. Generally consistent with the description provided for the Jim Bridger Units 3 and 4 SCR systems, the Craig Unit 2 SCR system is primarily comprised of: a reactor with multiple catalyst levels; inlet and outlet ductwork; an ammonia reagent system; certain boiler structure and ancillary infrastructure retrofits; electrical and control system installation; and integration with the existing plant.

Q. What was the required timeline for Tri-State to install the SCR system at Craig Unit 2?

A. The Craig Unit 2 SCR system was required by the Clean Air Act Regional Haze Rules and the associated state of Colorado Regional Haze SIP to be installed by January 30, 2018. Colorado's Regional Haze SIP was first approved by the Colorado Air Quality Control Commission in January 2011, and was submitted to EPA for review and approval on May 25, 2011.

Q. Did EPA approve the State of Colorado's Regional Haze SIP compliance requirements for Craig Unit 2?

A. Yes. EPA published its approval of the Colorado Regional Haze SIP compliance requirements for Craig Unit 2 in the *Federal Register* on December 31, 2012.[8] EPA's final rule became effective January 30, 2013.

Q. Please generally describe the joint ownership governance of Craig Unit 2.

A. The terms and conditions of joint ownership in Craig Unit 2 are governed by a Participation Agreement. The Participation Agreement mandates the installation of capital improvements that are required by applicable law. The Participation Agreement also places an independent obligation on Tri-State, as Operating Agent, to operate Craig Unit 2 in accordance with applicable laws. The applicable laws requiring the Craig Unit 2 SCR system installation are discussed above in my testimony.

As Operating Agent, Tri-State is also responsible for development of operating budgets and capital investment recommendations to be set forth for joint owner review and approvals. The Participation Agreement's provisions for approval of capital expenditures requires that the proposed expenditures be included in the annual capital expenditure budget prepared by the Operating Agent and that the annual capital expenditure budget is approved by a majority vote (i.e. greater than 50 percent ownership share) of the joint owners.

[8] https://www.epa.gov/sites/production/files/2014-02/documents/epafinalactiononcoloradoregionalhazeplan.pdf; http://www2.epa.gov/region8/air-program.

Q. Did Tri-State request approval of the Craig Unit 2 SCR system investment in accordance with the terms of the Participation Agreement and was it approved by greater than 50 percent ownership share of the joint owners?

A. Yes. Tri-State initially included costs associated with the Craig Unit 2 SCR system in the 2013 capital expenditures budget for review and approval pursuant to the Participation Agreement. The project was approved by a greater than 50 percent ownership share of the joint owners.

Q. Did PacifiCorp independently assess the benefits associated with the Craig Unit 2 SCR system project?

A. Yes. In July 2013, PacifiCorp independently assessed the benefits associated with the Craig Unit 2 SCR system project against a hypothetical wherein PacifiCorp could unilaterally effectuate an accelerated shutdown of the unit. This hypothetical was not a realistic option because PacifiCorp cannot unilaterally effectuate an accelerated shutdown of the Craig units based on the language of the Participation Agreement. PacifiCorp's hypothetical did not favor the installation of an SCR system.

Q. What position did PacifiCorp take with respect to the Craig Unit 2 SCR system project capital budget approval?

A. PacifiCorp voted "no" with respect to the Craig Unit 2 SCR system project. PacifiCorp recognized that under the terms of the Participation Agreement its "no" vote alone would not change the outcome with the other joint-owners voting "yes", and the company remained obligated to pay its share of the Craig Unit 2 SCR system.

Q. Did PacifiCorp also independently assess its legal options with respect to the capital expenditures approval process incorporated into the Participation Agreement?

A. Yes. In June 2013, PacifiCorp engaged internal and external counsel to independently assess the company's rights under the Participation Agreement with respect to payment options and dispute resolution that may occur with a majority decision on capital expenditures that was not supported by PacifiCorp. The ultimate determination of the internal and external legal reviews of the Participation Agreement was that PacifiCorp had the right to challenge the majority's decision, but there was little to no opportunity to successfully challenge the project through arbitration or litigation. This was primarily because the project met the requirements under the Participation Agreements, specifically: (i) the project is required by applicable law (the Colorado Regional Haze SIP); (ii) Craig Unit 2 is required to be operated in accordance with applicable law under the Participation Agreement; and (iii) the majority of the Craig Unit 2 joint-owners (in fact all other than PacifiCorp) voted in support of the project.

Q. Considering the terms and conditions of the Participation Agreement, did PacifiCorp pursue arbitration or litigation of the Craig Unit 2 SCR system project decision?

A. No, for the reasons explained above.

Q. What was PacifiCorp's cost to complete the Craig Unit 2 SCR system?

A. The cost of the Craig Unit 2 SCR system included in this proceeding is [redacted] on a total-company basis, or approximately [redacted] on a California-allocated basis with an in-service date of December 2017.

Q. What is the current status of the Craig Unit 2 SCR system?

A. The Craig Unit 2 SCR system was placed in service in December 2017, following the planned major maintenance overhaul for the unit. Completion of the Craig Unit 2 SCR system satisfied the compliance deadlines established for the unit, as well as the prescribed emissions reductions.

In each case, installation of these major emissions control retrofit projects have been aligned with scheduled major maintenance outages for the affected units to mitigate replacement power cost impacts while benefiting from overlapping major maintenance outage time frames. These environmental compliance projects allow the retrofitted facilities to continue to operate as low-cost generation resources for the benefit of customers.

<u>Hayden Units 1 & 2 SCR Systems</u>

Q. Please describe the Hayden Facility.

A. The Hayden plant is a 446 MW, two-unit coal-fired electrical generating facility located in Routt County, Colorado. Unit 1 is jointly owned by Public Service Company of Colorado (PSCo) and PacifiCorp (PacifiCorp owns 24.5 percent). Unit 2 is jointly owned by PSCo, Salt River Project, and PacifiCorp (PacifiCorp owns 12.6 percent). PSCo operates the plant.

Q. Please provide a general description of the Hayden Units 1 and 2 SCR systems.

A. Generally consistent with the description provided for the Jim Bridger Units 3 and 4 SCRs, the Hayden Units 1 and 2 SCR systems are primarily comprised of: reactors with multiple catalyst levels; inlet and outlet ductwork; ammonia reagent systems;

certain boiler structures and ancillary infrastructure retrofits; electrical and control systems installation; and integration with the existing plant.

Q. What was the required timeline for PacifiCorp to install the SCR systems at Hayden Units 1 and 2?

A. The Hayden Units 1 and 2 SCR systems were required by the State of Colorado's Regional Haze SIP to be installed no later than December 31, 2016.

Q. Did EPA approve the state of Colorado's Regional Haze SIP compliance requirements for Hayden Units 1 and 2?

A. Yes. The EPA published its approval of the Colorado Regional Haze SIP in the Federal Register on December 31, 2012.[9] EPA's final approval made these emissions reduction compliance requirements at Hayden Units 1 and 2 federally enforceable, in addition to being enforceable under state law.

Q. What regulations required the Hayden Units 1 and 2 SCR system projects to be installed?

A. In December 2010, the Colorado Air Quality Control Commission promulgated new BART determinations and emissions control requirements for the Hayden units in the Colorado Regional Haze SIP. These BART determinations set emissions limits of 0.08 lbs NO_X/MMBtu for Hayden Unit 1 and 0.07 lbs NO_X/MMBtu for Hayden Unit 2. Although the BART determinations did not specify how these limits were to be achieved, installation of SCR systems was the only technically feasible method available.

[9] https://www.epa.gov/sites/production/files/2014-02/documents/epafinalactiononcoloradoregionalhazeplan.pdf; http://www2.epa.gov/region8/air-program.

The Hayden Unit 1 SCR system was also a key component of the NO_X reduction plan required by PSCo (the operator of Hayden Unit 1) to the Colorado Public Utilities Commission under the Colorado Clean Air Clean Jobs Act. The Colorado Public Utilities Commission approved PSCo's NO_X reduction plan, including the Hayden Unit 1 SCR system project, on December 9, 2010.

Q. Was a CPCN acquired for the Hayden Units 1 and 2 SCR systems in the state of Colorado, where the projects were constructed?

A. On January 26, 2011, the Colorado Public Utilities Commission found that the Hayden Units 1 and 2 SCR systems were necessary and in the public interest.[10] PSCo's request for a CPCN for the SCR systems was subsequently granted by the Colorado Public Utilities Commission.[11]

Q. Please generally describe the joint ownership governance of Hayden Units 1 and 2.

A. The terms and conditions of joint ownership in Hayden Units 1 and 2 are governed by a Participation Agreement. The Participation Agreement mandates the installation of capital improvements that are required by applicable law. The Participation Agreement also places an independent obligation on PSCo, as Operating Agent, to

[10] *In re Public Service Co. of Colorado's Plan in Compliance with House Bill 10-1365*, "Clean Air-Clean Jobs Act, Docket No. 10M-245E, Decision No. C10-1328 (January 26, 2011)(available at: http://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0ahUKEwisv6r2xPHZAhXnr1QKHUt5BhYQFggnMAA&url=http%3A%2F%2Fwww.dora.state.co.us%2FPUC%2FDocketsDecisions%2Fdecisions%2F2010%2FC10-1328_10M-245E.doc&usg=AOvVaw016pmadIR-vCs3VyPuOf5l)

[11] *In the matter of the Application of Public Service Co. of Colorado for a Certificate of Public Convenience and Necessity for the Hayden Emissions Control Project,* Docket No. 11A917E, Recommended Decision R12-0593 (June 1, 2012 (available at: http://www.dora.state.co.us/puc/docketsdecisions/decisions/2012/R12-0593_11A-917E.doc); Order Denying Exceptions, Decision C12-0843 (July 24, 2012)(available at: http://www.dora.state.co.us/puc/docketsdecisions/decisions/2012/C12-0843_11A-917E.doc).

operate Hayden Units 1 and 2 in accordance with applicable laws. The applicable laws requiring the Hayden Units 1 and 2 SCR systems installation are discussed above in my testimony.

Q. Were the SCR system projects intended to extend the operational life of Jim Bridger Units 3 and 4, Craig Unit 2, or Hayden Units 1 and 2?

A. No. The SCR system projects were required to continue operations in Wyoming and Colorado to meet state requirements.

IV. CONCLUSION

Q. Do you have any final comments?

A. Yes. PacifiCorp prudently managed the analysis, implementation, and costs of the Jim Bridger Units 3 and 4 SCR system projects. The projects were analyzed and managed in accordance with PacifiCorp's environmental compliance obligations, the Wyoming Public Service Commission Order granting a CPCN for the projects, the Public Service Commission of Utah Order granting Resource Decision Pre-approval for the projects, and the company's integrated resource planning processes. PacifiCorp completed the Jim Bridger Units 3 and 4 systems on time to meet all environmental compliance deadlines and performance requirements under budget, further supporting the prudence of the project.

PacifiCorp also prudently managed the analysis and appropriately exercised its rights under the Participation Agreement with respect to the Craig Unit 2 SCR system project. The project was completed on time to meet all environmental compliance deadlines and performance requirements, and was administered by the plant Operating Agent, and supported by a majority vote of the unit's remaining joint owners, in accordance with Participation Agreement terms and conditions.

PacifiCorp's support of the Hayden Units 1 and 2 SCR system installations included in this case has been administered pursuant to applicable law and the Partnership Agreement applicable to those units.

These environmental compliance projects have reduced emissions and allowed the retrofitted facilities to continue to operate as low-cost generation resources for the remainder of the units lives to benefit PacifiCorp's customers. Accordingly, the investments should be approved as prudent expenditures.

Q. Does this conclude your direct 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

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[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

[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

[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.

[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

[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

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[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.

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.

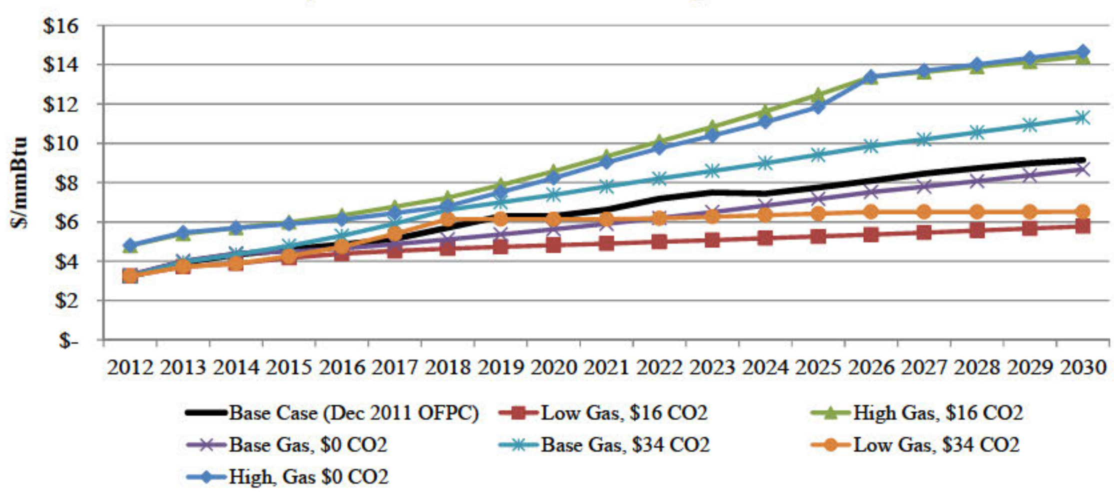
Q. How did the Company choose its natural gas and CO_2 price assumptions as used in the six market price scenarios?

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.

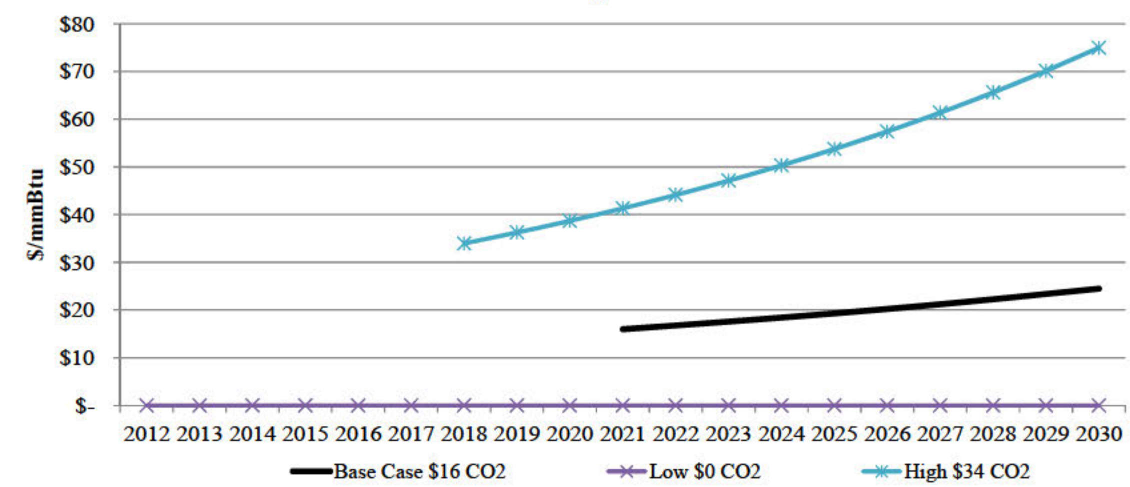
Figure 1
Henry Hub Natural Gas Prices among All Scenarios



[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-___
Exhibit PAC/500
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP

REDACTED

Direct Testimony of Rick T. Link

Economic Analysis

Installation of Selective Catalytic Reduction Systems and Wind Repowering

April 2018

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ATTACHED EXHIBITS

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Pacific Power (PacifiCorp).

A. My name is Rick T. Link. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My position is Vice President, Resource and Commercial Strategy.

I. QUALIFICATIONS

Q. Please describe your professional experience and education.

A. I joined PacifiCorp in December 2003 and assumed the responsibilities of my current position in September 2016. Over this time period, I held several analytical and leadership positions where I was responsible for developing long-term commodity price forecasts, pricing structured commercial contract opportunities and developing financial models to evaluate resource investment opportunities, negotiating commercial contract terms, and overseeing development of PacifiCorp's resource plans. I was responsible for delivering PacifiCorp's 2013, 2015, and 2017 integrated resource plans (IRPs); have been directly involved in several resource request for proposals (RFP) processes, and performed economic analysis supporting a range of resource investment opportunities. Before joining PacifiCorp, I was an energy and environmental economics consultant with ICF Consulting (now ICF International) from 1999 to 2003, where I performed financial modeling of environmental policies applicable to the electric sector for utility clients. 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.

Q. Briefly describe the responsibilities of your current position.

A. I am responsible for PacifiCorp's IRP, structured commercial business and valuation activities, long-term commodity price forecasts, and long-term load forecasts. Most relevant to this docket, I am responsible for the economic analysis used to screen resource investments.

Q. Have you testified in previous regulatory proceedings?

A. Yes. I have testified in regulatory proceedings in Oregon, Utah, Washington, and Wyoming.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony explains the economic analysis performed in 2012 that supported PacifiCorp's decisions to install selective catalytic reduction (SCR) emission control systems on Units 3 and 4 of the Jim Bridger generating plant. I also present and explain the economic analysis that shows PacifiCorp's decision to upgrade, or "repower", certain wind resources is prudent and provides significant customer benefits. I also summarize PacifiCorp's assessment of the wind repowering project in its 2017 IRP.

Q. Please summarize your testimony.

A. PacifiCorp's economic analysis of SCR emission control systems at Jim Bridger Units 3 and 4 demonstrate that these systems were expected to provide net customer benefits relative to alternatives that included conversion to natural gas and early retirement. Specifically, my testimony on the SCR systems at Jim Bridger Units 3 and 4 presents the following:

- A description of the methodology used to analyze the SCR systems required to continue operating Jim Bridger Units 3 and 4 as coal-fueled facilities.

- A base case economic analysis showing $183 million in total company present-value customer benefits from the SCR systems that are necessary to continue operating Jim Bridger Units 3 and 4 as coal-fueled assets.[1]

- Natural-gas price and carbon dioxide (CO_2) price scenario assumptions and results showing a range of economic outcomes that support the SCR systems in six of the nine scenarios studied.

- A description of an additional sensitivity showing that the Jim Bridger Units 3 and 4 SCR systems are favorable to both gas conversion and early retirement alternatives.

Additionally, my testimony provides the economic analysis that supports repowering approximately 999 megawatts (MW) of existing wind resource capacity located in Wyoming, Oregon, and Washington. The repowered wind facilities will qualify for an additional 10 years of federal production tax credits (PTCs), produce more energy, reset the 30-year depreciable life of the assets, and reduce run-rate operating costs. PacifiCorp's economic analysis of the wind repowering opportunity demonstrates that net benefits, which include federal PTC benefits, net power cost (NPC) benefits, other system variable-cost benefits, and system fixed-cost benefits, more than outweigh net project costs. My testimony on the wind repowering project demonstrates the following:

- The economic analysis shows net customer benefits in all scenarios analyzed.

- The wind repowering project will produce present-value net customer benefits, based on economic analysis over the remaining life of the repowered wind facilities, ranging between $121 million to $466 million.

[1] All results from the economic analyses presented in my testimony are stated on a total-company basis.

- Present-value gross customer benefits calculated over the remaining life of the repowered wind facilities range between $1.14 billion and $1.48 billion, which compares to present-value costs totaling $1.02 billion.

- These net and gross customer benefits are conservative, as they do not account for potential incremental benefits from renewable energy credits (RECs) and understate potential benefits from reduced CO_2 emissions.

- When measured over a 20-year period, the present value net customer benefits from wind repowering range between $139 million and $273 million, which does not account for the value of incremental energy output that will increase significantly beyond 2036.

III. JIM BRIDGER UNITS 3 AND 4

Methodology

Q. What model was used to evaluate the SCR systems for Jim Bridger Units 3 and 4?

A. PacifiCorp used its System Optimizer (SO) model to perform a present-value revenue requirement differential (PVRR(d)) economic analysis of the SCR emission control systems at Jim Bridger Units 3 and 4. This same analysis was presented in PacifiCorp's 2013 IRP and 2013 IRP Update. This same economic analysis was also used to support the Wyoming certificate of public convenience and necessity process for the SCR emission control systems at Jim Bridger Units 3 and 4 described in the testimony of Mr. Chad A. Teply (Exhibit PAC/400).

Q. Please describe the SO model and how it is used by PacifiCorp.

A. The SO model is a capacity expansion optimization tool that is used in PacifiCorp's IRP to produce resource portfolios in support of long-term system planning. The SO model is also used in PacifiCorp's analysis of resource acquisition opportunities and resource procurement activities. The SO model endogenously considers tradeoffs between operating and capital revenue requirement costs of both existing and prospective new resources while simultaneously evaluating tradeoffs in energy value between existing and prospective new resource alternatives.

Q. Why is the SO model an appropriate tool for analyzing incremental emission control equipment installations required on 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 emission control systems required to meet 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 emission control installation decisions by evaluating NPC impacts along with the impacts those decisions might have on future resource acquisition needs. This is particularly important when resource retirement and replacement is considered to be an environmental compliance alternative.

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

A. For a range of market price scenarios, which I 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 determined whether continued operation of Jim Bridger Units 3 and 4 inclusive of incremental SCR emission control systems and other planned costs required to achieve compliance with environmental regulations was a lower cost solution than avoiding those expenses through early retirement and resource replacement or through conversion to natural gas. In the change-case simulation, the SO model was forced to produce a suboptimal decision by not allowing it to make the preferred decision that was made in the optimized simulation.

When the optimized simulation selected continued operations with incremental SCR emission control systems and other planned costs, then the change case was created by removing the SCR emission control systems as an alternative, allowing the SO model to select either an early retirement or gas-conversion alternative. In each of these change-case simulations, the SO model selected natural-gas conversion as a lower-cost alternative to early retirement. In scenarios where the optimized simulation selected conversion to natural gas, then the change case forced continued operations with incremental SCR emission control systems and other planned costs. The difference in total-company costs, inclusive of differences in NPC, operating costs and capital 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 emission control systems required for Jim Bridger Units 3 and 4, along with projected costs required to achieve compliance with an array of known and prospective environmental regulations. This included 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 PacifiCorp's fleet are summarized in Confidential Exhibit PAC/501.

Q. What resource-replacement alternatives were made available to the SO model in the event SCR emission control systems were not installed on Jim Bridger Units 3 and 4?

A. In addition to brownfield natural-gas conversion of Jim Bridger Units 3 and 4, the SO model was configured with a range of resource-replacement alternatives, which included:

- greenfield natural-gas resources;
- firm market purchases;
- demand-side management; and
- incremental wind resources.

Since the installation of SCR systems was 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. Did PacifiCorp's economic analysis consider how the power requirements from the SCR emission control systems might affect the net capacity of Jim Bridger Units 3 and 4?

A. Yes. The SCR emission control systems, once installed and operational, were assumed to reduce PacifiCorp's share of capacity of both Jim Bridger Unit 3 and Unit 4 by approximately 3.5 MW.

Q. Did your analysis account for changes in the fueling plan at the Jim Bridger plant between the SCR and natural-gas conversion or early-retirement scenarios?

A. Yes. If Jim Bridger Units 3 and 4 were to convert to natural gas or retire early, the coal fueling needs at the four-unit Jim Bridger plant would be reduced, which in turn, would influence mine plans and reclamation plans. Cash coal cost assumptions used in the SO model were based on non-capital-related costs to fuel the Jim Bridger plant, which included then-current third party coal prices and transportation costs from Black Butte coal as well as then-current cash operating cost forecasts for Bridger Coal Company (BCC) inclusive of final reclamation trust contributions. Under a two-unit coal operating plan, cash costs assumed closure of the Bridger Coal surface mine. Under a four-unit coal operating plan, cash costs assumed a two dragline operation at the surface mine. Cash coal cost assumptions for both the two-unit and four-unit coal operating plans used in the economic analysis are provided in Confidential Exhibit PAC/502.

Q. Please describe mine reclamation costs considered in PacifiCorp's economic analysis.

A. In 1989, the BCC owners established a final reclamation trust to fund actual final reclamation work. A sinking fund calculation is used to determine the appropriate final reclamation trust contribution rate and ensure sufficient funds exist in the trust to support final reclamation work once coal production ceases. Contributions to the final reclamation trust were included as part of the Jim Bridger plant cash coal costs through 2030, the study horizon used for the SO model analysis. Considering that reclamation costs continue beyond the 2030 study horizon, reclamation costs from 2031 through 2037 were included in the PVRR(d) calculations to capture differences in reclamation costs beyond the SO model study period. Confidential Exhibit PAC/503 summarizes reclamation costs for both the two-unit and four-unit coal operating plans used in the economic analysis.

Q. Did PacifiCorp consider differences in incremental mine capital costs between the two-unit and four-unit coal operating plans?

A. Yes. Over the period 2013 through 2030, average annual mine capital cost assumptions for a four-unit coal operating plan are higher than those in a two-unit coal operating plan. Confidential Exhibit PAC/504 shows annual mine capital cost assumptions used in the economic analysis for both the two-unit and four-unit coal operating plans.

Natural-Gas and CO_2 Price Scenarios

Q. Please explain why natural-gas and CO_2 price assumptions were important when analyzing the SCR emission control systems at Jim Bridger Units 3 and 4.

A. PacifiCorp evaluated early retirement and resource replacement or conversion of Jim Bridger Unit 3 and Unit 4 to natural gas as alternatives to SCR emission control systems. 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, natural-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 natural 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. Did PacifiCorp evaluate different assumptions for natural-gas prices and CO_2 prices in its analysis of the Jim Bridger Units 3 and 4 SCR systems?

A. Yes. In PacifiCorp's analysis of the SCR systems at Jim Bridger Units 3 and 4, eight different combinations of natural-gas and CO_2 price assumptions were analyzed as variations to the base case, which was tied to the September 2012 official forward price curve (OFPC). Table 1 summarizes the directional changes to base case assumptions among the eight scenarios. 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 four scenarios pair different combinations of natural-gas price and CO_2 price assumptions. In any scenario where the CO_2 assumption varies from that used in the base case, the underlying natural-gas price assumption was adjusted to account for an assumed 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	September 2012 OFPC	$16/ton in 2022 rising to $23/ton by 2030
Low Gas, Base CO_2	Low	$16/ton in 2022 rising to $23/ton by 2030
High Gas, Base CO_2	High	$16/ton in 2022 rising to $23/ton by 2030
Base Gas, $0 CO_2	Base case adjusted for price response	No CO_2 costs
Base Gas, High CO_2	Base case adjusted for price response	$14/ton in 2020 rising to $65/ton by 2030
Low Gas, High CO_2	Low case adjusted for price response	$14/ton in 2020 rising to $65/ton by 2030
High Gas, $0 CO_2	High case adjusted for price response	No CO_2 costs
Low Gas, $0 CO_2	Low case adjusted for price response	No CO_2 costs
High Gas, High CO_2	High case adjusted for price response	$14/ton in 2020 rising to $65/ton by 2030

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

A. As I stated earlier, 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, can 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 can also be influenced by low- or zero-emitting renewable generation sources; however, it was assumed that these low- or zero-emitting renewable resources would not 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 could be 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. Did PacifiCorp only apply upward adjustments to natural-gas prices in response to changes in CO_2 price level?

A. No. The assumed interaction between natural-gas prices and CO_2 prices was applied on a bi-directional basis. That is, PacifiCorp not only assumed natural-gas prices rise in the presence of a CO_2 price (or with increased CO_2 price levels), but also incorporated downward natural-gas price pressures when CO_2 prices were removed or lowered.

Q. How did PacifiCorp choose its natural-gas and CO_2 price assumptions as used in the eight market price scenarios?

A. The range of low- and high-price assumptions were based upon the range of then current third-party expert forecasts and government agency price projections. Confidential Exhibit PAC/505 shows how the low and high price assumptions that were used in PacifiCorp's economic analysis compare to these third-party forecasts.

Low natural-gas price assumptions were derived from a third-party, low price scenario, which was 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 were based on a blend of two, third-party price scenarios. This blending approach recognized that the most extreme high natural-gas price forecast was a strong outlier relative to price projections from other forecasters, and would have resulted in a high-price scenario that exceeds the highest of 47 natural-gas price forecasts in the U.S. Energy Information Administration's 2011 Annual Energy Outlook.[2]

Fundamental drivers to a high price scenario included 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

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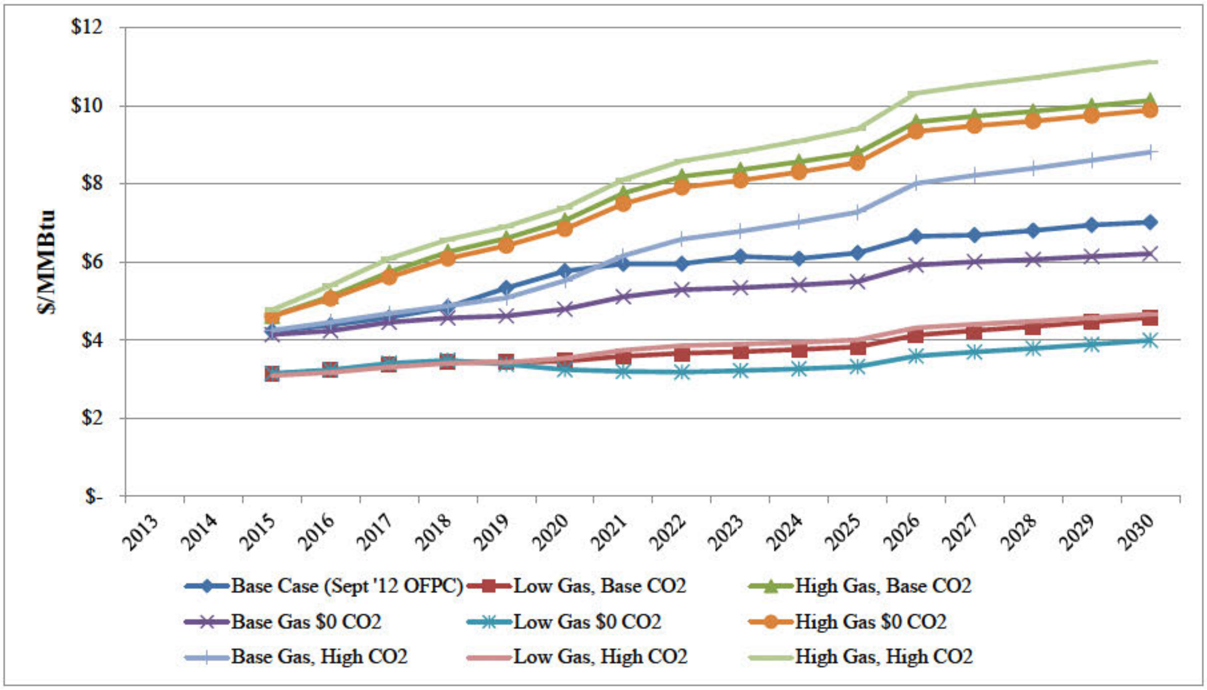
[2] The U.S. Energy Information Administration is the statistical and analytical agency within the U.S. Department of Energy. The highest natural-gas price forecast in the 2011 Annual Energy Outlook assumed that total unproved technically recoverable shale gas resources are reduced by 49 percent and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

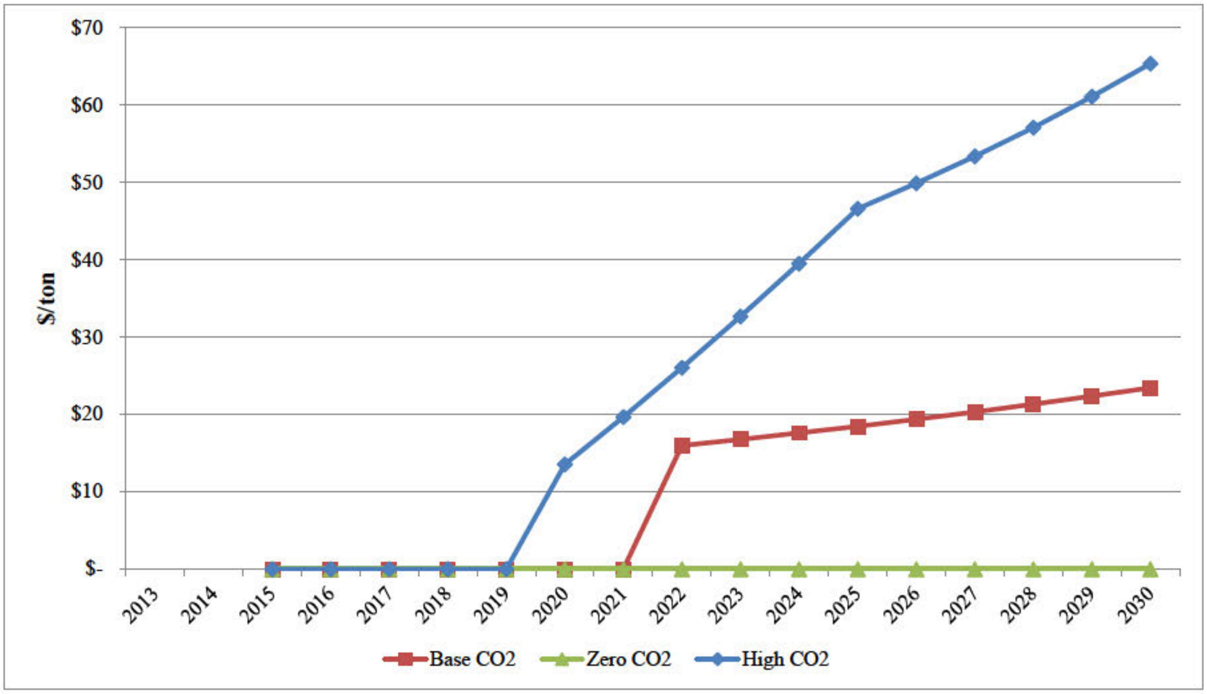
liquefied natural-gas exports out of the U.S. natural-gas market. Figure 1 shows the Henry Hub natural-gas price forecast among all market price scenarios considered in the economic analysis of the SCR emission control systems at Jim Bridger Units 3 and 4.

Figure 1. Henry Hub Natural-Gas Prices among All Scenarios



PacifiCorp assumed a zero CO_2 price for the low scenario recognizing that there had been limited activity in the CO_2 policy arena. For the high CO_2 price scenario, prices were assumed to begin in 2020, escalate rapidly through 2025 and reach $65/ton by 2030. The high CO_2 price scenario aligns with the then-current high CO_2 price forecast from a third-party source. Figure 2 shows the three CO_2 price assumptions used in the market-price scenarios supporting the economic analysis.

Figure 2. CO_2 Prices among All Scenarios



1 **<u>Base-Case Results</u>**

2 **Q. Please describe the base-case results.**

3 A. The optimized base-case simulation selected the SCR emission control systems at Jim Bridger Unit 3 and Jim Bridger Unit 4. The change-case simulation in which Jim Bridger Units 3 and 4 were not allowed to select SCR emission control systems showed that gas conversion was the next best, albeit higher cost, alternative to the installation of these SCR systems. The PVRR(d), as summarized in Exhibit PAC/506, shows that installation of SCR systems is $183 million lower cost than gas conversion.

Q. How were system costs impacted between the base-case simulation, where SCRs were installed on Jim Bridger Units 3 and 4, and the change-case simulation, where both units were converted to natural gas?

A. When SCR emission control systems were installed on Jim Bridger Units 3 and 4, total-company fuel costs are lower and net system balancing revenues are higher relative to a natural-gas conversion alternative that would significantly reduce generation levels from the two units. These total-company benefits more than offset the increased fixed costs associated with the capital for the SCR emission control systems, which were assumed to be approximately $372/kilowatts (kW) higher than gas conversion capital costs, and levelized annual operating and run-rate capital costs, which were assumed to be approximately $52/kW higher than projected gas conversion costs. On a total-company basis, the PVRR(d) of system variable costs was $775 million favorable to the SCR systems compliance alternative, which more than offset the $592 million increase to total-company fixed costs.[3]

<u>Natural-Gas and CO_2 Price Scenario Results</u>

Q. Please describe the results from the natural-gas and CO_2 price scenarios.

A. The natural-gas and CO_2 price scenario results showed that the investment in SCR emission control systems at Jim Bridger Unit 3 and Jim Bridger Unit 4 remained favorable to the next best, albeit higher cost natural-gas conversion alternative under all base and high natural-gas price scenarios at all assumed CO_2 price levels. In these

[3] System variable costs include fuel, net system balancing revenue, variable operations and maintenance (O&M) expenses, and CO_2 emissions expenses, as applicable. System fixed costs include incremental environmental controls costs, fixed O&M and run-rate capital expenses for existing and new resources, and changes to system demand-side management costs.

scenarios, the PVRR(d) ranges between $51 million favorable for the SCR systems (base gas, high CO_2) and $997 million favorable for the SCR systems (high gas, zero CO_2). The PVRR(d) results were unfavorable for the SCR systems only in those scenarios where then-current low natural-gas prices were assumed.

When low natural-gas price assumptions were paired with base CO_2 price assumptions, the nominal levelized price of natural gas at Opal[4] over the period 2016 to 2030 is $3.70 per million British thermal units (MMBtu) and the PVRR(d) is $285 million unfavorable for the SCR emission control systems required at Jim Bridger Units 3 and 4. In the low natural-gas, zero CO_2 price-policy scenario, the nominal levelized price of natural gas at Opal is $3.41 per MMBtu over the 2016 to 2030 time frame, and the PVRR(d) is $224 million unfavorable for the SCR emission control systems. When low natural-gas prices are paired with high CO_2 price assumptions, the nominal levelized price at Opal over the period 2016 to 2030 is $3.78 per MMBtu, and the PVRR(d) is $378 million unfavorable for the SCR emission control systems. The PVRR(d) results from the natural-gas and CO_2 price scenarios are summarized alongside the base case results in Exhibit PAC/506.

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

A. The scenario results show that there is a strong trend between natural-gas price assumptions and the PVRR(d) benefit/cost associated with the SCRs required for continued operation of Jim Bridger Units 3 and 4 as coal-fueled assets. With higher natural-gas price assumptions, the SCR emission control systems are more favorable

[4] Opal is a natural-gas market hub located in Lincoln County, Wyoming.

as compared to the Jim Bridger Unit 3 and Unit 4 gas conversion alternative. Conversely, lower natural-gas prices improve the PVRR(d) results in favor of the gas conversion alternative. Lower natural-gas prices reduce the fuel cost of the gas conversion alternative, reduce 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 reduce the opportunity cost of reduced off-system sales when Jim Bridger Units 3 and 4 operate as a gas-fueled generation assets.

Q. Could you infer from this trend how far natural-gas prices would have had to fall for gas conversion to have been favorable to installation of SCR systems at Jim Bridger Units 3 and 4?

A. Yes. Exhibit PAC/507 graphically displays the relationship between the nominal levelized natural-gas price at Opal over the period 2016 through 2030 and the PVRR(d) benefit/cost of continued coal operation of Jim Bridger Units 3 and 4 with installation of SCR emission control systems. To isolate the effects of CO_2 prices, which as I described earlier were 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 CO_2 price assumption was used. Based on this trend, levelized natural-gas prices over the period 2016 through 2030 would have to decrease by 15 percent, from $5.72 per MMBtu to $4.86 per MMBtu, to achieve a breakeven PVRR(d).

Q. How did 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 SCR emission control systems. 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 SCR systems required 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 lead to relatively lower cost of emissions for the gas conversion alternative and offset the costs related to any generation lost from the coal-fueled Jim Bridger Units 3 and 4 assets.

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

A. Exhibit PAC/508 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 installing the SCR emission control systems. 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 were paired with the same underlying base case natural-gas price assumption. Based upon the trend between PVRR(d) and nominal levelized CO_2 price assumptions, the levelized CO_2 prices over the period 2016 through 2030 would need to exceed $30 per ton, more than three times the base case nominal levelized CO_2 price assumption, to achieve a breakeven PVRR(d) for the Jim Bridger Unit 3 and Unit 4 SCR emission control systems.

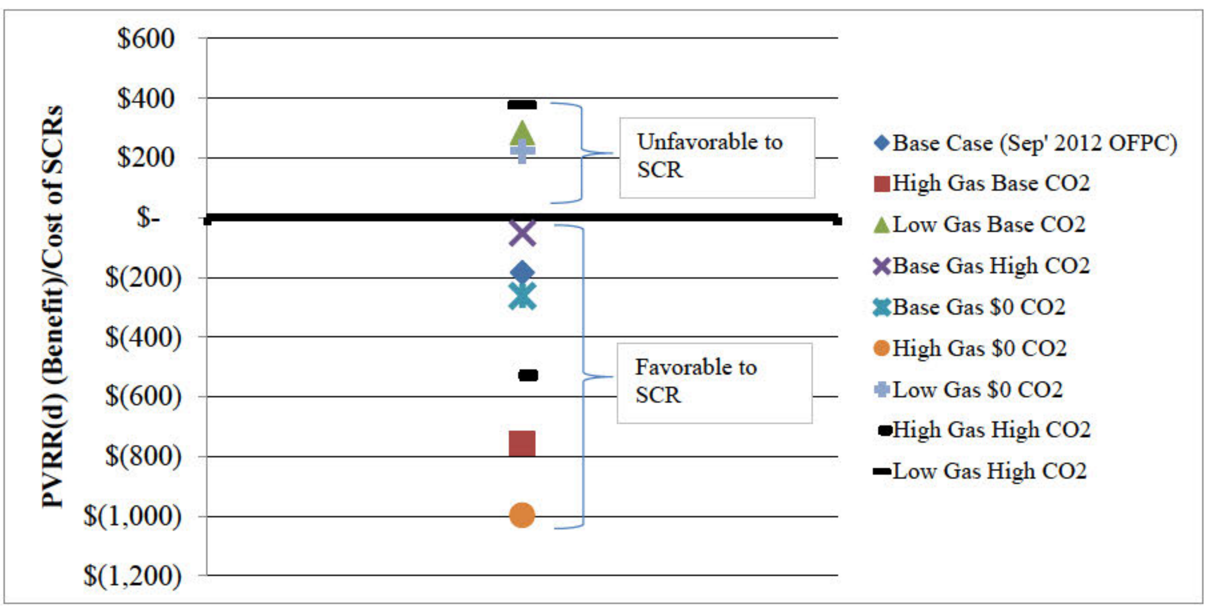
Q. How did PacifiCorp use the natural-gas and CO_2 price scenario results to inform its decision to install the Jim Bridger Unit 3 and Unit 4 SCR emission control systems?

A. PacifiCorp first reviewed the magnitude of the PVRR(d) results from the base case, which is defined by assumptions representing the company's best estimate of forward-looking assumptions at the time the analysis was completed. The base-case results provided an initial look at how favorable or unfavorable the SCR systems are in relation to the next best alternative and provided context when reviewing scenario results. The base case results summarized earlier in my testimony yield a PVRR(d) showing that the Jim Bridger Unit 3 and Unit 4 SCR systems would be $183 million lower cost than the natural-gas conversion alternative. This outcome also shows that when PacifiCorp's best estimate of forward-looking assumptions were used, there was a reasonably sized "cushion" in the PVRR(d) results allowing for some erosion of the favorable economics should long-term natural-gas prices or CO_2 prices change from what was assumed in the base case analysis. The natural-gas and CO_2 price scenarios were then used to quantify how sensitive the PVRR(d) results are to these key assumptions and provided a foundation for judging risk.

Q. Can you describe how PacifiCorp evaluated risk in the context of the results from the natural-gas and CO_2 price scenarios?

A. Yes. Figure 3 shows the distribution of PVRR(d) results for the base case and the eight natural-gas and CO_2 price scenarios. The figure shows that of the nine cases analyzed, six scenarios produce a PVRR(d) favorable to the SCR systems and the three scenarios with low gas price assumptions produce a PVRR(d) that was unfavorable to the SCR systems. The figure further illustrates the range of potential PVRR(d) outcomes among the scenarios analyzed. At one end of the spectrum, the PVRR(d) for the high gas, zero CO_2 scenario is \$997 million favorable to the SCR systems. On the other end of the spectrum, the PVRR(d) for the low gas high CO_2 scenario is \$378 million unfavorable to the Jim Bridger Unit 3 and Unit 4 SCR systems. Among the scenarios analyzed, the distribution of PVRR(d) outcomes indicate a disproportionate risk profile. While there is a possibility that the evolution of future natural-gas prices could have rendered the decision to invest in SCR systems to be higher cost than a gas conversion alternative, the cost impacts to customers of such an outcome were projected to be higher under a gas conversion alternative should future natural-gas prices rise relative to the base case.

Figure 3. Distribution of Scenario PVRR(d) Results

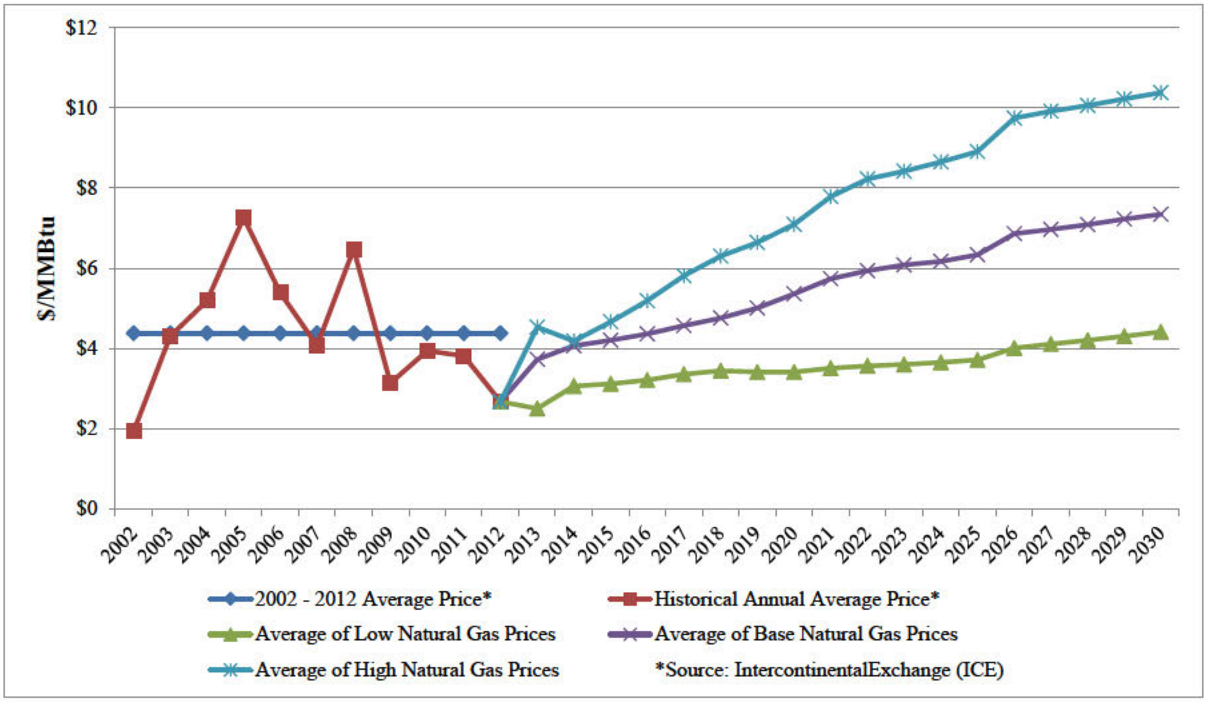


Q. Given the impact of low gas prices on the PVRR(d) results, how did you analyze the uncertainty around future natural-gas prices?

A. I compared the potential range of future natural-gas price scenarios in the context of historical natural-gas price levels. Figure 4 plots historical natural-gas prices alongside the average annual natural-gas price at Opal among the three low natural-gas price scenarios, the three base natural-gas price scenarios, and the three high natural-gas price scenarios.

Opal natural-gas prices in the low natural-gas price scenarios never reach 2002 to 2012 historical average prices over the course of the next 18 years. Among the low natural-gas price scenarios, the average annual price for natural gas at Opal over the period 2013 through 2030 is $3.59 per MMBtu, which is 18 percent below 2002–2012 historical price levels. Among the base natural-gas price scenarios, which are representative of the best estimate of forward-looking assumptions available at the time, the average annual price for Opal natural gas was $5.66 per MMBtu, or 29 percent above 2002–2012 historical price levels. Among the high natural-gas price scenarios, Opal natural-gas prices averaged $7.60 per MMBtu, representing a 73-percent increase relative to 2002-2012 historical prices.

Figure 4. Average Annual Natural-Gas Prices at Opal



Q. Did PacifiCorp consider the impact of changing market conditions on its Jim Bridger SCR analysis before issuing a full notice to proceed in December 2013?

A. Yes. PacifiCorp's economic analysis was designed to allow for rapid re-assessment of the PVRR(d) between the SCR and natural-gas conversion compliance alternatives with changing market conditions, complementing flexibility provisions that were negotiated in the engineering, procurement, and construction contract. PacifiCorp used this analysis when choosing installation of SCR emission control systems as the best compliance alternative in May 2013 and to assess how changes in market conditions affected customer benefits before issuing the full notice to proceed in December 2013.

Q. What were forward natural-gas prices at the time PacifiCorp committed to installing SCR systems at Jim Bridger Units 3 and 4?

A. Levelized natural-gas prices at Opal over the period 2016 through 2030 from the September 2013 OFPC, the most current OFPC at the time the full notice to proceed was issued, were $5.35 per MMBtu. Based upon the relationship described above, the predicted PVRR(d) with natural-gas prices applicable at the time PacifiCorp committed to install SCR systems at Jim Bridger Units 3 and 4 would have been approximately $130 million lower cost than the gas conversion alternative.

Q. Based on the analysis described above, was it in customers' best interest to pursue the installation of SCR emission control systems at Jim Bridger Units 3 and 4?

A. Yes. The economic analysis conducted by PacifiCorp clearly showed that installation of the SCR emission control systems was the least-cost, least-risk alternative.

Early Retirement Sensitivity Analysis

Q. Did PacifiCorp's base case and scenario analyses allow for early retirement as an alternative to the SCR emission control systems?

A. Yes. The PVRR(d) was calculated by taking the difference in system costs between two SO model simulations. One simulation assumed the SCR emission control systems would be installed and Jim Bridger Unit 3 and Unit 4 would continue operating as coal-fueled assets. The second simulation forced Jim Bridger Unit 3 and Unit 4 to stop operating as coal-fueled assets, allowing the model to choose among the most economical alternative, which includes gas conversion and early retirement. In all of the simulations forcing Jim Bridger Unit 3 and Unit 4 to stop operating as coal-fueled assets, the SO model chose gas conversion over early retirement when it is was assumed that the SCR emission control systems would not be installed.

Q. Did PacifiCorp perform an additional sensitivity that showed gas conversion would be a lower cost alternative to the SCR emission control systems than an early-retirement alternative?

A. Yes. For this sensitivity, in the case where Jim Bridger Unit 3 and Unit 4 were assumed to stop operating as coal-fueled assets, each unit was forced to retire (not allowing it to choose gas conversion) for purposes of calculating the PVRR(d).

Q. What are the results of this sensitivity analysis?

A. When Jim Bridger Unit 3 and Unit 4 were forced to retire early, the SO model added a 597 MW combined-cycle unit located in southern Utah in 2017.[5] As compared to an early retirement alternative, the PVRR(d) is $588 million in favor of the Jim Bridger Unit 3 and Unit 4 SCR emission control systems. The sensitivity also shows that gas conversion, while unfavorable to the SCR systems, has a PVRR(d) that is $405 million favorable to early retirement.

IV. WIND REPOWERING

<u>2017 Integrated Resource Plan</u>

Q. Did PacifiCorp analyze wind repowering in its 2017 IRP?

A. Yes. The preferred portfolio in the 2017 IRP, representing PacifiCorp's least-cost, least-risk plan to reliably meet customer demand over a 20-year planning period, includes repowering of 905 MW of existing wind resource capacity located in

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[5]Incremental front office transactions are also included in the portfolio when Jim Bridger Unit 3 and 4 are forced to retire early.

Wyoming, Washington, and Oregon. As discussed later in my testimony, PacifiCorp has since expanded the wind repowering scope to include its Goodnoe Hills wind facility. With the addition of Goodnoe Hills, PacifiCorp is planning to repower approximately 999 MW of existing wind capacity.

Q. What led PacifiCorp to evaluate the wind repowering opportunity in its 2017 IRP?

A. As explained in Mr. Timothy J. Hemstreet's testimony (Exhibit PAC/600), PacifiCorp purchased safe-harbor equipment from General Electric International, Inc., and Vestas American Wind Technology, Inc., in December 2016. Consistent with Internal Revenue Service (IRS) guidance, these equipment purchases, totaling $77.8 million, secured an option for PacifiCorp to repower its fleet of owned wind resources, thereby qualifying them for the full value of federal PTCs.

Wind repowering presents an opportunity to deliver several different types of benefits for customers. First, federal PTCs will apply to 10 additional years of generation from each repowered wind resource. The current value of federal PTCs, which is adjusted annually for inflation by the IRS, is $24/megawatt-hour (MWh). At a federal and state effective tax rate of 24.587 percent, the current PTC equates to a $31.82/MWh reduction in revenue requirement that can be passed through to customers.

Second, existing wind resources will be upgraded with modern technology, which improves efficiency and increases energy output. The additional energy output from these zero-fuel-cost assets provides incremental NPC benefits for customers.

Third, repowering a wind resource, which replaces the mechanical equipment of an existing wind facility, resets the usable life of the asset (currently 30 years), thereby extending and increasing NPC benefits over the period in which the repowered wind resource would have otherwise been retired from service.

Finally, the turbine-supply contracts for repowering will include a two-year warranty on the new equipment, which will avoid capital expenditures that would otherwise be needed to replace or refurbish existing equipment. Moreover, PacifiCorp anticipates that new, modern equipment will have reduced failure rates. Further, before installing the new equipment, PacifiCorp can avoid capital replacement costs for component failures on the existing equipment. This cost savings will be partially offset by lost energy output for specific wind turbines from the time that component failures occur through the time that the new equipment is installed.

After executing its safe-harbor equipment purchase in December 2016, PacifiCorp developed a wind repowering sensitivity in the first quarter of 2017, for consideration in its 2017 IRP, to evaluate potential net customer benefits.

Q. What wind resources did PacifiCorp include in the wind repowering sensitivity presented in its 2017 IRP?

A. PacifiCorp assumed repowering 905 MW of existing wind resource capacity in the 2017 IRP. Of the 905 MW, approximately 594 MW of this capacity are located in Wyoming (Glenrock, Rolling Hills, Seven Mile Hill, High Plans, McFadden Ridge, and Dunlap), approximately 101 MW are located in Oregon (Leaning Juniper), and approximately 210 MW are located in Washington (Marengo). PacifiCorp has since expanded its economic analysis to include Goodnoe Hills, which is located in Washington.

Q. What were the results of the wind repowering sensitivity presented in PacifiCorp's 2017 IRP?

A. The 2017 IRP wind repowering sensitivity showed significant net customer benefits across a range of assumptions related to forward market prices and possible federal CO_2 policy.

Q. Did the wind repowering sensitivity influence selection of the preferred portfolio in the 2017 IRP?

A. Yes. The wind repowering sensitivity included in the 2017 IRP showed significant net customer benefits by lowering the projected system present-value revenue requirement (PVRR) relative to other resource portfolio options. Consequently, wind repowering was included in the 2017 IRP preferred portfolio, which represents PacifiCorp's plan to deliver reliable and reasonably priced service with manageable risk for customers through specific action items.

Q. Did PacifiCorp include a wind repowering action item in its 2017 IRP action plan?

A. Yes. The 2017 IRP action plan, which lists the specific steps PacifiCorp will take over the next two to four years to deliver resources in the preferred portfolio, includes the following action item:

> PacifiCorp will implement the wind repowering project, taking advantage of safe-harbor wind-turbine-generator equipment purchase agreements executed in December 2016.

- Continue to refine and update economic analysis of plant-specific wind repowering opportunities that maximize customer benefits before issuing the notice to proceed.

- By September 2017, complete technical and economic analysis of other potential repowering opportunities at PacifiCorp wind plants not studied in the 2017 IRP (i.e., Foote Creek I and Goodnoe Hills).

- Pursue regulatory review and approval as necessary.

- By May 2018, issue the engineering, procurement and construction (EPC) notice to proceed to begin implementing wind repowering for specific projects consistent with updated financial analysis.

- By December 31, 2020, complete installation of wind repowering equipment on all identified projects.[6]

Q. Please summarize PacifiCorp's progress with this action item.

A. PacifiCorp refined and updated its economic analysis of plant-specific wind repowering opportunities, and is now including Goodnoe Hills in the wind repowering project. The economic analysis has also been updated to reflect more current assumptions resulting from recent changes in the federal tax rate for corporations. The rest of my testimony presents and explains this economic analysis. Mr. Hemstreet explains that PacifiCorp continues to evaluate repowering of the Foote Creek facility in Wyoming, but due to differences in project scope for this older-vintage facility, Foote Creek was not included in the economic analysis of the wind repowering project at this time. Mr. Hemstreet also discusses the need to execute contracts by [redacted] and addresses the construction schedule.

[6] PacifiCorp 2017 Integrated Resource Plan, Volume I at 16 (Apr. 4, 2017).

System Modeling Methodology

Q. Please summarize the methodology PacifiCorp used in its system analysis of the wind repowering project.

A. PacifiCorp relied upon the same modeling tools used to develop and analyze resource portfolios in its 2017 IRP to refine and update its analysis of the wind repowering project. These modeling tools calculate a system PVRR by identifying least-cost resource portfolios and dispatching system resources over a 20-year forecast period (2017–2036). Net customer benefits are calculated as the PVRR(d) between two simulations of PacifiCorp's system. One simulation includes the wind repowering project and the other simulation excludes the wind repowering project. Customers are expected to realize benefits when the system PVRR with wind repowering is lower than the system PVRR without repowering. Conversely, customers would experience increased costs if the system PVRR with wind repowering were higher than the system PVRR without wind repowering.

Q. What modeling tools did PacifiCorp use to perform its system analysis of the wind repowering project?

A. PacifiCorp used the SO model and the Planning and Risk model (PaR) to develop resource portfolios and to forecast dispatch of system resources in simulations with and without wind repowering.

Q. Please describe the SO model and PaR.

A. The SO model is used to develop resource portfolios with sufficient capacity to achieve a target planning-reserve margin. The SO model selects a portfolio of resources from a broad range of resource alternatives by minimizing the system

PVRR. In selecting the least-cost resource portfolio for a given set of input assumptions, the SO model performs time-of-day, least-cost dispatch for existing resources and prospective resource alternatives, while considering the cost-and-performance characteristics of existing contracts and prospective demand-side-management (DSM) resources—all within or connected to PacifiCorp's system. The system PVRR from the SO model reflects the cost of existing contracts, wholesale-market purchases and sales, the cost of new and existing generating resources (fuel, fixed and variable O&M, and emissions, as applicable), the cost of new DSM resources, and levelized revenue requirement of capital additions for existing coal resources and potential new generating resources.

PaR is used to develop a chronological unit commitment and dispatch forecast of the resource portfolio generated by the SO model, accounting for operating reserves, volatility and uncertainty in key system variables. PaR captures volatility and uncertainty in its unit commitment and dispatch forecast by using Monte Carlo sampling of stochastic variables, which include load, wholesale electricity and natural-gas prices, hydro generation, and thermal unit outages. PaR uses the same common input assumptions that are used in the SO model, with resource-portfolio data provided by the SO model results. The PVRR from the PaR model reflects a distribution of system variable costs, including variable costs associated with existing contracts, wholesale-market purchases and sales, fuel costs, variable O&M costs, emissions costs, as applicable, and costs associated with energy or reserve deficiencies. Fixed costs that do not change with system dispatch, including the cost of DSM resources, fixed O&M costs, and the levelized revenue requirement of capital additions for existing coal resources and potential new generating resources, are based on the fixed costs from the SO model, which are combined with the distribution of PaR variable costs to establish a distribution of system PVRR for each simulation.

Q. How has PacifiCorp historically used the SO model and PaR?

A. PacifiCorp uses the SO model and PaR to produce and evaluate resource portfolios in its IRP. PacifiCorp also uses these models to analyze resource-acquisition opportunities, resource retirements, resource capital investments, and system transmission projects. The models were used to support the successful acquisition of the Chehalis combined-cycle plant, to support selection of the Lake Side 2 combined-cycle resource through a RFP process, and as discussed earlier in my testimony, the SO model has been used to evaluate installation of emissions control systems. These models will also be used to evaluate bids in PacifiCorp's recent 2017R RFP, issued to solicit bids for new wind resources, and in PacifiCorp's recent 2017S RFP, issued to solicit bids for new solar resources.

Q. Are the SO model and PaR the appropriate tools for analyzing the wind repowering opportunity?

A. Yes. The SO model and PaR are the appropriate modeling tools when evaluating significant capital investments that influence PacifiCorp's resource mix and affect least-cost dispatch of system resources. The SO model simultaneously and endogenously evaluates capacity and energy trade-offs associated with resource capital projects and is needed to understand how the type, timing, and location of future resources might be affected by the wind repowering project. PaR provides additional granularity on how wind repowering is projected to affect system operations, recognizing that key system conditions are volatile and uncertain. Together, the SO model and PaR are best suited to perform a net-benefit analysis for the wind repowering opportunity that is consistent with long-standing least-cost, least-risk planning principles applied in PacifiCorp's IRP.

Q. How did PacifiCorp use PaR to assess stochastic system cost risk associated with wind repowering?

A. Just as it evaluates resource-portfolio alternatives in the IRP, PacifiCorp uses the stochastic-mean PVRR and risk-adjusted PVRR, calculated from PaR study results, to assess the stochastic system cost risk of repowering. With Monte Carlo sampling of stochastic variables, PaR produces a distribution of system variable costs. The stochastic-mean PVRR is the average of net variable operating costs from the distribution of system variable costs, combined with system fixed costs from the SO model. PacifiCorp uses a risk-adjusted PVRR to evaluate stochastic system cost risk. The risk-adjusted PVRR incorporates the expected value of low-probability, high-cost outcomes. The risk-adjusted PVRR is calculated by adding five percent of system variable costs, from the 95th percentile of the distribution of system variable costs, to the stochastic-mean PVRR.

When applied to the wind repowering analysis, the stochastic-mean PVRR represents the expected level of system costs from cases with and without repowering. The risk-adjusted PVRR is used to assess whether wind repowering causes a disproportionate increase to system variable costs under low-probability, high-cost system conditions.

Q. Please describe how the effective combined federal and state income tax rate assumption is applied in the SO model and the PaR in the economic analysis.

A. The effective combined federal and state income tax rate affects PacifiCorp's post-tax weighted average cost of capital, which is used as the discount rate in the SO model and PaR. With the recent changes in tax law, PacifiCorp's discount rate is 6.91 percent.

The income tax rate also affects the capital revenue requirement for all new resource options available for selection in the SO model. Capital revenue requirement is levelized in the SO and PaR models to avoid potential distortions in the economic analysis of capital-intensive assets that have different lives and in-service dates. This is achieved through annual capital recovery factors, which are expressed as a percentage of the initial capital investment for any given resource alternative in any given year. Capital recovery factors, which are based on the revenue requirement for specific types of assets, are differentiated by each asset's assumed life, book-depreciation rates, and tax-depreciation rates. Because capital revenue requirement accounts for the impact of income taxes on rate-based assets, the capital recovery factors applied to new resource costs in the SO model were reflected for each system simulation.

Finally, the income tax rate affects the tax gross-up of all PTC-eligible resources. The current value of federal PTCs is $24/MWh, which equates to a $31.82/MWh reduction in revenue requirement assuming an effective combined federal and state income tax rate of 24.587 percent. The impact of the income tax rate assumptions were applied to all PTC-eligible resource alternatives available in the SO model.

Q. Did PacifiCorp analyze how other assumptions affect its economic analysis of the wind repowering project?

A. Yes. In addition to assessing stochastic system cost risk, PacifiCorp analyzed the wind-repowering project under a range of assumptions regarding wholesale market prices and CO_2 policy (price-policy) assumptions. These assumptions drive NPC-related benefits, and so it is important to understand how the net-benefit analysis is affected under a range of potential outcomes. PacifiCorp developed low, medium, and high scenarios for the market price of electricity and natural gas and zero, medium, and high CO_2 price scenarios. Each pair of model simulations—with and without repowering, in both the SO model and PaR—was analyzed under each combination of these price-policy assumptions. I summarize the assumptions for each price-policy scenario later in my testimony.

Q. How did PacifiCorp assess which wind facilities to include in the scope of the wind repowering project in this application?

A. PacifiCorp completed a series of SO model and PaR studies to determine how the system PVRR changes when a specific wind facility is added or removed from the scope of the wind repowering project. This project-by-project analysis was performed by running one SO model simulation that included the full scope of the wind repowering project and then 12 separate SO model simulations where one of the repowered wind facilities is assumed to be excluded from the scope of the wind repowering project. The total system cost from the SO model simulation where all facilities are repowered and from the SO model simulation where one facility is removed from scope is used to calculate the marginal PVRR(d) for each wind facility. Using the resource portfolio from the SO model simulations, this same approach was used to calculate the PVRR(d) for each wind facility using projected system costs from PaR.

Q. What key assumptions did PacifiCorp update since analyzing the wind repowering project in its 2017 IRP?

A. Beyond the price-policy assumptions used to analyze a range of NPC-related benefits, the updated wind repowering analysis reflects updated assumptions for up-front capital costs, run-rate operating costs, and energy output for both the existing and repowered wind facilities. PacifiCorp's analysis assumes an up-front capital investment totaling approximately $1.101 billion with a 25.7 percent average increase in annual energy output (738 gigawatt-hours (GWh) per year). The cost and performance assumptions for the wind facilities studied in this updated economic analysis are summarized in Confidential Exhibit PAC/509.

Q. Did PacifiCorp analyze potential energy imbalance market (EIM) benefits in its wind repowering analysis?

A. Yes. In its final 2017 IRP resource-portfolio screening process, PacifiCorp described how the EIM can provide potential benefits when incremental energy is added to transmission-constrained areas of Wyoming. Unscheduled or unused transmission from participating EIM entities enables more efficient power flows within the hour. With increasing participation in the EIM, there will be increasing opportunities to move incremental energy from Wyoming to offset higher-priced generation in the

PacifiCorp system or other EIM participants' systems. The more efficient use of transmission that is expected with growing participation in the EIM was captured in the wind repowering analysis by increasing the transfer capability between the east and west sides of PacifiCorp's system by 300 MW (from the Jim Bridger plant to south-central Oregon). The ability to more efficiently use intra-hour transmission from a growing list of EIM participants is not driven by the wind repowering project; however, this increased connectivity provides the opportunity to move low-cost incremental energy out of transmission-constrained areas of Wyoming.

Q. How did PacifiCorp account for the unrecovered investments in the original equipment that will be replaced with new equipment?

A. The economic analysis assumes that PacifiCorp will fully recover the unrecovered investment in the original equipment and earn its authorized rate of return on the unrecovered balance over the remainder of the original 30-year depreciable life of each repowered facility. Ms. Shelley E. McCoy (Exhibit PAC/1100) describes PacifiCorp's proposed accounting treatment for the replaced equipment.

Q. Did PacifiCorp assume any salvage value for the equipment that will be replaced with repowering?

A. No. But any salvage value for the existing equipment would decrease the unrecovered investment and increase customer benefits.

<u>Annual Revenue Requirement Modeling Methodology</u>

Q. In addition to the system modeling used to calculate present-value net benefits over a 20-year planning period, has PacifiCorp forecasted the change in nominal-annual revenue requirement due to the wind repowering project?

A. Yes. The system PVRR from the SO model and PaR is calculated from an annual stream of forecasted revenue requirement over a 20-year time frame, consistent with the planning period in the IRP. The annual stream of forecasted revenue requirement captures nominal revenue requirement for non-capital items (*e.g.*, NPC, fixed O&M) and levelized revenue requirement for capital expenditures. To estimate the annual revenue-requirement impacts of repowering, project capital costs need to be considered in nominal terms (*i.e.*, not levelized).

Q. Why is the capital revenue requirement used in the calculation of the system PVRR from the SO model and PaR levelized?

A. Levelization of capital revenue requirement is necessary in these models to avoid potential distortions in the economic analysis of capital-intensive assets that have different lives and in-service dates. Without levelization, this potential distortion is driven by how capital costs are included in rate base over time. Capital revenue requirement is generally highest in the first year an asset is placed in service and declines over time as the asset depreciates.

Consider the potential implications of modeling nominal capital revenue requirement for a future generating resource needed in 2036, the last year of the 2017 IRP planning period. If nominal capital revenue requirement were assumed, the model would capture in its economic assessment of resource alternatives the highest, first-year revenue requirement capital cost without having any foresight on the potential benefits that resource would provide beyond 2036. If nominal capital costs were applied, the model's economic assessment of resource alternatives for the 2036 resource need would inappropriately favor less capital-intensive projects or projects having longer asset lives, even if those alternatives would increase system costs over their remaining life. Levelized capital costs for assets that have different lives and in-service dates is an established way to address these types of distortions in the comparative economic analysis of resource alternatives.

Q. How did PacifiCorp forecast the annual revenue-requirement impacts of the wind repowering project?

A. In the models that exclude repowered wind, the annual stream of costs for wind facilities that are within the wind repowering scope, including levelized capital, are removed from the annual stream of costs used to calculate the stochastic-mean system PVRR. Similarly, in the simulation that includes repowered wind, the annual stream of costs for repowered wind facilities, including levelized capital and PTCs, are temporarily removed from the annual stream of costs used to calculate the stochastic-mean PVRR. The differential in the remaining stream of annual costs, which includes all system costs except for those associated with the wind facilities that are within the wind repowering scope, represents the net system benefit caused by the wind repowering project.

These data are disaggregated to isolate the estimated annual NPC benefits, other non-NPC variable-cost benefits (*i.e.*, variable O&M and emissions costs for those scenarios that include a CO_2 price assumption), and fixed-cost benefits. To complete the annual revenue-requirement forecast, the change in fixed costs for those wind facilities included in the wind repowering scope, including nominal capital revenue requirement and PTCs, are added back in with the annual system net benefits caused by wind repowering.

Q. Over what time frame did PacifiCorp estimate the change in annual revenue requirement due to the wind repowering project?

A. The change in annual revenue requirement was estimated through 2050. This captures the full 30-year life of the new equipment installed on repowered wind facilities.

Q. How did PacifiCorp calculate the net annual benefits caused by wind repowering beyond the 20-year forecast period used in PaR?

A. The PaR forecast period runs from 2017 through 2036. The change in net system benefits caused by wind repowering over the 2028-through-2036 time frame, expressed in dollars-per-MWh of incremental energy output from wind repowering, were used to estimate the change in system net benefits from 2037 through 2050. This calculation was performed in several steps.

First, the net system benefits caused by wind repowering were divided by the change in incremental energy expected from the wind repowering project, as modeled in PaR over the 2028-through-2036 time frame. Next, the net system benefits per MWh of incremental energy from the repowered wind projects over the 2028-through-2036 time frame were levelized. These levelized results were extended out through 2050 at inflation. The levelized net system benefits per MWh of incremental energy output from the repowered wind projects over the 2037-through-2050 time frame were then multiplied by the change in incremental energy output from repowered wind projects over the same period.

Q. Why did PacifiCorp use PaR results from the 2028-through-2036 time frame to extend system cost impacts out through 2050?

A. Consistent with the 2017 IRP, PacifiCorp's wind repowering analysis assumes the Dave Johnston coal plant, located in eastern Wyoming, retires at the end of 2027. When this plant is assumed to retire, transmission congestion affecting energy output from resources in eastern Wyoming, where many repowered wind resources are located, is reduced. The incremental energy output from repowered wind resources provides more system benefits when not constrained by transmission limitations. Consequently, the net system benefits caused by wind repowering over the 2028-through-2036 time frame, after Dave Johnston is assumed to retire, is representative of net system benefits that could be expected beyond 2036.

Q. Did PacifiCorp calculate a PVRR(d) for the wind repowering project using its estimate of annual revenue-requirement impacts projected out through 2050?

A. Yes.

Q. Does the PVRR(d) calculated from estimated annual revenue requirement through 2050 capture wind repowering benefits not included in the PVRR(d) calculated from the 20-year forecast coming out of the SO model and PaR?

A. Yes. The PVRR(d) calculated off of estimated annual revenue requirement extended out through 2050 captures the significant increase in projected wind energy output beyond the 20-year forecast period.

Q. Why is there a significant increase in projected wind energy output beyond the 20-year forecast period ending 2036?

A. The change in wind energy output between cases with and without repowering experiences a step change in the 2036-through-2040 time frame, when the wind facilities, originally placed in-service during the 2006-through-2010 time frame, would otherwise have hit the end of their depreciable life. Before the 2036-through-2040 time frame, the change in wind energy output reflects the incremental energy production that results from installing modern equipment on repowered wind assets. Beyond the 2036-through-2040 time frame, the change in wind energy output between a case with and without repowering reflects the full energy output from the repowered wind facilities that would otherwise be retired.

<u>Price-Policy Scenarios</u>

Q. Please explain why price-policy scenarios are important when analyzing the wind repowering project.

A. Wholesale-power prices, often set by natural-gas prices, and the system cost impacts of potential CO_2 policies influence the forecast of net system benefits from wind repowering. Wholesale-power prices and CO_2 policy outcomes affect the value of system energy, the dispatch of system resources, and PacifiCorp's resource mix. Consequently, wholesale-power prices and CO_2 policy assumptions affect NPC benefits, non-NPC variable cost benefits, and system fixed-cost benefits of wind repowering. Because wholesale-power prices and CO_2 policy outcomes are both uncertain and important drivers to the wind repowering analysis, PacifiCorp studied the economics of the wind repowering project under a range of different price-policy scenarios.

Q. What price-policy scenarios did PacifiCorp use in its wind repowering analysis?

A. PacifiCorp analyzed the wind repowering project under nine different price-policy scenarios. PacifiCorp developed three wholesale-power price scenarios (low, medium, and high), and similarly developed three CO_2 policy scenarios (zero, medium, and high). The nine price-policy scenarios developed for the wind repowering analysis reflect different combinations of these scenario assumptions.

Considering that there is a high level of correlation between wholesale-power prices and natural-gas prices, the wholesale-power price scenarios were based on a range of natural-gas price assumptions. This ensures consistency between power price and natural-gas price assumptions for each scenario. PacifiCorp implemented its CO_2 policy assumptions through a CO_2 price, expressed in dollars-per-ton recognizing that it is possible that future CO_2 policies targeting electric-sector emissions could be adopted and impose incremental costs to drive emission reductions. CO_2 price assumptions used in the price-policy scenarios are not intended to mimic a specific type of policy mechanism (*i.e.*, a tax or an allowance price under a cap-and-trade program), but are intended to recognize that there might be future CO_2 policies that impose a cost to reduce emissions.

Q. Please describe the natural-gas price assumptions used in the price-policy scenarios.

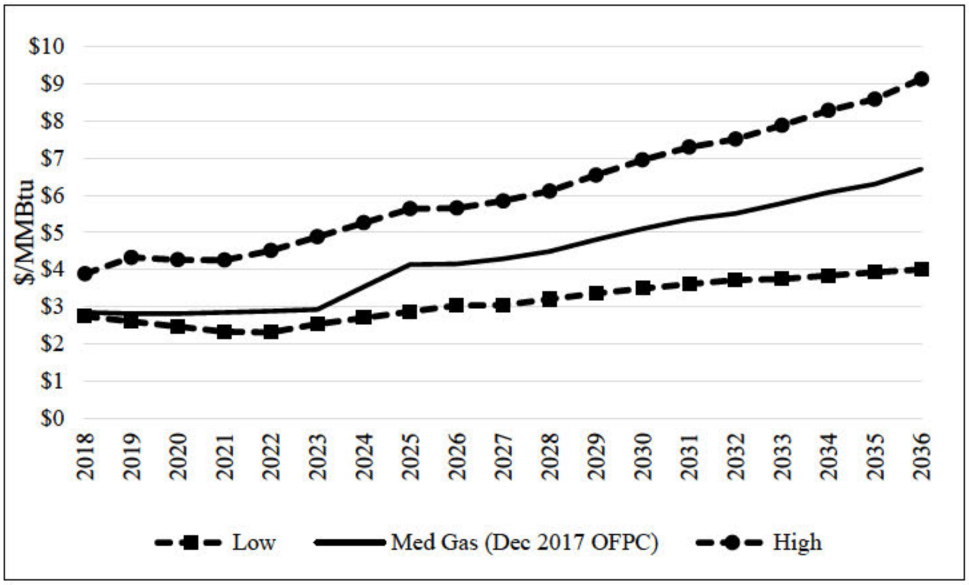
A. The medium-natural-gas price assumptions that are paired with zero CO_2 prices reflect natural-gas prices from PacifiCorp's OFPC dated December 29, 2017. This

OFPC uses observed forward market prices as of December 29, 2017, for 72 months, followed by a 12-month transition to natural-gas prices based on a forecast developed by [redacted]. The medium-, low-, and high-natural-gas price assumptions used for all other scenarios were chosen after reviewing a range of credible third-party forecasts developed by [redacted], and the U.S. Department of Energy's Energy Information Administration. Confidential Exhibit PAC/510 shows the range in natural-gas price assumptions from these third-party forecasts relative to those adopted for the price-policy scenarios to evaluate the wind repowering project.

The low-natural-gas price assumption was derived from a low-price scenario developed by [redacted]. The medium-natural-gas price assumption, which is used beyond month 84 in the December 2017 OFPC, and in all months when medium-natural-gas prices are paired with medium or low CO_2 price assumptions, is based on a base-case forecast from [redacted] that is reasonably aligned with other base-case forecasts. The high-natural-gas price assumption was based on a high-price scenario from [redacted] that is characterized by exaggerated boom-bust cycles (cyclical periods of high prices and low prices). PacifiCorp smoothed the boom-bust cycle in this third party's high-price scenario because the specific timing of these cycles are extremely difficult to project with reasonable accuracy.

Figure 5 shows Henry Hub natural-gas price assumptions from the December 2017 OFPC, low-, and high-natural-gas price scenarios.

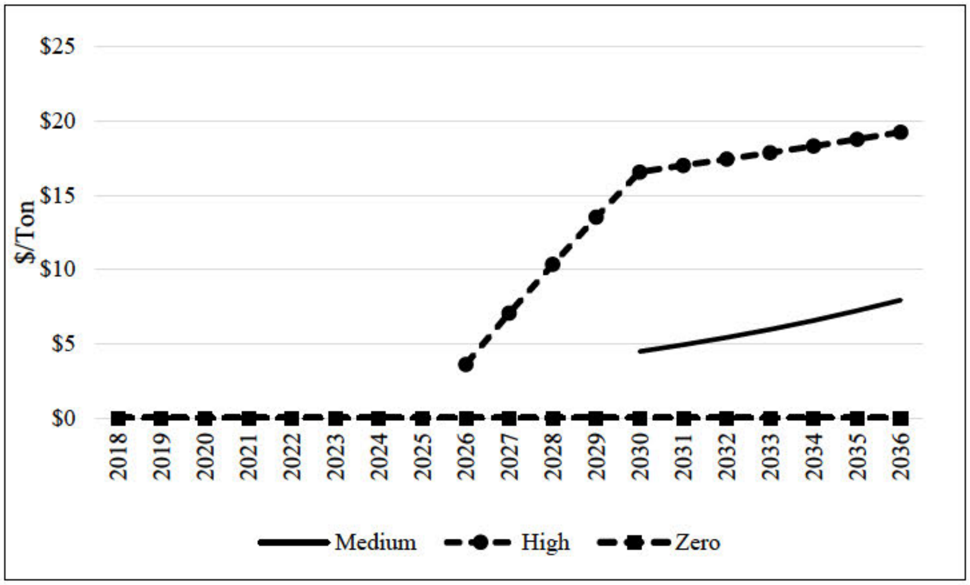
Figure 5. Nominal Natural-Gas Price Scenarios



Q. Please describe the CO_2 price assumptions used in the price-policy scenarios.

A. As with natural-gas prices, the medium and high CO_2 price assumptions are based on third-party projections from [redacted]. To bracket the low end of potential policy outcomes, PacifiCorp assumes there are no future policies adopted that would require incremental costs to achieve emissions reductions in the electric sector. In this scenario, the assumed CO_2 price is zero. Figure 6 shows the CO_2 price assumptions used to analyze the wind repowering project.

Figure 6. Nominal CO_2 Price Scenarios



Project-by-Project Results

Q. What price-policy scenarios were used in the project-by-project analysis?

A. PacifiCorp used two price-policy scenarios—the low natural-gas and zero CO_2 price-policy scenario and the medium natural-gas and medium CO_2 price-policy scenario. Based on the results of these two price-policy scenarios, the company determined which individual projects are expected to provide net customer benefits, and then these projects were analyzed under all price-policy scenarios.

Q. Please summarize the project-by-project PVRR(d) results calculated from the SO model and PaR through 2036 when assuming medium natural-gas and medium CO_2 price-policy assumptions.

A. Table 2 summarizes the PVRR(d) results for each wind facility within the scope of the wind repowering project. The PVRR(d) between cases with and without wind repowering are shown for each wind facility based on system modeling results from the SO model and PaR, before accounting for the substantial increase in incremental energy beyond the 2036 time frame. When applying medium natural-gas and medium CO_2 price-policy assumptions, benefits from repowering the Leaning Juniper wind facility are equal to costs. All other wind facilities are projected to deliver net benefits.

Table 2. Project-by-Project SO Model and PaR PVRR(d) (Benefit)/Cost of Wind Repowering with Medium Natural-Gas and Medium CO_2 Price-Policy Assumptions ($ million)

Wind Facility	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Glenrock 1	($25)	($21)	($23)
Glenrock 3	($8)	($7)	($7)
Seven Mile Hill 1	($33)	($28)	($29)
Seven Mile Hill 2	($7)	($7)	($7)
High Plains	($17)	($13)	($13)
McFadden Ridge	($5)	($4)	($4)
Dunlap Ranch	($30)	($26)	($27)
Rolling Hills	($12)	($9)	($10)
Leaning Juniper	($0)	($0)	($0)
Marengo 1	($35)	($33)	($34)
Marengo 2	($15)	($14)	($15)
Goodnoe Hills	($18)	($18)	($19)
Total	($205)	($180)	($189)

Q. Please summarize the project-by-project PVRR(d) results calculated from the SO model and PaR through 2036 when assuming low natural-gas and zero CO_2 price-policy assumptions.

A. Table 3 summarizes the PVRR(d) results for each wind facility within the scope of the wind repowering project. The PVRR(d) between cases with and without wind repowering are shown for each wind facility based on system modeling results from the SO model and PaR, before accounting for the substantial increase in incremental energy beyond the 2036 time frame. When applying low natural-gas and zero CO_2 price-policy assumptions, costs from repowering the Leaning Juniper wind facility are slightly higher than the benefits. All other wind facilities are projected to deliver net benefits.

Table 3. Project-by-Project SO Model and PaR PVRR(d) (Benefit)/Cost of Wind Repowering with Low Natural-Gas and Zero CO_2 Price-Policy Assumptions ($ million)

Wind Facility	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Glenrock 1	($21)	($21)	($22)
Glenrock 3	($7)	($6)	($6)
Seven Mile Hill 1	($28)	($28)	($29)
Seven Mile Hill 2	($6)	($6)	($6)
High Plains	($12)	($9)	($10)
McFadden Ridge	($4)	($3)	($3)
Dunlap Ranch	($25)	($22)	($24)
Rolling Hills	($9)	($7)	($7)
Leaning Juniper	$6	$3	$4
Marengo 1	($27)	($25)	($26)
Marengo 2	($11)	($10)	($11)
Goodnoe Hills	($13)	($15)	($15)
Total	($157)	($149)	($156)

Q. Please summarize the project-by-project PVRR(d) results calculated from the change in annual revenue requirement through 2050.

A. Table 4 summarizes the PVRR(d) results for each wind facility calculated off of the change in annual nominal revenue requirement through 2050 for both price-policy scenarios. Unlike the results summarized in Tables 2 and 3, these results account for the substantial increase in incremental energy beyond the 2036 time frame. Each of the wind facilities within the scope of the proposed repowering project show net benefits with repowering under the medium natural-gas and medium CO_2 price-policy scenario and all facilities show net benefits under the low-natural-gas and zero CO_2 price-policy scenario, except for the Leaning Juniper wind facility, where the benefits are equal to the costs.

Table 4. Project-by-Project Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering ($ million)

Wind Facility	Medium Natural-Gas and Medium CO_2	Low Natural-Gas and Zero CO_2
Glenrock 1	($33)	($33)
Glenrock 3	($11)	($6)
Seven Mile Hill 1	($41)	($40)
Seven Mile Hill 2	($10)	($6)
High Plains	($22)	($6)
McFadden Ridge	($7)	($2)
Dunlap Ranch	($39)	($23)
Rolling Hills	($15)	($5)
Leaning Juniper	($8)	($0)
Marengo 1	($50)	($22)
Marengo 2	($20)	($7)
Goodnoe Hills	($26)	($19)
Total	($282)	($170)

Q. **The project-by-project results vary by wind facility, and some wind facilities appear to show relatively small PVRR(d) benefits. Have you calculated the net benefits of the wind repowering project taking into account the size of each wind facility?**

A. Yes. The magnitude of the PVRR(d) results must be considered in relation to the specific attributes of the repowered wind facility, including the size of the facility, the expected cost to repower the facility, and the level of annual energy output expected after the new equipment is installed. For example, the PVRR(d) for McFadden Ridge shows a $7 million benefit when repowered (using medium natural-gas and medium CO_2 price-policy assumptions)—the lowest PVRR(d) among all of the project-by-project results. The PVRR(d) benefit for McFadden Ridge is approximately 14 percent of the $50 million benefit for Marengo I, which yields the highest PVRR(d) among all of the project-by-project results. However, the current capacity of McFadden Ridge (28.5 MW) is approximately 20 percent of the current capacity of Marengo I (140.4 MW). Similarly, the expected energy output after repowering for McFadden Ridge (approximately 117 GWh per year) is approximately 24 percent of the expected energy output after repowering for Marengo I (approximately 488 GWh per year).

A reasonable metric to evaluate the relative benefits among the wind facilities that captures the specific attributes of each facility is the nominal levelized net benefit per incremental MWh expected after the facility is repowered. This metric captures the specific repowering cost for each facility net of the specific benefits of each facility per incremental MWh of energy expected after the facility is repowered. Table 5 shows the nominal levelized net benefit of repowering per MWh of expected incremental energy output after repowering for each wind facility. When using medium natural-gas and medium CO_2 price-policy assumptions, the table shows the Seven Mile Hill II facility produces the largest net benefit per incremental MWh

($36/MWh), and Leaning Juniper produces the smallest net benefit per incremental MWh ($7/MWh).

Table 5. Nominal Levelized Net Benefit per MWh of Incremental Energy Output after Repowering ($/MWh)

Wind Facility	Medium Natural-Gas and Medium CO_2	Low Natural-Gas and Zero CO_2
Glenrock 1	$29/MWh	$29/MWh
Glenrock 3	$28/MWh	$16/MWh
Seven Mile Hill 1	$30/MWh	$29/MWh
Seven Mile Hill 2	$36/MWh	$23/MWh
High Plains	$17/MWh	$5/MWh
McFadden Ridge	$17/MWh	$5/MWh
Dunlap Ranch	$28/MWh	$17/MWh
Rolling Hills	$19/MWh	$7/MWh
Leaning Juniper	$7/MWh	$0/MWh
Marengo 1	$25/MWh	$11/MWh
Marengo 2	$21/MWh	$8/MWh
Goodnoe Hills	$26/MWh	$18/MWh
Weighted Average	$25/MWh	$16/MWh

Q. Is there an upside to the project-by-project PVRR(d) results?

A. Yes. The project-by-project results do not reflect the potential value of RECs that will be generated by the incremental energy output from each facility. For instance, as applied to the Leaning Juniper project discussed above, present-value net customer benefits would increase by approximately $1.1 million (approximately 14 percent of the PVRR(d) benefits under the medium natural-gas and medium CO_2 price-policy scenario as shown in Table 4) for every dollar assigned to the incremental RECs that will be generated from this facility. Moreover, the CO_2 price assumptions used in the economic analysis were inadvertently modeled in 2012 real dollars instead of nominal dollars. Consequently, the PVRR(d) net benefits in the medium natural-gas, medium CO_2 price-policy scenario are conservative.

Q. Based on these results, has the company decided against repowering any of the 12 facilities that were originally included in the repowering project?

A. No. The project-by-project analysis demonstrates that the proposed scope of the wind repowering project, which includes repowering 12 wind facilities with a current capacity totaling just over 999 MW is appropriate and will maximize customer benefits.

<u>**System Modeling Price-Policy Results**</u>

Q. Please summarize the PVRR(d) results for the full scope of the wind repowering project as calculated from the SO model and PaR through 2036 among all nine price-policy scenarios.

A. Table 6 summarizes the PVRR(d) results for each price-policy scenario for the full scope of the wind repowering project. The PVRR(d) between cases with and without the repowering project, are shown for the SO model and for PaR, which was used to calculate both the stochastic-mean PVRR(d) and the risk-adjusted PVRR(d). The data used to calculate the PVRR(d) results shown in the table are provided as Exhibit PAC/511.

Table 6. SO Model and PaR PVRR(d)
(Benefit)/Cost of the Wind Repowering Projects ($ million)

Price-Policy Scenario	SO Model PVRR(d)	PaR Stochastic-Mean PVRR(d)	PaR Risk-Adjusted PVRR(d)
Low Gas, Zero CO_2	($159)	($141)	($148)
Low Gas, Medium CO_2	($158)	($139)	($146)
Low Gas, High CO_2	($183)	($165)	($173)
Medium Gas, Zero CO_2	($201)	($171)	($180)
Medium Gas, Medium CO_2	($204)	($180)	($189)
Medium Gas, High CO_2	($215)	($193)	($203)
High Gas, Zero CO_2	($257)	($234)	($246)
High Gas, Medium CO_2	($260)	($248)	($260)
High Gas, High CO_2	($273)	($240)	($252)

Over a 20-year period, the wind repowering project reduces customer costs in all nine price-policy scenarios. This outcome is consistent in both the SO model and PaR results. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) net benefits range between $180 million, when derived from PaR stochastic-mean results, and $204 million, when derived from SO model results.

Q. What trends do you observe in the modeling results across the different price-policy scenarios?

A. Projected system net benefits increase with higher-natural-gas price assumptions, and similarly, generally increase with higher CO_2 price assumptions. Conversely, system net benefits generally decline when low natural-gas prices and low CO_2 prices are assumed. This trend holds true when looking at the results from the two simulations used to calculate the PVRR(d) for all nine of the price-policy scenarios. Importantly, both models show that the net benefits from the wind repowering project are robust across a range of price-policy assumptions.

Q. Is there incremental customer upside to the PVRR(d) results calculated from the SO model and PaR through 2036?

A. Yes. The PVRR(d) results presented in Table 6 do not reflect the potential value of RECs generated by the incremental energy output from the repowered facilities. Customer benefits for all price-policy scenarios would improve by approximately $6 million for every dollar assigned to the incremental RECs that will be generated from the repowered facilities through 2036. Quantifying the potential upside associated with incremental REC revenues is intended to simply communicate that the net benefits from the repowering project would improve if the incremental RECs can be monetized in the market or if those RECs are used to reduce incremental costs associated with meeting state renewable portfolio standard targets.

Q. Is there additional upside to the net benefits shown in Table 6?

A. Yes. As noted earlier in my testimony, the CO_2 price assumptions used in the economic analysis were inadvertently modeled in 2012 real dollars instead of nominal dollars. Consequently, the PVRR(d) net benefits in the six price-policy scenarios that use medium and high CO_2 price assumptions are conservative.

Q. Why do the PaR results tend to show a different level of benefits from the wind repowering project when compared to the results from the SO model?

A. The two models assess the system impacts of the wind repowering project in different ways. The SO model is designed to dynamically assess system dispatch, with less granularity than PaR, while optimizing the selection of resources to the portfolio over time. PaR is able to dynamically assess system dispatch, with more granularity than the SO model and with consideration of stochastic risk variables; however, PaR does not modify the type, timing, size, and location of resources in the portfolio in response to its more detailed assessment of system dispatch. In evaluating differences in annual system costs between the two models, PaR's ability to better simulate system dispatch relative to the SO model results in lower benefits from repowering being reported from PaR.

Q. Does one of these two models provide a better assessment of the wind repowering project relative to the other?

A. No. The two models are simply different, and both are useful in establishing a range of wind repowering benefits through the 20-year forecast period. Importantly, the PVRR(d) results from both models show customer benefits across the same set of price-policy scenarios with consistent trends in the difference in PVRR(d) results between price-policy scenarios. The consistency in the trend of forecasted benefits between the two models, each having its own strengths, shows that the wind repowering benefits are robust across a range of price-policy assumptions and when analyzed using different modeling tools.

Q. How do the risk-adjusted PVRR(d) results compare to the stochastic-mean PVRR(d) results?

A. The risk-adjusted PVRR(d) results show slightly greater net benefits than those calculated from the stochastic-mean PVRR(d) results. This indicates that the wind repowering project, which provides incremental zero-fuel-cost energy, provides incremental benefits in reducing the impact of high-cost, low-probability outcomes that can occur due to volatility in stochastic variables like load, wholesale-market prices, hydro generation, and thermal-unit outages.

Annual Revenue Requirement Price-Policy Results

Q. Please summarize the PVRR(d) results calculated from the change in annual revenue requirement through 2050.

A. Table 7 summarizes the PVRR(d) results for each price-policy scenario calculated off of the change in annual nominal revenue requirement through 2050. The annual data over the period 2017 through 2050 that was used to calculate the PVRR(d) results shown in the table are provided as Exhibit PAC/512.

Table 7. Nominal Revenue Requirement PVRR(d) (Benefit)/Cost of Wind Repowering ($ million)

Price-Policy Scenario	Annual Revenue Requirement PVRR(d)
Low Gas, Zero CO_2	($127)
Low Gas, Medium CO_2	($121)
Low Gas, High CO_2	($223)
Medium Gas, Zero CO_2	($224)
Medium Gas, Medium CO_2	($273)
Medium Gas, High CO_2	($321)
High Gas, Zero CO_2	($389)
High Gas, Medium CO_2	($386)
High Gas, High CO_2	($466)

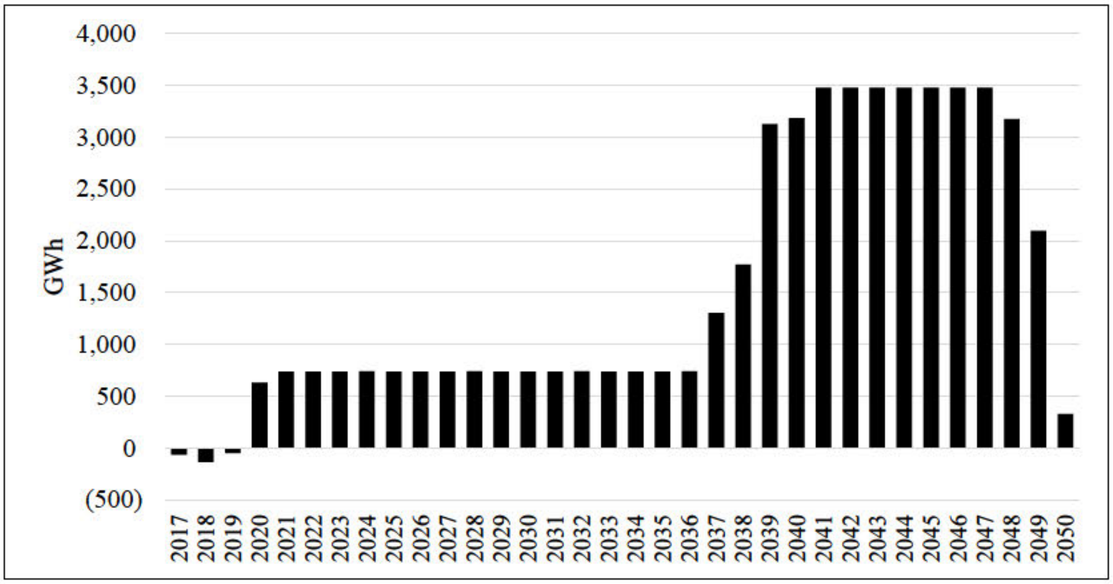
When calculated through 2050, which covers the remaining life of the repowered facilities, the wind repowering project reduces customer costs in all nine price-policy scenarios, with PVRR(d) benefits ranging from $121 million in the low natural-gas and medium CO_2 price-policy scenario to $466 million in the high natural-gas and high CO_2 price-policy scenario. Under the central price-policy scenario, assuming medium natural-gas prices and medium CO_2 prices, the PVRR(d) benefits are $273 million.

Q. What causes the increase in PVRR(d) benefits for many of the price-policy scenarios when calculated off of nominal revenue requirement through 2050 relative to the PVRR(d) results calculated from the SO model and PaR results through 2036?

A. The PVRR(d) calculated from estimated annual revenue requirement through 2050 picks up the sizable increase in incremental wind energy output beyond the 20-year forecast period analyzed with the SO model and PaR. As discussed earlier in my testimony, the change in wind energy output between cases with and without wind repowering experiences a step change beyond this 20-year period, when the existing wind facilities would otherwise have hit the end of their depreciable life. Beyond the 20-year forecast period, the change in wind energy output between cases with and without repowering reflects the full energy output from the repowered wind facilities.

Figure 7 shows the incremental change in wind energy output resulting from the repowering project. Incremental energy output associated with wind repowering progressively increases over the 2036-through-2040 period, as wind facilities originally placed in service in the 2006-through-2010 time frame would have otherwise hit the end of their lives. Before 2036, and once all of the wind resources within the project scope are repowered, the average annual incremental increase in wind energy output is approximately 738 GWh. Beyond 2040, and before the new equipment hits the end of its depreciable life, the average annual incremental increase in wind-energy output is approximately 3,478 GWh.

Figure 7. Change in Incremental Wind Energy Output Due to Wind Repowering (GWh)



Q. Is there additional potential upside to the PVRR(d) results calculated from the change in estimated annual revenue requirement through 2050?

A. Yes. As in the case with the PVRR(d) results calculated from the SO model and PaR results through 2036, the PVRR(d) results presented in Table 7 do not reflect the potential value of RECs produced by the repowered facilities. Customer benefits for all price-policy scenarios would improve by approximately $12 million for every dollar assigned to the incremental RECs that will be generated from the wind repowering project through 2050.

Q. Is there additional potential upside to these PVRR(d) results shown in Table 8?

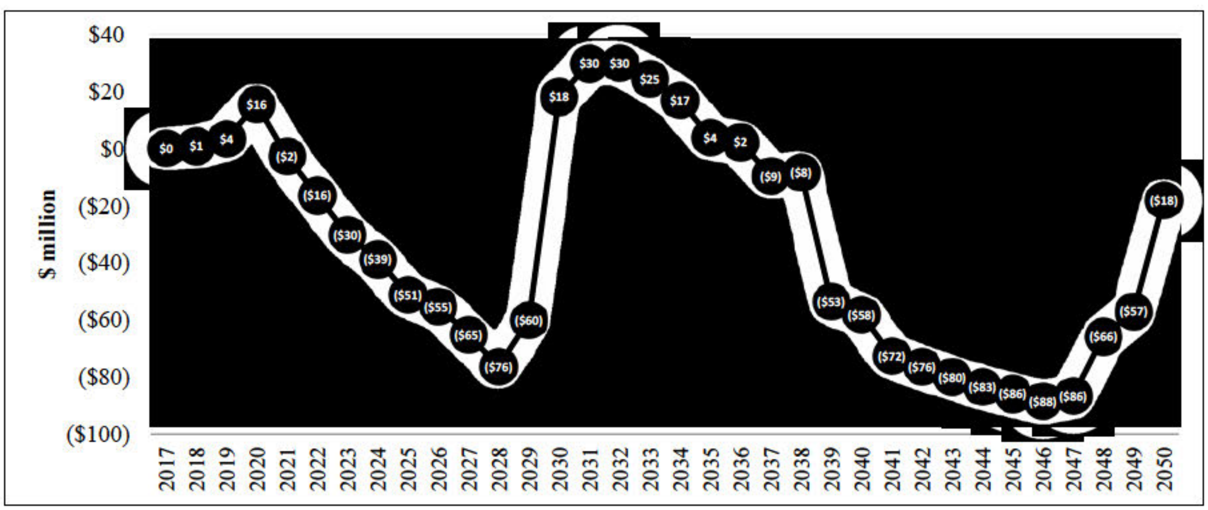
A. Yes. As noted earlier, the updated CO_2 price assumptions used in the economic analysis were inadvertently modeled in 2012 real dollars instead of nominal dollars.

Consequently, the PVRR(d) net benefits in the six price-policy scenarios that use medium and high CO_2 price assumptions are conservative.

Q. Please describe the change in annual nominal revenue requirement from the wind repowering project.

A. Figure 8 shows the updated change in nominal revenue requirement due to the wind repowering project for the medium natural-gas, medium CO_2 price-policy scenario on a total-system basis. The change in nominal revenue requirement shown in the figure reflects updated costs, including capital revenue requirement (*i.e.*, depreciation, return, income taxes, and property taxes), O&M expenses, the Wyoming wind-production tax, and PTCs. The project costs are netted against updated system impacts from the wind repowering project, reflecting the change in NPC, emissions, non-NPC variable costs, and system fixed costs that are affected by, but not directly associated with, the wind repowering project.

Figure 8. Total-System Annual Revenue Requirement With the Wind Repowering Project (Benefit)/Cost ($ million)



As this chart shows, the wind repowering project generates substantial near-term customer benefits and continues to contribute to customer benefits over the long-term. Before repowering, the reduction in wind energy output due to component failures on the existing wind resource equipment is assumed to reduce wind energy output for specific wind turbines until the time new equipment is installed. This contributes to an increase in revenue requirement in 2017 and 2018 ($1 million to $4 million, total system). All but the Dunlap facility, which is repowered toward the end of 2020, are repowered in 2019. Over the 2019-to-2020 time frame, project costs reflecting partial-year capital revenue requirement net of PTCs and system cost impacts cause slight changes to revenue requirement.

The wind repowering project reduces revenue requirement soon after the new equipment is placed in service, and from 2021 through 2028, annual revenue requirement is reduced as PTC benefits increase with inflation and the new equipment continues to depreciate. The reduction in annual revenue requirement is $76 million by 2028. Revenue requirement increases once the PTCs expire toward the end of 2030. Annual revenue requirement is reduced over the 2037-through-2050 time frame when, as discussed earlier in my testimony, the incremental wind energy output associated with wind repowering increases substantially.

Q. Did you evaluate how wind repowering benefits assumed beyond 2036 affect the PVRR(d) results calculated from the change in annual nominal revenue requirement through 2050?

A. Yes. The point of extrapolating results beyond 2036 is to capture the benefits from the significant increase in the expected annual energy output from the repowered wind facilities beyond the period in which the existing wind facilities would have otherwise reached the end of their lives. While the methodology used in my analysis is valid, the value of this incremental energy can be evaluated in different ways.

Table 8 summarizes how the PVRR(d) results through 2050 would change if flat market prices at the Palo Verde (PV) market from the December 29, 2017 OFPC were used as the basis to evaluate the value of incremental energy from wind repowering over the 2037-through-2050 time frame. Recognizing there is both upside and downside price risk to the value of this energy, I assume different levels of PV prices—70 percent of the PV forward curve, 100 percent of the PV forward curve, and 130 percent of the PV forward curve. PacifiCorp's December 29, 2017 OFPC includes forward prices through 2042. Conservatively, I assume no escalation in PV prices beyond 2042 for each of these scenarios. Each of these scenarios is shown alongside the $273 million PVRR(d) net benefit when incremental energy from repowering beyond 2036 is calculated from system modeling results over the 2028 through 2036 time frame.

Table 8. Long-Term Benefit Sensitivity

Source of 2037-2050 Benefits	Nominal Levelized Benefit from 2037-2050	Annual Revenue Requirement PVRR(d) (Benefit)/Cost
2027-2036 System Modeling	$59.08	($273)
70% of PV	$49.49	($213)
100% of PV	$70.70	($351)
130% of PV	$91.92	($489)

This analysis demonstrates that regardless of the methodology used to extend wind repowering benefits to 2050, the PVRR(d) result shows significant customer savings. If the incremental energy is valued at the PV forward curve, the PVRR(d) benefits of the wind repowering project are $351 million, which is $78 million higher than the methodology used in my analysis.

New Wind Sensitivity Study

Q. Did PacifiCorp produce any sensitivities on its economic analysis of the wind repowering project?

A. Yes. PacifiCorp developed a sensitivity to quantify how the net benefits of wind repowering are affected when combined with 1,170 MW of new Wyoming wind resources and the Aeolus-to-Bridger/Anticline transmission included in the company's 2017 IRP.[7] This sensitivity assumes the new wind and transmission is operational by the end of 2020.

Q. Please summarize the results of the sensitivity that includes new Wyoming wind resources and the planned Aeolus-to-Bridger/Anticline transmission project.

A. Table 9 summarizes the PVRR(d) results for the new wind sensitivity that assumes wind repowering is implemented in combination with adding 1,170 MW of new Wyoming wind and the Aeolus-to-Bridger/Anticline transmission project. This sensitivity was developed using SO model and PaR simulations through 2036 for the medium natural-gas, medium CO_2 and the low natural-gas, zero CO_2 price-policy scenarios. The results are shown alongside the base repowering study presented above in which wind repowering was evaluated without the new wind and transmission

[7] The 2017 IRP assumed 1,100 MW of new Wyoming wind by the end of 2020. Since filing the 2017 IRP, PacifiCorp issued its 2017R RFP and initially identified 1,170 MW of new Wyoming wind to the final shortlist, which serves as the basis for this sensitivity. PacifiCorp has since updated its 2017R RFP final shortlist to include 1,311 MW of new Wyoming wind.

Table 9. New Wind and Aeolus-to-Bridger/Anticline Sensitivity (Benefit)/Cost of Wind Repowering ($ million)

	Sensitivity (Repowering + New Wind & Trans.) PVRR(d)	Base Study (Repowering) PVRR(d)	Change in PVRR(d)
Medium Gas, Medium CO_2			
SO Model	($532)	($204)	($328)
PaR Stochastic Mean	($466)	($180)	($286)
PaR Risk Adjusted	($489)	($189)	($300)
Low Gas, Zero CO_2			
SO Model	($301)	($159)	($142)
PaR Stochastic Mean	($300)	($141)	($159)
PaR Risk Adjusted	($315)	($148)	($167)

Customer benefits increase significantly when the wind repowering project is implemented with the new wind and transmission in both the medium natural-gas, medium CO_2 and the low natural-gas, zero CO_2 price-policy scenarios. These results demonstrate that customer benefits not only persist, but increase, if both the wind repowering project and the new wind and transmission projects are completed.

V. CONCLUSION

Q. Please summarize the conclusions of your testimony.

A. The conclusions of my Jim Bridger SCR emission control system testimony are as follows:

- The base case analysis results in a PVRR(d) that is $183 million favorable to the Jim Bridger Unit 3 and Unit 4 SCR emission control systems as compared to a natural-gas conversion alternative.

- Additional sensitivity analysis shows a PVRR(d) that is $588 million favorable to the Jim Bridger Unit 3 and Unit 4 SCR emission control systems as compared to an early retirement and resource replacement alternative.

- Natural-gas and CO_2 price scenario results support the SCR systems in all scenarios but those with low-natural-gas price assumptions, which were not projected to reach historical price levels for the next 18 years.

The conclusions of my wind repowering testimony are as follows:

- PacifiCorp's analysis supports repowering approximately 999 MW of existing wind resource capacity located in Wyoming, Oregon, and Washington.

- The repowered wind facilities will qualify for an additional 10 years of federal PTCs, produce more energy, reset the 30-year depreciable life of the assets, and reduce run-rate operating costs.

- The economic analysis of the wind repowering opportunity demonstrates that net benefits, which include federal PTC benefits, NPC benefits, other system variable-cost benefits, and system fixed-cost benefits, more than outweigh net project costs.

Q. What is your recommendation?

A. I recommend the Commission determine that both the decision to install SCR emission control systems on Jim Bridger Units 3 and 4, and the decision to repower certain wind facilities is prudent and in the public interest and therefore approve the application as filed.

Q. Does this conclude your direct testimony?

A. Yes.

Application No. 18-04-002
Exhibit PAC/1800
Witness: Rick T. Link

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP

REDACTED

Rebuttal Testimony of Rick T. Link

Economic Analysis

Installation of Selective Catalytic Reduction Systems

November 2018

TABLE OF CONTENTS

Q. Are you the same Rick T. Link who previously provided direct testimony in this case on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp)?

A. Yes.

I. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your rebuttal testimony?

A. I respond to adjustments proposed by Sierra Club in the direct testimony of Dr. Jeremy Fisher. I provide more detail about the company's process for developing its integrated resource plan (IRP); explain how that process has evolved to address stakeholder feedback and changes in energy markets, policies, and regulations related to coal generation; and demonstrate how the IRP supports the prudence of continued operation of the company's coal resources through the target retirement dates set in the IRP. I also show that, in 2013, PacifiCorp made a prudent and reasonable decision to install selective catalytic reduction (SCR) emission-reduction systems at Jim Bridger Units 3 and 4 based on the information available at that time.

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony addresses Sierra Club's claim that the company does not use its IRP to assess whether continued operation of its coal resources is in the best interests of customers. My rebuttal testimony demonstrates that:

- PacifiCorp analyzes the cost-effectiveness of continued operation of its coal fleet in its IRP, and the results of these analyses are explicitly considered in the company's selection of a least-cost, least-risk resource plan.

- PacifiCorp's IRP is sophisticated, robust, and has evolved to respond to stakeholder feedback and changes in energy markets, policies, and regulations.
- Since PacifiCorp began developing analysis that is specifically focused on its coal units during the 2011 IRP cycle, the company has produced hundreds upon hundreds of studies to assess whether continued operation of coal resources are in the best interest of its customers.

My rebuttal testimony also shows that Sierra Club's recommendation to disallow ongoing capital costs for specific coal units is meritless. My rebuttal testimony shows that:

- The studies that Sierra Club relies on to support its recommendation are incomplete and/or mischaracterized.
- There is not a single study supporting Sierra Club's claim that nearly [redacted] of the company's coal fleet should be economically retired by 2023.
- Sierra Club does not explain how it can rely on a study that models potential early plant retirements by 2023 as the basis for disallowing costs in 2019.

Finally, my rebuttal testimony addresses Sierra Club's claims that the company acted imprudently when it installed SCRs at Jim Bridger Units 3 and 4. My rebuttal testimony demonstrates that:

- Sierra Club did not file any economic analysis, market data, or workpapers that support its adjustment to the Jim Bridger SCRs.

- While Sierra Club relies on testimony filed with the Washington Utilities and Transportation Commission (Washington commission), and exhibits it filed with the Washington commission, it has not included any of this evidence in the record in this case.
- Sierra Club cites to an analysis it filed with the Washington commission that was superseded in a subsequent filing where Sierra Club admitted that its original analysis overstated the impact of proposed changes to PacifiCorp's calculations.
- Sierra Club's recitation of the Washington order omits the critical fact that the Washington commission *rejected* Sierra Club's analysis because Sierra Club improperly used post-decision information.
- Sierra Club's Washington analysis also included material errors that, when corrected, eliminated the alleged decrease in the economic case for the SCR investment.

II. RESPONSE TO SIERRA CLUB'S CLAIMS ABOUT PACIFICORP'S PLANNING PROCESS

Q. How does Sierra Club address PacifiCorp's resource-planning process in its rate case testimony?

A. Sierra Club raises the company's IRP process in two ways. First, Sierra Club alleges the company does not analyze the ongoing, cost-effective operation of its coal units in its IRP. Sierra Club relies on this claim to support its specific adjustments for environmental compliance projects at the Jim Bridger, Naughton, Craig, and Hayden plants. Second, Sierra Club points to PacifiCorp's studies of coal plants in its IRP and claims these support an adjustment to remove ongoing capital investments at certain PacifiCorp coal units. Neither claim is accurate. And Sierra Club's second argument—that PacifiCorp's IRP coal studies support removal of coal costs from rates—conflicts with its first argument that PacifiCorp does not analyze the costs of ongoing operation of coal plants in its IRP.

Q. Did Sierra Club also challenge PacifiCorp's IRP process in the Order Instituting Investigation (OII) docket, consolidated with this case?

A. Yes. One of the sub-issues in the OII docket is whether PacifiCorp does resource planning on a system or control-area basis. The company's direct testimony confirmed that its resource planning is system based. Sierra Club responded, claiming that PacifiCorp does not engage in least-cost resource planning on any basis. Sierra Club made many inaccurate and irrelevant claims about the IRP in its OII testimony, which the company corrected in the rebuttal testimony of Ms. Shayleah LaBray. In its rate case testimony, Sierra Club appears to have ignored Ms. LaBray's OII rebuttal testimony and repeats many of the same inaccurate statements about the company's IRP. I am adopting the direct and rebuttal testimony of Ms. LaBray in the OII docket.

Q. How do you respond to Sierra Club's testimony on the company's IRP?

A. In this section of my testimony, I rebut Sierra Club's claim that the company does not use its IRP to assess whether continued operation of its coal resources is in the best interests of customers. In the next section of my testimony, I rebut Sierra Club's claim that PacifiCorp's IRP analysis supports removal of ongoing capital costs for certain PacifiCorp coal units. On both issues, I rely by reference on the OII testimony of Ms. LaBray, which has already refuted many of Sierra Club's claims about PacifiCorp's IRP.

Q. Please provide an overview of the company's resource-planning process.

A. PacifiCorp's resource-planning process uses thorough analysis and modeling that measures cost and risk to develop its IRP, which presents the company's plans to provide reliable and reasonably priced service to its customers. The primary objective of the resource-planning process is to identify the least-cost, least-risk portfolio of resources to serve customers in the future. The least-cost, least-risk resource portfolio—defined as the "preferred portfolio"—is the portfolio that can be delivered through specific action items at a reasonable cost and with manageable risks, while considering customer demand for clean energy and ensuring compliance with state and federal regulatory obligations.

The company completes an IRP cycle every two years, which includes preparation of a full IRP every two years and preparation of an update to the full IRP in the off years. The company files both its IRP and IRP update with each of the six regulatory commissions in the states where the company provides retail service, including California.

Each IRP is developed through an open and public process, with input from an active and diverse group of stakeholders, including staff of state regulatory commissions, staff of state consumer-advocacy departments, customer-sponsored advocacy groups, environmental-advocacy groups, resource-advocacy groups, independent-power producers and project developers, staff of other utilities, and customers. During the public-input process, which typically spans at least nine to ten months, PacifiCorp holds regular meetings with stakeholders to get feedback on the company's planning assumptions and preliminary model results.

Q. Please explain how California has treated the company's IRP filings.

A. PacifiCorp files its IRP in California in two separate proceedings. First, it is filed to meet California's requirements for a renewable portfolio standard (RPS) procurement plan. Second, it is filed to meet California's new requirement for load-serving entities to prepare an IRP.

California's RPS procurement requirements allow multi-jurisdictional utilities like PacifiCorp to use an IRP prepared for regulatory agencies in other states to satisfy California's annual requirement to file an RPS procurement plan, as long as the IRP complies with the requirements specified in California Public Utilities Code § 399.17(d). As required by Decision (D.) 08-05-029, PacifiCorp files its IRP in Rulemaking (R.) 06-05-027 or its successor proceeding at the same time it files with the jurisdictions requiring the IRP. An IRP on-year supplement is filed within 30 days of filing the IRP. In accordance with D.11-04-030, PacifiCorp files an IRP off-year supplement on July 15 in years in which it does not file an IRP in lieu of an RPS procurement plan. PacifiCorp filed its IRP off-year supplement on July 16, 2018 (because July 15 fell on a Sunday).

In Rulemaking 16-02-007, the California Public Utilities Commission (Commission) is developing an IRP process for California. In February 2018, the Commission issued D.18-02-018 which set the requirements for load-serving entities in California to file an IRP. The decision allows PacifiCorp to file an IRP submitted to another public regulatory entity within the previous calendar year along with an explanation of how it has considered disadvantaged communities. PacifiCorp filed its IRP in California on August 1, 2018.

Q. Does PacifiCorp analyze the cost-effectiveness of continued operation of its coal fleet in its IRP?

A. Yes. The IRP examines PacifiCorp's existing coal plants as part of determining the least-cost, least-risk portfolio of resources to serve customers. This examination includes analyzing the early retirement of coal plants while appropriately considering the potential avoidance of incremental environmental compliance costs, which represents a potentially significant benefit in early closure scenarios.

Q. Has the company's approach to analyzing its coal resources evolved over the last several IRPs to respond to stakeholder feedback and changes in energy markets, policies, and regulations?

A. Yes. The company's planning process has become more sophisticated over time to respond to stakeholder feedback and the increasing complexities presented by changing energy markets, including lower prices for natural gas and the declining cost of renewable energy resources; the proliferation of clean energy policies, including state laws promoting renewable energy, controlling energy emissions, and promoting energy efficiency; and application of environmental regulations, especially those designed to regulate clean air and greenhouse gas (GHG) emissions.

Q. When did PacifiCorp begin developing economic analyses focused on its coal fleet within the IRP?

A. PacifiCorp began developing modeling scenarios focused on the company's coal fleet during the 2011 IRP cycle. At that time, PacifiCorp developed proof-of-concept studies to evaluate how carbon dioxide (CO_2) prices and natural gas prices affected a potential transition from coal generation to natural gas resources. After completing the 2011 IRP, Sierra Club and other stakeholders filed comments with the Public Utility Commission of Oregon (Oregon commission) recommending, among other things, that PacifiCorp provide a thorough accounting of environmental compliance costs, and develop an economic analysis to determine whether customers would benefit if coal facilities having environmental compliance obligations were retired or curtailed.[1] Sierra Club's comments document its advocacy for coal studies that consider coal retirement triggered by known or reasonably foreseeable environmental compliance costs.

Q. How did PacifiCorp respond to this stakeholder feedback?

A. PacifiCorp produced a supplemental coal analysis in September 2011. The supplemental coal analysis updated and documented environmental compliance cost assumptions for PacifiCorp's coal fleet and broadened the scope of potential replacement resources alternatives in potential early retirement scenarios.

Q. What were the key findings from the 2011 supplemental coal analysis?

A. The 2011 supplemental coal analysis showed that continued operation of PacifiCorp's coal units, inclusive of costs for known and reasonably foreseeable environmental compliance obligations, was lower cost than early retirement.

Q. Did PacifiCorp perform other coal analyses during the 2011 IRP cycle?

A. Yes. PacifiCorp worked with stakeholders, including Sierra Club, to evaluate

[1] *In the Matter of PacifiCorp's 2011 Integrated Resource Plan*, Public Utility Commission of Oregon, Docket No. LC 52, Sierra Club's Preliminary Comments (Aug. 25, 2011).

whether potential flexibility in emerging environmental regulations could be leveraged to avoid near-term compliance costs by committing to retire specific coal units before the end of their useful lives. PacifiCorp developed a spreadsheet-based coal-screening model to prioritize specific coal units to analyze further. To support this effort, PacifiCorp held technical workshops with stakeholders, including Sierra Club, to describe and discuss input assumptions, methodology, and results. High-priority coal units identified for further analysis were then further evaluated in an updated coal-replacement study that was included in PacifiCorp's 2011 IRP update. The high-priority coal units included Naughton Unit 3, Jim Bridger Units 3 and 4, Hunter Unit 1, Craig Units 1 and 2, and Hayden Units 1 and 2.

The updated coal-replacement study considered a broader spectrum of natural gas price and CO_2 price scenarios and broadened the scope of potential replacement resources to include wind resources, brownfield natural-gas conversion alternatives, and demand-side management alternatives. The updated analysis also accounted for potential flexibility in environmental compliance obligations and eliminated all incremental environmental compliance costs in the years preceding early retirement or conversion to natural gas.

Q. What were the key findings from the updated coal-replacement study that was included in PacifiCorp's 2011 IRP update?

A. The study showed that installation of equipment required to achieve environmental compliance was lower cost than early retirement or conversion to natural gas for Jim Bridger Units 3 and 4 and for Hunter Unit 1. For Naughton Unit 3, the analysis showed that conversion to natural gas was the least-cost compliance alternative. For the Craig and Hayden units, the analysis showed that early retirement might be lower cost than proceeding with environmental compliance projects. However, the study highlighted that the analysis of these coal units is unique for two reasons. First, PacifiCorp's ownership share of these units is relatively small such that the unit-by-unit studies did not capture the potential cumulative impacts of retiring more than one unit. Second, and as discussed by Mr. Chad Teply, PacifiCorp does not operate the Craig and Hayden units and does not have unilateral rights to alter the compliance plan for these assets.

Q. Did Sierra Club provide comments on PacifiCorp's updated coal-replacement study included in the 2011 IRP update?

A. Yes. Sierra Club stated the updated coal-replacement study was an improvement on the previous study, and that PacifiCorp should do more by continually updating cost assumptions and by broadening the scope of the analysis to consider compliance alternatives for other coal units.[2]

Q. Did Sierra Club propose that PacifiCorp perform coal studies in the 2011 IRP cycle to evaluate possible early retirement outcomes regardless of environmental triggers?

A. No.

Q. How did PacifiCorp apply findings from the coal studies developed during the 2011 IRP cycle in the 2013 IRP cycle?

A. Beyond updating its modeling assumptions to account for changes in energy markets,

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[2] *In the Matter of PacifiCorp's 2011 Integrated Resource Plan*, Public Utility Commission of Oregon, Docket No. LC 52, Sierra Club's Reply Comments (Nov. 3, 2011).

policies, and regulations related to coal generation, PacifiCorp continued to advance its analysis of coal units in the 2013 IRP cycle in several ways. First, rather than performing stand-alone studies, the company began to consider coal unit retirements and gas-conversion alternatives within the portfolio-development process of the IRP. Consistent with Sierra Club's comments on PacifiCorp's updated coal-replacement study, this advancement inherently expanded the scope of the company's modeling to consider early retirement and gas-conversion alternatives over a wide range of coal units using the most up-to-date cost assumptions. Second, PacifiCorp continued to analyze specific coal units with near-term compliance time lines (within two to four years) to quantify the economic benefits of compliance outcomes identified during the portfolio-development process. Third, PacifiCorp further expanded the scope of its coal analyses by preparing hypothetical intertemporal trade-off analysis for Jim Bridger Units 3 and 4.

Q. Please explain what you mean by "hypothetical intertemporal trade-off analysis".

A. This type of analysis assumes that legally binding compliance deadlines under regional haze can be delayed in exchange for a firm commitment to retire a unit before the end of its useful life. In its 2013 IRP, PacifiCorp evaluated these alternatives for Jim Bridger Units 3 and 4 whereby it was assumed that Jim Bridger Units 3 and 4 could avoid the cost of SCR equipment by 2015 and 2016, respectively, if these units were retired at the end of 2020 and 2021, respectively.

Q. What were the key findings related to coal units in PacifiCorp's 2013 IRP?

A. Modeling prepared for the 2013 IRP continued to show the gas-conversion as the preferred compliance alternative for Naughton Unit 3. The analysis presented in the 2013 IRP for Jim Bridger Units 3 and 4 includes the same analysis presented in my direct testimony, which supports the installation of SCRs on these two units.

Q. Did the hypothetical inter-temporal analysis for Jim Bridger Units 3 and 4 support PacifiCorp's plans to install SCRs on these two units?

A. Yes. This analysis, intended to explore potential flexible compliance alternatives to the installation of SCR by committing to an early retirement at the end of 2020 for Jim Bridger Unit 3 and by the end of 2021 for Jim Bridger Unit 4, was significantly higher cost than proceeding with the installation of SCRs.

Q. Considering results for Craig and Hayden from the 2011 IRP update, did PacifiCorp address these coal units in the 2013 IRP?

A. Yes. PacifiCorp summarized legal considerations associated with compliance obligations for Craig and Hayden units. These considerations addressed compliance with Colorado law and PacifiCorp's contractual rights under the respective participation agreements that govern the relationship between joint owners at the Craig and Hayden facilities. Consistent with Mr. Teply's testimony, the 2013 IRP concluded that environmental compliance obligations at the Craig and Hayden facilities are driven by these considerations.

Q. Did Sierra Club propose that PacifiCorp perform coal studies in the 2013 IRP cycle to evaluate possible early retirement outcomes regardless of environmental triggers?

A. No.

Q. How did PacifiCorp advance its coal resource modeling in the 2015 IRP cycle?

A. During the 2013 IRP cycle, PacifiCorp received stakeholder feedback to continue to advance and broaden the scope of the company's analysis of coal resources within the IRP. The Oregon commission directed stakeholders to schedule several workshops to determine specific parameters for coal analyses in future IRPs. PacifiCorp worked with Oregon stakeholders, including Sierra Club, before initiating the 2015 IRP cycle to establish these specific parameters.

Q. What was the result of these workshops?

A. After Oregon IRP stakeholders participated in four workshops, Oregon commission staff made specific recommendations for an expanded coal analysis that included intertemporal trade-off analysis and fleet trade-off analysis for specific units. The Oregon commission adopted these recommendations in Order No. 14-296.

Q. Please explain what you mean by "fleet trade-off analysis".

A. Fleet trade-off analysis considers potential flexible compliance alternatives that combine alternative retirement dates and/or compliance obligations for a specific coal unit that might be used to negotiate a lower cost compliance obligation at another coal unit.

Q. What were the key findings from this specific analysis performed during the 2015 IRP cycle?

A. PacifiCorp found that a compliance strategy that avoids installation of SCR equipment at Wyodak, Cholla Unit 4, and Dave Johnston Unit 3 is lower cost. The analysis continued to support gas-conversion for Naughton Unit 3. The preferred portfolio from the 2015 IRP assumed that approximately 2,800 megawatts (MW) of existing coal capacity will either retire or convert to natural gas by the end of the 20-year study period.

Q. How did PacifiCorp advance its coal resource modeling in the 2017 IRP cycle?

A. PacifiCorp continued to evaluate a range of potential compliance alternatives, taking into consideration a broader range of intertemporal and fleet trade-off compliance outcomes on more coal units.

Q. What were the key findings from these updated and expanded studies performed during the 2017 IRP cycle?

A. The 2017 IRP preferred portfolio continues to reflect a compliance strategy that avoids incremental SCR equipment and assumes that approximately 3,650 MW of existing coal capacity will be retired by the end of the 20-year study period.

Q. How do you respond to Sierra Club's claim that the company does not use its IRP to assess whether continued operation of its coal resources in is the best interests of customers?

A. Sierra Club's claim is not consistent with the facts. Since PacifiCorp began developing analysis that is specifically focused on its coal units during the 2011 IRP cycle, the company has produced hundreds upon hundreds of studies to assess whether continued operation of coal resources are in the best interest of its customers.

Q. In this case, Sierra Club challenges investments at the Naughton, Jim Bridger, Craig, and Hayden plants. When were these investment decisions made?

A. The decisions were made between 2006 and 2013 (Naughton in 2006–2009; Jim Bridger in 2013; Craig Unit 2 in 2013; Hayden in 2012).

Q. Does Sierra Club's criticism of the company's IRP and its capital investment decisions in its coal plants improperly apply current planning approaches, standards, and insights to decisions made many years ago?

A. Yes, Sierra Club's criticisms are based on hindsight rather than examining the information known at the time. For example, Sierra Club testifies that utilities started to change their mindsets about the cost-effectiveness of continued operation of coal plants by late 2016.[3] This is several years *after* the investment decisions challenged in this case—all of which preceded publication of the Clean Power Plan in 2015.

Q. Sierra Club accuses PacifiCorp of bias in its IRP, claiming that PacifiCorp "continues to look for reasons to keep the coal units online." Please respond.[4]

A. This statement is untrue and is completely at odds with the results of PacifiCorp's most recent IRPs (the 2017 IRP and 2017 IRP update) which "presents a cost-conscious plan to transition to a cleaner energy future with near-term investments in both existing and new renewable resources, new transmission infrastructure, and energy efficiency programs."[5] The key findings of the 2017 IRP, as summarized and updated in the 2017 IRP update, include PacifiCorp's plan to significantly reduce its existing coal capacity, rely exclusively on incremental efficiency and renewable energy to meet load, and make no new SCR investments:[6]

- Through the end of 2036, the company's updated preferred portfolio includes over 2,700 MW of new wind resources, 1,860 MW of new solar resources, 1,877 MW

[3] Fisher Direct at 7.
[4] Fisher Direct at 62.
[5] *In the Matter of PacifiCorp d/b/a Pacific Power, 2017 Integrated Resource Plan*, Public Utility Commission of Oregon, Docket No. LC 67, 2017 Integrated Resource Plan at 1 (April 4, 2017).
[6] *In the Matter of PacifiCorp d/b/a Pacific Power, 2017 Integrated Resource Plan*, Public Utility Commission of Oregon, Docket No. LC 67, 2017 IRP Update at 1-2 (May 1, 2018).

of incremental energy efficiency resources, and approximately 268 MW of direct-load-control resources.

- The updated preferred portfolio assumes existing owned coal capacity will be reduced by 3,650 MW through the end of 2036.
- With reduced loads and lower renewable resource costs, the updated preferred portfolio contains no new natural gas resources through the 20-year planning horizon. This is the first time an IRP has not included new fossil-fueled generation as a least-cost, least-risk resource for PacifiCorp
- Based on unit-specific coal studies, the 2017 IRP update assumes no incremental SCR investments are needed to satisfy compliance obligations under regional haze regulations.

Q. In addition to planning its own transition to a cleaner energy future, has the company helped facilitate the region's transition by starting the Energy Imbalance Market (EIM) with the California Independent System Operator Corporation (CAISO)?

A. Yes. PacifiCorp and the CAISO launched the EIM on November 1, 2014. The EIM is a voluntary market and the first western energy market outside of California. The EIM provides for more efficient dispatch of participating resources in real-time through an automated system that dispatches generation across the EIM footprint. As noted in the rebuttal testimony of company witness Mr. Joseph Hoerner in the OII docket, PacifiCorp's participation in the EIM has contributed to California's decline in total GHG emissions to serve California load due to PacifiCorp's increased ability to avoid curtailment of its renewable resources and exports of hydro and renewable generation. The benefits of more efficient dispatch, reduced renewable curtailment, and reduced flexibility reserves have significantly increased as many other utilities have joined the EIM.[7]

Q. Sierra Club claims that PacifiCorp "has strictly constrained its review of its coal plant economics" to only instances where a capital investment was required and that "there is no record of PacifiCorp ever reviewing the economics of its existing coal fleet without a capital trigger."[8] Please respond.

A. Sierra Club's allegations are misguided. Due to the magnitude of the investments necessary to maintain compliance with environmental regulations, potential early retirement of existing coal units is typically assessed as an alternative to such investments. As stated earlier in my testimony, Sierra Club did not advocate for coal analysis without a capital trigger in the 2011 IRP and the 2013 IRP—the IRP planning cycles preceding the investment decisions that Sierra Club opposes in this proceeding. In fact, Sierra Club's comments during the 2011 IRP recommended that PacifiCorp produce economic analysis to determine whether customers would benefit if coal facilities having environmental compliance obligations were retired or curtailed. Further, as demonstrated by the treatment of Cholla Unit 4 in the 2017 IRP, PacifiCorp also analyzes early retirement relative to continued operation. While

[7] The EIM currently includes PacifiCorp, NV Energy, Puget Sound Energy, Arizona Public Service, Portland General Electric, Idaho Power Company, Powerex, and the CAISO balancing authority areas. Entities scheduled to join the EIM include the Balancing Authority of Northern California (April 2019), Seattle City Light (April 2020), Los Angeles Dept.of Water and Power (April 2020), and Salt River Project (April 2020). CENACE Baja California is investigating future entry into the market.

[8] Fisher Direct at 7.

Cholla Unit 4 may continue operations until 2025 under regional haze rules, the company's preferred portfolio includes a 2020 retirement date for that unit.

Q. Sierra Club claims that the company never "establish[ed] whether the continued operation of its coal plants was in the best interests of customers."[9] Is this true?

A. No. PacifiCorp's biennial IRPs have demonstrated the value to customers of the ongoing operation of the company's coal resources through the selection of the least-cost, least-risk resource portfolio, which has included an analysis that determines whether the preferred portfolio should include continued operation of the company's coal resources.

Q. Does Sierra Club's testimony contradict its claim that PacifiCorp does not review ongoing coal plant operation in its IRP?

A. Yes. Sierra Club correctly states that the company's 2013 IRP included studies that analyzed whether early retirement of individual coal units was more cost-effective than continued operation, after considering the need for additional capital investments.[10] The company has performed comparable analysis in the 2015 and 2017 IRP.

Q. Sierra Club also claims that PacifiCorp's resource planning does not consider the emission-performance standards that have been adopted by California and Oregon.[11] Is this true?

A. No. The company's IRPs include extensive modeling that evaluates the impact of GHG emissions on the economics of its resources, and the modeling is designed to

[9] Fisher Direct at 45.
[10] Fisher Direct at 46.
[11] Fisher Direct at 12.

ensure that PacifiCorp meets or exceeds all applicable emission-performance standards and that the potential regulatory cost associated with emission regulation is appropriately considered in all resource selections. None of the new resource alternatives evaluated in the IRP exceed the emission-performance standards adopted by California, Oregon, and Washington.

Q. Does every one of the company's generation resources meet the applicable emission-performance standards?

A. Yes, as explained by company witness Ms. Mary Wiencke in her direct testimony in the OII docket.

III. RESPONSE TO SIERRA CLUB'S CHALLENGE TO PRUDENCE OF PACIFICORP'S ONGOING CAPITAL COSTS IN SPECIFIC COAL UNITS

Q. Sierra Club recommends that the Commission disallow ongoing capital costs at [redacted] from January 2018 through December 2019[12] and beyond 2019 until the units are shown to be in the interests of California customers.[13] How do you respond?

A. This adjustment is meritless. Sierra Club bases its proposed disallowance on the results of a 2017 study by Synapse and PacifiCorp's preliminary coal analysis for its 2019 IRP (2018 Coal Analysis). As described below, however, neither study is designed to comprehensively evaluate the economics of retiring individual coal units in 2018 (the date used in the Synapse study) or 2023 (the date assumed in the

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[12] Fisher Direct at 4, 63.
[13] Fisher Direct at 4-5.

preliminary 2018 Coal Analysis). Thus, Sierra Club has not justified its proposed disallowance.

Q. Is it appropriate to consider decisions about early coal-plant retirement through the IRP process instead of through a disallowance in a rate case?

A. Yes. The IRP process allows a collaborative, long-term, multi-state approach to PacifiCorp's resource planning. This planning process, rather than rate case litigation, is best suited to produce sustainable and well-supported resource decisions.

Q. Does Sierra Club's adjustment account for the benefits provided by the coal units?

A. No. Sierra Club's adjustment fails to account for the net-power-cost benefits that have been provided to customers by the coal plants that it claims should have been retired.

Q. Sierra Club claims that the company's last three IRPs "have strongly indicated that the continuation of capital costs at multiple coal units is not in the best interests of ratepayers."[14] How do you respond?

A. An examination of each of those three IRPs shows that Sierra Club's claim is untrue. For example, Sierra Club cites to the 2013 IRP and claims that the company's analysis in that plan showed that when gas price forecasts were low and carbon dioxide prices were modest, the IRP showed that "PacifiCorp's entire coal fleet was rendered non-economic and selected for retirement by 2022."[15] As PacifiCorp explained at the time, however, portfolios with early coal-unit retirements occur in

[14] Fisher Direct at 9.
[15] Fisher Direct at 46.

those cases where commodity prices (and CO_2 price assumptions) favor alternatives to environmental investments. For instance, portfolios with low natural-gas price inputs, high CO_2 prices, and high coal costs produced portfolios with significant early coal-unit retirements. When evaluated during the portfolio selection process, however, those portfolios were high risk and high cost, and were not chosen as the preferred portfolio.

Q. Sierra Club claims that PacifiCorp "was not responsive to stakeholder concerns" raised in the 2013 IRP related to coal-plant modeling.[16] Do you agree?

A. No. In response to Sierra Club's concerns that the 2013 IRP modeling could be more refined, and to provide more transparency on model inputs and outputs and scenarios, PacifiCorp proposed in the Oregon IRP review proceeding a separate process to develop parameters for analyzing coal investments and allow the company to seek acknowledgment of emissions-control investments or alternatives for specific units.[17]

In its order acknowledging the 2013 IRP, the Oregon commission "recognize[d] the additional coal analysis that PacifiCorp provided in this proceeding and PacifiCorp's willingness to establish a separate proceeding to address coal investments."[18] As I discussed earlier, to further refine the coal fleet analysis, the Oregon commission directed Oregon IRP stakeholders to schedule several workshops to determine the parameters of coal analyses in future IRPs. Following those

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[16] Fisher Direct at 48.
[17] *In the Matter of PacifiCorp d/b/a Pacific Power 2013 Integrated Resource Plan*, Public Utility Commission of Oregon, Docket No. LC 57, Order No. 14-252 at 5 (Jul. 8, 2014).
[18] *In the Matter of PacifiCorp d/b/a Pacific Power 2013 Integrated Resource Plan*, Public Utility Commission of Oregon, Docket No. LC 57, Order No. 14-252 at 5 (Jul. 8, 2014).

workshops, the Oregon commission adopted its staff's recommendation for future coal analysis that would be used in PacifiCorp's 2015 IRP.[19]

Q. Did PacifiCorp provide the coal analysis requested by staff of the Oregon commission in the 2015 IRP?

A. Yes. In the 2015 IRP, PacifiCorp implemented the modeling refinements that grew out of the 2013 IRP, and the Oregon commission found that PacifiCorp complied with its "requests and directives" from the 2013 IRP and acknowledged the four action items related to coal resources.[20]

Q. Sierra Club claims that the company's Clean Power Plan modeling in the 2015 IRP did not assess "whether compliance could be more readily achieved through the retirement of an existing fossil unit."[21] Is this true?

A. No. PacifiCorp evaluated a broad range of potential compliance alternatives in its modeling of the Clean Power Plan. These compliance alternatives included strategies to, in varying combinations, achieve incremental energy efficiency savings, procure incremental renewable resources, and re-dispatch natural-gas and coal resources. The Clean Power Plan compliance strategies were evaluated among four different sets of regional haze compliance scenarios, each with varying levels of early retirement assumptions that ranged between 899 MW and 3,269 MW of coal-fired capacity. This modeling structure allowed PacifiCorp to explicitly evaluate how the cost of achieving compliance with the Clean Power Plan was affected by alternative coal

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[19] *In the Matter of PacifiCorp d/b/a Pacific Power 2013 Integrated Resource Plan*, Public Utility Commission of Oregon, Docket No. LC 57, Order No. 14-296 (Aug. 19, 2014).
[20] *In the Matter of PacifiCorp d/b/a Pacific Power 2015 Integrated Resource Plan*, Public Utility Commission of Oregon, Docket No. LC 57, Order No. 16-071 at 2-3, 7-8 (Feb 29, 2016).
[21] Fisher Direct at 10.

retirement scenarios, which directly informed PacifiCorp's assessment of costs and risks when selecting the 2015 IRP preferred portfolio.

Q. Sierra Club also refers to an alternative study performed by Synapse in 2015 that purportedly showed that the near-term retirement of several coal units was "optimal."[22] Was that Synapse study reasonable?

A. No. In fact, Sierra Club concedes that the Synapse study that called for early retirement was higher cost than the preferred portfolio selected in the 2015 IRP. This fact alone shows that the Synapse study did not prove that near-term retirement was optimal.

Q. Sierra Club claims that the only reason that its preferred early retirement scenarios were higher cost was because the company assumed there would be "few or no environmental obligations."[23] Is this accurate?

A. No. Once again, Sierra Club mispresents the company's IRP modeling. In fact, the company's preferred portfolio from the 2015 IRP included all the necessary investments to comply with known and reasonably foreseeable environmental regulations, including prospective GHG regulations and regional haze obligations that appropriately account for flexibility to achieve compliance through intertemporal and fleet trade-off outcomes. As I discussed earlier in my testimony, PacifiCorp worked with Oregon IRP stakeholders in advance of the 2015 IRP to define specific scenarios that were explicitly designed to evaluate potential compliance-cost savings through intertemporal and fleet trade-off compliance strategies.

[22] Fisher Direct at 10-11; 48.
[23] Fisher Direct at 50.

Q. Sierra Club claims that the company's 2017 IRP "repeated the 2015 IRP process and failed to assess the value of the existing coal fleet or the customer value in early retirement."[24] How do you respond?

A. PacifiCorp's 2017 IRP includes the same type of modeling approach to consider intertemporal and fleet trade-off compliance strategies that was used in the 2015 IRP, which has been supported by the Oregon commission and the Utah Public Service Commission (Utah commission). As in past IRPs, the 2017 IRP studied a range of regional haze compliance scenarios, reflecting potential bookend alternatives that consider early retirement outcomes as a means to avoid installation of expensive emissions-control equipment. Based on this analysis, by the end of the planning horizon, PacifiCorp assumes 3,650 MW of existing coal capacity will be retired.

Q. Did the 2017 IRP specifically study early retirement of certain coal units as part of the preferred portfolio?

A. Yes. PacifiCorp's 2017 IRP considered the economic retirement of coal resources, which appropriately considers run-rate operating costs and potential resource-replacement costs on a present-value revenue-requirement (PVRR) basis. In addition to a reference case and five other regional haze scenarios developed and modified with input from stakeholders, PacifiCorp also modeled an endogenous-retirement case specifically in response to a request from Sierra Club (Regional Haze Case 6, or RH-6) that allowed PacifiCorp's capacity-expansion model to choose early retirement or SCR equipment installation. This study selected one plant for early retirement and installed SCR equipment on the remaining plants, demonstrating that installation of

[24] Fisher Direct at 50.

SCR equipment is lower cost than retiring these coal units early absent application of intertemporal and fleet trade-off compliance strategies. This scenario, and all regional haze scenarios and supporting assumptions, are detailed in the presentation materials for the public-input meeting[25] and were discussed at the public-input meetings by the company's senior vice president of strategy and development (Mr. Teply), who also responded to stakeholder questions regarding the assumptions and how they were initially developed.

Q. Did the outcome of the endogenous-retirement case RH-6 show that early retirement of coal plants was least-cost on a system-wide basis?

A. No. The overall portfolio of resources in case RH-6 had higher net costs relative to the other regional haze compliance cases that reflected a range of potential negotiated compliance alternatives. And PacifiCorp's analysis of alternative regional haze compliance outcomes, accounting for intertemporal and fleet trade-off scenarios, demonstrated that customers would benefit from potential negotiated environmental compliance alternatives. Under these alternatives, costly SCR equipment can be avoided by retiring certain units before the end of their depreciable life, but later than the currently established regional haze compliance deadlines for SCR installation. Consequently, the least-cost combination of resources that was ultimately selected in the 2017 IRP preferred portfolio includes early retirement of five of PacifiCorp's coal plants over the 20-year study period and did not include any incremental SCR equipment installations.

[25] All public input meeting presentations are available at: http://www.pacificorp.com/es/irp.html. PacifiCorp discussed regional haze compliance and scenarios at its July 20, August 25–26, and September 22–23, 2016 public input meetings. Detailed portfolio results for the regional haze compliance cases were presented at the January 26–27, 2017 public input meeting.

Q. Did any other state commission address the company's coal-plant modeling in the 2017 IRP?

A. Yes. In response to Sierra Club's arguments, the Utah commission found that PacifiCorp's approach to modeling coal resources was reasonable for the 2017 IRP because PacifiCorp refined its analytical approach beyond that used in the 2015 IRP. In addition, the Utah commission found that PacifiCorp presented regional haze obligations and incorporated stakeholder feedback in developing its regional haze cases during the public-input process, used reasonable legal assumptions related to future compliance requirements, and increased the number of modeled scenarios.[26]

Q. Sierra Club claims that in the 2017 IRP docket in Oregon, the Oregon commission "ordered PacifiCorp to analyze as part of its fundamental planning process the viability of each individual coal unit and to prove that continued operation is in the customers' interest."[27] Do you agree with this characterization of the Oregon process?

A. No. In response to stakeholder requests, PacifiCorp agreed to provide additional unit-by-unit coal analysis using simplified assumptions and modeling. Specifically, stakeholders requested that PacifiCorp use one of its IRP models (the system optimizer, or SO, model) to conduct 25 individual analyses, one for each of the company's 24 coal units and a base case. In agreeing to perform the analysis, the company highlighted that the study could inform further modeling in the 2019 IRP cycle, but that on a stand-alone basis, the model would have limited value in

[26] *PacifiCorp's 2017 Integrated Resource Plan*, Public Service Commission of Utah Docket No. 17-035-16, Report and Order at 28 (March 2, 2018) (https://pscdocs.utah.gov/electric/17docs/1703516/3005351703516rao3-2-2018.pdf).
[27] Fisher Direct at 54.

establishing potential economic benefits or costs associated with the early retirement of specific coal units.

The analysis was structured to first calculate the forecasted total-system costs to serve customers (represented in the analysis as a PVRR) under a benchmark regional haze modeling scenario from the 2017 IRP (benchmark case). Next, PacifiCorp calculated the PVRR assuming that each individual coal unit was retired by the end of 2022 (early retirement case). PacifiCorp cautioned that this simplified assessment of its coal units would not provide a complete, portfolio-level view of the economics of PacifiCorp's coal units, would not capture system cost impacts that would result with early retirements at more than one facility, and would not assess whether system reliability might be compromised. While the coal study on its own provides limited insight into a least-cost, least-risk resource portfolio, the company indicated that it will inform further work with stakeholders in the 2019 IRP process regarding PacifiCorp's economic modeling of its coal fleet. PacifiCorp completed this preliminary coal study and provided it to IRP stakeholders in June 2018.

Q. Sierra Club claims that the preliminary 2018 Coal Analysis shows that nearly [redacted] of PacifiCorp's coal fleet should be economically retired by 2023.[28] How do you respond?

A. Sierra Club's characterization of the preliminary 2018 Coal Analysis is incorrect. This preliminary analysis did not include any scenario that assumes [redacted] of PacifiCorp's coal fleet is retired, and so it is misleading for Sierra Club to characterize the preliminary results in this way. As PacifiCorp explained when it

[28] Fisher Direct at 56.

agreed to perform the additional studies, the 2018 Coal Analysis is preliminary and incomplete. Most importantly, as noted above, the simplified assumptions do not consider the economic impact of retiring more than one unit, let alone [redacted] of PacifiCorp's coal fleet. Each study assumed that only the particular unit being studied was retired early, while all other remained in operation until their retirement date as assumed in the benchmark case. Consequently, this analysis provides no basis to conclude that [redacted] units could economically be retired early.

Retiring [redacted] of the company's coal capacity could also have significant impacts on the company's transmission system and could present reliability challenges that could require incremental investment to remedy. None of these issues were studied in the preliminary 2018 Coal Analysis.

Q. Has the company continued to refine the preliminary 2018 Coal Analysis for purposes of the 2019 IRP?

A. Yes. The company expects to complete an update to this analysis in December 2018. While that update will consider system impacts of the retirement of individual coal units, additional analysis will be required to layer in consideration of regional haze compliance alternatives. The company expects to complete this analysis in time to inform the preferred portfolio for the company's 2019 IRP, which is scheduled to be finalized in March 2019.

Q. Does Sierra Club explain how it can rely on a study that models potential early plant retirements by 2023 as the basis for disallowing costs in 2019?

A. No.

Q. Sierra Club criticizes the company's preliminary 2018 Coal Analysis for including an "intra-hour dispatch credit" in the analysis.[29] How do you respond?

A. PacifiCorp included an intra-hour flexible resource dispatch credit in the preliminary 2018 Coal Analysis to ensure it was accounting for the potential loss of financial benefits that these resources provide within the EIM. The ability of coal resources to increase or decrease output within the hour in response to changes in system conditions across the EIM footprint results in quantifiable incremental revenues and/or reduced costs that would be lost if the assets enabling these benefits are retired.

In response to stakeholder feedback in the on-going public-input process of the 2019 IRP, PacifiCorp has decided to eliminate this credit in the 2019 IRP modeling, including elimination of this credit in the updated coal analysis expected to be completed in December 2018. Nonetheless, PacifiCorp will calculate—as an out-of-model adjustment—the potential impact of this intra-hour dispatch credit, as applicable to a broad range of flexible resource capacity, on model results from the 2019 IRP. The estimated impact of the intra-hour flexible resource credit will be reported separately. This will enable PacifiCorp and IRP stakeholders to better understand the potential impact of changes to intra-hour EIM benefits associated with flexible resources without having it directly affect modeled outcomes.

[29] Fisher Direct at 60.

Q. Sierra Club also relies on its own study, prepared by Synapse in 2017, to corroborate its claims about the results of the preliminary 2018 Coal Analysis.[30] Was the 2017 Synapse study reasonable?

A. No. The Synapse analysis suffers from the same flaws and limitations as the preliminary 2018 Coal Analysis. Sierra Club had Synapse perform a unit-by-unit analysis to determine whether each individual unit is economic without examining how the retirement of individual unit(s) impacts the system as a whole. In other words, each analysis implicitly assumes that the coal unit being studied is the only one that would be retired. Proper analysis, however, would need to assess the economic impact of each unit that is retired on the next unit analyzed. In addition, Sierra Club's analysis fails to consider the operational impacts of retiring so many coal units to ensure that system reliability can be maintained (and it cannot), to account for the incremental costs required to remedy potential reliability issues.

Moreover, the Synapse study is based on a static view of the future from a single point in time and it does not appropriately consider resource-replacement costs, which could be substantial if [redacted] of the company's coal capacity was retired early. In short, a cursory review of the structure of the analysis reveals that it cannot be viewed as a credible critique of PacifiCorp's least-cost, least-risk system-wide planning.

[30] Fisher Direct at 51–53.

IV. RESPONSE TO SIERRA CLUB CHALLENGE TO SCR INVESTMENTS AT JIM BRIDGER UNITS 3 AND 4

Q. Please describe Sierra Club's adjustment related to the SCR investment at Jim Bridger Units 3 and 4.

A. Sierra Club claims that the company acted imprudently when it installed SCRs at Jim Bridger Units 3 and 4. Specifically, Sierra Club argues that before the company issued its Full Notice to Proceed (FNTP) on December 1, 2013, changes in both natural gas and coal prices had rendered the SCRs less economic than converting the units to natural gas. Sierra Club claims the company did not update its economic analysis in the six-month period between the company's initial decision to proceed with the SCRs and the FNTP. Sierra Club contends that if the analysis had been refreshed, it would have shown that the SCRs were no longer the least-cost, least-risk resource choice.

Q. Is Sierra Club's position that the company should have conducted an additional, comprehensive economic analysis at the last minute inconsistent with its other positions in this case?

A. Yes. Sierra Club contends elsewhere that the company should make irrevocable plans now to close coal plants in the next several years—even though market conditions could change.

Q. Has Sierra Club provided any evidence substantiating its claim that the Jim Bridger SCR investment was imprudent?

A. No. Sierra Club did not file any economic analysis, market data, or workpapers that support its adjustment to the Jim Bridger SCRs. Instead, to support its key factual and analytical allegations, Sierra Club points only to an order issued by the

Washington commission that allowed full recovery of the company's Jim Bridger SCR investment, but disallowed a return on the investment. There are several reasons why this is insufficient to support Sierra Club's adjustment.

First, the Washington commission's decision is one of three commission decisions on the Jim Bridger SCRs. The other two decisions (from the Utah commission and the Public Service Commission of Wyoming) allowed full recovery of the investment. Mr. Teply provides more background on the Washington order and explains why this Commission should act consistently with the two commissions that allowed full recovery of the Jim Bridger SCRs, not the one commission that partially disallowed recovery.

Second, while Sierra Club appears to be relying on the testimony and exhibits it filed with the Washington commission, it has not included any of this evidence in the record in this case. In fact, as noted by Mr. Teply, Sierra Club cites only to the sections of the Washington order where that commission described Sierra Club's evidence, it does not rely on the Washington commission's findings and conclusions. Sierra Club cannot establish facts in this case through an order describing the evidence it presented in a different case before a different commission.

Third, the analysis that Sierra Club cites to in this case is its original analysis submitted to the Washington commission. Sierra Club filed superseding analysis at the Washington commission, admitting that its original analysis overstated the changes to PacifiCorp's calculations of its present-value revenue-requirement differential (PVRR(d)). Sierra Club does not explain why it cites—but does not provide—its admittedly erroneous analysis in this case instead of its corrected analysis.

Fourth, Sierra Club's recitation of the Washington order omits the critical fact that the Washington commission *rejected* Sierra Club's analysis because Sierra Club improperly used post-decision information. Thus, even if this Commission could look to the Washington order for the evidence underlying Sierra Club's adjustment in this case, the Washington commission expressly found that Sierra Club's evidence was insufficient to support its proposed disallowance.

Q. Assuming Sierra Club had actually filed the same analysis it relied upon before the Washington commission, would its claims have merit?

A. No. Sierra Club alleges that the benefits of the SCRs were overstated because coal costs increased and natural gas prices decreased. Sierra Club's Washington analysis supporting this claim used information that became available only after the company decided to move forward with the Jim Bridger Units 3 and 4 SCRs. This is improper evidence for a prudence challenge, which requires the Washington commission to examine what the company knew or should have known at the time the decision was made.

Sierra Club's Washington analysis also included material errors that, when corrected, eliminated the alleged decrease in the economic case for the SCR investment. As explained in the rebuttal testimony of Mr. Dana Ralston, Sierra Club's errors overstated the reduction in SCR benefits due to changes in coal costs by $112 million. Sierra Club mischaracterized assumptions underlying the natural-gas price forecast available to the company in fall 2013, and ignored uncertainty in natural-gas prices in its comparative natural-gas-price analysis. These errors invalidated Sierra Club's proposed adjustment related to the natural-gas price forecast, which purportedly reduced SCR benefits by $146 million.

In summary, even if Sierra Club had filed its Washington analysis in this case, that analysis does not demonstrate that the Jim Bridger SCRs are imprudent.

Coal Costs

Q. What was the basis for Sierra Club's coal-cost adjustment before the Washington commission?

A. Sierra Club compared Jim Bridger coal-cost assumptions used in the company's SCR analysis with Jim Bridger coal-cost assumptions used in the company's 2015 IRP.[31]

Q. Was it appropriate to make this comparison?

A. No. The Jim Bridger coal-cost assumptions used in the 2015 IRP were not available to the company before December 1, 2013, when the company issued the FNTP to the contractor.

Q. Does Sierra Club justify its use of coal-cost forecasts from the 2015 IRP in its comparative analysis of coal-cost assumptions used in the company's Jim Bridger SCR analysis?

A. No. In fact, Sierra Club's testimony in this case never even explains how it calculated its $143 million reduction in coal costs. Instead, Sierra Club just points to the Washington order describing Sierra Club's testimony in that case.[32] Notably, the Washington commission gave no weight to Sierra Club's analysis because it relied on

[31] Order 12 n. 116.
[32] Fisher Direct at 26, 29.

"information not available to the company at the time of its decision to execute the FNTP."[33]

Q. In its Washington testimony, did Sierra Club concede that its $143 million adjustment relied on coal-cost data that was unavailable when the company issued its FNTP on December 1, 2013?

A. Yes. Sierra Club admitted that its adjustment was based on data from July 2014—more than six months after the company issued the FNTP.[34]

Q. Aside from Sierra Club's reliance on post-FNTP data, were the calculations performed by Sierra Club in its Washington testimony accurate?

A. No. As Mr. Ralston explains, Sierra Club's comparative analysis was incomplete. Sierra Club only considered changes in cash costs when it compared coal-cost assumptions used in the company's Jim Bridger SCR analysis with those used in the 2015 IRP. Sierra Club's analysis omitted the change in Bridger Coal Company's forecasted capital expenses. Had Sierra Club performed an accurate comparative coal-cost analysis that included future mine capital expenses, the differential in coal costs used in the 2015 IRP—which were not available in fall 2013—and the coal costs used in the company's analysis would have reduced this change in benefits to only $31 million. Sierra Club's coal-cost adjustment (when corrected) does not support its conclusion that gas conversion would be lower cost than installation of SCRs on Jim Bridger Units 3 and 4.

[33] Order 12 ¶ 111; *id.* n. 158.
[34] *In the Matter of Pacific Power and Light Co. Petition for a Rate Increase Based on a Modified Commission Basis Report*, *Two-Year Rate Plan, and Decoupling Mechanism*, Docket No. UE-152253, Supplemental Cross-Answering Testimony of Jeremy I. Fisher, PhD (Redacted) at 16 (May 13, 2016).

Natural-Gas Prices

Q. At the time it made the decision to proceed with the Jim Bridger SCRs and issue the FNTP, did the company evaluate how projections of natural-gas prices affected its base case analysis of the Jim Bridger SCRs?

A. Yes. The economic analysis of the Jim Bridger SCRs used base-case natural-gas prices from the company's September 2012 official forward price curve (OFPC), which yielded a nominal levelized price at Opal over the 2016-through-2030 time frame of $5.72 per mmBtu. The most current OFPC when the FNTP was issued on December 1, 2013, was the September 2013 OFPC, which yielded a nominal levelized price at Opal of $5.35 per mmBtu over the 2016-through-2030 time frame. This is above the break-even levelized Opal natural-gas price for the SCRs at $4.86/mmBtu, referenced in my direct testimony at Exhibit PAC/507. As described in my direct testimony, the company estimated that the Jim Bridger SCRs remained approximately $130 million lower cost than the gas-conversion alternative when applying natural-gas price assumptions from the September 2013 OFPC.

Q. Please describe Sierra Club's claims about the natural-gas price assumptions used in the SCR economic analysis.

A. Sierra Club again points to evidence it presented to the Washington commission in 2015, where it used the December 2013 OFPC to make an adjustment to the company's analysis.[35] Using the December 2013 OFPC, Sierra Club reduced the company's base-case analysis developed using the September 2012 OFPC showing a

[35] Fisher Direct at 30–31.

$183 million benefit from the Jim Bridger SCRs by $146 million.[36] This equates to a $93 million reduction from the company's analysis showing a $130 million benefit from the Jim Bridger SCRs when applying the September 2013 OFPC.

Q. Was the December 2013 OFPC completed at the time the FNTP was issued to the contractor?

A. No. The December 2013 OFPC was completed approximately one full month after the FNTP was issued to the contractor. The company has a long and well-documented history of finalizing its OFPC on the last trading day of each calendar quarter. The December 2013 OFPC was produced on December 31, 2013. The FNTP was issued to the contractor on December 1, 2013.

Q. Did the Washington commission rely on Sierra Club's adjustment to natural-gas prices based on the December 2013 OFPC?

A. No. The Washington commission found that Sierra Club improperly relied on data that was unavailable to the company when it issued its FNTP.[37]

Q. What fundamentals-based long-term natural-gas price forecasts were available to the company during the development of the December 2013 OFPC?

A. PacifiCorp received an updated long-term natural-gas price forecast from three different third-party experts after it finalized its September 2013 OFPC—an updated forecast from [redacted] dated October 22, 2013; an updated forecast from [redacted] dated November 20, 2013; and an updated forecast from [redacted] dated December 11, 2013. The [redacted] long-term price forecast for Opal showed

[36] *Id*., 25, 31.
[37] Exhibit JIF-11, Redacted Order 12 ¶ 111; *id.* n. 158.

a nominal levelized price of [redacted]/mmBtu over the 2016-through-2030 time frame, which was higher than the September 2013 OFPC and a decrease of only [redacted], between May and October 2013. Over this same forecast period, the [redacted] and [redacted] long-term forecasts for Opal showed a nominal levelized price of [redacted]/mmBtu and [redacted]/mmBtu, respectively. Nominal levelized prices for two of these three price forecasts were well above the break-even levelized Opal natural-gas price of $4.86/mmBtu.

Q. Sierra Club claims that "[e]ven from September 2013 to December 1, 2013 . . . gas price forwards continued to fall."[38] Is this true?

A. No. As noted above, the nominal levelized natural-gas price in the September 2013 OFPC was $5.35 per MMBtu. Two of the company's three third-party forecasts *increased* after September 2013. And the only consultant forecast that was less than the break-even point showed a [redacted] relative to the same consultant's August forecast—undermining Sierra Club's claim that natural-gas prices were in free fall after September 2013.

Q. How do you respond to Sierra Club's representation of short-term market forwards available before December 1, 2013?[39]

A. Sierra Club claims that short-term market forwards available before December 1, 2013, indicated declining natural gas prices.[40] The company's long-term resource planning decisions are based on long-term price forecasts, because these are the prices that have the most influence on the economic analysis for long-term resource

[38] Fisher Direct at 30.
[39] Fisher Direct at 30.
[40] Fisher Direct at 30.

decisions. While short-term market forwards may have been declining in late 2013, the long-term forecasts were still above the company's break-even point when it provided the FNTP to the contractor.

Q. Were there any other SCR-related costs that changed before the company issued its FNTP?

A. Yes. As described in the rebuttal testimony of Mr. Teply, by the December 2013 time frame, when the company issued its FNTP to the contractor, the company was aware that its share of the SCR cost was reduced by approximately [redacted]. When issuing the FNTP, the company was aware that these reduced costs would partially offset lower natural-gas prices, while recognizing that there was uncertainty in how future natural-gas prices might compare to then-current forecasts.

Economic Assessment before Issuing FNTP

Q. Sierra Club claims that no one in the planning or coal teams at PacifiCorp alerted the management team that changing coal costs and gas prices "had likely collapsed any benefit" associated with the Jim Bridger SCRs.[41] Please respond.

A. First, as discussed above, this testimony wrongly assumes that changes in coal costs and gas prices made the SCR investments non-beneficial. Second, the testimony also wrongly implies that the company did not consider potential changes to its calculation of economic benefits related to the Jim Bridger SCRs before it issued the FNTP.

[41] Fisher Direct at 31.

Q. Did the company's scenario analysis allow it to readily consider the impact of changing market conditions on its Jim Bridger SCR analysis before issuing the FNTP on December 1, 2013?

A. Yes. PacifiCorp's economic analysis of compliance alternatives for Jim Bridger Units 3 and 4 was designed to allow for rapid re-assessment of the PVRR(d) between the SCR and natural-gas conversion alternatives with changing market conditions, complementing flexibility provisions that the company negotiated in the SCR engineer, procure, and construct (EPC) contract. PacifiCorp used this analysis when choosing installation of SCRs as the best regional haze compliance alternative in May 2013 *and* to assess how changes in market conditions affected the customer benefits before issuing the FNTP in December 2013.

Q. What types of changes in market conditions did the company consider before issuing the FNTP?

A. As described in the direct and rebuttal testimony of Mr. Teply, PacifiCorp considered all factors material to its SCR analysis, recognizing that the base-case natural-gas price forecast had fallen, the estimated cost for the EPC contract had been reduced, Bridger Coal Company mine costs had been updated, and there was no reason to change CO_2 price assumptions.

Q. Please explain how PacifiCorp considered the impact of a reduced natural-gas price forecast on the SCR benefits before issuing the FNTP.

A. As I stated above, the company performed comprehensive analysis of the compliance alternatives for Jim Bridger Units 3 and 4 under the regional haze regulations. As part of this analysis, the company produced natural-gas price sensitivities that show a strong linear relationship between natural-gas price inputs and the PVRR(d) between the SCR and natural-gas-conversion compliance alternatives. I present this relationship in my direct testimony as Exhibit PAC/507.[42]

Based upon this relationship, PacifiCorp's comprehensive analysis was used to establish how the SCR benefits are affected by natural-gas price assumptions. Before issuing the FNTP, the company reviewed its most recent OFPC and, using the relationship shown in Exhibit PAC/507, readily determined that the base-case PVRR(d) continued to show significant SCR benefits ($130 million).[43]

When evaluating natural-gas prices before issuing the FNTP, the company also considered that there is uncertainty in long-term natural-gas price forecasts. The company was aware that natural-gas prices had fallen and considered this in making the decision to issue the FNTP. PacifiCorp was also aware that there is volatility in long-term price forecasts, that natural-gas prices cannot trend downward indefinitely, and that there was a reasonable possibility that actual natural-gas prices could be higher than then-current base-case projections.

Q. Please explain how PacifiCorp considered the impact of reduced EPC contract costs on the SCR benefits before issuing the FNTP.

A. PacifiCorp was aware, before issuing the FNTP, that EPC costs for the Jim Bridger SCRs had been reduced by [redacted].[44] The reduced EPC cost contributes approximately [redacted] in additional benefits to the SCR compliance alternative. These incremental benefits, tied to fixed costs for the SCRs, are easily calculated, and

[42] PAC/500, Link/18.
[43] *Id.* at 24.
[44] *See* PAC/1600, Teply/10.

no model runs are required to understand how reduced EPC costs improve benefits for the SCR compliance alternative. Before issuing the FNTP, PacifiCorp knew that these EPC cost reductions would only add to the already substantial benefits of the SCR compliance alternative even after accounting for reduced base-case natural-gas price assumptions. Moreover, as Mr. Teply testifies, there would be increased costs and risks of natural-gas conversion under a hypothetical post-FNTP cancellation.

Q. Please explain how PacifiCorp considered the impact of updated Bridger Coal Company mine costs before issuing the FNTP.

A. As described in Mr. Ralston's testimony, in October 2013, PacifiCorp updated its Bridger Coal Company mine costs. At the time the FNTP was issued, the company was aware that the base case SCR compliance alternative was approximately [redacted] ($130 million PVRR(d) based on the September 2013 OFPC plus [redacted] for EPC cost savings) lower cost than the natural-gas conversion alternative. While PacifiCorp was aware that its Bridger Coal Company mine costs had been updated before issuing the FNTP, there was nothing in the updated mine costs—an interim step to developing a new long-term fueling plan for the Jim Bridger generating plant, which was completed in November 2014 and used in the 2015 IRP—to suggest delivered coal costs were increasing to a level that would eliminate the substantial SCR benefits. In fact, this observation was later substantiated when the long-term fueling plan for the Jim Bridger generating plant used in the 2015 IRP was completed. As noted above, when coal costs for the Jim Bridger generating plant used in the company's SCR analysis are compared to coal costs used in the 2015 IRP, SCR benefits would be reduced by only $31 million.[45]

Q. Does this conclude your rebuttal testimony?

A. Yes.

[45] *See* PAC/1700, Ralston/6.

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Part III

Environmental Protection Agency

40 CFR Part 52

Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze; Proposed Rule

CUB/508
2

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R08–OAR–2012–0026, FRL–9820–4]

Approval, Disapproval and Promulgation of Implementation Plans; State of Wyoming; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule.

SUMMARY: EPA is proposing to partially approve and partially disapprove a State Implementation Plan (SIP) submitted by the State of Wyoming on January 12, 2011, that addresses regional haze. This SIP revision was submitted to address the requirements of the Clean Air Act (CAA or ''the Act'') and our rules that require states to prevent any future and remedy any existing anthropogenic impairment of visibility in mandatory Class I areas caused by emissions of air pollutants from numerous sources located over a wide geographic area (also referred to as the ''regional haze program''). States are required to assure reasonable progress toward the national goal of achieving natural visibility conditions in Class I areas. EPA is taking this action pursuant to section 110 of the CAA.

EPA is also proposing a Federal Implementation Plan (FIP) to address the deficiencies identified in our proposed partial disapproval of Wyoming's regional haze SIP. In lieu of our proposed FIP, or a portion thereof, we will propose approval of a SIP revision as expeditiously as practicable if the State submits such a revision and the revision matches the terms of our proposed FIP. We will also review and take action on any regional haze SIP submitted by the state to determine whether such SIP is approvable, regardless of whether or not its terms match those of the FIP. We encourage the State to submit a SIP revision to replace the FIP, either before or after our final action.

DATES: *Comments:* Written comments must be received at the address below on or before August 9, 2013. *Public Hearing:* A public hearing for this proposal is scheduled to be held on Monday, June 24, 2013, at the Hershchler Building, Room 1699, 122 W. 25th St., Cheyenne, Wyoming 82002. The public hearing will be held from 1 p.m. until 5 p.m., and again from 6 p.m. until 8 p.m.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R08–OAR–2012–0026, by one of the following methods:

- *http://www.regulations.gov.* Follow the on-line instructions for submitting comments.
- *Email: r8airrulemakings@epa.gov.*
- *Fax:* (303) 312–6064 (please alert the individual listed in the **FOR FURTHER INFORMATION CONTACT** if you are faxing comments).
- *Mail:* Carl Daly, Director, Air Program, Environmental Protection Agency (EPA), Region 8, Mailcode 8P–AR, 1595 Wynkoop Street, Denver, Colorado 80202–1129.
- *Hand Delivery:* Carl Daly, Director, Air Program, Environmental Protection Agency (EPA), Region 8, Mailcode 8P–AR, 1595 Wynkoop, Denver, Colorado 80202–1129. Such deliveries are only accepted Monday through Friday, 8:00 a.m. to 4:30 p.m., excluding Federal holidays. Special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–R08–OAR–2012–0026. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or email. The *http://www.regulations.gov* Web site is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to EPA, without going through *http://www.regulations.gov*, your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional instructions on submitting comments, go to Section I. General Information of the **SUPPLEMENTARY INFORMATION** section of this document.

Docket: All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, e.g., CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly-available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the Air Program, Environmental Protection Agency (EPA), Region 8, Mailcode 8P–AR, 1595 Wynkoop, Denver, Colorado 80202–1129. EPA requests that if at all possible, you contact the individual listed in the **FOR FURTHER INFORMATION CONTACT** section to view the hard copy of the docket. You may view the hard copy of the docket Monday through Friday, 8:00 a.m. to 4:00 p.m., excluding Federal holidays.

FOR FURTHER INFORMATION CONTACT:
Laurel Dygowski, Air Program, U.S. Environmental Protection Agency, Region 8, Mailcode 8P–AR, 1595 Wynkoop, Denver, Colorado 80202–1129, (303) 312–6144, *dygowski.laurel@epa.gov.*

SUPPLEMENTARY INFORMATION:

Definitions

For the purpose of this document, we are giving meaning to certain words or initials as follows:

i. The words or initials *Act* or *CAA* mean or refer to the Clean Air Act, unless the context indicates otherwise.

ii. The initials *AFRC* mean or refer to air-fuel ratio controls.

iii. The initials *BART* mean or refer to Best Available Retrofit Technology.

iv. The initials *CAMx* mean or refer to Comprehensive Air Quality Model.

v. The initials *CMAQ* mean or refer to Community Multi-Scale Air Quality modeling system.

vi. The initials *CEMS* mean or refer to continuous emission monitoring systems.

vii. The initials *EC* mean or refer to elemental carbon.

viii. The initials *EGUs* mean or refer to Electric Generating Units.

ix. The initials *EGR* mean or refer to exhaust gas recirculation.

x. The words *EPA, we, us* or *our* mean or refer to the United States Environmental Protection Agency.

xi. The initials *ESP* mean or refer to electrostatic precipitator.

xii. The initials *FGC* mean or refer to flue gas conditioning.

xiii. The initials *FGD* mean or refer to flue gas desulfurization.

xiv. The initials *FGR* mean or refer to external flue gas recirculation.

xv. The initials *FIP* mean or refer to Federal Implementation Plan.

xvi. The initials *FLMs* mean or refer to Federal Land Managers.

xvii. The initials *FS* mean or refer to the U.S. Forest Service.

xviii. The initials *IMPROVE* mean or refer to Interagency Monitoring of Protected Visual Environments monitoring network.

xix. The initials *IWAQM* mean or refer to Interagency Workgroup on Air Quality Modeling.

xx. The initials *LEC* mean or refer to low-emission combustion.

xxi. The initials *LNB* mean or refer to low NO_X burner.

xxii. The initials *LTS* mean or refer to the long-term strategy.

xxiii. The initials *MW* mean or refer to megawatts.

xxiv. The initials NH_3 mean or refer to ammonia.

xxv. The initials NO_X mean or refer to nitrogen oxides.

xxvi. The initials *NPS* mean or refer to National Park Service.

xxvii. The initials *OC* mean or refer to organic carbon.

xxviii. The initials *OFA* mean or refer to overfire air.

xxix. The initials $PM_{2.5}$ mean or refer to particulate matter with an aerodynamic diameter of less than 2.5 micrometers.

xxx. The initials PM_{10} mean or refer to particulate matter with an aerodynamic diameter of less than 10 micrometers.

xxxi. The initials *PSAT* mean or refer to Particle Source Apportionment Technology.

xxxii. The initials *PSD* mean or refer to Prevention of Signification Deterioration.

xxxiii. The initials *RAVI* mean or refer to Reasonably Attributable Visibility Impairment.

xxxiv. The initials *RHR* mean or refer to the Regional Haze Rule.

xxxv. The initials *RMC* mean or refer to the Regional Modeling Center at the University of California Riverside.

xxxvi. The initials *RPGs* mean or refer to Reasonable Progress Goals.

xxxvii. The initials *RPOs* mean or refer to regional planning organizations.

xxxviii. The initials *SCR* mean or refer to selective catalytic reduction.

xxxix. The initials *SIP* mean or refer to State Implementation Plan.

xl. The initials *SNCR* mean or refer to selective non-catalytic reduction.

xli. The initials SO_2 mean or refer to sulfur dioxide.

xlii. The initials *SOFA* mean or refer to separated overfire air.

xliii. The initials *TSD* mean or refer to Technical Support Document.

xliv. The initials *ULNB* mean or refer to ultra-low NO_X burners.

xlv. The initials *URP* mean or refer to Uniform Rate of Progress.

xlvi. The initials *VOC* mean or refer to volatile organic compounds.

xlvii. The initials *WAQSR* mean or refer to Wyoming Air Quality Standards and Regulations.

xlviii. The initials *WEP* mean or refer to Weighted Emissions Potential.

xlix. The initials *WRAP* mean or refer to the Western Regional Air Partnership.

l. The words *Wyoming* and *State* mean the State of Wyoming.

Table of Contents

I. General Information

A. What should I consider as I prepare my comments for EPA?

1. *Submitting CBI.* Do not submit CBI to EPA through *http://www.regulations.gov* or email. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD ROM that you mail to EPA, mark the outside of the disk or CD ROM as CBI and then

identify electronically within the disk or CD ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

2. *Tips for Preparing Your Comments.* When submitting comments, remember to:

a. Identify the rulemaking by docket number and other identifying information (subject heading, **Federal Register** date and page number).

b. Follow directions—The agency may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.

c. Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.

d. Describe any assumptions and provide any technical information and/or data that you used.

e. If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.

f. Provide specific examples to illustrate your concerns, and suggest alternatives.

g. Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

h. Make sure to submit your comments by the comment period deadline identified.

II. EPA's Prior Action

We signed a notice of proposed rulemaking on May 15, 2012, and it was published in the **Federal Register** on June 4, 2012 (77 FR 33022).

In our proposal, we proposed to disapprove the following:

- The State's nitrogen oxides (NO_X) best available retrofit technology (BART) determinations for PacifiCorp Dave Johnston Unit 3, PacifiCorp Jim Bridger Units 1 and 2, PacifiCorp Wyodak Unit 1, and Basin Electric Laramie River Station Units 1, 2, and 3.
- The State's NO_X reasonable progress determination for PacifiCorp Dave Johnston Units 1 and 2.
- The State's Reasonable Progress Goals (RPGs).
- The State's monitoring, recordkeeping, and reporting requirements in Chapter 6.4 of the SIP.
- Portions of the State's long-term strategy (LTS) that rely on or reflect aspects of the regional haze SIP that we are disapproving.
- The State's SIP because it does not contain the necessary provisions to meet the requirements for the coordination of the review of the reasonably attributable visibility impairment (RAVI) and the regional haze LTS.

We proposed to approve the remaining aspects of the State's January 12, 2011 SIP submittal. We also sought comment on two alternative proposals related to the State's NO_X BART determination for PacifiCorp Jim Bridger Units 1 and 2.

We proposed the promulgation of a FIP to address the deficiencies in the Wyoming regional haze SIP that we identified in the proposal. The proposed FIP included the following elements:

- NO_X BART determinations and limits for PacifiCorp Dave Johnston Unit 3, PacifiCorp Jim Bridger Units 1 and 2, PacifiCorp Wyodak Unit 1, and Basin Electric Laramie River Station Units 1, 2, and 3.
- NO_X reasonable progress determination and limits for PacifiCorp Dave Johnston Units 1 and 2.
- RPGs consistent with the SIP limits proposed for approval and the proposed FIP limits.
- Monitoring, recordkeeping, and reporting requirements applicable to all BART and reasonable progress sources for which there is a SIP or FIP emissions limit.
- LTS elements pertaining to emission limits and compliance schedules for the proposed BART and reasonable progress FIP emission limits.
- Provisions to ensure the coordination of the RAVI and regional haze LTS.

In lieu of our proposed FIP, or a portion thereof, we stated that we would propose approval of a SIP revision if the State submits such a revision and the revision matches the terms of our proposed FIP. We encouraged the State to submit a SIP revision to replace the FIP, either before or after our final action.

We requested comments on all aspects of our proposed action and provided a 60-day comment period, with the comment period closing on August 3, 2012. We also held two public hearings. The public hearings were held on June 26, 2012, in Cheyenne, Wyoming and June 28, 2012, in Rock Springs, Wyoming.

The Conservation Organizations [1] and the National Park Service submitted comments during the public comment period pertaining to, among other things, the cost analyses that the State relied upon in its SIP and that EPA subsequently relied on to make its proposed rulemaking decision. The commenters asserted that the State overestimated the costs for some control technologies and underestimated the costs for other control technologies. Based on our review of these comments and upon further review of the State's cost and visibility analyses, we determined that the State's analyses are flawed in several respects and are therefore inconsistent with the BART Guidelines and statutory requirements, as discussed further in this notice. As a result, EPA conducted its own cost analyses for the BART and reasonable progress electric generating units (EGUs), and also revised its modeling of the visibility improvement for these sources in order to be comparable to the revised costs analyses as explained in section V.II.C.3. The revised costs and visibility modeling are explained in further detail in section VII.C.3. Because we have developed new cost and visibility improvement modeling analyses, we are re-proposing action on Wyoming's SIP in order to give the public the opportunity to comment on our updated cost and visibility analyses and our proposed determinations based on this new information.

III. Overview of Proposed Actions

EPA is proposing to partially approve and partially disapprove a regional haze SIP submitted by the State of Wyoming on January 12, 2011. Specifically, we are proposing to disapprove the following:

- The State's NO_X BART determinations for PacifiCorp Dave Johnston Units 3 and 4, PacifiCorp Naughton Units 1 and 2, PacifiCorp Wyodak Unit 1, and Basin Electric Laramie River Units 1, 2, and 3.
- The State's NO_X reasonable progress determinations for PacifiCorp Dave Johnston Units 1 and 2.
- Wyoming's RPGs.
- The State's monitoring, recordkeeping, and reporting requirements in Chapter 6.4 of the SIP.
- Portions of the State's LTS that rely on or reflect other aspects of the regional haze SIP.
- The provisions necessary to meet the requirements for the coordination of the review of the RAVI and the regional haze LTS.

We are proposing to approve the remaining aspects of the State's January 12, 2011SIP submittal. However, we are also seeking comment on an alternative proposal, related to the State's NO_X BART determinations, for PacifiCorp Jim Bridger Units 1 and 2, that would

[1] The Conservation Organizations refers to comments submitted on behalf of Powder River Basin Resource Council, Wyoming Outdoor Council, Greater Yellowstone Coalition, Sierra Club, National Parks Conservation Association, and WildEarth Guardians.

involve disapproval and the promulgation of a FIP.

We are proposing the promulgation of a FIP to address the deficiencies in the Wyoming regional haze SIP that we have identified in this notice. The proposed FIP includes the following elements:

• NO_X BART determinations and limits for PacifiCorp Dave Johnston Units 3 and 4, PacifiCorp Naughton Units 1 and 2, PacifiCorp Wyodak Unit 1, and Basin Electric Laramie River Units 1, 2, and 3.

• NO_X reasonable progress determinations and limits for PacifiCorp Dave Johnston Units 1 and 2.

• RPGs consistent with the SIP limits proposed for approval and the proposed FIP limits.

• Monitoring, recordkeeping, and reporting requirements applicable to all BART and reasonable progress sources for which there is a SIP or FIP emissions limit.

• LTS elements pertaining to emission limits and compliance schedules for the proposed BART and reasonable progress FIP emission limits.

• Provisions to ensure the coordination of the RAVI and regional haze LTS.

In lieu of our proposed FIP, or a portion thereof, we will propose approval of a SIP revision as expeditiously as practicable if the State submits such a revision and the revision matches the terms of our proposed FIP. We will also review and take action on any regional haze SIP submitted by the state to determine whether such SIP is approvable, regardless of whether or not its terms match those of the FIP. We encourage the State to submit a SIP revision to replace the FIP, either before or after our final action.

IV. SIP and FIP Background

The CAA requires each state to develop plans to meet various air quality requirements, including protection of visibility. CAA sections 110(a), 169A, and 169B. The plans developed by a state are referred to as SIPs. A state must submit its SIPs and SIP revisions to us for approval. Once approved, a SIP is enforceable by EPA and citizens under the CAA, also known as being federally enforceable. If a state fails to make a required SIP submittal or if we find that a state's required submittal is incomplete or unapprovable, then we must promulgate a FIP to fill this regulatory gap. CAA section 110(c)(1). As discussed elsewhere in this notice, we are proposing to disapprove aspects of Wyoming's regional haze SIP. We are proposing a FIP to address the deficiencies in Wyoming's regional haze SIP.

V. Background

A. Regional Haze

Regional haze is visibility impairment that is produced by a multitude of sources and activities which are located across a broad geographic area and emit fine particles ($PM_{2.5}$) (e.g., sulfates, nitrates, organic carbon (OC), elemental carbon (EC), and soil dust), and their precursors (e.g., sulfur dioxide (SO_2), NO_X, and in some cases, ammonia (NH_3) and volatile organic compounds (VOC)). Fine particle precursors react in the atmosphere to form $PM_{2.5}$, which impairs visibility by scattering and absorbing light. Visibility impairment reduces the clarity, color, and visible distance that one can see. $PM_{2.5}$ can also cause serious health effects and mortality in humans and contributes to environmental effects such as acid deposition and eutrophication.

Data from the existing visibility monitoring network, the ''Interagency Monitoring of Protected Visual Environments'' (IMPROVE) monitoring network, show that visibility impairment caused by air pollution occurs virtually all the time at most national park and wilderness areas. The average visual range [2] in many Class I areas (i.e., national parks and memorial parks, wilderness areas, and international parks meeting certain size criteria) in the western United States is 100–150 kilometers, or about one-half to two-thirds of the visual range that would exist without anthropogenic air pollution. In most of the eastern Class I areas of the United States, the average visual range is less than 30 kilometers, or about one-fifth of the visual range that would exist under estimated natural conditions. 64 FR 35715 (July 1, 1999).

B. Requirements of the CAA and EPA's Regional Haze Rule (RHR)

In section 169A of the 1977 Amendments to the CAA, Congress created a program for protecting visibility in the nation's national parks and wilderness areas. This section of the CAA establishes as a national goal the ''prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas [3] which impairment results from manmade air pollution.'' On December 2, 1980, EPA promulgated regulations to address visibility impairment in Class I areas that is ''reasonably attributable'' to a single source or small group of sources, i.e., ''reasonably attributable visibility impairment.'' 45 FR 80084. These regulations represented the first phase in addressing visibility impairment. EPA deferred action on regional haze that emanates from a variety of sources until monitoring, modeling and scientific knowledge about the relationships between pollutants and visibility impairment were improved.

Congress added section 169B to the CAA in 1990 to address regional haze issues. EPA promulgated a rule to address regional haze on July 1, 1999. 64 FR 35714 (July 1, 1999), codified at 40 CFR part 51, subpart P. The RHR revised the existing visibility regulations to integrate into the regulation provisions addressing regional haze impairment and established a comprehensive visibility protection program for Class I areas. The requirements for regional haze, found at 40 CFR 51.308 and 51.309, are included in EPA's visibility protection regulations at 40 CFR 51.300–309. Some of the main elements of the regional haze requirements are summarized in section III of this preamble. The requirement to submit a regional haze SIP applies to all 50 states, the District of Columbia and the Virgin Islands. 40 CFR 51.308(b) requires states to submit the first implementation plan addressing regional haze visibility impairment no later than December 17, 2007.[4]

Few states submitted a regional haze SIP prior to the December 17, 2007 deadline, and on January 15, 2009, EPA found that 37 states (including Wyoming), the District of Columbia, and the Virgin Islands, had failed to submit SIPs addressing the regional haze requirements. 74 FR 2392. Once EPA

[2] Visual range is the greatest distance, in kilometers or miles, at which a dark object can be viewed against the sky.

[3] Areas designated as mandatory Class I Federal areas consist of national parks exceeding 6000 acres, wilderness areas and national memorial parks exceeding 5000 acres, and all international parks that were in existence on August 7, 1977. 42 U.S.C. 7472(a). In accordance with section 169A of the CAA, EPA, in consultation with the Department of Interior, promulgated a list of 156 areas where visibility is identified as an important value. 44 FR 69122 (November 30, 1979). The extent of a mandatory Class I area includes subsequent changes in boundaries, such as park expansions. 42 U.S.C. 7472(a). Although states and tribes may designate as Class I additional areas which they consider to have visibility as an important value, the requirements of the visibility program set forth in section 169A of the CAA apply only to ''mandatory Class I Federal areas.'' Each mandatory Class I Federal area is the responsibility of a ''Federal Land Manager.'' 42 U.S.C. 7602(i). When we use the term ''Class I area'' in this action, we mean a ''mandatory Class I Federal area.''

[4] EPA's regional haze regulations require subsequent updates to the regional haze SIPs. 40 CFR 51.308(g)–(i).

has found that a state has failed to make a required submission, EPA is required to promulgate a FIP within two years unless the state submits a SIP and the Agency approves it within the two-year period. CAA § 110(c)(1).

C. Roles of Agencies in Addressing Regional Haze

Successful implementation of the regional haze program will require long-term regional coordination among states, tribal governments, and various federal agencies. As noted above, pollution affecting the air quality in Class I areas can be transported over long distances, even hundreds of kilometers. Therefore, to effectively address the problem of visibility impairment in Class I areas, states need to develop strategies in coordination with one another, taking into account the effect of emissions from one jurisdiction on the air quality in another.

Because the pollutants that lead to regional haze can originate from sources located across broad geographic areas, EPA has encouraged the states and tribes across the United States to address visibility impairment from a regional perspective. Five regional planning organizations (RPOs) were developed to address regional haze and related issues. The RPOs first evaluated technical information to better understand how their states and tribes impact Class I areas across the country, and then pursued the development of regional strategies to reduce emissions of pollutants that lead to regional haze.

The Western Regional Air Partnership (WRAP) RPO is a collaborative effort of state governments, tribal governments, and various federal agencies established to initiate and coordinate activities associated with the management of regional haze, visibility and other air quality issues in the western United States. WRAP member state governments include: Alaska, Arizona, California, Colorado, Idaho, Montana, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming. Tribal members include Campo Band of Kumeyaay Indians, Confederated Salish and Kootenai Tribes, Cortina Indian Rancheria, Hopi Tribe, Hualapai Nation of the Grand Canyon, Native Village of Shungnak, Nez Perce Tribe, Northern Cheyenne Tribe, Pueblo of Acoma, Pueblo of San Felipe, and Shoshone-Bannock Tribes of Fort Hall.

VI. Requirements for Regional Haze SIPs

The following is a summary of the requirements of the RHR. See 40 CFR 51.308 for further detail regarding the requirements of the rule.

A. The CAA and the Regional Haze Rule

Regional haze SIPs must assure reasonable progress towards the national goal of achieving natural visibility conditions in Class I areas. Section 169A of the CAA and EPA's implementing regulations require states to establish long-term strategies for making reasonable progress toward meeting this goal. Implementation plans must also give specific attention to certain stationary sources that were in existence on August 7, 1977, but were not in operation before August 7, 1962, and require these sources, where appropriate, to install BART controls for the purpose of eliminating or reducing visibility impairment. The specific regional haze SIP requirements are discussed in further detail below.

B. Determination of Baseline, Natural, and Current Visibility Conditions

The RHR establishes the deciview as the principal metric or unit for expressing visibility. *See* 70 FR 39104, 39118. This visibility metric expresses uniform changes in the degree of haze in terms of common increments across the entire range of visibility conditions, from pristine to extremely hazy conditions. Visibility expressed in deciviews is determined by using air quality measurements to estimate light extinction and then transforming the value of light extinction using a logarithmic function. The deciview is a more useful measure for tracking progress in improving visibility than light extinction itself because each deciview change is an equal incremental change in visibility perceived by the human eye. Most people can detect a change in visibility at one deciview.[5]

The deciview is used in expressing RPGs (which are interim visibility goals towards meeting the national visibility goal), defining baseline, current, and natural conditions, and tracking changes in visibility. The regional haze SIPs must contain measures that ensure ''reasonable progress'' toward the national goal of preventing and remedying visibility impairment in Class I areas caused by anthropogenic air pollution by reducing anthropogenic emissions that cause regional haze. The national goal is a return to natural conditions, i.e., anthropogenic sources of air pollution would no longer impair visibility in Class I areas.

To track changes in visibility over time at each of the 156 Class I areas covered by the visibility program (40 CFR 81.401–437), and as part of the process for determining reasonable progress, states must calculate the degree of existing visibility impairment at each Class I area at the time of each regional haze SIP submittal and periodically review progress every five years midway through each 10-year implementation period. To do this, the RHR requires states to determine the degree of impairment (in deciviews) for the average of the 20 percent least impaired (''best'') and 20 percent most impaired (''worst'') visibility days over a specified time period at each of their Class I areas. In addition, states must also develop an estimate of natural visibility conditions for the purpose of comparing progress toward the national goal. Natural visibility is determined by estimating the natural concentrations of pollutants that cause visibility impairment and then calculating total light extinction based on those estimates. We have provided guidance to states regarding how to calculate baseline, natural and current visibility conditions.[6]

For the first regional haze SIPs that were due by December 17, 2007, ''baseline visibility conditions'' were the starting points for assessing ''current'' visibility impairment. Baseline visibility conditions represent the degree of visibility impairment for the 20 percent least impaired days and 20 percent most impaired days for each calendar year from 2000 to 2004. Using monitoring data for 2000 through 2004, states are required to calculate the average degree of visibility impairment for each Class I area, based on the average of annual values over the five-year period. The comparison of initial baseline visibility conditions to natural visibility conditions indicates the amount of improvement necessary to attain natural visibility, while the future comparison of baseline conditions to the then current conditions will indicate the amount of progress made. In general, the 2000–2004 baseline period is considered the time from which improvement in visibility is measured.

[5] The preamble to the RHR provides additional details about the dv. 64 FR 35714, 35725 (July 1, 1999).

[6] *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule,* September 2003, EPA–454/B–03–005, *available* at *http://www.epa.gov/ttncaaa1/t1/memoranda/Regional Haze_envcurhr_gd.pdf,* (hereinafter referred to as ''our 2003 Natural Visibility Guidance''); and *Guidance for Tracking Progress Under the Regional Haze Rule,* (September 2003, EPA–454/B–03–004, available at *http://www.epa.gov/ttncaaa1/t1/memoranda/rh_tpurhr_gd.pdf,* (hereinafter referred to as our ''2003 Tracking Progress Guidance'').

C. Determination of Reasonable Progress Goals

The vehicle for ensuring continuing progress towards achieving the natural visibility goal is the submission of a series of regional haze SIPs from the states that establish two RPGs (i.e., two distinct goals, one for the ''best'' and one for the ''worst'' days) for every Class I area for each (approximately) 10-year implementation period. *See* 40 CFR 51.308(d), (f). The RHR does not mandate specific milestones or rates of progress, but instead calls for states to establish goals that provide for ''reasonable progress'' toward achieving natural visibility conditions. In setting RPGs, states must provide for an improvement in visibility for the most impaired days over the (approximately) 10-year period of the SIP, and ensure no degradation in visibility for the least impaired days over the same period. *Id.*

In establishing RPGs, states are required to consider the following factors established in section 169A of the CAA and in our RHR at 40 CFR 51.308(d)(1)(i)(A): (1) The costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of any potentially affected sources. States must demonstrate in their SIPs how these factors are considered when selecting the RPGs for the best and worst days for each applicable Class I area. In setting the RPGs, states must also consider the rate of progress needed to reach natural visibility conditions by 2064 (referred to as the ''uniform rate of progress'' (URP) or the ''glidepath'') and the emission reduction measures needed to achieve that rate of progress over the 10-year period of the SIP. Uniform progress towards achievement of natural conditions by the year 2064 represents a rate of progress, which states are to use for analytical comparison to the amount of progress they expect to achieve. In setting RPGs, each state with one or more Class I areas (''Class I state'') must also consult with potentially ''contributing states,'' i.e., other nearby states with emission sources that may be affecting visibility impairment at the state's Class I areas. 40 CFR 51.308(d)(1)(iv). In determining whether a state's goals for visibility improvement provide for reasonable progress toward natural visibility conditions, EPA is required to evaluate the demonstrations developed by the state pursuant to paragraphs 40 CFR 51.308(d)(1)(i) and (d)(1)(ii). 40 CFR 51.308(d)(1)(iii).

D. Best Available Retrofit Technology

Section 169A of the CAA directs states to evaluate the use of retrofit controls at certain larger, often uncontrolled, older stationary sources in order to address visibility impacts from these sources. Specifically, section 169A(b)(2)(A) of the CAA requires states to revise their SIPs to contain such measures as may be necessary to make reasonable progress towards the natural visibility goal, including a requirement that certain categories of existing major stationary sources [7] built between 1962 and 1977 procure, install, and operate the ''Best Available Retrofit Technology'' as determined by the state. Under the RHR, states are directed to conduct BART determinations for such ''BART-eligible'' sources that may be anticipated to cause or contribute to any visibility impairment in a Class I area. Rather than requiring source-specific BART controls, states also have the flexibility to adopt an emissions trading program or other alternative program as long as the alternative provides greater reasonable progress towards improving visibility than BART.

On July 6, 2005, EPA published the *Guidelines for BART Determinations Under the Regional Haze Rule* at appendix Y to 40 CFR part 51 (hereinafter referred to as the ''BART Guidelines'') to assist states in determining which of their sources should be subject to the BART requirements and in determining appropriate emission limits for each applicable source. 70 FR 39104. In making a BART determination for a fossil fuel-fired electric generating plant with a total generating capacity in excess of 750 megawatts (MW), a state must use the approach set forth in the BART Guidelines. A state is encouraged, but not required, to follow the BART Guidelines in making BART determinations for other types of sources. Regardless of source size or type, a state must meet the requirements of the CAA and our regulations for selection of BART, and the state's BART analysis and determination must be reasonable in light of the overarching purpose of the regional haze program.

The process of establishing BART emission limitations can be logically broken down into three steps: First, states identify those sources which meet the definition of ''BART-eligible source'' set forth in 40 CFR 51.301;[8] second, states determine which of such sources ''emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area'' (a source which fits this description is ''subject to BART''); and third, for each source subject-to-BART, states then identify the best available type and level of control for reducing emissions.

States must address all visibility-impairing pollutants emitted by a source in the BART determination process. The most significant visibility impairing pollutants are SO_2, NO_X, and PM. EPA has stated that states should use their best judgment in determining whether VOC or NH_3 emissions impair visibility in Class I areas.

Under the BART Guidelines, states may select an exemption threshold value for their BART modeling, below which a BART-eligible source would not be expected to cause or contribute to visibility impairment in any Class I area. The state must document this exemption threshold value in the SIP and must state the basis for its selection of that value. Any source with emissions that model above the threshold value would be subject to a BART determination review. The BART Guidelines acknowledge varying circumstances affecting different Class I areas. States should consider the number of emission sources affecting the Class I areas at issue and the magnitude of the individual sources' impacts. Any exemption threshold set by the state should not be higher than 0.5 deciview. 40 CFR part 51, appendix Y, section III.A.1.

In their SIPs, states must identify the sources that are subject-to-BART and document their BART control determination analyses for such sources. In making their BART determinations, section 169A(g)(2) of the CAA requires that states consider the following factors when evaluating potential control technologies: (1) The costs of compliance; (2) the energy and non-air quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

A regional haze SIP must include source-specific BART emission limits and compliance schedules for each source subject-to-BART. Once a state

[7] The set of ''major stationary sources'' potentially subject-to-BART is listed in CAA section 169A(g)(7).

[8] BART-eligible sources are those sources that have the potential to emit 250 tons or more of a visibility-impairing air pollutant, were not in operation prior to August 7, 1962, but were in existence on August 7, 1977, and whose operations fall within one or more of 26 specifically listed source categories. 40 CFR 51.301.

has made its BART determination, the BART controls must be installed and in operation as expeditiously as practicable, but no later than five years after the date of EPA approval of the regional haze SIP. CAA section 169(g)(4) and 40 CFR 51.308(e)(1)(iv). In addition to what is required by the RHR, general SIP requirements mandate that the SIP must also include all regulatory requirements related to monitoring, recordkeeping, and reporting for the BART controls on the source. See CAA section 110(a). As noted above, the RHR allows states to implement an alternative program in lieu of BART so long as the alternative program can be demonstrated to achieve greater reasonable progress toward the national visibility goal than would BART.

E. Long-Term Strategy

Consistent with the requirement in section 169A(b) of the CAA that states include in their regional haze SIP a 10- to 15-year strategy for making reasonable progress, section 51.308(d)(3) of the RHR requires that states include a LTS in their regional haze SIPs. The LTS is the compilation of all control measures a state will use during the implementation period of the specific SIP submittal to meet applicable RPGs. The LTS must include ''enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the reasonable progress goals'' for all Class I areas within, or affected by emissions from, the state. 40 CFR 51.308(d)(3).

When a state's emissions are reasonably anticipated to cause or contribute to visibility impairment in a Class I area located in another state, the RHR requires the impacted state to coordinate with the contributing states in order to develop coordinated emissions management strategies. 40 CFR 51.308(d)(3)(i). In such cases, the contributing state must demonstrate that it has included, in its SIP, all measures necessary to obtain its share of the emission reductions needed to meet the RPGs for the Class I area. *Id.* at (d)(3)(ii). The RPOs have provided forums for significant interstate consultation, but additional consultations between states may be required to sufficiently address interstate visibility issues. This is especially true where two states belong to different RPOs.

States should consider all types of anthropogenic sources of visibility impairment in developing their long-term strategy, including stationary, minor, mobile, and area sources. At a minimum, states must describe how each of the following seven factors listed below are taken into account in developing their LTS: (1) Emission reductions due to ongoing air pollution control programs, including measures to address RAVI; (2) measures to mitigate the impacts of construction activities; (3) emissions limitations and schedules for compliance to achieve the RPG; (4) source retirement and replacement schedules; (5) smoke management techniques for agricultural and forestry management purposes including plans as currently exist within the state for these purposes; (6) enforceability of emissions limitations and control measures; and (7) the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the LTS. 40 CFR 51.308(d)(3)(v).

F. Coordinating Regional Haze and Reasonably Attributable Visibility Impairment

As part of the RHR, EPA revised 40 CFR 51.306(c) regarding the LTS for RAVI to require that the RAVI plan must provide for a periodic review and SIP revision not less frequently than every three years until the date of submission of the state's first plan addressing regional haze visibility impairment, which was due December 17, 2007, in accordance with 40 CFR 51.308(b) and (c). On or before this date, the state must revise its plan to provide for review and revision of a coordinated LTS for addressing RAVI and regional haze, and the state must submit the first such coordinated LTS with its first regional haze SIP. Future coordinated LTS's, and periodic progress reports evaluating progress towards RPGs, must be submitted consistent with the schedule for SIP submission and periodic progress reports set forth in 40 CFR 51.308(f) and 51.308(g), respectively. The periodic review of a state's LTS must report on both regional haze and RAVI impairment and must be submitted to EPA as a SIP revision.

F. Monitoring Strategy and Other Implementation Plan Requirements

Section 51.308(d)(4) of the RHR includes the requirement for a monitoring strategy for measuring, characterizing, and reporting of regional haze visibility impairment that is representative of all mandatory Class I Federal areas within the state. The strategy must be coordinated with the monitoring strategy required in section 51.305 for RAVI. Compliance with this requirement may be met through ''participation'' in the IMPROVE network, i.e., review and use of monitoring data from the network. The monitoring strategy is due with the first regional haze SIP, and it must be reviewed every five years. The monitoring strategy must also provide for additional monitoring sites if the IMPROVE network is not sufficient to determine whether RPGs will be met.

The SIP must also provide for the following:

- Procedures for using monitoring data and other information in a state with mandatory Class I areas to determine the contribution of emissions from within the state to regional haze visibility impairment at Class I areas both within and outside the state;
- Procedures for using monitoring data and other information in a state with no mandatory Class I areas to determine the contribution of emissions from within the state to regional haze visibility impairment at Class I areas in other states;
- Reporting of all visibility monitoring data to the Administrator at least annually for each Class I area in the state, and where possible, in electronic format;
- Developing a statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any Class I area. The inventory must include emissions for a baseline year, emissions for the most recent year for which data are available, and estimates of future projected emissions. A state must also make a commitment to update the inventory periodically; and
- Other elements, including reporting, recordkeeping, and other measures necessary to assess and report on visibility.

The RHR requires control strategies to cover an initial implementation period extending to the year 2018, with a comprehensive reassessment and revision of those strategies, as appropriate, every 10 years thereafter. Periodic SIP revisions must meet the core requirements of section 51.308(d) with the exception of BART. The requirement to evaluate sources for BART applies only to the first regional haze SIP. Facilities subject-to-BART must continue to comply with the BART provisions of section 51.308(e), as noted above. Periodic SIP revisions will assure that the statutory requirement of reasonable progress will continue to be met.

G. Consultation With States and Federal Land Managers (FLMs)

The RHR requires that states consult with FLMs before adopting and submitting their SIPs. 40 CFR 51.308(i). States must provide FLMs an opportunity for consultation, in person and at least 60 days prior to holding any public hearing on the SIP. This consultation must include the opportunity for the FLMs to discuss their assessment of impairment of visibility in any Class I area and to offer recommendations on the development of the RPGs and on the development and implementation of strategies to address visibility impairment. Further, a state must include in its SIP a description of how it addressed any comments provided by the FLMs. Finally, a SIP must provide procedures for continuing consultation between the state and FLMs regarding the state's visibility protection program, including development and review of SIP revisions, five-year progress reports, and the implementation of other programs having the potential to contribute to impairment of visibility in Class I areas.

VII. EPA's Evaluation of Wyoming's Regional Haze SIP

A. Affected Class I Areas

Pursuant to 40 CFR 51.308(d), the State identified seven mandatory Class I areas in Wyoming: Grand Teton National Park, Yellowstone National Park, Bridger Wilderness, Fitzpatrick Wilderness, North Absaroka Wilderness, Teton Wilderness, and Washakie Wilderness.

B. Baseline Visibility, Natural Visibility, and Uniform Rate of Progress

As required by 40 CFR 51.308(d)(2), Wyoming provided baseline visibility, natural visibility, and the URP for each Class I area in the State. Natural background visibility, as defined in our *2003 Natural Visibility Guidance,* is estimated by calculating the expected light extinction using default estimates of natural concentrations of fine particle components adjusted by site-specific estimates of humidity. This calculation uses the IMPROVE equation, which is a formula for estimating light extinction from the estimated natural concentrations of fine particle components (or from components measured by the IMPROVE monitors). As documented in our *2003 Natural Visibility Guidance,* EPA allows states to use "refined" or alternative approaches to this guidance to estimate the values that characterize the natural visibility conditions of Class I areas.

One alternative approach is to develop and justify the use of alternative estimates of natural concentrations of fine particle components. Another alternative is to use the "new IMPROVE equation" that was adopted for use by the IMPROVE Steering Committee in December 2005.[9] The purpose of this refinement to the "old IMPROVE equation" is to provide more accurate estimates of the various factors that affect the calculation of light extinction.

Wyoming used the new IMPROVE equation to calculate natural conditions and baseline visibility. The natural condition for each Class I area represents the visibility goal expressed in deciviews for the 20% worst days and the 20% best days that would exist if there were only naturally occurring visibility impairment. In accordance with 40 CFR 51.308(d)(2)(iii), the State calculated natural visibility conditions based on available monitoring information and appropriate data analysis techniques and in accordance with our *2003 Natural Visibility Guidance.* The State also calculated the number of deciviews by which baseline conditions exceed natural conditions at each of its Class I areas to meet the requirements of 40 CFR 51.308(d)(2)(iv)(A).

Wyoming established the baseline visibility for the best and worst visibility days for each Class I area based on data from the IMPROVE monitoring sites. Each IMPROVE monitor collects particulate concentration data which are converted into reconstructed light extinction through a complex calculation using the IMPROVE equation (see Chapter 13 of the SIP for more information on reconstructed light extinction and the IMPROVE equation). Per 40 CFR 51.308(d)(2)(i), the State calculated baseline visibility using a five-year average (2000 to 2004) of IMPROVE data for both the 20% best and 20% worst days. The State's baseline calculations were made in accordance with our *2003 Tracking Progress Guidance.*

Pursuant to 40 CFR 51.308(d)(1)(i)(B), the State calculated the URP for each of its Class I areas. For the 20% worst days, the URP is the calculation of the deciview reduction needed to achieve natural conditions by 2064. For the 20% worst days, the State calculated the URP in deciviews per year using the following formula: URP = [Baseline Condition—Natural Condition]/60 years. In order to determine the uniform progress needed by 2018 to be on the path to achieving natural visibility conditions by 2064, the State multiplied the URP by the 14 years in the first planning period (2004–2018).

Table 1 shows the baseline visibility, natural conditions, and URP for each of the Class I areas. As indicated by the table, some Class I areas share a single monitor because of the proximity of the areas to each other.

TABLE 1—BASELINE VISIBILITY, NATURAL CONDITIONS, AND URP FOR WYOMING CLASS I AREAS

20% Worst Days							20% Best Days
Wyoming Class I areas	Monitor name	2000–2004 Baseline (deciview)	2018 URP (deciview)	Reduction Needed to Reach 2018 URP (delta deciview)	2064 Natural Conditions (deciview)	Delta Baseline—2064 Natural Conditions	2000–2004 Baseline (deciview)
Yellowstone National Park, Grand Teton National Park, Teton Wilderness	YELL2	11.8	10.5	1.3	6.44	5.36	2.58

[9] The IMPROVE program is a cooperative measurement effort governed by a steering committee composed of representatives from Federal agencies (including representatives from EPA and the FLMs) and regional planning organizations. The IMPROVE monitoring program was established in 1985 to aid the creation of Federal and State implementation plans for the protection of visibility in Class I areas. One of the objectives of IMPROVE is to identify chemical species and emission sources responsible for existing anthropogenic visibility impairment. TheIMPROVE program has also been a key participant in visibility-related research, including the advancement of monitoring instrumentation, analysis techniques, visibility modeling, policy formulation and source attribution field studies.

TABLE 1—BASELINE VISIBILITY, NATURAL CONDITIONS, AND URP FOR WYOMING CLASS I AREAS—Continued

		20% Worst Days					20% Best Days
Wyoming Class I areas	Monitor name	2000–2004 Baseline (deciview)	2018 URP (deciview)	Reduction Needed to Reach 2018 URP (delta deciview)	2064 Natural Conditions (deciview)	Delta Baseline—2064 Natural Conditions	2000–2004 Baseline (deciview)
North Absaroka Wilderness .... Washakie Wilderness	NOABI	11.5	10.4	1.1	6.83	4.67	2.0
Bridger Wilderness, Fitzpatrick Wilderness	BRID1	11.1	10.0	1.1	6.45	4.65	2.1

We have reviewed Wyoming's baseline visibility, natural conditions, and URP. We find they have been calculated correctly and are proposing to approve them.

C. BART Determinations

BART is an element of Wyoming's LTS for the first implementation period. As discussed in more detail in section VI.D of this notice, the BART evaluation process consists of three components: (1) An identification of all the BART-eligible sources; (2) an assessment of whether those BART-eligible sources are in fact subject-to-BART; and (3) a determination of any BART controls. Wyoming addressed these steps as follows:

1. BART-Eligible Sources

The first step of a BART evaluation is to identify all the BART-eligible sources within the state's boundaries. Wyoming identified its BART-eligible sources by using the approach set out in the BART Guidelines (70 FR 39158). This approach provides three criteria for identifying BART-eligible sources: (1) One or more emission units at the facility fit within one of the 26 categories listed in the BART Guidelines; (2) the emission unit or units began operation on or after August 6, 1962, and were in existence on August 6, 1977; and (3) combined potential emissions of any visibility-impairing pollutant from the units that meet the criteria in (1) and (2) are 250 tons or more per year. Wyoming reviewed source permits and emission data from 2001–2003 to identify facilities in the BART source categories with potential emissions of 250 tons per year or more for any visibility-impairing pollutant from any unit or units that were in existence on August 7, 1977 and began operation on or after August 7, 1962. The BART Guidelines direct states to address SO_2[10], NO_X, and direct PM (including both PM_{10} and $PM_{2.5}$) emissions as visibility-impairing pollutants and to exercise their ''best judgment to determine whether VOC or NH_3 emissions from a source are likely to have an impact on visibility in an area.'' (70 FR 39162).

The State analyzed the emissions from VOC and NH_3 from sources in the State and eliminated them from further consideration for BART controls. The State evaluated the BART-eligible sources and determined emissions of VOC and NH_3 were negligible. Thus, the State has eliminated VOC and NH_3 from further consideration for BART controls. We agree with the State that emissions of VOC and NH_3 are negligible and propose to accept this determination.

The State determined that the following were BART-eligible sources: PacifiCorp Jim Bridger, P4 Production, PacifiCorp Naughton, OCI Wyoming, FMC Granger, Dyno Nobel, FMC Westvaco, Sinclair Casper Refinery, Basin Electric Laramie River, Black Hills Neil Simpson 1, PacifiCorp Wyodak, Sinclair—Sinclair Refinery, PacifiCorp Dave Johnston, and General Chemical Green River.

We have reviewed this information and propose to accept this determination.

2. Sources Subject-to-BART

The second step of the BART evaluation is to identify those BART-eligible sources that may reasonably be anticipated to cause or contribute to any visibility impairment at any Class I area, i.e., those sources that are subject-to-BART. The BART Guidelines allow states to consider exempting some BART-eligible sources from further BART review because they may not reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area. Consistent with the BART Guidelines, Wyoming performed dispersion modeling on the BART-eligible sources to assess the extent of their contribution to visibility impairment at surrounding Class I areas.

a. Modeling Methodology

The BART Guidelines provide that states may use the CALPUFF[11] modeling system or another appropriate model to predict the visibility impacts from a single source on a Class I area and to, therefore, determine whether an individual source is anticipated to cause or contribute to impairment of visibility in Class I areas, i.e., ''is subject to BART.'' The Guidelines state that CALPUFF is the best regulatory modeling application currently available for predicting a single source's contribution to visibility impairment (70 FR 39162).

The BART Guidelines also recommend that states develop a modeling protocol for making individual source attributions, and suggest that states may want to consult with EPA and their RPO to address any issues prior to modeling. Wyoming used the CALPUFF model for Wyoming BART sources in accordance with a protocol it developed titled *BART Air Modeling Protocol Individual Source Visibility Impairment Analysis,* March 2006, which was approved by EPA and is included in Chapter 6 of the State's TSD. The Wyoming protocol follows

[10] Wyoming has elected to submit its RH SIP pursuant to the requirements of 40 CFR 51.309. For states electing to submit under section 309, States do not have to do a BART analysis for SO_2. SO_2 controls are included in the backstop trading program under 40 CFR 51.309(d)(4).

[11] Note that our reference to CALPUFF encompasses the entire CALPUFF modeling system, which includes the CALMET, CALPUFF, and CALPOST models and other pre and post processors. The different versions of CALPUFF have corresponding versions of CALMET, CALPOST, etc. which may not be compatible with previous versions (e.g., the output from a newer version of CALMET may not be compatible with an older version of CALPUFF). The different versions of the CALPUFF modeling system are available from the model developer at *http://www.src.com/verio/download/download.htm.*

recommendations for long-range transport described in appendix W to 40 CFR part 51, *Guideline on Air Quality Models,* and in EPA's *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts* as recommended by the BART Guidelines. (40 CFR part 51, appendix Y, section III.A.3). To determine if each BART-eligible source has a significant impact on visibility, Wyoming used the CALPUFF model to estimate daily visibility impacts above estimated natural conditions at each Class I area within 300 km of any BART-eligible facility. The emission rates used in the CALPUFF modeling were determined by Wyoming based upon existing permits, allowable rates, and emissions reporting data.

b. Contribution Threshold

For states using modeling to determine the applicability of BART to single sources, the BART Guidelines note that the first step is to set a contribution threshold to assess whether the impact of a single source is sufficient to cause or contribute to visibility impairment at a Class I area. The BART Guidelines state that, ''[a] single source that is responsible for a 1.0 deciview change or more should be considered to 'cause' visibility impairment.'' (70 FR 39104, 39161). The BART Guidelines also state that ''the appropriate threshold for determining whether a source contributes to visibility impairment may reasonably differ across states,'' but, ''[a]s a general matter, any threshold that you use for determining whether a source ''contributes'' to visibility impairment should not be higher than 0.5 deciviews.'' *Id.* Further, in setting a contribution threshold, states should ''consider the number of emissions sources affecting the Class I areas at issue and the magnitude of the individual sources' impacts.'' The Guidelines affirm that states are free to use a lower threshold if they conclude that the location of a large number of BART-eligible sources in proximity to a Class I area justifies this approach.

Wyoming used a contribution threshold of 0.5 deciviews for determining which sources are subject-to-BART. By using a contribution threshold of 0.5 deciviews, Wyoming exempted seven of the fourteen BART-eligible sources in the State from further review under the BART requirements. Based on the modeling results, the State determined that P4 Production, FMC Granger,[12] and OCI Wyoming had an impact of .07 deciview, 0.39 deciview, and 0.07 deciview, respectively, at Bridger Wilderness. Black Hills Neil Simpson 1, Sinclair Casper Refinery, and Sinclair—Sinclair Refinery have an impact of 0.27 deciview, 0.06 deciview, and 0.12 deciview, respectively, at Wind Cave. Dyno-Nobel had an impact of 0.22 deciview at Rocky Mountain National Park. These sources' modeled visibility impacts fell below the State's threshold of 0.5 deciview and were determined not to be subject-to-BART.[13] Given the relatively limited impact on visibility from these seven sources, we propose to agree with Wyoming that 0.5 deciviews is a reasonable threshold for determining whether its BART-eligible sources are subject-to-BART.

Because our recommended modeling approach already incorporates choices that tend to lower peak daily visibility impact values,[14] our BART Guidelines state that a state should compare the 98th percentile (as opposed to the 90th or lower percentile) of CALPUFF modeling results against the ''contribution'' threshold established by the state for purposes of determining BART applicability. Wyoming used a 98th percentile comparison that we find appropriate. Further explanation on use of the 98th versus 90th percentile value is provided at 70 FR 39121.

c. Sources Identified by Wyoming as Subject-to-BART

Table 2 shows the sources identified by the State as subject-to-BART and the results of the CALPUFF modeling. The results reflect the single highest impacted year.

[12] The State of Wyoming performed a refined CALPUFF visibility modeling analysis for the two BART-eligible units at the FMC Wyoming Granger Facility and demonstrated that the predicted 98th percentile impacts at Bridger Wilderness Area and Fitzpatrick Wilderness Area would be below 0.5 dv for all meteorological periods modeled. This modeling used higher-resolution meteorological data as compared to the data used by the State for the initial screening modeling that identified the facility as subject-to-BART.

[13] CALPUFF modeling results, which provide the maximum change in visibility are summarized in the *WY BART Screening Analysis Results* and the *WY BART Screening Analysis Results DV Frequency,* which can also be found in Chapter 6 of the State's TSD.

[14] See our BART Guidelines, Section III.A.3.

TABLE 2—WYOMING SUBJECT-TO-BART SOURCES AND CALPUFF MODELING RESULTS

Facility name	Subject-to-BART units	State modeling results—98th percentile delta-deciview
PacifiCorp—Jim Bridger	Units 1–4	3.1
Basin Electric—Laramie River	Units 1, 2 and 3	3.68
PacifiCorp—Dave Johnston	Units 3 and 4	3.30
PacifiCorp—Naughton	Units 1–3	4.36
PacifiCorp—Wyodak	Unit 1	1.66
FMC—Westvaco	Units NS–1A and NS–1B	1.3
General Chemical—Green River	Boilers C and D	1.36

We are proposing to approve the State's determination of the subject-to-BART sources.

3. BART Determinations and Federally Enforceable Limits

The third step of a BART evaluation is to perform the BART analysis. The BART Guidelines (70 FR 39164) describe the BART analysis as consisting of the following five steps:

- Step 1: Identify All Available Retrofit Control Technologies;
- Step 2: Eliminate Technically Infeasible Options;
- Step 3: Evaluate Control Effectiveness of Remaining Control Technologies;
- Step 4: Evaluate Impacts and Document the Results; and
- Step 5: Evaluate Visibility Impacts.

In determining BART, the State must consider the five statutory factors in section 169A of the CAA: (1) The costs of compliance; (2) the energy and non-air quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. *See also* 40 CFR 51.308(e)(1)(ii)(A).

We find that Wyoming considered all five steps above in its BART determinations, but we propose to find that its consideration of the costs of compliance and visibility improvement for the EGUs was inadequate and did not properly follow the requirements in the BART Guidelines and statutory requirements, as explained below.

a. Costs of Compliance

Wyoming obtained the costs of compliance for controls from the BART applications submitted by sources that were subject to BART.[15] EPA in turn relied on these costs in our original proposed rule. EPA has reviewed Wyoming's cost analyses and has identified deficiencies in various cost assumptions and methods. Accordingly, EPA has subsequently and independently calculated costs of compliance and performed new visibility modeling. In many instances, the BART sources underestimated the cost of selective non-catalytic reduction (SNCR), while overestimating the cost of selective catalytic reduction (SCR) (both in combination with additional combustion controls). Depending on the particular BART source in question, we believe this was due to a number of errors, such as: use of incorrect baseline emissions; overestimation of the ability of SNCR to reduce NO_X; underestimation of SNCR reagent (urea) usage and cost; and underestimation of the ability of SCR to reduce NO_X.

EPA has identified a number of flaws in Wyoming's cost analyses for SNCR. For example, in the case of Laramie River Units 1–3, Wyoming significantly overestimated the ability of SNCR to reduce NO_X. The analyses submitted by the source, and in turn used by Wyoming, assumed that after the installation of additional combustion controls, SNCR would reduce NO_X from 0.23 lb/MMBtu to 0.12 lb/MMBtu (or by roughly 48%). However, SNCR typically reduces NO_X an additional 20 to 30% above combustion controls without excessive NH_3 slip.[16] NO_X reduction with SNCR is known to be greater at higher NO_X emission rates than lower rates.[17] Accordingly, EPA has estimated that the NO_X reduction from SNCR as 30% for initial NO_X greater than 0.25 lb/MMBtu, 25% for NO_X from 0.20 to 0.25 lb/MMBtu and 20% for NO_X less than 0.20 lb/MMBtu.[18] Due to the relatively recent installation of overfire air at the Laramie River units, the actual annual emissions in 2012 dropped to around 0.19 lb/MMBtu,[19] even lower than the 0.23 lb/MMbtu rate assumed by Wyoming. Therefore, EPA predicts that the reduction that can be achieved with SNCR at the Laramie River units is 20%, which is much lower than the 48% assumed by Wyoming. This significantly reduces the tons reduced by SNCR which is in turn used in the calculation of cost effectiveness. It also affects the incremental cost effectiveness between SNCR and SCR (both in combination with additional combustion controls). In addition, our analysis of urea prices indicates that producer prices for urea have increased the past three years. This increase in price is not reflected in the Wyoming estimates for SNCR.

EPA has also identified a number of flaws in Wyoming's cost analyses for SCR. For example, Wyoming assumed that SCR could only achieve a control effectiveness of 0.07 lb/MMBtu. By contrast, EPA has determined that on an annual basis SCR can achieve emission rates of 0.05 lb/MMbtu or lower. Moreover, we note that Wyoming's SCR capital costs on a $/kW basis often exceeded real-world industry costs. The capital costs for SCR claimed by Wyoming for Dave Johnston 3 and 4, Naughton Units 1–3, and Wyodak are in excess of the range of capital costs documented by various studies for actual installations. Five industry studies conducted between 2002 and 2007 have reported the installed unit capital cost of SCRs, or the costs actually incurred by owners, to range from $79/kW to $316/kW (2010 dollars). By contrast, Wyoming's SCR costs range from $415/kW to $531/kW.[20] These studies show actual capital costs are much lower than Wyoming's, particularly for the PacifiCorp units.

For all control technologies, EPA has identified instances in which

[15] Attachment A to the Wyoming 309(g) Regional Haze SIP.

[16] White Paper, SNCR for Controlling NO_X Emissions, Institute of Clean of Clean Air Companies, pp. 4 and 9, February 2008.

[17] Hofmann, J., Sun, W., ''Process for Nitrogen Oxides Reduction to Lowest Achievable Level'', US Patent 5,229,090, July 20, 1993, Figure 6.

[18] *Review of Estimated Compliance Costs for Wyoming Electric Generating (EGUs)—Revision of Previous Memo,* memo from Jim Staudt, Andover Technology Partners, to Doug Grano, EC/R, Inc., February 7, 2013, page 7 (Staudt Memo).

[19] Staudt memo, Table 2, p. 7.

[20] Staudt memo, Table 1, p. 4.

Wyoming's source-based cost analyses did not follow the methods set forth in the EPA Control Cost Manual.[21] For example, Wyoming included an allowance for funds used during construction and for owners costs and did not provide sufficient documentation such as vendor estimates or bids.

In addition, for the PacifiCorp units, Wyoming calculated the baseline annual emissions used for determining cost effectiveness based on allowable emissions, rated heat input, and 7,884 hours of operation (equivalent to a 85% capacity factor), which are not representative of actual emissions from the baseline period. By contrast, the BART Guidelines state that the baseline emissions should ''represent a realistic depiction of anticipated annual emissions for the source.''[22] Therefore, in our revised cost analyses, we have consistently used the actual annual average emissions from 2001–2003 to represent baseline emissions.

To address these flaws and deficiencies, EPA has developed independent cost analyses. In our revised cost analyses, we have followed the structure of the EPA Control Cost Manual, though we have largely used the Integrated Planning Model cost calculations to estimate direct capital costs and operating and maintenance costs. We have also followed the BART Guidelines. Detailed information on the revised costs can be found in the docket.[23] [24] In addition, we received comments on our original proposed rulemaking from the National Park Service and Conservation Organizations that expressed similar concerns with the State's cost analyses.

b. Visibility Improvement Modeling

The BART Guidelines provide that states may use the CALPUFF modeling system or another appropriate model to determine the visibility improvement expected at a Class I area from potential BART control technologies applied to the source. The BART Guidelines also recommend that states develop a modeling protocol for modeling visibility improvement, and suggest that states may want to consult with EPA and their RPO to address any issues prior to modeling. Wyoming developed a modeling protocol titled BART Air Modeling Protocol Individual Source Visibility Assessments for BART Control Analyses, September 2006, for sources to use when they performed their BART analysis (see Chapter 6 of the State's TSD). The Wyoming protocol follows recommendations for long-range transport described in appendix W to 40 CFR part 51, Guideline on Air Quality Models, and in EPA's Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts, as recommended by the BART Guidelines (40 CFR part 51, appendix Y, section III.D.5).

While we are able to propose approval of the State's PM BART determinations without having additional visibility improvement modeling for PM controls, as discussed below, additional visibility improvement modeling to address the EGU NO_X BART controls was needed and subsequently performed by EPA and presented in our original proposed rulemaking.[25] Our additional modeling to support the original proposed rule was intended to addresses two deficiencies. First, while Wyoming took into consideration the degree of visibility improvement for some BART NO_X control options for the PacifiCorp EGUs, such as SCR, they did not do so for SNCR. The visibility improvement for SNCR was neither provided in the State's SIP nor made available to EPA. Wyoming did not assess the visibility improvement of SNCR despite having found it to be a technically feasible control option, and having considered a number of the other statutory factors for SNCR, such as costs of compliance and energy impacts. Wyoming did not consider the visibility improvement associated with SNCR, which is clearly in conflict with the requirements set forth in section 169A(g)(2) of the CAA, as well as in the implementing regulations,[26] which require that states take into consideration ''the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.'' Because Wyoming did not do so, and in order to be consistent with the statutory and regulatory requirements, EPA conducted additional CALPUFF modeling to fill this gap in the State's visibility analysis (that is, to assess the visibility improvement associated with SNCR).

Second, it was not possible for EPA, or any other party, to ascertain the visibility improvement that would result from the installation of the various NO_X control options because Wyoming modeled the emission reductions for multiple pollutants together in its SIP. In other words, because the visibility improvement associated with each of the State's control scenarios was due to the combined emission reductions associated with SO_2, NO_X, and PM controls, it was not possible to isolate what portion of the improvement was attributable to the NO_X controls alone. In addition, because Wyoming varied SO_2 and PM emission rates along with NO_X emission rates, it was not possible to assess the incremental visibility improvement between the various NO_X controls options. For these reasons, EPA conducted additional modeling for the EGUs in which we held SO_2 and PM emission rates constant (reflecting the ''committed controls'' identified by Wyoming), and varied only the NO_X emission rate. This allowed us to isolate the degree of visibility improvement attributable to the NO_X control technologies. The modeling which EPA performed to support our original proposed rule addressed these two deficiencies in the State's analysis.

To support today's proposal, EPA has found it necessary to revise the CALPUFF modeling we performed in association with our original proposed rule. The revised modeling to support today's proposed rule is intended to address two additional issues that were raised by commenters during the comment period for the original proposed rule. First, as discussed above in section V.II, we have revised the costs of control submitted by the State. In the process of revising these costs, we have calculated a new removal efficiency for the control options under consideration to reflect updated assumptions about baseline emissions and control effectiveness.[27]

In order to align our cost and modeling analyses, these removal efficiencies have been incorporated into our revised modeling. Second, the emission rates we relied on in our original proposed rule for both the baseline (i.e., pre-control) and post-control modeling scenarios were not consistent with the BART Guidelines. For pre-control emission rates, the BART Guidelines recommend that States use the 24-hour average actual

[21] ''In order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual, where possible.'' 70 FR 39166.

[22] 70 FR 39167.

[23] *Review of Estimated Compliance Costs for Wyoming Electric Generating (EGUs)—Revision of Previous Memo,* memo from Jim Staudt, Andover Technology Partners, to Doug Grano, EC/R, Inc., February 7, 2013. (Staudt Memo).

[24] *Review of Estimated BART Compliance Costs for Wyoming Electricity Generating Units (EGUs)* memo from Jim Staudt, Andover Technology Partners, to Doug Grano, EC/R, Inc., February 7, 2013.

[25] A summary of EPA's modeling methodology and results for the original proposed rulemaking can be found in the docket under *EPA BART and RP Modeling for Wyoming Sources.*

[26] 40 CFR 51.308(e)(1)(ii)(A).

[27] See Staudt memos.

emission rate from the highest emitting day of the meteorological period modeled.[28] By contrast, the visibility modeling performed by PacifiCorp, and subsequently submitted by the State and utilized by EPA in our original proposal, deviates from the BART Guidelines by using permit limits and the maximum rated heat input to derive the modeled emission rates. Similarly, the visibility modeling performed by Basin Electric, and subsequently submitted by the State and utilized by EPA in our original proposal, deviates from the BART Guidelines by using actual annual average heat input and actual annual average emission rates (on a lb/MMBtu basis) from 2001–2003 continuous emissions monitoring data to derive modeled emission rates. Furthermore, the BART Guidelines recommend that post-control emission rates be calculated as a percentage of pre-control emission rates.[29] The visibility modeling performed by PacifiCorp and Basin Electric, and subsequently submitted by the State and utilized by EPA in our original proposal, deviates from the BART Guidelines by using post-control emission rates calculated in a similar manner to the pre-control emission rates. Our revised modeling remedies both of the issues identified by the commenters and is consistent with the requirements of the BART Guidelines. We have otherwise followed the procedures contained in the Wyoming BART Air Modeling Protocol. A summary of EPA's revised modeling methodology and results can be found in the docket.[30]

Because Wyoming relied on visibility modeling methodologies that are inconsistent with the statutory and regulatory requirements, we do not consider Wyoming's analyses of visibility improvement for NO_X BART to be reasonable. We propose to find that Wyoming's analyses are inconsistent with the statutory and regulatory requirement that Wyoming reasonably take into consideration ''the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.'' Therefore, as discussed in more detail below, we are proposing to disapprove several of the State's NO_X BART determinations that do not meet the requirements of the CAA and regional haze regulations because they are inconsistent with the visibility requirements.

c. Summary of BART Determinations and Federally Enforceable Limits

For the subject-to-BART sources, the State provided BART analyses, as well as additional technical information and materials, in Attachment A to the SIP. Chapter 6 of the SIP provides a summary of the five-factor analyses. As noted above, for this proposed rulemaking, EPA performed cost analyses and NO_X visibility improvement modeling for the control technology options analyzed for the subject-to-BART EGU sources. We are presenting the BART analyses that we based our June 4, 2012 proposed rulemaking on, as well as EPA's revised BART analyses, reflecting our revised cost and visibility improvement modeling for the EGUs.

EPA is proposing to approve the State's BART determinations for the following units because we have determined that the State's conclusions were reasonable despite the cost and visibility errors for the EGUs discussed earlier: NO_X and PM BART for FMC Westvaco Unit NS–1A and NS–1B; NO_X and PM BART for General Chemical Green River Boiler C and Boiler D;[31] PM BART for Basin Electric Laramie River Units 1, 2, and 3; PM BART for PacifiCorp Dave Johnston Unit 3; PM BART for PacifiCorp Dave Johnston Unit 4; NO_X and PM BART (including reasonable progress controls) for PacifiCorp Jim Bridger Units 1–4; PM BART for PacifiCorp Naughton Units 1and 2; NO_X and PM BART for Naughton Unit 3; and PM BART for PacifiCorp Wyodak Unit 1. A summary of the State's and EPA's BART determination for each source is provided below.

EPA is proposing to disapprove the State's NO_X BART determinations and promulgate a FIP for the following units: PacifiCorp Dave Johnston Units 3 and 4; PacifiCorp Naughton Units 1 and 2; PacifiCorp Wyodak Unit 1; and Basin Electric Laramie River Units 1, 2, and 3. After re-analyzing the costs of control and visibility improvement associated with these units, we determined that the State's selection of NO_X BART controls could not be supported, warranting a FIP. EPA's reasoning behind its own NO_X BART determinations and emission limitations for these units can be found in section VIII.A of this notice.

i. FMC Westvaco—Units NS–1A and NS–1B

Background

FMC's Westvaco facility is a trona mine and sodium products plant located in Sweetwater County, Wyoming. FMC Westvaco has two existing coal-fired boilers, Unit NS–1A and Unit NS–1B, that are subject to BART. Unit NS–1A and Unit NS–1B each have a design heat input rate of 887 MMBtu/hr and were constructed in 1975. They are both wall-fired, wet-bottom boilers burning subbituminous coal. The State's BART determinations for these units can be found in Chapter 6.5.2 and Attachment A of the SIP.

NO_X BART Determination

Units NS–1A and NS–1B are currently controlled with combustion air control with a permit limit of 0.7 lb/MMBtu (3-hour rolling average). The State determined that low NO_X burners (LNBs) and overfired air (OFA), LNBs and OFA with SNCR, and LNBs and OFA with SCR were all technically feasible for reducing NO_X emissions at Unit NS–1A and NS–1B. The State did not identify any technically infeasible options. The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, and there are no remaining-useful-life issues for this source. A summary of the State's NO_X BART analyses and the visibility impacts is provided in Table 3. Baseline NO_X emissions are 2,719.5 tpy for each unit based on a heat input rate of 887 MMBtu/hr and 8,760 hours of operation per year.

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[28] The BART Guidelines, Section IV. (70 FR 39170) specify that the modeling should ''[u]se the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario)''.

[29] The BART Guidelines, Section IV. (70 FR 39170) specify that ''[p]ost-control emission rates are calculated as a percentage of pre-control emission rates''.

[30] EPA's modeling results and a summary of EPA's modeling methodology can be found in the docket under *Summary of EPA's Revised Modeling—Including Revisions from Previous Version Posted on 1/18/2013 and Results for Jim Bridger Units 1–4* and *EPA's Revised Modeling Results;* posted to the docket on February 11, 2013.

[31] FMC Westvaco and General Chemical Green River are not EGUs and EPA did not identify the same cost and visibility improvement modeling issues as it did for the EGUs and are thus proposing to approve the State's BART analyses and determinations for these units.

TABLE 3—SUMMARY OF FMC WESTVACO UNIT NS–1A AND UNIT NS–1B NO_X BART ANALYSIS*

Control technology	Emission rate (lb/MMBtu) (30-day rolling average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Bridger Wilderness Area)
LNB + OFA	0.35	$1,359.7	$413,145	$304		0.13
LNB + OFA + SNCR	0.21	1,903.6	1,281,851	673	$1,597	0.19
LNB + OFA + SCR	0.10	2,331.0	8,141,177	3,493	16,051	0.24

*This table reflects the costs and visibility improvements per boiler.

The visibility modeling in the State's SIP only includes the visibility improvement at the two most impacted Class I areas: Bridger Wilderness Area and Fitzpatrick Wilderness Area. The visibility improvement at Bridger is listed in the Table above. For Fitzpatrick, the visibility improvement is .09 dv for LNBs with OFA, 0.11 dv for LNBs with SNCR, and 0.13 dv for LNBs with SCR. Given the limited visibility improvement at the two most impacted areas, we propose to find that it was reasonable for the State to model only those two receptors.

Based on its consideration of the five factors, the State determined that LNBs plus OFA are reasonable for BART. The State determined that the other control options were not reasonable based on the cost effectiveness and associated visibility improvement. The State has determined that NO_X BART emission limit for FMC Westvaco Unit NS–1A and Unit MS–1B is 0.35 lb/MMBtu (30-day rolling average).

We agree with the State's conclusions, and we are proposing to approve its NO_X BART determinations for FMC Westvaco Unit NS–1A and Unit NS–1B. Although the cost-effectiveness for SNCR is reasonable, we find it reasonable for the State not to select this control technology based on the incremental visibility improvement for this control technology.

PM BART Determination

Unit NS–1A and Unit NS–1B are currently controlled for PM emissions by electrostatic precipitators (ESPs). The units each currently have a PM emission limit of 0.05 lb/MMBtu. The State determined that fabric filters on the wet scrubber, addition of an ESP downstream of the wet scrubber, and replacement of the ESPs with fabric filters were technically feasible control options. The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, and there are no remaining-useful-life issues for this source. A summary of the State's PM BART analysis is provided in Table 4 below. Baseline PM emissions are 197 tpy for each unit based on a heat input rate of 887 MMBtu/hr and 8,760 hours of operation per year.

TABLE 4—SUMMARY OF FMC WESTVACO UNIT NS–1A AND UNIT NS–1B PM BART ANALYSIS*

Control technology	Control efficiency (%)	Emission rate (lb/mmbtu) (30-day rolling average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)
Fabric Filter on Wet Scrubber	21.4	0.04	41.7	$1,791,364	$42,948
ESP after Wet Scrubber	63.3	0.019	123.3	3,507,617	28,448
Replace ESP with Fabric Filter	71.3	0.015	138.8	4,116,036	29,654

*This table reflects the costs and visibility improvements per boiler.

Given the high cost of controls, which are higher than what EPA, or other states have considered reasonable for PM, FMC did not evaluate the visibility improvement that would result from the PM controls evaluated. Previous visibility modeling analyses from the source indicate that the contribution in visibility degradation from PM is minor when compared to the effects of NO_X and SO_2. Results from FMC's visibility modeling screening and analysis confirm this conclusion and are discussed in further detail within the comprehensive visibility analysis included as part of FMC's BART application (see Attachment A to the SIP). The State agreed with FMC's conclusions and did not require FMC to perform additional visibility analyses for the PM control options.

The State determined that the current ESP control was reasonable for PM BART. The State rejected other controls because of their high cost-effectiveness values. The State has determined that the PM BART emission limits for FMC Westvaco Unit NS–1A and NS–1B are 0.05 lb/MMBtu, 45.0 lb/hr, and 197 tpy.

We agree with the State's conclusions, and we are proposing to approve its PM BART determinations for FMC Westvaco Unit NS–1A and Unit NS–1B.

ii. General Chemical Green River—Boilers C and D

General Chemical Green River is a trona mine and sodium products plant. General Chemical's two existing coal-fired boilers, C and D, are co-located at the facility power plant. Both boilers burn low sulfur bituminous coal, and they supply power and process steam to mining and ore processing operations. Both boilers are tangentially fired using in-line coal pulverizers. The firing rate is 534 MMBtu/hr for Boiler C and 880 MMBtu/hr for Boiler D. The State's BART determinations can be found in Chapter 6.5.3 and Attachment A of the SIP.

NO_X BART Determination

Boiler C and Boiler D are currently controlled with LNBs plus OFA with a permit limit of 0.7 lb/MMBtu (3-hour rolling average). On August 7, 2009, the State issued a BART permit to General Chemical that required the source to meet a NO_X emission limit of 0.32 lb/MMBtu (30-day rolling average) for Boiler C and Boiler D. The State assumed the source could meet this emission limit with the installation and operation of new LNBs with the existing OFA. Upon further investigation, the source determined it could not meet a limit of 0.32 lbs/MMBtu with new LNBs and the existing OFA.

In response to the additional information provided by the source, the State reexamined its BART determination for Boiler C and D. The State determined that installing SOFA in addition to the existing LNBs and OFA could achieve an emission limit of 0.28 lb/MMBtu. Because SOFA in conjunction with the existing NO_X controls could achieve better emission reductions than new LNBs plus OFA, the State eliminated the latter from further consideration in the BART analysis. The State determined that SNCR and SCR were also technically feasible. The State did not identify any technically infeasible options.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, and there are no remaining-useful-life issues for this source. A summary of the State's NO_X BART analysis and visibility impacts is provided in Tables 5 and 6 below. Baseline NO_X emissions are 1,167 tpy for Boiler C and 1,816 tpy for Boiler D based on an average of 2001–2003 actual emissions.

TABLE 5—SUMMARY OF GENERAL CHEMICAL—GREEN RIVER BOILER C NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (30-day rolling average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Bridger Wilderness Area)
Existing LNBs with SOFA	0.28	512	$757,711	$1,480	—	0.05
SNCR	0.35	584	1,433,720	2,455	$4,782	0.08
SCR	0.14	934	2,434,809	2,607	3,156	0.14

TABLE 6—SUMMARY OF GENERAL CHEMICAL—GREEN RIVER BOILER D NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (30-day rolling average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Bridger Wilderness Area)
Existing LNBs with SOFA	028	737	$943,549	$1,280	—	0.07
SNCR	0.35	908	1,486,581	3,176	$2,913	0.12
SCR	0.14	1,453	3,399,266	3,510	4,342	0.17

The visibility modeling in the State's SIP only includes the visibility improvement at the two most impacted Class I areas: Bridger Wilderness Area and Fitzpatrick Wilderness Area. The visibility improvement at Bridger is listed in the Table above. For Fitzpatrick, the visibility improvement is 0.10 dv for LNBs with SOFA, 0.09 for SNCR, and 0.12 dv for SCR for each unit. Given the limited visibility improvement at the two most impacted areas, we propose to find that it was reasonable for the State to model only those two receptors.

Based on its consideration of the five factors, the State determined that NO_X BART is the existing LNBs with new SOFA, or a comparable performing technology. The State determined that SNCR and SCR were not reasonable based on the high cost effectiveness and low visibility improvement. The State determined the NO_X BART emission limit for General Chemical Green River Boiler C is 0.28 lb/MMBtu (30-day rolling average) and that the NO_X BART emission limit for Boiler D is 0.28 lb/MMBtu (30-day rolling average).

We agree with the State's conclusions, and we are proposing to approve its NO_X BART determinations for General Chemical Green River—Boiler C and D. Although the cost-effectiveness for SNCR and SCR is reasonable, we find it reasonable for the State not to select this control technology based on the low visibility improvement for these control technologies.

PM BART Determination

Boilers C and D are currently controlled by ESPs with permit limits of 50 lb/hr and 80 lb/hr, respectively. General Chemical addressed PM emissions through an abbreviated analysis by using PM BART information from FMC Westvaco, as discussed above. The facilities are similar in size and located about ten miles apart. Baseline PM emissions are 98 tpy for Boiler C and 161 tpy for Boiler D based on the average of 2001–2003 actual emissions. As discussed above, visibility modeling screening and analyses for FMC Westvaco indicate that the contribution in visibility degradation from PM for a source comparable to Boiler C and Boiler D is minor. Additionally, costs for controlling PM from similar boilers are high as indicated by the FMC analysis for Westvaco.

The State accepted General Chemical's abbreviated PM BART analysis. The State determined that the current ESP control was reasonable for PM BART. The State rejected other controls because of their high cost-effectiveness values. The State determined that the PM BART emission limits for Boiler C are 0.09 lb/MMBtu, 50 lb/hr, and 219 tpy, and that the PM BART emissions limits for Boiler D are 0.09 lb/MMBtu, 80 lb/hr, and 350.4 tpy.

We agree with the State's conclusions, and we are proposing to approve its PM BART determination for General Chemical Green River Boiler C and D.

iii. Basin Electric Laramie River Station—Units 1–3

Basin Electric Laramie River Station is located in Platte County, Wyoming. Laramie River Station is comprised of three 550 MW dry-bottom, wall-fired boilers (Units 1, 2, and 3) burning subbituminous coal for a total net generating capacity of 1,650 MW. All three units are subject-to-BART. The State's BART determination can be found in Chapter 6.5.8 and Attachment A of the SIP (The NO_X BART analysis is discussed in section VIII.A of this notice).

PM BART Determination

Laramie River Units 1, 2, and 3 are currently controlled with ESPs, each with a permit limit of 0.03 lb/MMBtu. The State determined that fabric filters were technically feasible for Unit 3 but not Units 1 and 2. Units 1 and 2 are controlled with wet flue gas desulfurization and fabric filters cannot be used downstream of such a system. The State determined that flue gas treatment and GE Max-9 hybrid were technically infeasible for all three units. Thus, the only technically feasible control option for PM is fabric filters on Unit 3.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, and there are no remaining-useful-life issues for this source. A summary of the State's PM BART analysis for Unit 3 is provided in Table 7 below. Baseline PM emissions are 716 tpy for the unit based on 2001–2003 actual emissions.

TABLE 7—SUMMARY OF BASIN ELECTRIC LARAMIE RIVER UNIT 3 PM BART ANALYSIS

Control technology	Control efficiency (%)	Emission rate (lb/MMBtu) (30-day rolling average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)
Fabric Filter—Peak Rate for Lost Generating Costs	50	0.015	358	$194,809,000	$54,707
Fabric Filter Non-Peak Rate for Lost Generating Costs	50	0.015	358	134,934,000	40,156

The State did not provide visibility improvement modeling for fabric filters, but EPA is proposing to conclude this is reasonable based on the high cost-effectiveness of fabric filters at each of the units, which is higher than EPA or other state have considered reasonable for PM BART.

Based on its consideration of the five factors, the State determined that the current ESPs are reasonable for PM BART, as fabric filters on Unit 3 are not cost-effective and there are no other technically feasible controls for Units 1 and 2. The State determined that the PM BART emission limit for each of the Laramie River Units 1, 2, and 3 is 0.03 lb/MMBtu.

We agree with the State's conclusions, and we are proposing to approve its PM BART determination for Basin Electric Laramie River Units 1, 2, and 3.

iv. PacifiCorp Dave Johnston—Units 3 and 4

Background

PacifiCorp's Dave Johnston power plant is located in Converse County, Wyoming. Dave Johnston Power Plant is comprised of four units burning pulverized subbituminous Powder River Basin coal. Units 3 and 4 are the only units subject-to-BART. Dave Johnston Unit 3 is a nominal 230 MW pulverized coal-fired boiler that commenced service in 1964. It was equipped with burners in a cell configuration until 2010, but was then converted to a dry bottom wall-fired boiler. Dave Johnston Unit 4 is a nominal 330 MW pulverized coal-fired boiler that commenced service in 1972. It is a tangential-fired boiler. The State's BART analysis can be found in Chapter 6.5.5 and Appendix A of the SIP (the NO_X BART determination for Dave Johnston Unit 3 and Unit 4 is discussed in section VIII.A of this notice).

PM BART Determination

Units 3 and 4 are currently controlled with fabric filters installed in 2008 with an emission limit of 0.015 lb/MMBtu. The State determined that fabric filters represent the most stringent PM control technology and that 0.015 lb/MMBtu is the most stringent emission limit. Consistent with the BART Guidelines, the State did not provide a five-factor analysis because the State determined BART to be the most stringent control technology and limit available (70 FR 39165). The State determined that the PM BART emission limits for Unit 3 and 4 are both 0.015 lb/MMBtu.

We agree with the State's conclusions, and we are proposing to approve its PM BART determination for Dave Johnston Units 3 and 4.

v. PacifiCorp Jim Bridger—Units 1–4

Background

PacifiCorp's Jim Bridger Power Plant is located in Sweetwater County, Wyoming. Jim Bridger is comprised of four identically sized nominal 530 MW tangentially fired boilers burning pulverized coal for a total net generating capacity of 2,120 MW. Jim Bridger Unit 1 was placed in service in 1974, Unit 2 in 1975, Unit 3 in 1976, and Unit 4 in 1979. The State's BART determination can be found in Chapter 6.5.4 and Appendix A of the SIP.

Wyoming's NO_X BART Determination for Jim Bridger Unit 1 and Unit 2

During the baseline period of 2001–2003, PacifiCorp Jim Bridger Units 1 and 2 were equipped with early generation LNBs with permit limits of 0.70 lb/MMBtu (3-hour fixed) and 0.42 lb/MMBtu and 0.40 lb/MMBtu (annual limit), respectively. The State determined that new LNBs with SOFA, new LNBs with SOFA plus SNCR, and new LNBs with SOFA plus SCR were all technically feasible for controlling NO_X emissions. The State did not identify any technically infeasible options.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, nor are there any remaining-useful-life issues for this source. Baseline NO_X emissions are 10,643 tpy for each unit based on unit heat input rate of 6,000 MMBtu/hr and 7,884 hours of operation. A summary of the State's NO_X BART analysis and the visibility impacts is provided in Table 8 below.[32]

[32] We are assuming the same costs for Unit 2 as the other Jim Bridger Units. The State analyzed Unit 2 using post installation of LNBs/OFA costs so the cost information provided in their analysis is not consistent with an uncontrolled baseline.

TABLE 8—SUMMARY OF WYOMING'S JIM BRIDGER UNITS 1 AND 2 NO_X BART ANALYSIS—COSTS PER BOILER

Control technology	Emission rate (lb/MMBtu) (30-day rolling average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta deciview for the maximum 98th percentile impact at Mt. Zirkel wilderness)
New LNB with SOFA	0.26	4,493	$1,144,969	$255	—	0.41/0.47
New LNB with SOFA and SNCR	0.20	5,913	2,710.801	459	$1,103	0.52/0.62
New LNB with SOFA and SCR	0.07	8,987	20,296,400	2,258	5,721	0.76/0.82

Based on its consideration of the five factors, the State determined new LNBs with SOFA was reasonable for NO_X BART. The State determined the NO_X BART emission limit for Jim Bridger Units 1and 2 is 0.28 lb/MMBtu (30-day rolling average).

PacifiCorp is required to install additional controls under the State's LTS. The State determined that based on the cost of compliance and visibility improvement presented by PacifiCorp in the BART applications for Jim Bridger Units 1 and 2 and taking into consideration the logistical challenge of managing multiple pollution control installations within the regulatory time allotted for installation of BART by the RHR, additional controls would be required under the LTS in order to achieve reasonable progress but would not be requires as BART. With respect to Jim Bridger Units 1 and 2, the State has required PacifiCorp to install SCR, or other NO_X control systems, to achieve an emission limit of 0.07 lb/MMBtu on a 30-day rolling average. As part of Wyoming's Regional Haze plan, PacifiCorp is required to meet the 0.07 lb/MMBtu emission rate on Unit 1 prior to December 31, 2021 and on Unit 2 prior to December 31, 2022.

EPA's PacifiCorp Jim Bridger Units 1 and 2 NO_X BART Determination

The EPA agrees with the State's analysis pertaining to energy or non-air quality environmental impacts and remaining-useful-life for this source. Baseline NO_X emissions are 8,426 tpy for Unit 1 and 7,577 for Unit 2 based on the actual annual average for the years 2001–2003. A summary of the EPA's NO_X BART analysis and the visibility impacts is provided in Tables 9–12 below. The cost effectiveness values for the Jim Bridger units vary considerably for the same control option. This is largely due to differences in the (actual) baseline emissions.

TABLE 9—SUMMARY OF EPA'S JIM BRIDGER UNIT 1 NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (annual average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Mt. Zirkel)
New LNBs with OFA	0.18	4,558	$1,167,297	$256	—	0.59
New LNBs with OFA and SNCR	0.14	5,332	4,402,757	826	$4,182	0.69
New LNBs with OFA and SCR	0.05	7,352	17,592,636	2,393	6,530	0.96

Jim Bridger Unit 1 also impacts other Class I areas. The visibility improvement modeled by EPA at other Class I areas is shown in Table 10 below.

TABLE 10—JIM BRIDGER UNIT 1: VISIBILITY IMPROVEMENT AT OTHER CLASS I AREAS

Class I area	Visibility improvement (delta dv for the maximum 98th percentile impact) – New LNBs + OFA	Visibility improvement (delta dv for the maximum 98th percentile impact) – New LNBs + OFA/SNCR	Visibility improvement (delta dv for the maximum 98th percentile impact) – New LNBs + OFA/SCR
Bridger	0.53	0.62	0.91
Fitzpatrick	0.22	0.26	0.36
Rawah	0.59	0.70	0.96
Rocky Mountain	0.50	0.58	0.79
Grand Teton	0.17	0.19	0.27
Teton	0.16	0.19	0.26
Washakie	0.18	0.21	0.27
Yellowstone	0.23	0.15	0.26

TABLE 11—SUMMARY OF EPA'S JIM BRIDGER UNIT 2 NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (annual average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Mt. Zirkel)
New LNBs with OFA	0.19	3,787	$1,167,297	$308	—	0.55
New LNBs with OFA and SNCR	0.15	4,545	4,360,958	959	$4,214	0.65
New LNBs with OFA and SCR	0.05	6,554	19,757,979	3,015	7,664	0.95

Jim Bridger Unit 2 also impacts other Class I areas. The visibility improvement modeled by EPA at other Class I areas is shown in Table 12 below.

TABLE 12—JIM BRIDGER UNIT 2: VISIBILITY IMPROVEMENT AT OTHER CLASS I AREAS

Class I area	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + OFA	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + OFA/SNCR	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + OFA/SCR
Bridger	0.48	0.58	0.89
Fitzpatrick	0.21	0.25	0.36
Rawah	0.46	0.48	0.78
Rocky Mountain	0.38	0.46	0.68
Grand Teton	0.15	0.18	0.26
Teton	0.15	0.18	0.25
Washakie	0.17	0.20	0.27
Yellowstone	0.15	0.18	0.26

As discussed in detail above, because Wyoming relied on visibility modeling methodologies that are inconsistent with the statutory and regulatory requirements, we do not consider Wyoming's analysis of visibility improvement for the NO_X BART to be reasonable for Wyodak Unit 1. We propose to find that Wyoming's analysis for this Unit is inconsistent with the statutory and regulatory requirement that ''the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.''

Also, we are not relying on the State's costs due to reasons stated in section VII.C.3.b of this notice. We propose to find that Wyoming did not properly or reasonably ''take into consideration the costs of compliance.''

Our analysis follows our BART Guidelines. With the exception of the NO_X emission limits, the visibility improvement analyses, and the cost effectiveness analyses, EPA is proposing to find that the Wyoming RH BART analysis NO_X for Dave Johnson Units 4 fulfills all the relevant requirements of CAA Section 169A and the RHR.

PacifiCorp asserted to the State during formulation of the SIP proposal, and has since asserted directly to EPA [33], that a number of factors, when considered together, suggest that requiring installation of SCR at Jim Bridger Units 1 and 2 earlier than 2021–2022 is not reasonable. First, PacifiCorp points to the large number of retrofit actions it is taking at 20 coal-fired electric generating units in Wyoming, Utah, Colorado, and Arizona in order to reduce their emissions.[34] These retrofits are intended to comply with the requirements in the regional haze SIPs that these states have submitted to EPA and with other regulatory requirements, including required controls for mercury and acid gases under the recent Mercury and Air Toxics Standards rule. The company asserts that there are high capital costs for the measures required for these air quality-improving retrofits. Moreover, PacifiCorp states that accelerating the required installation of SCR at Jim Bridger Units 1 and 2 to late 2017, rather than the 2021 and 2022 dates established by the State, would significantly increase the costs to the utility and to its customers.

In addition, the company asserts that it has designed the installation schedule in order to minimize the number of units that are out of service system wide for installation of emissions controls at any one time. Its goal, it asserts, is to be able to maintain service to its customers with an adequate capacity margin. The company asserts that accelerating the timeline for installation of SCR would upset the orderly shut-down schedule they have devised and would threaten both service interruptions and an increased risk of spot-purchases of more expensive electrical energy, if it is available, to serve customers, but that either eventuality would significantly increase costs to its customers.[35]

EPA notes that PacifiCorp has offered these assertions taking into account only the requirements in the SIPs that have been submitted to EPA by Wyoming, Utah, Colorado, and Arizona. Today's proposal includes requirements that would likely require the additional installation of SCRs at three units and SNCR at two units owned by PacifiCorp

[33] See July 12, 2012 letter from PacifiCorp to EPA Region 8 located in the docket for this notice.

[34] For a listing of PacifiCorp's retrofit actions, see Table 1 of *Exhibit A—PacifiCorp's Emissions Reductions Plan* in Chapter 6 of the State's TSD.

[35] See *Exhibit A—PacifiCorp's Emissions Reductions Plan* in Chapter 6 of the State's TSD.

in Wyoming. In addition, we have since finalized action on the SIP for Arizona, and are requiring LNBs plus SCR on three units under a FIP.

As stated in the BART Guidelines pertaining to affordability: ''1. Even if the control technology is cost effective, there may be cases where the installation of controls would affect the viability of continued plant operations. 2. There may be unusual circumstances that justify taking into consideration the conditions of the plant and the economic effects of requiring the use of a given control technology. These effects would include effects on product prices, the market share, and profitability of the source. Where there are such unusual circumstances that are judged to affect plant operations, you may take into consideration the conditions of the plant and the economic effects of requiring the use of a control technology. Where these effects are judged to have a severe impact on plant operations you may consider them in the selection process, but you may wish to provide an economic analysis that demonstrates, in sufficient detail for public review, the specific economic effects, parameters, and reasoning. (We recognize that this review process must preserve the confidentiality of sensitive business information). Any analysis may also consider whether other competing plants in the same industry have been required to install BART controls if this information is available.'' 40 CFR part 50, Appendix Y, IV.E.3.

Based on the points made by PacifiCorp and noting the additional requirements in the proposed FIP for Wyoming, the finalized FIP for Arizona, and the possibility of additional requirements in a future FIP or SIP for Utah, EPA is proposing that the additional time to install controls under the State's LTS on Jim Bridger Unit 1 and Unit 2 is warranted under the affordability provisions in the BART Guidelines discussed above. Although neither the CAA nor the RHR require states or EPA to consider the affordability of controls or ratepayer impacts as part of a BART analysis, the BART guidelines allow (but do not require) consideration of ''affordability'' in the BART analysis.

EPA is proposing to determine that BART for all units at Jim Bridger would be SCR if the units were considered individually, based on the five factors, without regard for the controls being required at other units in the PacifiCorp system. However, when the cost of BART controls at other PacifiCorp-owned EGUs is considered as part of the cost factor for the Jim Bridger Units, EPA is proposing that Wyoming's determination that NO_X BART for these units is new LNB plus OFA for is reasonable. Considering costs broadly, it would be unreasonable to require any further retrofits at this source within five years of our final action. We note that the CAA establishes five years at the longest period that can be allowed for compliance with BART emission limits.

EPA is proposing to approve the SIP with regard to the State's determination that the appropriate level of NO_X control for Units 1 and 2 at Jim Bridger for purposes of reasonable progress is the SCR-based emission limit in the SIP, with compliance dates of December 31, 2021 for Unit 2 and December 31, 2022 for Unit 1. In the context of reasonable progress in the second planning period of the regional haze program, we have determined it is appropriate to give considerable deference to the State's conclusions about what controls are reasonable and when they should be implemented. Thus, we do not find it appropriate to disapprove the State's preferred compliance deadlines for Jim Bridger Units 1 and 2. As discussed below, we are seeking comment on an alternative proposal to promulgate a FIP for PacifiCorp Jim Bridger Units 1 and 2.

Wyoming's NO_X BART Determination for Jim Bridger Units 3 and 4

During the 2001–2003 baseline period, PacifiCorp Jim Bridger Units 3 and 4 were equipped with early generation LNBs with permit limits of 0.70 lb/MMBtu (3-hour fixed) and 0.41 lb/MMBtu and 0.45 lb/MMBtu (annual), respectively. The State determined that new LNBs with SOFA, new LNBs with SOFA plus SNCR, and new LNBs with SOFA plus SCR were technically feasible for controlling NO_X emissions. The State did not identify any technically infeasible options.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, and there are no remaining-useful-life issues for this source. Baseline NO_X emissions are 10,643 tpy for each unit based on unit heat input rate of 6,000 MMBtu/hr and 7,884 hours of operation.

A summary of the State's NO_X BART analysis and the visibility impacts is provided in Table 13 below.

TABLE 13—SUMMARY OF WYOMING'S JIM BRIDGER UNITS 3 AND 4 NO_X BART ANALYSIS—COSTS PER BOILER

Control technology	Emission rate (lb/MMBtu) (30-day rolling average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta deciview for the maximum 98th percentile impact at Mt. Zirkel Wilderness) [36]
New LNB with SOFA	0.26	4,493	$1,144,969	$255	—	0.41/0.47
New LNB with SOFA and SNCR	0.20	5,913	2,710.801	459	$1,103	0.53/0.62
New LNB with SOFA and SCR	0.07	8,987	20,296,400	2,258	5,721	0.80/0.82

The State determined that new LNBs with SOFA were reasonable for NO_X BART for Jim Bridger Units 3 and 4. The State determined that the NO_X BART emission limits for Jim Bridger Units 3 and 4 are both 0.26 lb/MMBtu (30-day rolling average). As explained below, the State determined SCR was not reasonable for BART.

The State is requiring PacifiCorp to install SCR controls under its LTS. The State determined that based on the cost of compliance and visibility improvement presented by PacifiCorp in the BART applications for Jim Bridger Units 3 and 4 and taking into consideration the logistical challenge of managing multiple pollution control installations within the regulatory time

[36] Unit 4 has different modeling results as the stack parameters used in the modeling are different enough from Units 1–3 to yield different modeled results.

allotted for installation of BART by the RHR, SCR controls would be required under the LTS but not BART (see Chapter 8.3.3 of the SIP). With respect to Jim Bridger Units 3 and 4, the State has required PacifiCorp to install SCR, or other NO_X control systems, to achieve an emission limit of 0.07 lb/MMBtu (30-day rolling average). PacifiCorp is required to meet the 0.07 lb/MMBtu emission rate on Unit 3 prior to December 31, 2015 and on Unit 4 prior to December 31, 2016.

EPA's NO_X BART Determination for Jim Bridger Unit 3 and Unit 4

The EPA agrees with the State's analysis pertaining to energy and non-air quality environmental impacts and remaining-useful-life for this source. EPA determined that baseline NO_X emissions are 7,853 tpy for Unit 3 and 8,133 tpy for Unit 4 based on the actual annual average for the years 2001–2003 (compared to 10,643 tpy that Wyoming relied on as noted above). As explained above, Wyoming determined that taking into consideration the logistical challenge of managing multiple pollution control installations within the regulatory time allotted for installation of BART by the RHR, SCR controls would be required under the LTS but not BART. A summary of the EPA's NO_X BART analysis and the visibility impacts is provided in Tables 14–17 below.

TABLE 14—SUMMARY OF EPA'S JIM BRIDGER UNIT 3 NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (annual average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Mt. Zirkel)
New LNBs with SOFA	0.20	3,710	$1,167,297	$315	—	0.50
New LNBs with SOFA and SNCR	0.16	4,539	4,530,069	998	$4,058	0.61
New LNBs with SOFA and SCR	0.05	6,799	20,135,420	2,961	6,905	0.92

Jim Bridger Unit 3 also impacts other Class I areas. The visibility improvement modeled by EPA at other Class I areas is shown in Table 15 below.

TABLE 15—JIM BRIDGER UNIT 3: VISIBILITY IMPROVEMENT AT OTHER CLASS I AREAS

Class I area	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + SOFA	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + SOFA/SNCR	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + SOFA/SCR
Bridger	0.43	0.54	0.87
Fitzpatrick	0.19	0.23	0.34
Rawah	0.41	0.51	0.75
Rocky Mountain	0.34	0.42	0.65
Grand Teton	0.14	0.17	0.25
Teton	0.14	0.17	0.24
Washakie	0.22	0.19	0.26
Yellowstone	0.24	0.16	0.25

TABLE 16—SUMMARY OF EPA'S JIM BRIDGER UNIT 4 NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (Annual Average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Mt. Zirkel)
New LNBs with SOFA	0.19	4,161	$1,167,297	$281	—	0.63
New LNBs with SOFA and SNCR	0.15	4,956	4,445,990	897	$4,127	0.75
New LNBs with SOFA and SCR	0.05	7,108	17,712,336	2,492	6,165	1.01

Jim Bridger Unit 4 also impacts other Class I areas. The visibility improvement modeled by EPA at other Class I areas is shown in Table 17 below.

TABLE 17—JIM BRIDGER UNIT 3: VISIBILITY IMPROVEMENT AT OTHER CLASS I AREAS

Class I area	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + SOFA	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + SOFA/SNCR	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + SOFA/SCR
Bridger	0.56	0.68	1.00
Fitzpatrick	0.23	0.27	0.39
Rawah	0.45	0.53	0.71
Rocky Mountain	0.42	0.50	0.75
Grand Teton	0.18	0.21	0.30
Teton	0.15	0.18	0.27
Washakie	0.19	0.23	0.29
Yellowstone	0.17	0.20	0.29

As discussed in detail above, because Wyoming relied on visibility modeling methodologies that are inconsistent with the statutory and regulatory requirements, we do not consider Wyoming's analysis of visibility improvement for the NO_X BART to be reasonable for Jim Bridger Unit 3 and 4. We propose to find that Wyoming's analysis for this Unit is inconsistent with the statutory and regulatory requirement that ''the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.''

Also, we are not relying on the State's costs due to reasons stated in section VII.C.3.b of this notice. We propose to find that Wyoming did not properly or reasonably ''take into consideration the costs of compliance.''

Our analysis follows our BART Guidelines. With the exception of the NO_X emission limits, the visibility improvement analyses, and the cost effectiveness analyses, EPA is proposing to find that the Wyoming regional haze BART analysis NO_X for Jim Bridger Units 3 and 4 fulfills all the relevant requirements of CAA Section 169A and the RHR.

As stated above for Jim Bridger Units 1 and 2, EPA is proposing to determine that the facts indicate that BART for the all units at Jim Bridger is SCR when the units are considered individually based on the five factors without regard to the status of those factors for other units in the PacifiCorp system. However, when the five factors are considered across all the units, EPA is proposing that BART for Jim Bridger Units 3 and 4 is new LNB plus OFA.

EPA is proposing to approve the SIP with regard to the State's determination that the appropriate level of NO_X control for Units 3 and 4 at Jim Bridger for purposes of reasonable progress is the SCR-based emission limit in the SIP of 0.07 lb/MMBtu, with compliance dates of December 31, 2015 for Unit 3 and December 31, 2016 for Unit 4. As discussed above for Jim Bridger Units 1 and 2, in the context of reasonable progress in the second planning period of the regional haze program, we have determined it is appropriate to give considerable deference to the State's conclusions about what controls are reasonable and when they should be implemented. Thus, we do not find it appropriate to disapprove the State's preferred compliance deadlines for Jim Bridger Units 3 and 4. In addition, the State is requiring PacifiCorp to install the LTS controls within the timeline that BART controls would have to be installed pursuant to 40 CFR 51.308(e)(iv). Thus, we are proposing to approve the State's compliance schedule and emission limit of 0.07 lb/MMBtu for Jim Bridger Units 3 and 4 as meeting the BART requirements.

PM BART Determination for Jim Bridger Units 1–4

Units 1, 2, 3, and 4 are currently controlled for PM with ESPs and flue gas conditioning (FGC). The current permit limit for all four units is 0.03 lb/MMBtu. The State determined that fabric filters were technically feasible for controlling PM emissions. The State did not identify any technically infeasible controls or any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated. There are no remaining-useful-life issues for this source. A summary of the State's PM BART analyses for Units 1–4 is provided in Table 18 below. Baseline PM emissions are 1,064 tpy for Unit 1, 1,750 tpy for Unit 2, 1,348 tpy for Unit 3, and 710 tpy for Unit 4 based on unit heat input rate of 6,000 MMBtu/hr and 7,884 hours of operation per year.

TABLE 18—SUMMARY OF WYOMING'S PACIFICORP JIM BRIDGER UNITS 1–4 PM BART ANALYSIS

Control technology	Control efficiency (%)	Emission rate (lb/MMBtu) (30-day rolling average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)
Fabric Filter—Unit 1	66.6	0.015	709	$6,367,118	$8,980
Fabric Filter—Unit 2	79.7	0.015	1,395	6,357,658	4,557
Fabric Filter—Unit 3	73.7	0.015	993	6,337,434	6,382
Fabric Filter—Unit 4	50	0.015	355	6,367,118	17,936

The State did not provide visibility improvement modeling for fabric filters, but EPA is proposing to conclude this is reasonable based on the high cost for fabric filters at each of the units. In addition, we anticipate that the visibility improvement that would result from lowering the limit from 0.03 lb/MMBtu to 0.015 lb/MMBtu would be insignificant based on the State's analysis.[37]

Based on its consideration of the five-factors, the State determined the current ESPs with FGC are reasonable for BART. The State determined that fabric filters were not reasonable based on the high cost-effectiveness values. The State determined that the PM BART emission limit for Jim Bridger Units 1 through 4 is 0.03 lb/MMBtu.

We agree with the State's conclusions, and we are proposing approve its PM BART determination for Jim Bridger Units 1–4.

vi. PacifiCorp Naughton Units 1–3

PacifiCorp Naughton is located in Lincoln County, Wyoming. Naughton is comprised of three pulverized coal-fired units with a total net generating capacity of 700 MW. Naughton Unit 1 generates a nominal 160 MW and commenced operation in 1963. Naughton Unit 2 generates a nominal 210 MW and commenced operation in 1968. Naughton Unit 3 generates a nominal 330 MW and commenced operation in 1971. All three boilers are tangentially fired boilers. The State's BART determinations can be found in Chapter 6.5.6 and Appendix A of the SIP. The NO_X BART analysis for Unit 1 and Unit 2 is discussed in section VIII.A of this notice.

Wyoming's NO_X BART Determination for Naughton Unit 3

Naughton Unit 3 is currently controlled with LNBs with OFA with permit limits of 0.75 lb/MMBtu (93-hour block) and 0.49 lb/MMBtu (annual). The State determined that tuning the existing LNBs, existing LNBs with OFA and SNCR, and existing LNBs with OFA and SCR were all technically feasible for controlling NO_X emissions from Unit 3. The State did not identify any technically infeasible options.

Wyoming treated Naughton Unit 3 differently than most other units in that it did not assume that Unit 3 would first upgrade the combustion controls. The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, and there no remaining-useful-life issues for this source. A summary of the State's NO_X BART analyses for Unit 3 is provided in Table 19 below. Baseline NO_X emissions are 6,563 tpy for Unit 3 based on the unit heat input rate of 3,700 MMBtu/hr and 7,884 hours of operation per year.

TABLE 19—SUMMARY OF WYOMING'S NAUGHTON UNIT 3 NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (30-day rolling average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Bridger Wilderness Area)
Tuning Existing LNBs	0.37	1,167	$95,130	$82	—	0.25
Existing LNBs with OFA and SNCR	0.30	2,188	1,916,039	876	$1,783	0.46
Existing LNB with OFA and SCR	0.07	5,542	15,682,702	2,830	4,105	1.00

Based on its consideration of the five-factors, the State determined that the existing LNBs with OFA plus SCR were NO_X BART for Unit 3. The State determined the NO_X BART emission limit for Naughton Unit 3 is 0.07 lb/MMBtu (30-day rolling average).

EPA's NO_X BART Determination for Naughton Unit 3

The EPA agrees with the State's analysis pertaining to energy or non-air quality environmental impacts and remaining-useful-life for this source. Baseline NO_X emissions are 4,544 tpy for Unit 3 based on the actual annual average for the years 2001–2003. A summary of the EPA's NO_X BART analysis and the visibility impacts is provided in Tables 20 and 21 below.

TABLE 20—SUMMARY OF EPA'S NAUGHTON UNIT 3 NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (annual average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Wind Cave National Park)
Existing LNBs with OFA	0.33	442	$106,393	$240	—	0.17
Existing LNBs with OFA and SNCR	0.23	1,673	3,896,839	2,329	$3,081	0.70
Existing LNBs with OFA and SCR	0.05	3,922	12,718,731	3,243	3,922	1.51

Naughton Unit 3 also impacts other Class I areas. The visibility improvement modeled by EPA at other Class I areas is shown in Table 21 below.

[37] The cumulative 3-year averaged visibility improvement from new LNB with separated OFA, upgraded wet FGD, and FGC for enhanced ESP with FGC (Post-Control Scenario 1) across the three Class I areas achieved with LNB and separated OFA, upgraded wet FGD, and adding a polishing fabric filter (Post-Control Scenario 2) was 0.095 delta dv from Unit 1, 0.090 delta dv from Unit 2, 0.089 delta dv from Unit 3 and 0.025 delta dv from Unit 4.

TABLE 21—VISIBILITY IMPROVEMENT AT OTHER CLASS I AREAS

Class I area	Visibility improvement (delta dv for the maximum 98th percentile impact)—existing LNBs + OFA	Visibility improvement (delta dv for the maximum 98th percentile impact)—existing LNBs + OFA/SNCR	Visibility improvement (delta dv for the maximum 98th percentile impact)—existing LNBs + OFA/SCR
Fitzpatrick	0.09	0.33	0.74
N. Absaroka	0.04	0.16	0.36
Washakie	0.06	0.23	0.51
Teton	0.08	0.30	0.66
Grand Teton	0.09	0.33	0.73
Yellowstone	0.07	0.26	0.57

As stated above, the State determined that NO_X BART for Naughton Unit 3 was existing LNBs plus OFA with SCR with an emission limit of 0.07 lb/MMBtu (30-day rolling average). We find this determination reasonable given that the average cost effectiveness is reasonable at $3,243/ton with significant visibility improvement at the most impacted Class I area of 1.51 dv, as well as improvements ranging from 0.36 dv to 0.74 dv at six other Class I areas.

We agree with the State's conclusions, and we are proposing to approve its NO_X BART determination for Naughton Unit 3.

We are also asking if interested parties have additional information regarding the possible conversion of Naughton Unit 3 from a coal fired unit to a natural gas fired unit as part of a better-than-BART demonstration to the proposed requirement for the installation of combustion controls and SCR.[38] PacifiCorp has indicated that converting the unit to natural gas would reduce NO_X emissions to 0.10 lb/MMbtu, and nearly eliminate all SO_2 emissions. If PacifiCorp proceeds with their planned conversion to natural gas, we seek comment on whether the interested parties think the Agency should consider the conversion of Naughton Unit 3 to natural gas as a BART control technology option that could be finalized as either a FIP, or a SIP (if the Agency were to receive a SIP revision from the State) instead of BART as proposed, with associated changes to the proposed regulatory text as necessary.

PM BART Determination

Naughton Units 1 and 2 are currently controlled for PM with ESPs and FGC. The current permit limit for Units 1 and 2 is 0.04 lb/MMBtu. Unit 3 is required by permit to install fabric filters for both Units by 2014 with a permit limit of 0.015 lb/MMBtu. The State determined that fabric filters were technically feasible for controlling PM emissions for Units 1 and 2. The State did not identify any technically infeasible controls. The State determined that a fabric filter on Unit 3 represents the most stringent PM control technology and that 0.015 lb/MMBtu represents the most stringent emission limit. Consistent with the BART Guidelines, the State did not provide a full five-factor analysis because the State determined BART to be the most stringent control technology and limit.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, and there are no remaining-useful-life issues for this source. A summary of the State's PM BART analyses for Units 1 and 2 is provided in Table 22 below. Baseline emissions for Unit 1 are 409 tpy and 605 tpy for Unit 2 based on unit heat input rate of 1,850 MMBtu/hr and 7,884 hours of operation per year.

TABLE 22—SUMMARY OF PACIFICORP NAUGHTON UNIT 1 AND UNIT 2 PM BART ANALYSIS

Control technology	Control efficiency (%)	Emission rate (lb/MMBtu) (30-day rolling average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)
Fabric Filter—Unit 1	73.2	0.015	299	$3,436,594	$11,494
Fabric Filter—Unit 2	76.6	0.015	464	4,101,705	8,848

The State did not provide visibility improvement modeling for fabric filters, but EPA is proposing to conclude this is reasonable based on the high cost-effectiveness values of fabric filters at each of the units, which are higher than EPA or other state have considered reasonable for PM BART.

Based on its consideration of the five-factors, the State determined that the existing ESPs with FGC were reasonable for PM BART for Units 1 and 2. The State determined that fabric filters were not reasonable based on the high cost-effectiveness values. The State determined that the PM BART emission limit for Naughton Unit 1 and Unit 2 is 0.04 lb/MMBtu. The State determined the PM BART emission limit for Naughton Unit 3 is 0.015 lb/MMBtu.

We agree with the State's conclusions, and we are proposing to approve its PM BART determination for Naughton Units 1, 2, and 3.

vii. PacifiCorp Wyodak—Unit 1

Background

PacifiCorp Wyodak power plant is located in Campbell County, Wyoming. Wyodak is comprised of one coal-fired

[38] At PacifiCorp's request, on December 11, 2013, EPA Region 8 met with PacifiCorp. PacifiCorp discussed the option of Naughton Unit 3 being converted to natural gas and stated that they were working on the analysis. In subsequent conversations with the State, EPA learned that PacifiCorp had submitted its analysis to the State, which the State then provided to EPA. We have included this information in the docket (see document titled *2/19/2013 Email from Cole Anderson, Wyoming DEQ, to Laurel Dygowski, EPA Region 8).*

boiler, Unit 1, burning pulverized sub-bituminous Powder River Basin coal for a total net generating capacity of a nominal 335MW. Wyodak's boiler commenced service in 1978. The State's BART determination can be found in Chapter 6.5.7 and Appendix A of the SIP. The NO_X BART analysis for Wyodak Unit 1 is discussed in Section VII.A of this notice.

Wyodak Unit 1 PM BART Determination

Wyodak Unit 1 is currently controlled with fabric filters with an emission limit of 0.015 lb/MMBtu (30-day rolling average). The State determined that fabric filters on Wyodak Unit 1 represent the most stringent PM control technology and that 0.015 lb/MMBtu represents the most stringent emission limit. Consistent with the BART Guidelines, the State did not provide a full five-factor analysis because the State determined BART to be the most stringent control technology and limit. The State determined the PM BART emission limit for Wyodak Unit 1 is 0.015 lb/MMBtu.

We agree with the State's conclusions, and we are proposing to approve its PM BART determination for Wyodak Unit 1.

D. Reasonable Progress Requirements

In order to establish RPGs for it Class I areas, and to determine the controls needed for the LTS, Wyoming followed the process established in the RHR. Wyoming identified sources (other than BART sources) and source categories in Wyoming that are major contributors to visibility impairment and considered whether these sources should be controlled based on a consideration of the factors identified in the CAA and EPA's regulations (see CAA 169A(g)(1) and 40 CFR 51.308(d)(1)(i)(A)). Wyoming then identified the anticipated visibility improvement in 2018 in all its Class I areas using the WRAP Community Multi-Scale Air Quality (CMAQ) modeling results.

1. Visibility Impairing Pollutants and Sources

In order to determine the significant sources contributing to haze in Wyoming's Class I areas, Wyoming relied upon two source apportionment analysis techniques developed by the WRAP. The first technique was regional modeling using the Comprehensive Air Quality Model (CAMx) and the PM Source Apportionment Technology (PSAT) tool, used for the attribution for sulfate and nitrate sources only. The second technique was the Weighted Emissions Potential (WEP) tool, used for attribution of sources of OC, EC, $PM_{2.5}$, and PM_{10}. The WEP tool is based on emissions and residence time, not dispersion modeling, and looks at all sources throughout the modeling domain.

PSAT uses the CAMx air quality model to simulate nitrate-sulfate-ammonia chemistry and apply this chemistry to a system of tracers or "tags" to track the chemical transformations, transport, and removal of NO_X and SO_2. These two pollutants are important because they tend to originate from anthropogenic sources. Therefore, the results from this analysis can be useful in determining contributing sources that may be controllable, both in-state and in neighboring states.

WEP is a screening tool that helps to identify source regions that have the potential to contribute to haze formation at specific Class I areas. Unlike PSAT, this method does not account for chemistry or deposition. The WEP combines emissions inventories, wind patterns, and residence times of air masses over each area where emissions occur, to estimate the percent contribution of different pollutants. Like PSAT, the WEP tool compares baseline values (2000–2004) to 2018 values, to show the improvement expected by 2018 for OC, EC, $PM_{2.5}$, and PM_{10}. More information on the WRAP modeling methodologies is available in the document *Technical Support Document for Technical Products Prepared by the Western Regional Air Partnership (WRAP) in Support of Western Regional Haze Plans* in the Supporting and Related Materials section of the docket. Table 23 shows Wyoming's contribution to extinction at its own Class I areas.

TABLE 23—WYOMING SOURCES EXTINCTION CONTRIBUTION 2000–2004 FOR 20% WORST DAYS [39]

Class I area	Pollutant species	Extinction (Mm^{-1})	Species contribution to total particulate extinction (%)	Wyoming sources contribution to species extinction (%)
Yellowstone National Park, Grand Teton National Park, Teton Wilderness.	Sulfate	4.3	16.7	5.9
	Nitrate	1.8	7.0	4.7
	OC	13.5	52.4	72.6
	EC	2.5	9.7	66.8
	Fine PM	1.0	3.9	24.0
	Coarse PM	2.6	10.1	20.0
	Sea Salt	0.02	0.08	
North Absaroka Wilderness, Washakie Wilderness	Sulfate	4.9	20.7	5.6
	Nitrate	1.6	6.8	8.2
	OC	11.6	48.9	44.6
	EC	1.9	8.0	39.5
	Fine PM	0.8	3.4	14.0
	Coarse PM	2.9	12.2	12.1
	Sea Salt		0.04	
Bridger Wilderness, Fitzpatrick Wilderness	Sulfate	5.0	22.2	15.4
	Nitrate	1.4	6.2	19.4
	OC	10.5	46.6	58.5
	EC	2.0	8.9	51.0
	Fine PM	1.1	4.9	30.3
	Coarse PM	2.5	11.1	27.4

[39] Extinction and species contribution to total particulate extinction taken from IMPROVE data (*http://vista.cira.colostate.edu/dev/web/AnnualSummaryDev/Composition.aspx*). IMPROVE data for NOABI based on available data for 2002–2004. Contribution of sulfate and nitrate based on PSAT; OC, EC, $PM_{2.5}$, and PM_{10} contribution based on WEP as taken from the WRAP TSS (*http://vista.cira.colostate.edu/tss/*).

TABLE 23—WYOMING SOURCES EXTINCTION CONTRIBUTION 2000–2004 FOR 20% WORST DAYS [39]—Continued

Class I area	Pollutant species	Extinction (Mm^{-1})	Species contribution to total particulate extinction (%)	Wyoming sources contribution to species extinction (%)
	Sea Salt	0.04	0.2	....

Table 24 shows influences from sources both inside and outside of Wyoming per the PSAT modeling for 2018. As indicated, the outside domain (OD) region is the highest contributor to sulfate and nitrate at all Wyoming Class I areas. The outside domain region represents the concentration of pollutants at the boundaries of the modeling domain. Depending on meteorology and the type of pollutant (particularly sulfate), these emissions can be transported great distances from regions such as Canada, Mexico, and the Pacific Ocean. Wyoming is the second highest contributor of particulate sulfate and nitrate at Bridger and Fitzpatrick Wilderness areas, but is a lesser contributor at the other Class I areas.

TABLE 24—PSAT SOURCE REGION APPORTIONMENT FOR 20% WORST DAYS [40]

Class I area		2018 Sulfate PSAT					2018 Nitrate PSAT				
Yellowstone National Park, Grand Teton National Park, Teton Wilderness.	Region	OD	ID	WY	CAN	OR	OD	ID	WA	UT	OR
	% Contribution	46.5	8.1	5.8	5.4	4.6	31.3	28.2	9.4	7.4	7.0
North Absaroka Wilderness, Washakie Wilderness ...	Region	OD	CAN	MT	ID	WY	OD	ID	MT	CAN	WY
	% Contribution	50.1	12.5	6.5	5.7	5.5	30.7	16.7	14.8	11.5	8.2
Bridger Wilderness, Fitzpatrick Wilderness	Region	OD	WY	ID	UT	CAN	OD	WY	UT	ID	CA
	% Contribution	31.1	15.3	7.6	5.9	5.1	21.8	19.3	15.6	10.6	6.8

Table 25 shows the WEP contribution by source category for EC, OC, $PM_{2.5}$, and PM_{10}.

TABLE 25—WEP SOURCE CATEGORY CONTRIBUTION FOR 20% WORST DAYS

Class I area	Point	Area	Mobile	Anthropogenic fires	Natural fires and biogenic
OC					
Yellowstone National Park, Grand Teton National Park, Teton Wilderness	0.408	3.892	1.636	8.303	85.764
North Absaroka Wilderness, Washakie Wilderness	0.661	9.449	2.844	11.881	75.159
Bridger Wilderness, Fitzpatrick Wilderness	0.984	7.552	3.28	7.644	80.543
EC					
Yellowstone National Park, Grand Teton National Park, Teton Wilderness	0.243	2.628	13.659	5.51	77.958
North Absaroka Wilderness, Washakie Wilderness	0.386	5.755	23.253	7.054	63.55
Bridger Wilderness, Fitzpatrick Wilderness	0.54	4.509	25.65	4.105	65.195
$PM_{2.5}$					
Yellowstone National Park, Grand Teton National Park, Teton Wilderness	5.565	70.463	0.086	5.469	18.411
North Absaroka Wilderness, Washakie Wilderness	3.491	86.311	0.171	3.334	6.691
Bridger Wilderness, Fitzpatrick Wilderness	16.311	69.195	0.081	3.618	10.785

[40] OD denotes Outside Domain; ID denotes Idaho, MT denotes Montana, CAN denotes Canada, UT denotes Utah, WA denotes Washington, WY denotes Wyoming, CA denotes California, and OR denotes Oregon.

TABLE 25—WEP SOURCE CATEGORY CONTRIBUTION FOR 20% WORST DAYS—Continued

Class I area	Point	Area	Mobile	Anthropogenic fires	Natural fires and biogenic
PM_{10}					
Yellowstone National Park, Grand Teton National Park, Teton Wilderness	2.655	83.939	0.363	0.717	12.316
North Absaroka Wilderness, Washakie Wilderness	2.066	93.197	0.213	0.313	4.206
Bridger Wilderness, Fitzpatrick Wilderness	6.775	84.157	0.477	0.353	8.23

Table 25 shows that EC, OC, $PM_{2.5}$ and PM_{10} emissions come mainly from sources such as natural fire, windblown dust, and road dust. To select the sources that would undergo the required four-factor analysis, Wyoming looked at State emission inventory data in conjunction with the source apportionment information discussed above (a summary of the State's emission inventory can be found in section VI.E.1 of this notice). After evaluating this information, the State determined that stationary source emissions of NO_X and SO_2 were reasonable to evaluate for purposes of reasonable progress controls. The State also determined that emissions of NO_X from oil and gas development should be analyzed for purposes of reasonable progress. Since emissions of OC, EC, $PM_{2.5}$, and PM_{10} come from mainly uncontrollable sources, the State determined it was reasonable to not evaluate these pollutants for reasonable progress controls. The State submitted a January 12, 2011, SIP that addresses sources of SO_2.[41] Thus, the State evaluated emissions of the remaining pollutant, NO_X, for reasonable progress in this SIP.

2. Four-Factor Analysis

In determining the measures necessary to make reasonable progress, States must take into account the following four factors and demonstrate how they were taken into consideration in selecting reasonable progress goals for each Class I area:

- Costs of Compliance;
- Time Necessary for Compliance;
- Energy and Non-air Quality Environmental Impacts of Compliance; and
- Remaining Useful Life of any Potentially Affected Sources.

CAA § 169A(g)(1) and 40 CFR 308(d)(1)(i)(A).

The State performed a four factor analysis for each of the reasonable progress sources pursuant to 40 CFR 51.308(d)(1)(i)(A).

a. Stationary Sources

The State used a reasonable progress screening methodology termed ''Q/d'' to determine which stationary sources would be candidates for controls under reasonable progress. Q/d is a calculated ratio where Q represents (in this case) the NO_X emission rate in tpy of the source divided by the distance in kilometers of the point source from the nearest Class I area, denoted by ''d.'' The State used the maximum permitted emission rate for each source to determine the tpy of NO_X in the Q/d calculation. The State determined that a Q/d value of 10 is reasonable for determining which sources the State should consider for reasonable progress controls, since this value yielded sources of concern similar in magnitude to sources subject-to-BART.

The State determined there were three units with a Q/d of greater than 10 that are not already being controlled under BART and the State completed a reasonable progress analysis for each of the sources. The sources are PacifiCorp Dave Johnston Unit 1 and Unit 2 and Mountain Cement Company Laramie Plant kiln. Dave Johnston Units 1 and 2 are addressed as part of our FIP in section VII.B of this notice. In addition, as previously mentioned, the State considered reasonable controls on oil and gas development sources.

b. Summary of Reasonable Progress Determinations and Limits

For the subject-to-reasonable progress sources, the State provided analyses that took into consideration the four factors as required by section 169A(g)(1) of the CAA and 40 CFR 51.308(d)(1)(i)(A). For the stationary sources, the State relied on the analysis found in *Supplementary Information for Four-Factor Analyses for Selected Individual Facilities in Wyoming,* May 6, 2009, Revised Draft Report Prepared by EC/R Incorporated. For oil and gas sources, the State relied on the analysis found in *Supplementary Information for Four Factor Analyses by WRAP States,* May 4, 2009 (Corrected 4/20/10) Revised Draft Report Prepared by EC/R Incorporated (for a complete copy of the reports see Chapter 7 of the State's TSD). The analyses considered EPA's BART Guidelines as relevant to their reasonable progress evaluations, as well as EPA's *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program.*

In this action, EPA is proposing to approve the reasonable progress NO_X determinations submitted by the State for oil and gas sources and for Mountain Cement Company Laramie Plant kiln. EPA is proposing to disapprove the State's reasonable progress determinations and proposing to issue a reasonable progress determination NO_X FIP for PacifiCorp Dave Johnston Unit 1 and Unit 2. As with the BART EGUs, EPA is providing revised cost analyses and visibility improvement modeling for PacifiCorp Dave Johnston Unit 1 and 2. We are also providing the original reasonable progress analyses EPA relied on in its June 4, 2012 proposed rulemaking. EPA's rationale for disapproving the State's reasonable progress determination for these units, as well as EPA's reasonable progress FIP determination, can be found in section VIII.B of this notice.

A summary of the reasonable progress analysis and determination for each source/source category that we are proposing to approve is provided below.

i. Oil and Gas Sources

Background

Oil and gas exploration and production is occurring in numerous areas in Wyoming. The sources associated with oil and gas production mainly emit NO_X and VOCs; in this context, the State considered NO_X. Oil and gas production and exploration includes operation, maintenance, and servicing of production properties, including transportation to and from sites. EC/R evaluated reasonable progress control technologies for common sources in the oil and gas industry including compressor engines, turbines, process heaters, and drilling rig engines. The State's NO_X reasonable progress determination for oil and gas

[41] The State submitted a January 12, 2011 SIP submittal to address the requirements under 40 CFR 51.309, with the exception of the 40 CFR 51.309(g) requirements addressed in this SIP action.

sources can be found in Chapter 7.3.5 of the SIP.

NO_X Reasonable Progress Determination

For compressor engines, potential control options identified by the State include air-fuel ratio controls (AFRC), ignition timing retard, low-emission combustion (LEC) retrofit, SCR, SNCR, and replacement with electric motors. The State evaluated several control technologies for drilling rig engines including ignition timing retard, exhaust gas recirculation (EGR), SCR, replacement of Tier 2 engines with Tier 4 engines, and diesel oxidation catalyst. Potential controls for turbines identified by the State include water or steam injection, LNBs, SCR, and water or steam injection with SCR. NO_X emission control technologies identified by the State for process heaters include LNBs, ultra-low NO_X burners (ULNBs), LNBs with flue gas recirculation (FGR), SNCR, SCR, and LNBs installed in conjunction with SCR.

NO_X emissions vary based on the equipment and fuel source. Emissions from individual natural gas-fired turbines at production operations can be as high as 877 tpy of NO_X, while emissions from individual natural gas turbines at exploration operations can reach 131 tpy of NO_X. Individual gas reciprocating engines have comparable NO_X emissions with up to 700 tpy at production operations and 210 tpy at exploration operations. Diesel engine emissions can approach 46 tpy for production operations and 10 tpy for exploration operations.

Table 26 provides a summary of the reasonable progress NO_X analysis for oil and gas sources. Both the capital and annual costs for each technology is dependent on the engine size or on the process throughput; therefore, for most of the control technologies listed in Table 26, the State has provided cost estimate ranges. The lower end of the cost/ton estimates represent the cost per unit for larger or higher production units, while the higher end of the cost/ton estimates represent the cost per unit for the smaller or lower production units. The capital and annual cost figures are expressed in terms of the cost per unit of engine size or per unit of process throughput.

TABLE 26—SUMMARY OF REASONABLE PROGRESS NO_X ANALYSIS FOR OIL AND GAS EXPLORATION AND PRODUCTION EQUIPMENT

Source type	Control technology	Estimated control efficiency (%)	Pollutant controlled	Estimated capital cost ($/unit)	Annual cost ($/year/unit)	Units	Cost effectiveness ($/ton)
Compressor Engines	AFRC	10–40	NO_X	5.3–42	0.9–6.8	hp	68–2,500
	Ignition timing retard.	15–30	NO_X	N/A	1–3	hp	42–1,200
	LEC retrofit	80–90	NO_X	120–820	30–210	hp	320–2,500
	SCR	90	NO_X	100–450	40–270	hp	870–31,000
	SNCR	90–99	NO_X	17–35	3–6	hp	16–36
	Replacement with electric motors.	100	NO_X	120–140	38–44	hp	100–4,700
Drilling Rig Engines and Other Engines.	Ignition timing retard.	15–30	NO_X	16–120	14–66	hp	1,000–2,200
	EGR	40	NO_X	100	26–67	hp	780–2,000
	SCR	80–95	NO_X	100–2,000	40–1,200	hp	3,000–7,700
	Replacement of Tier 2 engines with Tier 4.	87	NO_X	125	20	hp	900–2,400
Turbines	Water or steam injection.	68–80	NO_X	4.4–16	2–5	1000 BTU	560–3,100
	LNB	68–84	NO_X	8–22	2.7–8.5	1000 BTU	2,000–10,000
	SCR	90	NO_X	13–34	5.1–13	1000 BTU	1,000–6,700
	Water or steam injection with SCR.	93–96	NO_X	13–34	5.1–13	1000 BTU	1,000–6,700
Process Heaters	LNB	40	NO_X	3.8–7.6	0.41–0.81	1000 BTU	2,100–2,800
	ULNB	75–85	NO_X	4.0–13	0.43–1.3	1000 BTU	1, 500–2,000
	LNB and FGR	48	NO_X	16	1.7	1000 BTU	2,600
	SNCR	60	NO_X	10–22	1.1–2.4	1000 BTU	4,700–5,200
	SCR	70–90	NO_X	33–48	3.7–5.6	1000 BTU	2,900–6,700
	LNB and SCR	70–90	NO_X	37–55	4–6.3	1000 BTU	2,900–6,300

Wyoming states that it would need up to two years to develop the necessary regulations to control oil and gas sources.[42] The State estimated that companies would require a year to procure the necessary capital to purchase the control equipment. The time required to design, fabricate, and install control technologies will vary based on the control technology selected and other factors.

The State determined that no additional controls for oil and gas sources were reasonable at this time. The State concluded that emissions from large stationary sources processing oil and gas in the WRAP region have been well quantified over the years, while smaller exploration and production sources that the State is evaluating for reasonable progress have not had the same degree of emission inventory development. The State points out that understanding the sources and volume of emissions at oil and gas production sites is necessary to recognizing the impact that these emissions have on visibility.

To better understand the emissions from stationary and mobile equipment

[42] For all reasonable progress sources, the time necessary to develop regulations is not a consideration under the time necessary for compliance factor. If regulations are needed to implement reasonable progress controls, the State must develop them as part of the regional haze SIP.

operated as part of oil and gas field operations, the WRAP has been working on developing an emission inventory to more fully characterize the oil and gas field operations emissions. The WRAP's development of a more comprehensive emission inventory is still in process (as of the date of the State's SIP submittal). The State determined it cannot complete the evaluation of oil and gas on visibility until the WRAP emission inventory study has been completed.

The State points out that in the case of compressor engines, many facilities have already installed control equipment.[43] For lean burn engines, oxidation catalysts are commonly installed, while SNCR with AFRC are commonly installed for rich burn engines. The State also points out that regulating drill rig engines can be problematic since drill rig engines are, for the most part, considered mobile sources and emission limits for mobile sources are set by the Federal government under section 202 of the CAA.

We disagree with the State's reasoning for not adopting reasonable progress controls for oil and gas sources. If the State determined that additional information was needed to potentially control oil and gas sources, the State should have developed the information. While we disagree with the State's reasoning for not requiring any controls under reasonable progress, we are proposing to approve the State's conclusion that no additional NO_X controls are warranted for this planning period. As shown by the four-factor analyses, the most reasonable controls are for compressor engines, which the State already controls through its minor source BACT requirements (see above). In addition, while the costs of some controls are within the range of cost-effectiveness values Wyoming, other states, and we have considered as reasonable in the BART context, they are not so low that we are prepared to disapprove the State's conclusion in the reasonable progress context. Therefore, we are proposing to approve the State's reasonable progress determination for oil and gas sources.

ii. Mountain Cement Company Laramie Plant—Kiln

Background

The Mountain Cement Company Laramie Plant cement kiln is a long dry kiln with a capacity of 1,500 tons of clinker per day. Assuming the plant runs 365 days of the year, the result is 547,500 tpy of clinker.

NO_X Reasonable Progress Determination

The kiln is currently uncontrolled for NO_X emissions. The State determined that indirect and direct firing of LNBs, biosolid injection, NOxOUT℠, CemSTAR℠, LoTOx™, SCR, SNCR (using urea), and SNCR (using ammonia) were technically feasible for controlling NO_X emissions from the kiln. The State did not identify any technically infeasible controls.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, and there are no remaining-useful-life issues for this source. A summary of the State's NO_X reasonable progress analyses for the kiln is provided in Table 27 below. Baseline NO_X emissions for the kiln are 524 tpy based on 2002 actual emissions.

TABLE 27—SUMMARY OF MOUNTAIN CEMENT COMPANY KILN NO_X REASONABLE PROGRESS ANALYSIS

Control technology	Control efficiency (%)	Emission reduction (tpy)	Annualized costs	Cost effectiveness ($/ton)
LNB (indirect)	30–40	157–210	$205,000	$6,568–4,910
LNB (direct)	40	210	449,000	13,853
Biosolid Injection [44]	50	262	−127,000	1,324
NOxOUT℠	35	183	507,000	8,023
CemSTAR℠ [45]	20–60	105–314	Unknown	Unknown
LoTOx™ [46]	80–90	419–472	Unknown	Unknown
SCR	80	419	7,553,000	82,535
SNCR (urea) [47]	35	183	Unknown	1,223
SNCR (ammonia)	35	183	Unknown	1,223

[44] A negative annual cost is given because cement kilns receive a credit for the biosolids tipping fee paid by facilities providing the biosolids to the cement plant. For the purposes of this analysis, the tipping fee is $5.00/ton.
[45] Cost effectiveness figures for the CemStar℠ process were not available for dry kilns.
[46] Cost effectiveness figures for LoTOx™ were not available for dry kilns.
[47] Capital and annual costs for SNCR have only been evaluated for preheater and precalcnier kilns. Only cost effectiveness figures were available for dry kilns.

The State estimated that it could potentially take seven years to install control equipment on the kiln. This estimate includes the two years that will be necessary for the State to implement new regulations and the one-year Mountain Cement will likely need to obtain the necessary capital for the purchase of new emission control technology. The State estimates the total time necessary for compliance will vary based on the control technology selected. For example, the State predicts that one and a half years will be required to design, fabricate, and install SCR or SNCR technology, while over two and a half years will be required to design, fabricate, and install LoTOx™ technology.

The State determined no controls were reasonable for reasonable progress for Mountain Cement Company Laramie Plant kiln. The State cited that the four-factor analysis was limited, in that no guidance was provided by EPA for identifying significant sources and EPA did not establish contribution to visibility impairment thresholds (a potential fifth factor for reasonable progress determinations).[48] The State further claims that the State cannot, per Wyoming Statute 35–11–202, establish emission control requirements except through State rule or regulation. Furthermore, the Wyoming statute requires the State to consider the

[43] Oil and gas sources are regulated by the State as part of its minor source BACT requirements in Wyoming Air Quality Standards and Regulations Chapter 6, Section 2.

[48] States must consider the four factors as listed above but can also take into account other relevant factors for the reasonable progress sources identified (see EPA's *Guidance for Setting Reasonable Progress Goals under the Regional Haze Program,* (''EPA's Reasonable Progress Guidance''), p. 2–3, July 1, 2007).

character and degree of injury of the emissions involved. In this case, the State claims it would need to have visibility modeling that assessed the degree of injury caused by the emissions, which the State does not have. The State believes it has taken a strong and reasonable first step in identifying potential contributors to visibility impairment, and that the next step of creating an appropriate rule or regulation will be accomplished in the next SIP revision.

We disagree with the State's reasoning for not adopting reasonable progress controls for Mountain Cement Company Laramie Plant kiln. If the State determined that it needed to adopt a rule or perform modeling to adequately assess and, if warranted, require reasonable progress controls, the State should have completed these steps before it submitted its regional haze SIP. The RHR does not allow for commitments to potentially implement strategies at some later date that are identified under reasonable progress or for the State to take credit for such commitments. Nor does it allow the State to consider the time to promulgate regulations as part of the time for compliance.

While we disagree with the State's reasoning for not requiring any controls under reasonable progress, we are proposing to approve the State's conclusion that no additional NO_X controls are warranted for this planning period. While the costs of some controls (i.e., biosolid injection and SNCR) are within the range of cost-effectiveness values that Wyoming, other states, and EPA have considered as reasonable in the BART context, the costs are not so low that we are prepared to disapprove the State's conclusion in the reasonable progress context. In addition, these additional controls only afford relatively modest emission reductions.

3. Reasonable Progress Goals

40 CFR 51.308(d)(1) requires states to "establish goals" (in deciviews) that provide for reasonable progress towards achieving natural visibility conditions for each Class I area of the State. These RPGs are interim goals that must provide for incremental visibility improvement for the most impaired visibility days, and ensure no degradation for the least impaired visibility days. The RPGs for the first planning period are goals for the year 2018.

Wyoming relied on WRAP modeling to establish its RPGs for 2018. The primary tool WRAP relied upon for modeling regional haze improvements by 2018, and for estimating Wyoming's RPGs, was the CMAQ model. The CMAQ model was used to estimate 2018 visibility conditions in Wyoming and all western Class I areas, based on application of anticipated regional haze strategies in the various states' regional haze plans, including assumed controls on BART sources.

The Regional Modeling Center (RMC) at the University of California Riverside conducted the CMAQ modeling under the oversight of the WRAP Modeling Forum. The RMC developed air quality modeling inputs including annual meteorology and emissions inventories for: (1) A 2002 actual emissions base case; (2) a planning case to represent the 2000–2004 regional haze baseline period using averages for key emissions categories; (3) a 2018 base case of projected emissions determined using factors known at the end of 2005; and (4) a 2018 reasonable progress case to represent anticipated BART controls. All emission inventories were spatially and temporally allocated using the Sparse Matrix Operator Kernel Emissions (SMOKE) modeling system. Each of these inventories underwent a number of revisions throughout the development process to arrive at the final versions used in CMAQ modeling.

The photochemical modeling of regional haze for the WRAP states for 2002 and 2018 was conducted on the 36-km resolution national regional planning organization domain that covered the continental United States, portions of Canada and Mexico, and portions of the Atlantic and Pacific Oceans along the east and west coasts. The RMC examined the model performance of the regional modeling for the areas of interest before determining whether the CMAQ model results were suitable for use in the regional haze assessment of the LTS and for use in the modeling assessment. The 2002 modeling efforts were used to evaluate air quality/visibility modeling for a historical episode, in this case, for calendar year 2002, to demonstrate the suitability of the modeling systems for subsequent planning, sensitivity, and emissions control strategy modeling. Model performance evaluation compares output from model simulations with ambient air quality data for the same time period to determine whether model performance is sufficiently accurate to justify using the model to simulate future conditions. Once the RMC determined that model performance was acceptable, it used the model to determine the 2018 RPGs using the current and future year air quality modeling predictions, and compared the RPGs to the uniform rate of progress. A more detailed description of the CMAQ modeling performed for the WRAP can be found in the Chapter 5 of the State's TSD.

The State determined that the WRAP 2018 projections represent significant visibility improvement and reasonable progress toward natural visibility based upon the State's consideration of the factors required for BART and reasonable progress. The State adopted the WRAPs 2018 projections as their RPG for each Class I area. Table 28 shows the URP and the 2018 RPGs adopted by the State.

TABLE 28—WYOMING'S URP AND RPGS FOR 2018

Wyoming Class I Areas	20% Worst days				20% Best days	
	2000–2004 Baseline (deciview)	2018 URP (deciview)	Reduction needed to reach URP goal (delta deciview)	2018 CMAQ modeling projection—State's RPG	2000–2004 Baseline (deciview)	2018 CMAQ modeling projection (deciview)
Yellowstone National Park, Grand Teton National Park, Teton Wilderness	11.8	10.5	0.7	11.2	2.6	2.4
North Absaroka Wilderness, Washakie Wilderness	11.5	10.4	0.6	11.0	2.0	2.0
Bridger Wilderness, Fitzpatrick Wilderness	11.1	10.0	0.6	10.6	2.1	2.0

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Table 28 shows that the State's regional haze SIP is providing for improvement in visibility for the most-impaired days for the period ending in 2018 and allows for no degradation in visibility for the least-impaired days.

Table 28 also shows that Wyoming is not meeting the URP to meet natural visibility conditions by 2064. In this case, 40 CFR 51.308(d)(1)(ii) requires the State to demonstrate, based on the four factors in 51.308(d)(1)(i)(A), that the RPGs established in this SIP are reasonable for this planning period and that achieving the URP in this planning period is not reasonable. In its demonstration, the State cited many reasons why meeting the URP was not reasonable, including the following. First, emissions from natural sources greatly affect the State's ability to meet the 2018 URP. As discussed earlier, WEP data shows that emissions of OC, EC, $PM_{2.5}$, and PM_{10} come mainly from natural or non-anthropogenic sources, such as natural wildfire and windblown dust. The State has little or no control over OC, EC, $PM_{2.5}$, and PM_{10} emissions associated with natural fire and windblown dust. Second, emissions from sources outside the WRAP modeling domain also affect the State's ability to meet the 2018 URP. Sources outside of the modeling domain are the single largest source region contributor to sulfate and nitrate at the State's Class I areas. These sources are not under the control of Wyoming or the surrounding states.

Because the State is not meeting the URP, the State is required by 40 CFR 51.308(d)(1)(ii) to assess the number of years it would take to reach natural conditions if visibility improvement continues at the current rate of progress. The State has calculated the year and the length of time to reach natural visibility as follows: Yellowstone National Park, Grand Teton National Park, and Teton Wilderness: 2130 (126 years); North Absaroka Wilderness and Washakie Wilderness: 2136 (132 years); and Bridger Wilderness and Fitzpatrick Wilderness: 2165 (161 years).

EPA disagrees with the State's assessment that, based on the factors in 40 CFR 51.308(d)(1)(i)(a), all reasonable controls were implemented by the State for this first planning period of the regional haze program. In particular, as discussed in sections VIII.A and VIII.B. below, we find unreasonable the State's determination to not impose more stringent NO_X BART controls on certain sources or not to impose any reasonable progress controls at PacifiCorp Dave Johnston Units 1 and 2. As a result, EPA is proposing to disapprove the State's RPGs, and because we are proposing to disapprove Wyoming's RPGs, we are also proposing a FIP to replace them. See discussion in section VIII.C below.

E. Long Term Strategy

1. Emission Inventories

40 CFR 51.308(d)(3)(iii) requires that Wyoming document the technical basis, including modeling, monitoring, and emissions information, on which it relied to determine its apportionment of emission reduction obligations necessary for achieving reasonable progress in each mandatory Class I Federal area it affects. Wyoming must identify the baseline emissions inventory on which its strategies are based. 40 CFR 51.308(d)(3)(iv) requires that Wyoming identify all anthropogenic sources of visibility impairment it considered in developing its LTS. This includes major and minor stationary sources, mobile sources, and area sources.

In order to meet these requirements, Wyoming relied on the emission inventory developed by the WRAP. The State has provided an emission inventory for SO_2, NO_X, VOC, OC, EC, $PM_{2.5}$, PM_{10}, and NH_3. The inventory provides the baseline year 2002 emissions and provides projections of future emissions in 2018 based on expected controls, growth, and other factors. The following are the inventory source categories identified by the State: point, area, on-road mobile, off-road mobile, anthropogenic fire, natural fire, road dust, fugitive dust, area source oil and gas, and biogenic emissions. The emission inventories developed by the WRAP were calculated using best available data and approved EPA methods.[49] Following is a summary of the emission inventory for each pollutant by source.

SO_2

Sulfur dioxide emissions come primarily from coal combustion at EGUs, but smaller amounts come from natural gas combustion, mobile sources, and wood combustion.

[49] The methods WRAP used to develop these emission inventories are described in more detail in *Technical Support Document for Technical Products Prepared by the Western Regional Air Partnership (WRAP) in Support of Western Regional Haze Plans* in the Supporting and Related Materials section of the docket.

TABLE 29—WYOMING SO_2 EMISSIONS—2002 AND 2018

Source category	Baseline 2002	Future 2018	Percent change
Point	119,717	96,809	−19
Area	16,689	23,093	38
On-Road Mobile	959	81	−92
Off-Road Mobile	5,866	65	−99
Oil & Gas	150	3	−98
Road Dust	0	0	0
Fugitive Dust	0	0	0
Windblown Dust	0	0	0
Anthropogenic Fire	173	109	−37
Natural Fire	2,286	2,286	0
Biogenic	0	0	0
Total	145,840	122,446	−16

The State expects a 16% reduction in SO_2 emissions by 2018 due to planned controls on existing sources, even with expected growth in generating capacity for the State.

NO_X

NO_X emissions in Wyoming come mostly from point sources and from on-road and off-road mobile sources.

TABLE 30—WYOMING NO_X EMISSIONS—2002 AND 2018

Source category	Baseline 2002	Future 2018	Percent change
Point	117,806	110,109	−7
Area	15,192	19,663	29
On-Road Mobile	38,535	9,728	−75
Off-Road Mobile	76,637	49,677	−35
Oil & Gas	14,725	34,142	132
Road Dust	0	0	0
Fugitive Dust	0	0	0
Windblown Dust	0	0	0
Anthropogenic Fire	782	484	−38
Natural Fire	8,372	8,372	0
Biogenic	15,925	15,925	0
Total	287,974	248,100	−14

The State expects NO_X emissions to decrease by 14% by 2018, primarily due to significant reductions in mobile source emissions. The State projects that off-road and on-road vehicles emissions will decline by more than 55,760 tpy from the baseline 2002 emissions of 115,172 tpy.

OC

A wide variety of sources contribute emissions to this pollutant, including diesel emissions and combustion byproducts from wood and agricultural burning.

TABLE 31—WYOMING OC EMISSIONS—2002 AND 2018

Source category	Baseline 2002	Future 2018	Percent change
Point	646	990	53
Area	2,000	1,975	−1
On-Road Mobile	304	249	−18
Off-Road Mobile	625	411	−34
Oil & Gas	0	0	0
Road Dust	20	26	30
Fugitive Dust	96	133	39
Windblown Dust	0	0	0
Anthropogenic Fire	1,709	886	−48
Natural Fire	23,793	23,793	0
Biogenic	0	0	0
Total	29,193	28,463	−3

OC emissions from all sources are expected to show a 3% decline. Natural fire is the largest source contributing to OC emissions. The State does not have the ability to predict future emissions from natural fires and thus, the State held this category constant in the inventory.

EC

EC is a byproduct of incomplete combustion. EC emissions mainly come from mobile sources and natural fires.

TABLE 32—WYOMING EC EMISSIONS—2002 AND 2018

Source category	Baseline 2002	Future 2018	Percent change
Point	104	180	73
Area	304	335	10
On-Road Mobile	443	86	−81
Off-Road Mobile	1,986	1,161	−42
Oil & Gas	0	0	0
Road Dust	2	2	0
Fugitive Dust	7	9	29
Windblown Dust	0	0	0
Anthropogenic Fire	298	153	−49
Natural Fire	4,922	4,922	0
Biogenic	0	0	0
Total	8,066	6,848	−15

The State predicts EC emissions to decrease approximately 15% by 2018. Reductions in manmade emissions of EC are largely due to mobile sources emission reductions resulting from new federal emission standards for mobile sources, especially for diesel engines.

$PM_{2.5}$

$PM_{2.5}$ emissions come mainly from agricultural and mining activities, windblown dust from construction areas, and emissions from unpaved and paved roads.

TABLE 33—WYOMING $PM_{2.5}$ EMISSIONS—2002 AND 2018

Source category	Baseline 2002	Future 2018	Percent change
Point	11,375	15,709	38
Area	1,601	1,756	10
On-Road Mobile	0	0	0
Off-Road Mobile	0	0	0
Oil & Gas	0	0	0
Road Dust	160	206	29
Fugitive Dust	2,082	2,882	38
Windblown Dust	5,838	5,838	0
Anthropogenic Fire	242	129	−47
Natural Fire	1,535	1,535	0
Biogenic	0	0	0
Total	22,833	28,055	23

The State predicts emissions of $PM_{2.5}$ to increase 23% by 2018. Emission increases are related to population growth and an increase in vehicle miles traveled.

PM_{10}

PM_{10} emissions come from many of the same sources as $PM_{2.5}$ emissions but other activities like rock crushing and processing, material transfer, open pit mining, and unpaved road emissions also can be prominent sources.

TABLE 34—WYOMING PM_{10} EMISSIONS—2002 AND 2018

Source category	Baseline 2002	Future 2018	Percent change
Point	24,751	30,619	24
Area	409	653	60
On-Road Mobile	171	165	−4
Off-Road Mobile	0	0	0
Oil & Gas	0	0	0
Road Dust	1,125	1,449	29
Fugitive Dust	18,030	25,144	39
Windblown Dust	52,546	52,546	0
Anthro Fire	259	109	−58
Natural Fire	5,369	5,369	0

TABLE 34—WYOMING PM_{10} EMISSIONS—2002 AND 2018—Continued

Source category	Baseline 2002	Future 2018	Percent change
Biogenic	0	0	0
Total	102,660	116,054	13

Overall, PM_{10} emissions are expected to increase by 13%. increases in coarse PM emissions are linked to population growth and vehicle miles traveled.

NH_3

NH_3 emissions come from a variety of sources including wastewater treatment facilities, livestock operations, fertilizer application, mobile sources, and point sources.

TABLE 35—WYOMING NH_3 EMISSIONS—2002 AND 2018

Source category	Baseline 2002	Future 2018	Percent change
Point	685	1,398	104
Area	29,776	29,901	0
On-Road Mobile	538	724	35
Off-Road Mobile	41	57	39
Oil & Gas	0	0	0
Road Dust	0	0	0
Fugitive Dust	0	0	0
Windblown Dust	0	0	0
Anthropogenic Fire	218	119	−45
Natural Fire	1,775	1,775	0
Biogenic	0	0	0
Total	33,033	33,974	3

NH_3 emissions are expected to increase by 3% by 2018. Increases in NH_3 emissions are linked to population growth and increased vehicular traffic.

2. Consultation and Emissions Reductions for Other States' Class I Areas

40 CFR 51.308(d)(3)(i) requires that Wyoming consult with another state if its emissions are reasonably anticipated to contribute to visibility impairment at that state's Class I area(s), and that Wyoming consult with other states if those other states' emissions are reasonably anticipated to contribute to visibility impairment at its Class I areas. The State participated in regional planning, coordination, and consultation with other states in developing emission management strategies through the WRAP. Through the WRAP consultation process, Wyoming has reviewed and analyzed contributions from other states that reasonably may cause or contribute to visibility impairment in Wyoming's Class I areas and analyzed Wyoming's impact on other states' Class I areas.

40 CFR 51.308(d)(3)(ii) requires that if Wyoming emissions cause or contribute to impairment in another state's Class I area, Wyoming must demonstrate that it has included in its regional haze SIP all measures necessary to obtain its share of the emission reductions needed to meet the RPG for that Class I area. Section 51.308(d)(3)(ii) also requires that, since Wyoming participated in a regional planning process, it must ensure it has included all measures needed to achieve its apportionment of emission reduction obligations agreed upon through that process. As we state in the RHR, Wyoming's commitments to participate in WRAP bind it to secure emission reductions agreed to as a result of that process.

The State determined it did potentially impact Class I areas in South Dakota, Colorado, Utah, Idaho, Montana, and North Dakota (see Table 8.1.2.1–1 in the SIP). Wyoming accepted and incorporated the WRAP-developed visibility modeling into its regional haze SIP and the SIP includes the controls assumed in the modeling. Wyoming has satisfied the RHR requirements for consultation and included controls in the SIP sufficient to address the relevant requirements related to impacts on Class I areas in other states.

We are proposing to find that the State has met the requirements for consultation under 40 CFR 51.308(d)(3)(i) and 40 CFR 51.308(d)(3)(ii).

3. Mandatory Long-Term Strategy Requirements

40 CFR 51.308(d)(3)(v) requires that Wyoming, at a minimum, consider certain factors in developing its LTS. These are: (a) Emission reductions due to ongoing air pollution control programs, including measures to address RAVI; (b) measures to mitigate the impacts of construction activities; (c) emissions limitations and schedules for compliance to achieve the reasonable progress goals; (d) source retirement and replacement schedules; (e) smoke management techniques for agricultural and forestry management purposes including plans that currently exist within the state for these purposes; (f) enforceability of emissions limitations and control measures; and (g) the anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the LTS.

a. Reductions Due to Ongoing Air Pollution Programs

In addition to its BART and reasonable progress determinations, the State's LTS contains other reductions due to ongoing air pollution programs. The State's LTS contains numerous ongoing air pollution programs, including: (1) New Source Review Program, which is a permit program for the construction of new sources and the modification of existing sources; (2) Prevention of Significant Deterioration Program, which protects visibility from proposed major stationary sources or major modifications to existing facilities; and (3) New Source Performance Standards, which the State incorporates by reference on an annual basis. For a complete listing of ongoing air pollution programs in Wyoming, see Chapter 8.2.1 of the SIP.

b. Measures To Mitigate the Impacts of Construction Activities

Chapter 3 of the Wyoming Air Quality Standards and Regulations (WAQSR) establishes limits on the quantity or concentration of emissions of air pollutants from numerous sources, including construction activities. Specifically, WAQSR Chapter 3, Section 2(f), prescribes measures to ensure the control of fugitive dust emissions during construction or demolition activities. WAQSR Chapter 3, Section 2(f) requires any person engaged in clearing or leveling of land, earthmoving, excavation, or movement of trucks or construction equipment over access haul roads or cleared land to take steps to minimize fugitive dust from such activities. Such control measures may include frequent watering and/or chemical stabilization. EPA approved WAQSR Chapter 3 into the SIP on July 28, 2004 (69 FR 44965).

c. Smoke Management

WAQSR Chapter 10 establishes restrictions and requirements on different types of burning in Wyoming. WAQSR Chapter 10, Section 2 regulates open burning, including refuse burning, open burning of trade wastes, open burning at salvage operations, open burning for firefighting training, and small vegetative material open burning (not exceeding 0.25 tons per day of PM). WAQSR Chapter 10, Section 3 regulates emissions from wood waste burners. EPA approved WAQSR Chapter 10, Section 2 and 3 into the SIP on July 28, 2004 (69 FR 44965). WAQSR Chapter 10, Section 4 was adopted by the State and submitted to EPA to meet the requirements for programs related to fire under 40 CFR 51.309(d)(6). Chapter 10, Section 4 seeks to minimize the impacts from private and prescribed burning on visibility in Class I areas and potentially affected populations. EPA is proposing approval of Chapter 10, Section 4 in a separate action.

d. Emission Limitations and Schedules for Compliance

Chapter 6.5 of the State's SIP contains the emission limitations and schedules for compliance for BART sources. Chapter 6.5 of the SIP requires the BART sources to install and demonstrate compliance with the State's BART determination as expeditiously as practicable, but no later than five years after EPA approval of the SIP. For some sources where controls have already been installed, the State specifies an earlier compliance deadline in Chapter 6.5 of the SIP. In addition, Chapter 8.3.3 of the SIP contains the emission limits and compliance schedule for LTS controls on Jim Bridger Units 1–4.

e. Source Retirement and Replacement Schedules

The State is not currently aware of any specific scheduled shutdowns, retirements in upcoming years, or replacement schedules, such as planned installation of new control equipment to meet other regulations. If such actions occur, the State will factor them into upcoming reviews.

f. Enforceability of Wyoming's Measures

As discussed in section VII.D of this notice, EPA is proposing to disapprove the State's SIP because it contains inadequate monitoring, recordkeeping, and reporting requirements, and we are proposing a FIP to address the enforceability of BART and reasonable progress controls.

g. Anticipated Net Effect on Visibility Due to Projected Changes

The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions during this planning period is addressed in section VI.D.3 of this notice.

4. Our Conclusions on Wyoming's Long-Term Strategy

We propose to partially approve and partially disapprove Wyoming's LTS. Because we are proposing to disapprove the NO_X BART determinations for PacifiCorp Dave Johnston Unit 3 and Unit 4, PacifiCorp Naughton Units 1 and 2, PacifiCorp Wyodak Unit 1, and Basin Electric Laramie River Units 1, 2, and 3, we are also proposing to disapprove the corresponding emission limits and compliance schedules that Wyoming relied on as part of its LTS. Because we are proposing to disapprove the reasonable progress determination for PacifiCorp Dave Johnston Units 1 and 2, we are also proposing to disapprove the LTS because it does not include appropriate NO_X reasonable progress emission limits and compliance schedules for Dave Johnston Units 1 and 2. We are also proposing to disapprove the State's LTS because it does not contain the necessary monitoring, recordkeeping, and reporting requirements to make the BART and reasonable progress limits practically enforceable. Except for these elements, the State's LTS satisfies the requirements of 40 CFR 51.308(d)(3), and we are proposing to approve it.

F. Coordination of RAVI and Regional Haze Rule Requirements

Per 40 CFR 51.306(c), the State must provide for review and revision of a coordinated LTS for addressing RAVI and regional haze, and the State must submit the first such coordinated LTS with its first regional haze SIP. The State did not provide for the coordination of their RAVI and regional haze LTS. We are proposing to disapprove the State's SIP as not meeting the requirements of 40 CFR 51.306(c). We are proposing a FIP as explained in section VIII.F of this notice to meet the coordination requirements of 40 CFR 51.306(c).

G. Monitoring Strategy and Other Implementation Plan Requirements

40 CFR 51.308(d)(4) requires that the SIP contain a monitoring strategy for measuring, characterizing, and reporting regional haze visibility impairment that is representative of all mandatory Class I Federal areas within the state. This monitoring strategy must be coordinated with the monitoring strategy required in 40 CFR 51.305 for RAVI. As 40 CFR 51.308(d)(4) notes, compliance with this requirement may be met through participation in the IMPROVE network. 40 CFR 51.308(d)(4)(i) further requires the establishment of any additional monitoring sites or equipment needed to assess whether the RPGs for all mandatory Class I Federal areas within the state are being achieved.

Consistent with EPA's monitoring regulations for RAVI and regional haze, Wyoming states in Chapter 9 of the regional haze SIP that it will rely on the IMPROVE network for compliance purposes, in addition to any additional visibility impairment monitoring that may be needed in the future.

Section 51.308(d)(4)(ii) requires that states establish procedures by which monitoring data and other information are used in determining the contribution of emissions from within Wyoming to regional haze visibility impairment at mandatory Class I Federal areas both within and outside the state. The IMPROVE monitoring program is national in scope, and other states have similar monitoring and data reporting procedures, ensuring a consistent and robust monitoring data collection system. As 40 CFR 51.308(d)(4) indicates, Wyoming's participation in the IMPROVE program constitutes compliance with this requirement.

40 CFR 51.308(d)(4)(iv) requires that the SIP provide for the reporting of all visibility monitoring data to the Administrator, at least annually, for each mandatory Class I Federal area in the state. To the extent possible, Wyoming should report visibility monitoring data electronically. 40 CFR 51.308(d)(4)(vi) also requires that the SIP provide for other elements, including reporting, recordkeeping, and other measures, necessary to assess and report on visibility. We propose that Wyoming's participation in the IMPROVE network ensures that the monitoring data is reported at least annually and is easily accessible; therefore, such participation complies with this requirement. IMPROVE data are centrally compiled and made available to EPA, states and the public via various electronic formats and Web sites including IMPROVE (*http://vista.cira.colostate.edu/improve/*) and VIEWS (*http://vista.cira.colostate.edu/views/*).

40 CFR 51.308(d)(4)(v) requires that Wyoming maintain a statewide inventory of emissions of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I Federal area. The inventory must include emissions for a baseline year, emissions for the most recent year for which data are available, and estimates of future projected emissions. The State must also include a commitment to update the inventory periodically. The State's emission inventory is discussed in section VI.F.1 of this notice. Wyoming states in Chapter 9 of the SIP that it intends to update the Wyoming statewide emissions inventories periodically and review periodic emissions information from other states and future emissions projections. We propose that this satisfies the requirement.

40 CFR 51.308(d)(4)(vi) requires that states provide for any additional reporting, recordkeeping, and measures necessary to evaluate and report on visibility. The State of Wyoming, in accordance with provisions of 40 CFR 51.308(d)(4)(vi), will track data related to regional haze for sources for which the State has regulatory authority, and will depend on the IMPROVE program and RPO sponsored collection and analysis efforts for monitoring and emissions inventory data, respectively. To ensure the availability of data and analyses to report on visibility conditions and progress toward Class I area visibility goals, the State of Wyoming will collaborate with members of a RPO to ensure the continued operation of the IMPROVE program and RPO sponsored technical support analysis tools and systems.

We propose to find that the State's SIP satisfies the requirements of 40 CFR 51.308(d)(4).

H. Consultation With FLMs

Although the FLMs are very active in participating in the RPOs, the RHR grants the FLMs a special role in the review of the regional haze SIPs, summarized in section V.H above. Under 40 CFR 51.308(i)(2), states are obligated to provide the FLMs with an opportunity for consultation, in person, and at least 60 days prior to holding a public hearing on the regional haze SIP. The State provided an opportunity for FLM consultation, in person and at least 60 days prior to holding any public hearing on the SIP. As required by 40 CFR Section 51.308(i)(3), the State has included FLM comments and State responses in Chapter 11 of the Wyoming TSD.

40 CFR 51.308(i)(3) requires that states provide in its regional haze SIP a description of how it addressed any comments provided by the FLMs. The FLMs formally commented on the Wyoming proposed SIP in November and December of 2010. The FLM comments provided support for the modeling approach used by the State in the BART determinations and complimented the State on thorough BART, reasonable progress, and area source analysis. The FLMs also recommended the State reevaluate costs and emission limits for some of the BART and reasonable progress sources. Chapter 11 of the State's TSD provides detailed information on the State's response to FLM comments.

Lastly, 40 CFR 51.308(i)(4) specifies the regional haze SIP must provide procedures for continuing consultation between a state and FLMs on the implementation of the visibility protection program required by 40 CFR 51.308. This includes development and review of implementation plan revisions and five-year progress reports and the implementation of other programs having the potential to contribute to impairment of visibility in mandatory Class I Federal areas. Pursuant to Chapter 11.2 of the SIP, the State will provide the FLMs an opportunity to review and comment on SIP revisions, the five-year progress reports, and other developing programs that may contribute to Class I visibility impairment.

We are proposing that the State's SIP satisfies the requirements of 40 CFR 51.308(i).

I. Periodic SIP Revisions and 5-Year Progress Reports

40 CFR 51.308(f) requires a state to revise and submit its regional haze SIP to EPA by July 31, 2018, and every ten years thereafter. Pursuant to Chapter 10 of the SIP, the State will provide this revision. In accordance with the requirements listed in 40 CFR 51.308(g), the State will submit a report on reasonable progress to EPA every five years following the initial submittal of the SIP. That report will be in the form of an implementation plan revision. The State's report will evaluate the progress made towards the RPGs for each mandatory Class I area located within the State and in each mandatory Class I area located outside the State, which have been identified as being affected by emissions from the State. The State will also evaluate the monitoring strategy adequacy in assessing RPGs.

Based on the findings of the five-year progress report, 40 CFR 51.308(h) requires a state to make a determination of adequacy of the current implementation plan. The State must take one or more of the actions listed in 40 CFR 51. 308(h)(1) through (4) that are applicable at the same time as the state submits a five-year progress report. Chapter 12 of the SIP requires the State to make an adequacy determination of the current SIP pursuant to 40 CFR 51.308(h)(1) through (4) at the same time a five-year progress report is due.

We propose to find the State's SIP satisfies the requirements of 40 CFR 51.308(f)–(h).

VIII. Federal Implementation Plan

EPA is proposing a FIP to address the deficiencies indentified in our proposed partial disapproval of Wyoming's regional haze SIP. In lieu of our proposed FIP, or a portion thereof, we will propose approval of a SIP revision as expeditiously as practicable if the State submits such a revision and the revision matches the terms of our proposed FIP. We will also review and take action on any regional haze SIP submitted by the state to determine whether such SIP is approvable, regardless of whether or not its terms match those of the FIP. We encourage the State to submit a SIP revision to replace the FIP, either before or after our final action.

A. Disapproval of the State's NO_X BART Determinations and Federal Implementation Plan for NO_X BART Determinations and Limits

As noted above, the State provided five-factor analyses that considered all factors, but we find that its consideration of the costs of compliance and visibility improvement was inconsistent with regulatory and statutory requirements. In disapproving specific State BART determinations in our proposed rulemaking notice on June 4, 2012, we based our analysis on information provided by the State in their BART analyses, with the exception of visibility improvement modeling, and thus accepted the cost information provided by the State. In this proposed rulemaking, in addition to the other BART information in the State SIP submittal, we are basing our proposed BART determinations on cost analyses and visibility improvement modeling developed by EPA, as explained in section VII.C of this notice. EPA is proposing to disapprove the State's NO_X BART determinations, and we are proposing to issue a BART FIP, for the following units: PacifiCorp Dave Johnston Unit 3 and Unit 4, PacifiCorp Naughton Unit 1 and Unit 2, PacifiCorp Wyodak Unit 1, and Basin Electric Laramie River Units 1, 2, and 3. EPA's rationale for disapproving the State's BART determinations for these units, as well as EPA's BART FIP determinations and emission limits, are discussed below.

We are also asking if interested parties have additional information or comments regarding the BART factors and EPA's proposed determinations, for example our weighing of average costs, incremental costs, visibility improvement, and timing of installation of such controls, and in light of such information, whether the interested parties think the Agency should consider another BART control technology option that could be finalized either instead of, or in conjunction with, BART as proposed. The Agency is also asking if interested parties have additional information or comments on the proposed timing of compliance when the challenge of coordinating the work our proposed SIP and FIP will require is considered.

The Agency will take the comments and testimony received, as well as any further SIP revisions submitted by the State, into consideration in our final promulgation. Supplemental information received may lead the Agency to adopt final SIP and/or FIP regulations that reflect a different BART control technology option, or impact other proposed regulatory provisions, which differ from this proposal.

1. Disapproval of the State's Basin Electric Laramie River Units 1–3 NO_X BART Determination and FIP to Address NO_X BART

Wyoming's NO_X BART Determination

During the 2001–2003 baseline, Basin Electric Laramie River Units 1–3 were all controlled with LNBs with a permit limit of 0.5 lbs/MMBtu (3-hour rolling average). The State determined that new LNBs, OFA, new LNBs and OFA, new SNCR/SCR hybrid [50], new LNBs and OFA with SNCR, and SCR were technically feasible for reducing NO_X emissions at Units 1–3. The State determined that natural gas re-burn was technically infeasible. The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, and there are no remaining-useful-life issues for this source. A summary of the State's NO_X BART analysis is provided in Tables 36–38 below. As discussed above, the visibility improvement modeling results in these tables were developed by EPA because Wyoming did not properly follow the BART Guidelines. Baseline NO_X emissions are 6,320 tpy for Unit 1, 6,285 tpy for Unit 2, and 6,448 tpy for Unit 3 based on annual average heat input for 2001–2003 and an emission rate of 0.27 lb/MMBtu.

TABLE 36—SUMMARY OF WYOMING'S BASIN ELECTRIC LARAMIE RIVER UNIT 1 NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (30-day rolling average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Wind Cave National Park) EPA analysis
OFA	0.23	936	$625,000	$668		0.08
New LNBs	0.23	936	1,360,000	1,453		0.08
New LNBs with OFA	0.23	936	1,944,000	2,077		0.08
SNCR/SCR Hybrid	0.20	1,639	7,429,000	4,534		
New LNBs with OFA and SNCR	0.12	3,511	7,365,000	2,098	$2,105	0.32
SCR	0.07	4,681	15,787,000	3,372	7,198	0.44

TABLE 37—SUMMARY OF WYOMING'S BASIN ELECTRIC LARAMIE RIVER UNIT 2 NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (30-day rolling average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Wind Cave National Park) EPA analysis
OFA	0.23	931	$625,000	$671		0.08

[50] A hybrid SNCR/SCR system combines the lower costs and higher ammonia slip of SNCR with the higher NOx reduction potential and lower ammonia slip of SCR. During operation, the SNCR system is allowed to inject higher amounts of reagent into the flue gas. The increased reagent flow brings about increased NOx reduction, but also causes increased ammonia slip which is then consumed by the SCR system. The use of the ammonia slip by the SCR system can reduce the size of the required SCR catalyst.

TABLE 37—SUMMARY OF WYOMING'S BASIN ELECTRIC LARAMIE RIVER UNIT 2 NO_X BART ANALYSIS—Continued

Control technology	Emission rate (lb/MMBtu) (30-day rolling average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Wind Cave National Park) EPA analysis
New LNBs	0.23	931	$1,360,000	$1,461	....	0.08
New LNBs with OFA	0.23	931	1,944,000	2,088	....	0.08
SNCR/SCR Hybrid	0.20	1,630	7,429,000	4,559	....	....
New LNBs with OFA and SNCR	0.12	3,492	7,365,000	2,109	$2,117	0.32
SCR	0.07	4,656	15,787,000	3,391	7,242	0.44

TABLE 38—SUMMARY OF WYOMING'S BASIN ELECTRIC LARAMIE RIVER UNIT 3 NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (30-day rolling average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Wind Cave National Park) EPA analysis
OFA	0.23	955	$625,000	$654	....	0.08
New LNBs	0.23	955	1,360,000	1,424	....	0.08
New LNBs with OFA	0.23	955	1,944,000	2,036	....	0.08
SNCR/SCR Hybrid	0.20	1,672	7,429,000	4,444	....	....
New LNBs with OFA and SNCR	0.12	3,582	7,365,000	2,056	$2,064	0.33
SCR	0.07	4,777	15,787,000	3,305	7,054	0.44

The State eliminated the SNCR/SCR hybrid from further consideration because it has higher cost-effectiveness values and lower control efficiency compared to new LNBs plus OFA with SNCR.

Based on its consideration of the five factors, the State determined that new LNBs with OFA were reasonable for NO_X BART. The State determined that the NO_X BART emission limit for Laramie River Unit 1 is 0.23 lb/MMBtu (30-day rolling average). The State determined that the NO_X BART emission limit for Laramie River Unit 2 is 0.23 lb/MMBtu (30-day rolling average). The State determined that the NO_X BART emission limit for Laramie River Unit 3 is 0.23 lb/MMBtu (30-day rolling average).

The State's proposed SIP required additional NO_X emission reductions for Laramie River under its LTS. Based on the costs and visibility improvement for Laramie River Station Units 1, 2, and 3, the State proposed installation of two SCRs, or equivalent performing emission control systems, at any of the three units. The State proposed that the add-on NO_X control achieve an emission rate, on an individual unit basis, at or below 0.07 lb/MMBtu on a 30-day rolling average. The State proposed that the add-on controls be installed and operational on one of the Laramie River Station units by December 31, 2018 and on a second Laramie River Station unit by December 31, 2023.

On March 8, 2010, Basin Electric Power Cooperative appealed the additional controls proposed by the State under its LTS before the Wyoming Environmental Quality Council. The State entered into a settlement agreement on November 16, 2010 with Basin Electric Power Cooperative (a copy of the settlement agreement is included in the State's revised NO_X BART Analysis for Laramie River dated January 3, 2011). As part of the settlement agreement, the State agreed to remove the requirement for Basin Electric to install additional controls under the LTS. In return, Basin Electric agreed to additional NO_X emissions reductions under BART. Under the settlement agreement, Basin Electric agreed to a NO_X emission limit of 0.21 lb/MMBtu (30-day rolling average) on all three units. Basin Electric also agreed to a NO_X emission limit for Unit 1 and Unit 2 of 4,780 tpy and a NO_X emission limit for Unit 3 of 4,914 tpy, effectively capping emissions from all three units at 12,773 tpy. In the SIP adopted by the State, the State determined the emission limits in the settlement agreement were BART for Basin Electric Laramie River Units 1, 2, and 3.

EPA's Basin Electric Laramie River Units 1–3 NO_X BART Determination and FIP for NO_X BART

The EPA agrees with the State's analysis pertaining to energy or non-air quality environmental impacts and remaining-useful-life for this source. However, EPA disagrees with the State's baseline NO_X emissions estimates, as listed above, because the State based its estimate on annual average heat input for 2001–2003 at an emission rate of 0.07 lb/MMBtu and not actual annual averages. EPA's revised baseline NO_X emissions are 6,051 tpy for Unit 1, 6,293 tpy for Unit 2, and 6,375 tpy for Unit 3 based on the actual annual average for the years 2001–2003. A summary of the EPA's NO_X BART analysis and the visibility impacts is provided in Tables 39–44 below.

TABLE 39—SUMMARY OF EPA'S LARAMIE RIVER UNIT 1 NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (annual average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Badlands)
New LNBs with OFA	0.19	1,556	$2,268,806	$1,458		0.29
New LNBs with OFA and SNCR	0.15	2,445	5,880,822	2,395	$4,018	0.44
New LNBs with OFA and SCR	0.05	4,880	18,146,629	3,718	5,057	0.79

Laramie River Unit 1 also impacts other Class I areas. The visibility improvement modeled by EPA at other Class I areas is shown in Table 40 below.

TABLE 40—LARAMIE RIVER UNIT 1: VISIBILITY IMPROVEMENT AT OTHER CLASS I AREAS

Class I area	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + OFA	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + OFA/SNCR	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + OFA/SCR
Wind Cave	0.20	0.30	0.64
Rawah	0.10	0.16	0.32
Rocky Mountain	0.12	0.19	0.37

TABLE 41—SUMMARY OF EPA'S LARAMIE RIVER UNIT 2 NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (annual average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Badlands)
New LNBs with OFA	0.19	1823	$2,268,806	$1,244		0.30
New LNBs with OFA and SNCR	0.15	2,717	5,884,257	2,166	$4,044	0.42
New LNBs with OFA and SCR	0.05	5,129	20,017,988	3,903	5,860	0.73

Laramie River Unit 2 also impacts other Class I areas. The visibility improvement modeled by EPA at other Class I areas is shown in Table 42 below.

TABLE 42—LARAMIE RIVER UNIT 2: VISIBILITY IMPROVEMENT AT OTHER CLASS I AREAS

Class I area	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + OFA	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + OFA/SNCR	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + OFA/SCR
Wind Cave	0.24	0.36	0.66
Rawah	0.10	0.16	0.29
Rocky Mountain	0.13	0.19	0.35

TABLE 43—SUMMARY OF EPA'S LARAMIE RIVER UNIT 3 NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (annual average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Badlands)
New LNBs with OFA	0.19	1789	$2,268,806	$1,268		0.22
New LNBs with OFA and SNCR	0.15	2,706	5,933,791	2,192	$3,996	0.33
New LNBs with OFA and SCR	0.05	5,181	18,597,027	3,589	5,117	0.67

Laramie River Unit 3 also impacts other Class I areas. The visibility improvement modeled by EPA at other Class I areas is shown in Table 44 below.

TABLE 44—LARAMIE RIVER UNIT 3: VISIBILITY IMPROVEMENT AT OTHER CLASS I AREAS

Class I area	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + OFA	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + OFA/SNCR	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + OFA/SCR
Wind Cave	0.20	0.31	0.60
Rawah	0.10	0.15	0.29
Rocky Mountain	0.12	0.18	0.34

As noted above, under the settlement agreement terms incorporated into the SIP, Basin Electric agreed to a NO_X emission limit of 0.21 lb/MMBtu (30-day rolling average) on all three units, and thus eliminated other control options. We propose to find that Wyoming did not properly follow the requirements of the BART Guidelines in determining NO_X BART for these units.

Furthermore, as discussed in detail above, because Wyoming relied on visibility modeling methodologies that are inconsistent with the statutory and regulatory requirements, we do not consider Wyoming's analyses of visibility improvement for the NO_X BART to be reasonable for the Laramie units. We propose to find that Wyoming's analyses for these units are inconsistent with the statutory and regulatory requirement that ''the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.''

Therefore, EPA does not agree with the State's conclusion that a limit of 0.21 lb/MMBtu is consistent with the BART Guidelines and reasonable for BART for Laramie River Units 1, 2, and 3, which can be achieved with the installation and operation of new LNBs with OFA. Specifically, we propose to find that in negotiating the emission limit, Wyoming did not properly or reasonably ''take into consideration the costs of compliance.'' Thus, the State's BART analyses for Basin Electric Laramie River Units 1, 2, and 3 do not meet the requirements of the regional haze regulation, and we are proposing to disapprove those analyses and the State's NO_X BART determination. We are proposing a FIP for NO_X BART to fill the gap left by our disapproval, as explained below.

Our analysis follows our BART Guidelines. Because the Basin Electric Laramie River Units 1, 2, and 3 are similar, we are proposing a single BART analysis and determination that applies to each unit. With the exception of the NO_X emission limits, the visibility improvement analyses, and the cost-effectiveness analyses, EPA is proposing to find that the Wyoming regional haze NO_X BART analyses for Units 1, 2 and 3, fulfills all the relevant requirements of CAA Section 169A and the RHR. As discussed above in section VII.C.3.b., Wyoming's visibility improvement analyses for these units is inconsistent with the requirements found in the CAA and BART Guidelines. Furthermore, we are not relying on the State's costs due to the reasons described in section VII.C.3.a above.

In addition, the cost-effectiveness for new LNBs with OFA and SCR ranges from approximately $3,600/ton to $3,900/ton with significant visibility improvement at the most impacted Class I area of 0.79 dv for Unit 1, 0.73 dv for Unit 2, and 0.67 dv for Unit 3. SCR provides significant visibility improvement at other impacted Class I areas, with cumulative visibility improvements of 2.12 dv for Unit 1, 1.97 dv for Unit 2, and 2.29 dv for Unit 3. When considering the cost effectiveness and visibility improvement of new LNBs plus OFA and SCR, it is within the range of what EPA has found reasonable for BART in other SIP and FIP actions. We also propose to find that the incremental cost-effectiveness does not preclude the selection of new LNBs with OFA and SCR.

EPA's NO_X BART analyses and the visibility impacts for Units 1, 2 and 3 is summarized in Tables 39–44 above and detailed information can be found in the docket.[51] We propose to find that at an emission limit of 0.07 lb/MMBtu (30-day rolling average), which can be achieved by the installation of new LNBs with OFA plus SCR, is reasonable and consistent with the CAA and BART Guideline requirements for NO_X BART for Basin Electric Laramie River Units 1, 2, and 3. Consequently, we are proposing that the FIP NO_X BART emission limit for Basin Electric Laramie River Unit 1, Unit 2, and Unit

[51] Detailed supporting information for our cost and visibility improvement analyses can be found in the Docket (see Staudt memos and *EPA BART and RP Modeling for Wyoming,* respectively).

3 is 0.07 lb/MMBtu (30-day rolling average).

We propose that Basin Electric meet our proposed emission limit at Laramie River Units 1, 2, and 3, as expeditiously as practicable, but no later than five years after EPA finalizes action on our proposed FIP. This is consistent with the requirements of 40 CFR 51.308(e)(iv).

We are also asking if interested parties have additional information regarding the BART factors and EPA's proposed determination, for example our weighing of average costs, incremental costs, visibility improvement, and timing of installation of such controls, and in light of such information, whether the interested parties think the Agency should consider another BART control technology option that could be finalized either instead of, or in conjunction with, BART as proposed. The Agency will take the comments and testimony received, as well as any further SIP revisions submitted by the State, into consideration in our final promulgation. Supplemental information received may lead the Agency to adopt final SIP and/or FIP regulations that reflect a different BART control technology option, or impact other proposed regulatory provisions, which differ from this proposal.

2. Disapproval of the State's PacifiCorp Dave Johnston Unit 3 and Unit 4 NO_X BART Determinations and FIP To Address NO_X BART

Wyoming's NO_X BART Determination for Dave Johnston Unit 3

During the baseline period of 2001–2003, Dave Johnston Unit 3 was uncontrolled for NO_X and had emission limits of 0.75 lb/MMbtu (3-hour rolling) and 0.59 lb/MMbtu (annual). The State determined LNBs with advanced OFA, LNBs with advanced OFA and SNCR, and LNBs with advanced OFA and SCR were technically feasible for controlling NO_X emissions from Unit 3. The State did not identify any technically infeasible controls.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, and there are no remaining-useful-life issues for this source. Baseline NO_X emissions are 5,814 tpy for Unit 3 based on unit heat input rate of 2,500 MMBtu/hr and 7,884 hours of operation. A summary of the State's NO_X BART analysis and the visibility impacts is provided in Table 45 below. As discussed above, the visibility improvement modeling results in these tables were developed by EPA because Wyoming did not properly follow the BART Guidelines.

TABLE 45—SUMMARY OF WYOMING'S DAVE JOHNSTON UNIT 3 NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (30-day rolling average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta deciview for the maximum 98th percentile impact at Wind Cave National Park) EPA analysis
LNB with advanced OFA	0.28	2,723	$1,764,775	$648	....	0.77
LNB with advanced OFA and SNCR	0.19	3,717	2,679,192	721	$920	0.94
LNB with advanced OFA and SCR	0.07	5,041	16,347,519	3,243	10,234	1.16

Based on its consideration of the five factors, the State determined LNBs with OFA were reasonable for NO_X BART. The State determined the cost of compliance (capital costs and annual operating and maintenance costs) were significantly higher for the addition of SCR. The State determined that the NO_X BART emission limit for Unit 3 is 0.28 lb/MMBtu (30-day rolling average).

EPA's Conclusions on Dave Johnston Unit 3 NO_X BART Determination and Proposed FIP for NO_X BART

The EPA agrees with the State's analysis pertaining to energy or non-air quality environmental impacts and remaining-useful-life for this source. We disagree with the State's estimate of baseline NO_X emissions (5,814 tpy) because it is based on a unit heat input rate of 2,500 MMBtu/hr and 7,884 hours of operation rather than an average of actual annual emissions. EPA finds that baseline NO_X emissions are 4,913 tpy for Unit 3 based on the actual annual average for the years 2001–2003. A summary of the EPA's NO_X BART analysis and the visibility impacts is provided in Tables 46 and 47 below.

TABLE 46—SUMMARY OF EPA'S DAVE JOHNSTON UNIT 3 NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (annual average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Wind Cave National Park)
LNBs with OFA	0.22	2,837	$1,699,807	$599	....	0.64
LNBs with OFA and SNCR	0.16	3,356	3,545,435	1,057	$3,555	0.76
LNBs with OFA and SCR	0.05	4,433	11,262,188	2,540	7,163	1.00

Dave Johnston Unit 3 also impacts other Class I areas. The visibility improvement modeled by EPA at other Class I areas is shown in Table 47 below.

TABLE 47—DAVE JOHNSTON UNIT 3: VISIBILITY IMPROVEMENT MODELED AT OTHER CLASS I AREAS

Class I area	Visibility improvement (delta dv for the maximum 98th percentile impact) – LNBs + OFA	Visibility improvement (delta dv for the maximum 98th percentile impact) – LNBs + OFA/SNCR	Visibility improvement (delta dv for the maximum 98th percentile impact) – LNBs + OFA/SCR
Badlands	0.44	0.52	0.67
Mt. Zirkel	0.21	0.25	0.33
Rawah	0.24	0.29	0.38
Rocky Mountain	0.34	0.41	0.54

EPA does not agree with the State's conclusion that a limit of 0.28 lb/MMBtu, which can be achieved with the installation and operation of LNBs with OFA, is reasonable for NO_X BART for Dave Johnston Unit 3. We propose to find that Wyoming did not properly follow the requirements of the BART Guidelines in determining NO_X BART for this unit. Specifically, we propose to find that Wyoming did not properly or reasonably conduct certain requirements of the BART analysis.

As discussed in detail above, because Wyoming relied on visibility modeling methodologies that are inconsistent with the statutory and regulatory requirements, we do not consider Wyoming's analysis of visibility improvement for the NO_X BART to be reasonable for Dave Johnston Unit 3. We propose to find that Wyoming's analysis for this Unit is inconsistent with the statutory and regulatory requirement that ''the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.''

Also, we are not relying on the State's costs due to reasons stated in section VII.C.3.a. We propose to find that Wyoming did not properly or reasonably ''take into consideration the costs of compliance.'' Thus, the State's BART analysis for Dave Johnson Unit 3 does not meet the requirements of the CAA and the RHR, and we are proposing to disapprove the analysis and the State's NO_X BART determination. We are proposing a FIP for NO_X BART to fill the gap left by our disapproval, as explained below.

Our analysis follows our BART Guidelines. With the exception of the NO_X emission limits, the visibility improvement analyses, and the cost analyses, EPA is proposing to find that the Wyoming regional haze NO_X BART analysis for Dave Johnson Units 3 fulfills all the relevant requirements of CAA Section 169A and the Regional Haze Rule. As discussed above, Wyoming's visibility improvement analyses for these units is inconsistent with the requirements found in the BART Guidelines.

EPA's NO_X BART analysis and the visibility impacts for Dave Johnson Units 3 are summarized in Tables 46–47 above and detailed information can be found in the docket.[52] The cost-effectiveness for LNB with OFA and SCR at this unit is $2,540, with visibility improvement at the most impacted Class I area of 1.00 dv. SCR provides significant visibility improvement at other impacted Class I areas, with cumulative visibility improvements of 2.92 dv. We do not find that the incremental cost-effectiveness for LNBs with OFA and SCR precludes the selection of this technology for BART. The cost-effectiveness and visibility improvement are within the range that Wyoming in its SIP and EPA in other SIP and FIP actions have considered reasonable in the BART context.

Based on our examination of the cost estimates and the predicted visibility improvement (along with a consideration of the other BART factors), we propose to find that LNBs with OFA plus SCR at an emission limit of 0.07 lb/MMBtu (30-day rolling average) is reasonable and consistent with the CAA and BART Guideline requirements for NO_X BART for Dave Johnston Unit 3. We are proposing that the FIP NO_X BART emission limit for PacifiCorp Dave Johnston Unit 3 is 0.07 lb/MMBtu (30-day rolling average).

We propose that PacifiCorp meet our proposed emission limit at Dave Johnston Unit, as expeditiously as practicable, but no later than five years after EPA finalizes action on our proposed FIP, consistent with the requirements of 40 CFR 51.308(e)(iv).

We are also asking if interested parties have additional information regarding the BART factors and EPA's proposed determination, for example our weighing of average costs, incremental costs, visibility improvement, and timing of installation of such controls, and in light of such information, whether the interested parties think the Agency should consider another BART control technology option that could be finalized either instead of, or in conjunction with, BART as proposed. The Agency will take the comments and testimony received, as well as any further SIP revisions submitted by the State, into consideration in our final promulgation. Supplemental information received may lead the Agency to adopt final SIP and/or FIP regulations that reflect a different BART control technology option, or impact other proposed regulatory provisions, which differ from this proposal.

Wyoming's NO_X BART Determination for Dave Johnston Unit 4

Unit 4 is currently controlled with LNBs that were placed in operation in 1976. The State determined new LNBs with advanced OFA, new LNBs with advanced OFA and SNCR, and new LNBs with advanced OFA and SCR were technically feasible for controlling NO_X emissions for Unit 4. The State did not identify any technically infeasible controls.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, and there are no remaining-useful-life issues for this source. Baseline NO_X emissions are 8,566 tpy for Unit 4 based on unit heat input rate of 2,500 MMBtu/hr and 7,884 hours of operation. A summary of the State's NO_X BART analysis and the visibility impacts is provided in Table 48 below. As discussed above, the visibility improvement modeling results in these tables were developed by EPA because Wyoming did not properly follow the BART Guidelines.

[52] Detailed supporting information for our cost and visibility improvement analyses can be found in the Docket (see Staudt memos and *EPA BART and RP Modeling for Wyoming,* respectively).

TABLE 48—SUMMARY OF WYOMING'S DAVE JOHNSTON UNIT 4 NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (30-day rolling average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta deciview for the maximum 98th percentile impact at Wind Cave National Park) EPA analysis
New LNB with advanced OFA	0.15	6,142	$841,527	$137	....	0.71
New LNB with advanced OFA and SNCR	0.12	6,626	2,141,786	323	$2,686	0.80
New LNB with advanced OFA and SCR	0.07	7,435	16,430,528	2,210	17,662	0.97

Based on its consideration of the five factors, the State determined new LNBs with advanced OFA was reasonable for NO_X BART for Dave Johnston Unit 4. The State determined the NO_X BART emission limit for Unit 4 is 0.15 lb/MMBtu (30-day rolling average).

EPA's Conclusions on Dave Johnston Unit 4 NO_X BART Determination and FIP for NO_X BART

The EPA agrees with the State's analysis pertaining to energy or non-air quality environmental impacts and remaining-useful-life for this source. We disagree with the State's estimate of baseline NO_X emissions (8,566 tpy) because it is based on a unit heat input rate of 2,500 MMBtu/hr and 7,884 hours of operation rather than an average of actual annual emissions. EPA finds that baseline NO_X emissions are 5,070 tpy for Unit 4 based on the actual annual average for the years 2001–2003. A summary of the EPA's NO_X BART analysis and the visibility impacts is provided in Tables 49 and 50 below.

TABLE 49—SUMMARY OF EPA'S DAVE JOHNSTON UNIT 4 NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (annual average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Wind Cave National Park)
New LNBs with OFA	0.14	3,114	$767,342	$246	....	0.84
New LNBs with OFA and SNCR	0.11	3,505	2,592,288	740	$4,665	0.95
New LNBs with OFA and SCR	0.05	4,377	13,021,894	2,975	11,951	1.2

Dave Johnston Unit 4 also impacts other Class I areas. The visibility improvement EPA modeled at other Class I areas is shown in Table 50 below.

TABLE 50—DAVE JOHNSTON UNIT 4: VISIBILITY IMPROVEMENT MODELED AT OTHER CLASS I AREAS

Class I area	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + OFA	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + OFA/SNCR	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + OFA/SCR
Badlands	0.54	0.57	0.73
Mt. Zirkel	0.28	0.32	0.37
Rawah	0.29	0.32	0.39
Rocky Mountain	0.45	0.51	0.63

EPA does not agree with the State's conclusion that a limit of 0.15 lb/MMBtu, which can be achieved with the installation and operation on new LNBs with OFA, is reasonable for NO_X BART for Dave Johnston Unit 4. We propose to find that Wyoming did not properly follow the requirements of the BART Guidelines in determining NO_X BART for this unit. Specifically, we propose to find that Wyoming did not properly or reasonably conduct certain requirements of the BART analysis.

As discussed in detail above, because Wyoming relied on visibility modeling methodologies that are inconsistent with the statutory and regulatory requirements, we do not consider Wyoming's analysis of visibility improvement for the NO_X BART to be reasonable for Dave Johnston Unit 4. We propose to find that Wyoming's analysis for this Unit is inconsistent with the statutory and regulatory requirement that ''the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.''

Also, we are not relying on the State's costs due to reasons stated in section VII.C.3.b. We propose to find that Wyoming did not properly or reasonably ''take into consideration the costs of compliance.'' Thus, the State's BART analysis for Dave Johnson Unit 4 does not meet the requirements of the regional haze regulation, and we are proposing to disapprove the analysis and the State's NO_X BART determination. We are proposing a FIP for NO_X BART to fill the gap left by our disapproval, as explained below.

Our analysis follows our BART Guidelines. With the exception of the NO_X emission limits, the visibility improvement analyses, and the cost-effectiveness analyses, EPA is proposing to find that the Wyoming RH BART analysis of NO_X for Dave Johnson Units 4 fulfills all the relevant requirements of CAA Section 169A and the RHR. As discussed above, Wyoming's visibility improvement analyses for these units are inconsistent with the requirements found in the BART Guidelines.

EPA's NO_X BART analysis and the visibility impacts for Dave Johnson Unit 4 are summarized in Tables 49–50 above and detailed information can be found in the docket.[53] Additionally, the cost effectiveness and visibility improvement are within the range that Wyoming in its SIP and EPA in other SIP and FIP actions have considered reasonable and consistent with the BART Guidelines.

Based on our examination of the cost estimates and the predicted visibility improvement (along with a consideration of the other BART factors), we propose to find that new LNBs with OFA plus SNCR at an emission limit of 0.12 lb/MMBtu (30-day rolling average) is reasonable and consistent with the CAA and BART Guideline requirements for NO_X BART for Dave Johnston Unit 4. We are proposing that the FIP NO_X BART emission limit for PacifiCorp Dave Johnston Unit 4 is 0.12 lb/MMBtu (30-day rolling average).

We propose to eliminate the higher performing control option (i.e., new LNBs with advanced OFA plus SCR) because, although the average cost effectiveness and visibility improvement for SCR are within the range EPA has found reasonable in other SIP or FIP actions, we find that the incremental cost of SCR at $11,951/ton is high enough so that it precludes the selection of SCR.

We propose that PacifiCorp meet our proposed emission limit at Dave Johnston Unit 4, as expeditiously as practicable, but no later than five years after EPA finalizes action on our proposed FIP. This is consistent with the requirements of 40 CFR 51.308(e)(iv).

We are also asking if interested parties have additional information regarding the BART factors and EPA's proposed determination, for example our weighing of average costs, incremental costs, visibility improvement, and timing of installation of such controls, and in light of such information, whether the interested parties think the Agency should consider another BART control technology option that could be finalized either instead of, or in conjunction with, BART as proposed. The Agency will take the comments and testimony received, as well as any further SIP revisions submitted by the State, into consideration in our final promulgation. Supplemental information received may lead the Agency to adopt final SIP and/or FIP regulations that reflect a different BART control technology option, or impact other proposed regulatory provisions, which differ from this proposal.

3. Proposal in the Alternative for PacifiCorp Jim Bridger Units 1 and 2 NO_X BART

As noted above, EPA is seeking comment on a proposal (''first proposed approach'') to approve the regional haze plan submitted by the State for Jim Bridger Unit 1 and Unit 2. EPA also is seeking comment on another alternative approach (''second proposed approach'') that would determine that BART for Units 1 and 2 at Jim Bridger power plant is SCR, and would establish corresponding NO_X emission limits for these units that would have to be achieved within five years of our final action. This would have the effect of accelerating the installation of the SCR controls at these units that the State and source owner (PacifiCorp) had proposed to install later (in the 2021–2022 time-period). The State determined that BART for these units is LNB plus OFA, and selected the 2021–2022 time-period for SCR-based emission limits as a reasonable progress measure. The timeframe was based on the large number of actions PacifiCorp is undertaking (or helping to finance) at a large number of EGUs in Wyoming, Utah, Colorado, and Arizona that it owns and operates or co-owns.

Under our second proposed approach, EPA would propose that it does not agree with the State's conclusion that a limit of 0.26 lb/MMBtu is reasonable for BART for Jim Bridger Units 1 and 2, which can be achieved with the installation and operation on LNBs with OFA. In particular, the cost-effectiveness values that EPA calculated for LNBs with OFA and SCR at Unit 1 is $2,393 with a 0.96 deciview visibility improvement at the most impacted Class I area. The cost-effectiveness values that EPA calculated for LNBs with SOFA and SCR at Unit 2 is $2,492, with a 0.95 deciview visibility improvement at the most impacted Class I area. Under this approach, EPA would propose to find that the cost effectiveness values are reasonable and the visibility improvement significant for LNBs with SOFA plus SCR. In addition, the costs are within the range that Wyoming in its SIP and EPA in other SIP and FIP actions have considered reasonable in the BART context. We would propose in the alternative to find that it was unreasonable for the State not to determine that LNBs with OFA plus SCR was NO_X BART for Jim Bridger Units 1 and 2. Though the State is requiring the installation of SCR on Units 1 and 2 under its LTS, the compliance date for both installations is beyond the five-years allowed for BART sources by 40 CFR 51.308(e)(iv). Thus, we would propose to disapprove the State's NO_X BART determination for Jim Bridger Units 1 and 2 and propose a FIP for NO_X BART.

Based on our examination of the cost estimates and the predicted visibility improvement (along with a consideration of the other BART factors), for our second proposed approach we would propose to find that LNBs with SOFA plus SCR at an emission limit of 0.07 lb/MMBtu (30-day rolling average) is reasonable for NO_X BART for Jim Bridger Units 1 and 2. We would propose that the FIP NO_X BART emission limit for PacifiCorp Units 1 and 2 is 0.07 lb/MMBtu (30-day rolling average).

Under our second proposed approach, we would propose that PacifiCorp meet our proposed emission limit at Jim Bridger Unit 1 and 2, as expeditiously as practicable, but no later than five years after EPA finalizes action on our proposed FIP. This is consistent with

[53] Detailed supporting information for our cost and visibility improvement analyses can be found in the Docket (see Staudt memos and *EPA BART and RP Modeling for Wyoming,* respectively).

the requirements of 40 CFR 51.308(e)(iv).[54]

4. Disapproval of the State's PacifiCorp Naughton Units 1 and 2 NO_X BART Determinations and FIP to Address NO_X BART

Wyoming's NO_X BART Determination

During the baseline period of 2001–2003, NO_X emissions from Naughton Unit 1 and Unit 2 were controlled with good combustion practices with NO_X emission limits of 0.75 lb/MMBtu (3-hour block) per boiler, and 0.58 lb/MMBtu (annual) and 0.54 lb/MMBtu (annual), respectively. The State determined that new LNBs with OFA, new LNBs with OFA and SNCR, and new LNBs with OFA and SCR were all technically feasible for controlling NO_X emissions from Unit 1 and Unit 2. The State did not identify any technically infeasible options.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, and there are no remaining-useful-life issues for this source. A summary of the State's NO_X BART analyses for Units 1 and 2 is provided in Tables 51 and 52 below. As discussed above, the visibility improvement modeling results in these tables were developed by EPA because Wyoming did not properly follow the BART Guidelines. Baseline NO_X emissions are 4,230 tpy for Unit 1 and 5,109 tpy for Unit 2 based on heat input rates of 1,850 MMBtu/hr and 2,400 MMBtu/hr, respectively, and 7,884 hours of operation.

TABLE 51—SUMMARY OF WYOMING'S NAUGHTON UNIT 1 NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (30-day rolling average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta deciview for the maximum 98th percentile impact at Bridger Wilderness Area) EPA Analysis
New LNBs with OFA	0.26	2,334	$993,248	$426		0.79
New LNBs with OFA and SNCR	0.21	2,699	1,972,363	731	$2,683	0.80
New LNBs with OFA and SCR	0.07	3,720	10,231,210	2,750	8,089	1.07

TABLE 52—SUMMARY OF WYOMING'S NAUGHTON UNIT 2 NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (30-day rolling average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta deciview) (delta deciview for the maximum 98th percentile impact at Bridger Wilderness Area) EPA Analysis
New LNBs with OFA	0.26	2,649	$945,683	$357		0.70
New LNBs with OFA and SNCR	0.21	3,122	2,260,957	724	$2,781	0.74
New LNBs with OFA and SCR	0.07	4,447	12,664,919	2,848	7,852	1.10

Based on its consideration of the five factors, the State determined new LNBs with OFA was reasonable for NO_X BART for Unit 1 and Unit 2. The State determined SNCR and SCR were not reasonable based on the high cost effectiveness and associated visibility improvement. The State determined that the NO_X BART emission limit for Naughton Unit 1 is 0.26 lb/MMBtu (30-day rolling average), and the NO_X BART emission limit for Naughton Unit 2 is 0.26 lb/MMBtu (30-day rolling average).

EPA's PacifiCorp Naughton Units 1 and 2 NO_X BART Determination and Proposed FIP for NO_X BART

The EPA agrees with the State's analysis pertaining to energy or non-air quality environmental impacts and remaining-useful-life for this source. We disagree with the State's estimate of baseline NO_X emissions of 4,230 tpy for Unit 1 and 5,109 tpy for Unit 2 because these estimates are based on heat input rates of 1,850 MMBtu/hr and 2,400 MMBtu/hr, respectively rather than an average of actual annual emissions. EPA finds that baseline NO_X emissions are 3,553 tpy for Unit 1 and 4,337 tpy for Unit 2 based on the actual annual average for the years 2001–2003. A summary of the EPA's NO_X BART analysis and the visibility impacts is provided in Tables 53–56 below.

[54] The proposed regulatory language for this rulemaking only covers our first proposed approach. If EPA finalizes an action that differs from our first proposed approach for Jim Bridger Units 1 and 2, we will revise the regulatory language accordingly. If we finalize action on our first proposed approach, the regulatory language will reflect a compliance deadline of December 31, 2021 for Unit 2 and December 31, 2022 for Unit 1. If we finalize action on our second proposed approach, the regulatory language would be revised to require compliance at Unit 1 and Unit 2 no later than five years after we take final action.

TABLE 53—SUMMARY OF EPA'S NAUGHTON UNIT 1 NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (annual average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Bridger Wilderness Area)
New LNBs with OFA	0.21	2,100	$932,466	$444	....	0.84
New LNBs with OFA and SNCR	0.16	2,463	2,258,826	917	$3,650	0.99
New LNBs with OFA and SCR	0.05	3,209	7,437,269	2,318	6,947	1.23

Naughton Unit 1 also impacts other Class I areas. The visibility improvement modeled by EPA at other Class I areas is shown in Table 54 below.

TABLE 54—NAUGHTON UNIT 1: VISIBILITY IMPROVEMENT AT OTHER CLASS I AREAS

Class I area	Visibility improvement (delta dv for the maximum 98th percentile impact) new LNBs + OFA	Visibility improvement (delta dv for the maximum 98th percentile impact) new LNBs + OFA/SNCR	Visibility improvement (delta dv for the maximum 98th percentile impact) new LNBs + OFA/SCR
Fitzpatrick	0.38	0.45	0.56
N. Absaroka	0.14	0.16	0.20
Washakie	0.20	0.23	0.29
Teton	0.25	0.29	0.36
Grand Teton	0.33	0.39	0.49
Yellowstone	0.28	0.32	0.41

TABLE 55—SUMMARY OF EPA'S NAUGHTON UNIT 2 NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (annual average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Bridger Wilderness Area)
New LNBs with OFA	0.21	2,586	$883,900	$342	....	0.97
New LNBs with OFA and SNCR	0.16	3,024	2,510,049	830	$3,713	1.15
New LNBs with OFA and SCR	0.05	3,922	8,843,387	2,255	7,050	1.42

Naughton Unit 2 also impacts other Class I areas. The visibility improvement modeled by EPA at other Class I areas is shown in Table 56 below.

TABLE 56—NAUGHTON UNIT 2: VISIBILITY IMPROVEMENT AT OTHER CLASS I AREAS

Class I area	Visibility improvement (delta dv for the maximum 98th percentile impact) new LNBs + OFA	Visibility improvement (delta dv for the maximum 98th percentile impact) new LNBs + OFA/SNCR	Visibility improvement (delta dv for the maximum 98th percentile impact) new LNBs + OFA/SCR
Fitzpatrick	0.43	0.51	0.64
N. Absaroka	0.18	0.21	0.26
Washakie	0.24	0.28	0.34
Teton	0.24	0.37	0.45
Grand Teton	0.48	0.56	0.70

TABLE 56—NAUGHTON UNIT 2: VISIBILITY IMPROVEMENT AT OTHER CLASS I AREAS—Continued

Class I area	Visibility improvement (delta dv for the maximum 98th percentile impact) new LNBs + OFA	Visibility improvement (delta dv for the maximum 98th percentile impact) new LNBs + OFA/ SNCR	Visibility improvement (delta dv for the maximum 98th percentile impact) new LNBs + OFA/ SCR
Yellowstone	0.26	0.30	0.37

EPA does not agree with the State's conclusion that a limit of 0.26 lb/ MMBtu, which can be achieved with the installation and operation of new LNBs with SOFA, is reasonable for BART for Naughton Units 1 and 2. We propose to find that Wyoming did not properly follow the requirements of the BART Guidelines in determining NOx BART for these units. Specifically, we propose to find that Wyoming did not properly or reasonably conduct certain requirements of the BART analyses.

As discussed in detail above, because Wyoming relied on visibility modeling methodologies that are inconsistent with the statutory and regulatory requirements, we do not consider Wyoming's analysis of visibility improvement for the NO_X BART to be reasonable for Naughton Units 1 and 2. We propose to find that Wyoming's analyses for these Units are inconsistent with the statutory and regulatory requirement that ''the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.''

Also, we are not relying on the State's costs due to reasons stated in section VII.C.3.b. We propose to find that Wyoming did not properly or reasonably ''take into consideration the costs of compliance.'' Thus, the State's BART analyses for Naughton Units 1 and 2 do not meet the requirements of the CAA and RHR, and we are proposing to disapprove the analyses and the State's NO_X BART determinations. We are proposing a FIP for NO_X BART to fill the gaps left by our disapproval, as explained below.

Our analysis follows our BART Guidelines. With the exception of the NO_X emission limits, the visibility improvement analyses, and the cost effectiveness analyses, EPA is proposing to find that the Wyoming's regional haze NO_X BART analysis for Naughton Units 1 and 2, fulfills all the relevant requirements of CAA Section 169A and the RHR.

EPA's NO_X BART analysis and the visibility impacts for Naughton Units 1 and 2 are summarized in Tables 53–56 above and detailed information can be found in the docket.[55] EPA's cost analysis estimated the cost-effectiveness value for LNBs with OFA and SCR at Unit 1 is $2,318/ton with a 1.23 dv visibility improvement at the most impacted Class I area. The cost effectiveness value for LNBs with OFA and SCR at Unit 2 is estimated at $2,255/ton, with a 1.42 dv visibility improvement at the most impacted Class I area. In addition, the installation of SCR will also have substantial visibility benefits for other Class I areas, besides the most impacted area. The cumulative visibility improvement is 3.54 dv for Unit 1 and 4.18 dv for Unit 2. EPA followed the BART Guidelines in developing these cost-effectiveness values, which are reasonable and the visibility improvement is significant for new LNBs with OFA plus SCR. The costs and visibility improvements are within the range that Wyoming in its SIP and EPA in other SIP and FIP actions have considered reasonable in the BART context.

Based on our examination of the cost estimates and the predicted visibility improvement (along with a consideration of the other BART factors), we propose to find that new LNBs with OFA plus SCR at an emission limit of 0.07 lb/MMBtu (30-day rolling average) is reasonable and consistent with the CAA and BART Guidelines requirements for NO_X BART for Naughton Units 1 and 2. We are proposing that the FIP NO_X BART emission limit for PacifiCorp Naughton Units 1 and 2 is 0.07 lb/MMBtu (30-day rolling average).

We propose that PacifiCorp meet our proposed emission limit at Naughton Unit 1 and 2, as expeditiously as practicable, but no later than five years after EPA finalizes action on our proposed FIP. This is consistent with the requirements of 40 CFR 51.308(e)(iv).

We are also asking if interested parties have additional information regarding the BART factors and EPA's proposed determination, for example our weighing of average costs, incremental costs, visibility improvement, and timing of installation of such controls, and in light of such information, whether the interested parties think the Agency should consider another BART control technology option that could be finalized either instead of, or in conjunction with, BART as proposed. The Agency will take the comments and testimony received, as well as any further SIP revisions submitted by the State, into consideration in our final promulgation. Supplemental information received may lead the Agency to adopt final SIP and/or FIP regulations that reflect a different BART control technology option, or impact other proposed regulatory provisions, which differ from this proposal.

[55] Detailed supporting information for our cost and visibility improvement analyses can be found in the Docket (see Staudt memos and *EPA BART and RP Modeling for Wyoming*, respectively).

5. Disapproval of the State's PacifiCorp Wyodak Unit 1 NO_X BART Determination and FIP To Address NO_X BART

Wyoming's NO_X BART Determination

During the baseline period, Wyodak Unit 1 was controlled for NO_X emissions with early generation LNBs with emission limits of 0.70 lb/MMBtu (3-hour block) and 0.31 lb/MMbtu (annual). The State determined new LNBs with OFA, existing LNBs with ROFA, new LNBs with OFA plus SNCR, and new LNBs with OFA plus SCR were technically feasible for controlling NO_X emissions. The State did not identify any technically infeasible control options.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, and there are no remaining-useful-life issues for this source. A summary of the State's NO_X BART analyses for Unit 1 is provided in Table 57 below. Baseline NO_X emissions are 5,744 tpy based on the unit heat input rate of 4,700 MMBtu/hr and 7,884 hours of operation per year. As discussed above, the visibility improvement modeling results in these tables were developed by EPA because Wyoming did not properly follow the BART Guidelines.

TABLE 57—SUMMARY OF WYOMING'S WYODAK UNIT 1 NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (30-day rolling average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Wind Cave National Park) EPA analysis
LNBs with OFA	0.23	1,483	$1,306,203	$881		0.25
LNBs with OFA and SNCR	0.18	2,409	2,306,728	958	$1,080	0.40
LNBs with OFA and SCR	0.07	4,447	18,910,781	4,252	8,147	0.72

Based on its consideration of the five factors, the State determined LNBs with OFA was reasonable for NO_X BART for Unit 1. The State determined other control technologies were not reasonable based on the high-cost effectiveness values and low visibility improvement. The State determined the NO_X BART emission limit for Wyodak Unit 1 is 0.23 lb/MMBtu (30-day rolling average).

EPA's Conclusions on Wyodak Unit 1 NO_X BART Determination and FIP for NO_X BART

The EPA agrees with the State's analysis pertaining to energy or non-air quality environmental impacts and remaining-useful-life for this source. We disagree with the State's estimate of baseline NO_X emissions of 5,744 tpy because these estimates are based on the unit heat input rate of 4,700 MMBtu/hr and 7,884 hours of operation per year rather than an average of actual annual emissions. EPA finds that baseline NO_X emissions are 4,615 tpy based on the actual annual average for the years 2001–2003. A summary of the EPA's NO_X BART analysis and the visibility impacts is provided in Tables 58 and 59 below.

TABLE 58—SUMMARY OF EPA'S WYODAK'S NO_X BART ANALYSIS

Control technology	Emission rate (lb/MMBtu) (annual average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Wind Cave National Park)
New LNBs with OFA	0.19	1,239	$1,272,427	$1,027		0.24
New LNBs with OFA and SNCR	0.15	1,914	3,787,466	1,979	$3,725	0.38
New LNBs with OFA and SCR	0.05	3,735	14,386,417	3,852	5,822	0.71

Wyodak also impacts one other Class I area. The visibility improvement EPA modeled at the other Class I area is shown in Table 59 below.

TABLE 59—WYODAK: VISIBILITY IMPROVEMENT AT OTHER CLASS I AREAS

Class I area	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + OFA	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + OFA/ SNCR	Visibility improvement (delta dv for the maximum 98th percentile impact) – new LNBs + OFA/ SCR
Badlands	0.17	0.23	0.45

EPA does not agree with the State's conclusion that a limit of 0.23 lb/ MMBtu is reasonable for NO_X BART for Wyodak Unit 1, which can be achieved with the installation and operation of new LNBs with OFA. We propose to find that Wyoming did not properly follow the requirements of the BART Guidelines in determining NOx BART for this unit. Specifically, we propose to find that Wyoming did not properly or reasonably conduct certain requirements of the BART analysis.

As discussed in detail above, because Wyoming relied on visibility modeling methodologies that are inconsistent with the statutory and regulatory requirements, we do not consider Wyoming's analysis of visibility improvement for the NO_X BART to be reasonable for Wyodak Unit 1. We propose to find that Wyoming's analysis for this Unit is inconsistent with the statutory and regulatory requirement that "the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.''

Also, we are not relying on the State's costs due to reasons stated in section VII.C.3.b of this notice. We propose to find that Wyoming did not properly or reasonably ''take into consideration the costs of compliance.'' Thus, the State's BART analysis for Wyodak Unit 1 does not meet the requirements of the CAA and RHR, and we are proposing to disapprove the analysis and the State's NO_X BART determination. We are proposing a FIP for NO_X BART to fill the gap left by our disapproval, as explained below.

Our analysis follows our BART Guidelines. With the exception of the NO_X emission limits, the visibility improvement analyses, and the cost-effectiveness analyses, EPA is proposing to find that the Wyoming's regional haze NO_X BART analysis for Wyodak Unit 1 fulfills all the relevant requirements of CAA Section 169A and the RHR.

EPA's NO_X BART analysis and the visibility impacts for Wyodak Unit 1 are summarized in Tables 58–59 above and detailed information can be found in the docket.[56] In particular, the cost effectiveness value for new LNB with OFA plus SNCR at this unit is $1,979/ton with a visibility improvement at the most impacted Class I area of 0.38 deciviews. The costs are within the range that EPA in other SIP and FIP actions has considered reasonable and consistent with the BART Guidelines.

Based on our examination of the costs estimates, emission reductions, and the predicted visibility improvement, we propose to find that new LNBs with OFA plus SNCR at an emission limit of 0.17 lb/MMBtu (30-day rolling average) is reasonable and consistent with the CAA and BART Guideline requirements for NO_X BART for Wyodak Unit 1. We are proposing that the FIP NO_X BART emission limit for PacifiCorp Wyodak Unit 1 is 0.17 lb/MMBtu (30-day rolling average).

We have eliminated the highest performing option from consideration—new LNBs with OFA plus SCR. Although the cost-effectiveness and visibility improvement are within the range of other EPA FIP actions, we find that the cumulative visibility improvement of 1.16 deciviews for new LNBs with OFA plus SCR is low compared to the cumulative visibility benefits that will be achieved by requiring SCR at Dave Johnston Unit 3 (2.92 dv), Laramie River Unit 1 (2.12 dv), Laramie River Unit 2 (1.97 dv), Laramie River Unit 3 (2.29 dv), Naughton Unit 1 (3.54 dv), and Naughton Unit 2 (4.18 dv).

We propose that PacifiCorp meet our proposed emission limit at Wyodak Unit 1, as expeditiously as practicable, but no later than five years after EPA finalizes action on our proposed FIP. This is consistent with the requirements of 40 CFR 51.308(e)(iv).

We are also asking if interested parties have additional information regarding the BART factors and EPA's proposed determination, for example our weighing of average costs, incremental costs, visibility improvement, and timing of installation of such controls, and in light of such information, whether the interested parties think the Agency should consider another BART control technology option that could be finalized either instead of, or in conjunction with, BART as proposed. The Agency will take the comments and testimony received, as well as any further SIP revisions submitted by the State, into consideration in our final promulgation. Supplemental information received may lead the Agency to adopt final SIP and/or FIP regulations that reflect a different BART control technology option, or impact other proposed regulatory provisions, which differ from this proposal.

B. Disapproval of the State's NO_X Reasonable Progress Determinations and Federal Implementation Plan for NO_X Reasonable Progress Determinations and Limits

We are proposing to disapprove the State's reasonable progress determination for PacifiCorp Dave Johnston Unit 1 and Unit 2, and we are proposing a reasonable progress NO_X FIP for these units, as explained below. As noted above, the State provided four-factor analyses that evaluated the required factors. However, due to deficiencies in the control cost estimates, EPA conducted its own cost analyses for Dave Johnston Unit 1 and 2. The cost analysis was done in the same manner as described for BART sources in Section VII.C.

We concluded that it is also appropriate to consider a fifth factor for these units for evaluating potential reasonable progress control options—the degree of visibility improvement that may reasonably be anticipated from the use of the reasonable progress controls. Our reasonable progress guidance contemplates that states (or EPA in lieu of a state) may be able to consider other relevant factors for reasonable progress sources (see EPA's *Guidance for Setting Reasonable Progress Goals under the Regional Haze Program,* (''Reasonable Progress Guidance''), pp. 2–3, July 1, 2007). We find it appropriate, in certain circumstances, to consider visibility improvement when evaluating potential reasonable progress controls. Thus, in the same manner as described for BART sources in Section VII.C, EPA conducted visibility improvement modeling for Dave Johnston Units 1 and 2.

1. PacifiCorp Dave Johnston—Units 1 and 2

Background

PacifiCorp's Dave Johnston power plant is comprised of four units burning pulverized subbituminous Powder River Basin coal. Units 3 and 4 are subject to BART, as described above. Units 1 and 2 are nominal 106 MW dry bottom wall-fired boilers. Unit 1 began operation in 1958 and Unit 2 in 1960.

Wyoming's NO_X Reasonable Progress Determinations

Unit 1 and Unit 2 are currently uncontrolled for NO_X emissions. The State determined that LNBs, LNBs with OFA, SNCR, and SCR were technically feasible for controlling NO_X emissions. The State did not identify any technically infeasible control options.

The State did not identify any energy or non-air quality environmental impacts that would preclude the selection of any of the controls evaluated, and there are no remaining-useful-life issues for this source. A summary of the State's NO_X reasonable progress analyses for Unit 1 and Unit 2, along with our visibility modeling results, are provided in Tables 60 and 61 below. Baseline NO_X emissions are 2,256 tpy for Unit 1 and 2,174 tpy for Unit 2 based on 2002 actual emissions. Wyoming did not provide controlled emission rates in their reasonable progress analysis.

[56] Detailed supporting information for our cost and visibility improvement analyses can be found in the Docket (see Staudt memos and *EPA BART and RP Modeling for Wyoming,* respectively.

TABLE 60—SUMMARY OF DAVE JOHNSTON UNIT 1 NO_X REASONABLE PROGRESS ANALYSIS

Control technology	Control efficiency (%)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Visibility improvement (delta dv for the maximum 98th percentile impact at Wind Cave National Park) EPA Analysis
LNBs	51	1,150	$631,000	$528	0.37
LNBs with OFA	65	1,466	962,000	632	0.49
SNCR	40	902	2,490,000	2,659	0.26
SCR	80	1,804	3,390,000	1,810	0.58

TABLE 61—SUMMARY OF DAVE JOHNSTON UNIT 2 NO_X REASONABLE PROGRESS ANALYSIS

Control technology	Control efficiency (%)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Visibility improvement (delta dv for the maximum 98th percentile impact at Wind Cave National Park) EPA Analysis
LNBs	51	1,108	$631,000	$538	0.38
LNBs with OFA	65	1,413	962,000	644	0.49
SNCR	40	869	2,490,000	2,709	0.28
SCR	80	1,739	3,390,000	1,844	0.58

The State estimated that it would take nearly five and a half years for NO_X reduction strategies to become effective. The State determined that roughly two years would be necessary for the State to develop the necessary regulations to implement the selected control measures. The State estimated that it would take up to a year for the source to secure the capital necessary to purchase emission control devices and approximately 18 months would be required for the company to design, fabricate, and install SCR or SNCR technology. Because there are two boilers being evaluated at Dave Johnston, the State determined an additional year may be required for staging the installation process.

The State determined that no controls were reasonable for this planning period. The State cited that the four-factor analysis was limited, in that no guidance was provided by EPA for identifying significant sources and EPA did not establish contribution to visibility impairment thresholds (a potential fifth factor for reasonable progress determinations).[57] The State further claims that the State cannot, per Wyoming Statute 35–11–202, establish emission control requirements except through state rule or regulation. Furthermore, the Wyoming statute requires the State to consider the character and degree of injury of the emissions involved. In this case, the State claims it would need to have visibility modeling that assessed the degree of injury caused by the emissions, which the State does not have. The State believes it has taken a strong and reasonable first step in identifying potential contributors to visibility impairment, and that the next step of creating an appropriate rule or regulation will be accomplished in the next SIP revision.

EPA's Conclusions on Dave Johnston Units 1 and 2 NO_X Reasonable Progress Determination and FIP for NO_X Reasonable Progress Controls

The EPA agrees with the State's analysis pertaining to energy or non-air quality environmental impacts and remaining-useful-life for this source. We disagree with the State's estimate of baseline NO_X emissions of 2,256 tpy for Unit 1 and 2,174 tpy for Unit 2, which were based on 2002 actual emissions. EPA's estimate of baseline NO_X emissions are 2,188 tpy for Unit 1 and 2,161 tpy for Unit 2 based on the actual annual average for the years 2001–2003. A summary of the EPA's NO_X BART analysis and the visibility impacts is provided in Tables 62–65 below.

[57] States must consider the four factors as listed above but can also take into account other relevant factors for the reasonable progress sources identified (see EPA's *Guidance for Setting Reasonable Progress Goals under the Regional Haze Program,* (''EPA's Reasonable Progress Guidance''), p. 2–3, July 1, 2007).

TABLE 62—SUMMARY OF EPA'S DAVE JOHNSTON UNIT 1 NO_X REASONABLE PROGRESS ANALYSIS

Control technology	Emission rate (lb/MMBtu) (annual average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Wind Cave National Park)
LNBs with OFA	0.20	1,226	$1,187,179	$968	....	0.31
LNBs with OFA and SNCR	0.15	1,466	2,087,189	1,423	$3,743	0.35
LNBs with OFA and SCR	0.05	1,947	6,417,536	3,296	9,004	0.44

Dave Johnston Unit 1 also impacts other Class I areas. The visibility improvement EPA modeled at other Class I areas is shown in Table 63 below.

TABLE 63—VISIBILITY IMPROVEMENT MODELED AT OTHER CLASS I AREAS

Class I area	Visibility improvement (delta dv for the maximum 98th percentile impact) – LNBs + OFA	Visibility improvement (delta dv for the maximum 98th percentile impact) – LNBs + OFA/SNCR	Visibility improvement (delta dv for the maximum 98th percentile impact) – LNBs + OFA/SCR
Badlands	0.17	0.16	0.25
Mt. Zirkel	0.06	0.08	0.13
Rawah	0.10	0.12	0.15
Rocky Mountain	0.13	0.16	0.22

TABLE 64—SUMMARY OF EPA'S DAVE JOHNSTON UNIT 2 NO_X REASONABLE PROGRESS ANALYSIS

Control technology	Emission rate (lb/MMBtu) (annual average)	Emission reduction (tpy)	Annualized costs	Average cost effectiveness ($/ton)	Incremental cost effectiveness	Visibility improvement (delta dv for the maximum 98th percentile impact at Wind Cave National Park)
LNBs with OFA	0.20	1,180	$1,188,797	$1,007		0.29
LNBs with OFA and SNCR	0.15	1,425	2,100,619	1,474	$3,718	0.33
LNBs with OFA and SCR	0.05	1,916	6,432,035	3,357	8,830	0.42

Dave Johnston Unit 1 also impacts other Class I areas. The visibility improvement EPA modeled at other Class I areas is shown in Table 65 below.

TABLE 65—VISIBILITY IMPROVEMENT MODELED AT OTHER CLASS I AREAS

Class I area	Visibility improvement (delta dv for the maximum 98th percentile impact) – LNBs + OFA	Visibility improvement (delta dv for the maximum 98th percentile impact) – LNBs + OFA/SNCR	Visibility improvement (delta dv for the maximum 98th percentile impact) – LNBs + OFA/SCR
Badlands	0.14	0.17	0.24
Mt. Zirkel	0.06	0.09	0.12
Rawah	0.09	0.11	0.15
Rocky Mountain	0.13	0.16	0.21

We disagree with the State's reasoning for not adopting reasonable progress controls for Dave Johnston Unit 1 and Unit 2. If the State determined that it needed to adopt a rule or perform modeling to adequately assess and, if warranted, require reasonable progress controls, the State should have completed these steps before it submitted its regional haze SIP. The RHR does not allow for commitments to potentially implement strategies at some later date that are identified under reasonable progress or for the State to take credit for such commitments.

In addition, the cost effectiveness value for LNBs with OFA at Unit 1 is $968/ton and $1,007/ton at Unit 2. These values are very reasonable and far less than some of the cost effectiveness values the State found reasonable in making its BART determinations. Given predicted visibility improvement of approximately 0.30 deciviews per unit at the most impacted Class I area and the fact that Wyoming's reasonable progress goals will not meet the URP, we find that it was unreasonable for the State to reject these very inexpensive controls. Thus, we are proposing to disapprove the State's NO_X reasonable progress determination for Dave Johnston Unit 1 and Unit 2 and proposing a FIP for NO_X reasonable progress controls as explained below.

Based on our examination of the State's costs estimates, emission reductions, and the predicted visibility improvement, we propose to find that LNBs with OFA at an emission limit of 0.22 lb/MMBtu (30-day rolling average) is reasonable for NO_X reasonable progress controls for Dave Johnston Units 1 and 2. We are proposing that the FIP NO_X reasonable progress emission limit for PacifiCorp Dave Johnston Unit 1 and Unit 2 is 0.22 lb/MMBtu (30-day rolling average).

We propose that PacifiCorp meet our proposed emission limit at Dave Johnston Units 1 and 2 as expeditiously as practicable, but no later than July 31, 2018. This is consistent with the requirement that the SIP cover an initial planning period that ends July 31, 2018.

C. Reasonable Progress Goals

We are proposing to impose reasonable progress controls on Dave Johnston Units 1 and 2, as well as more stringent NO_X BART controls on PacifiCorp Dave Johnston Unit 3 and Unit 4, PacifiCorp Naughton Unit 1 and Unit 2, PacifiCorp Wyodak Unit 1, and Basin Electric Laramie River Units 1, 2, and 3, than WRAP assumed in modeling Wyoming's RPGs.

We could not re-run the WRAP modeling due to time and resource constraints, but anticipate that the additional controls would result in an increase in visibility improvement during the 20% worst days. As noted in our analyses, many of our proposed controls would result in significant incremental visibility benefits when modeled against natural background. We anticipate that this would translate into measurable improvement if modeled on the 20% best days as well. While we expect our proposed controls will result in additional visibility improvement, we do not expect that these improvements will result in the State achieving the URP. For some of the reasons discussed in section VII.D.3, in particular, emissions from sources outside the WRAP modeling domain, along with our consideration of the statutory reasonable progress factors, we find it reasonable for the State to not achieve the URP during this planning period. We expect the State to quantify the visibility improvement in its next regional haze SIP revision.

For purposes of this action, we are proposing RPGs that are consistent with the additional controls we are proposing. While we would prefer to quantify the RPGs, we note that the RPGs themselves are not enforceable values. The more critical elements for our FIP are the emissions limits we are proposing to impose, which will be enforceable.

D. Federal Monitoring, Recordkeeping, and Reporting Requirements

The CAA requires that SIPs, including the regional haze SIP, contain elements sufficient to ensure emission limits are practically enforceable.[58] Other applicable regulatory provisions are contained in Appendix V to Part 51—Criteria for Determining the Completeness of Plan Submissions.[59] We are proposing to find that the State's regional haze SIP does not contain adequate monitoring, recordkeeping and reporting requirements. Chapter 6.4, Section V of the SIP contains monitoring and reporting requirements that we find inadequate for numerous reasons, summarized as follows: (1) The State's language includes references to WAQSR Chapters that EPA has not approved as part of the SIP and are thus not federally enforceable. These references should be to the appropriate sections in the CFR; (2) Definitions have not been included; (3) The State's language allows for data substitution pursuant to 40 CFR part 75. The data substitution procedures of 40 CFR part 75 were never intended to apply to BART sources; (4) There are numerous language clarifications and rewordings needed; and (5) The State did not include appropriate recordkeeping language.[60]

EPA is proposing to disapprove the State's monitoring, recordkeeping, and reporting requirements in Chapter 6.4 of the SIP. EPA is proposing regulatory language as part of our FIP that specifies monitoring, recordkeeping, and reporting requirements for all BART and reasonable progress sources. For purposes of consistency, EPA is proposing to adopt language that is the same as we have adopted for other states in Region 8.

E. Federal Implementation Plan for the Long-Term Strategy

We are proposing regulatory language as part of our FIP that specifies NO_X emission limits and compliance schedules for the following sources: PacifiCorp Dave Johnston Units 1–4, PacifiCorp Jim Bridger Units 1 and 2, PacifiCorp Naughton Unit 1 and Unit 2, PacifiCorp Wyodak Unit 1, and Basin Electric Laramie River Units 1, 2, and 3. We are also proposing monitoring, recordkeeping, and reporting requirements for all BART SIP and FIP sources and for Dave Johnston Units 1 and 2. We are proposing this regulatory language to fill the gap in the LTS that would be left by our proposed partial disapproval of the LTS.

F. Federal Implementation Plan for Coordination of RAVI and Regional Haze Long-Term Strategy

In response to EPA's RAVI rules, Wyoming adopted WAQSR Chapter 9, Section 2. EPA approved WAQSR Chapter 9, Section 2 as part of the SIP on July 28, 2004 (69 FR 44965). As discussed above, the State is required to coordinate the review of its RAVI and regional haze LTS and conduct the

[58] CAA Section 110(a)(2) states that SIPs ''shall (A) include enforceable emission limitations and other control measures, means, or techniques (including economic incentives such as fees, marketable permits, and auctions of emissions rights), as well as schedules and timetables for compliance, as may be necessary or appropriate to meet the applicable requirements of this chapter; (C) include a program to provide for the enforcement of the measures described in subparagraph (A), and regulation of the modification and construction of any stationary source within the areas covered by the plan as necessary to assure that national ambient air quality standards are achieved, including a permit program as required in parts C and D of this subchapter; (F) require, as may be prescribed by the Administrator—(i) the installation, maintenance, and replacement of equipment, and the implementation of other necessary steps, by owners or operators of stationary sources to monitor emissions from such sources, (ii) periodic reports on the nature and amounts of emissions and emissions-related data from such sources, and (iii) correlation of such reports by the State agency with any emission limitations or standards established pursuant to this chapter, which reports shall be available at reasonable times for public inspection''

[59] Appendix V part 51 states in section 2.2 that complete SIPs contain: ''(g) Evidence that the plan contains emission limitations, work practice standards and recordkeeping/reporting requirements, where necessary, to ensure emission levels''; and ''(h) Compliance/enforcement strategies, including how compliance will be determined in practice.''

[60] On July 6, 2011, EPA sent an email to the State with detailed comments (that are summarized above) on the State's monitoring, recordkeeping, and reporting requirements in Chapter 6.4, Section V of the SIP. The July 6, 2011 email from Laurel Dygowski, EPA Region 8, to Tina Anderson, State of Wyoming, is included in the Supporting and Related Materials section of the docket.

reviews together. WAQSR Chapter 9, Section 2(f) requires the State to review its RAVI LTS every three years, which does not coordinate with the five-year review for the State's regional haze LTS. Thus, we are proposing to disapprove the State's SIP because it does not meet the requirements of 40 CFR 51.306(c). We are proposing a FIP in which EPA commits to coordinating the State's RAVI LTS review with the regional haze LTS review. Thus, EPA is committing to provide a review of the State's RAVI LTS every five years in coordination with the State's regional haze LTS review. EPA is proposing that our review of the State's RAVI LTS will follow those items as indicated by 40 CFR 51.306(c).

IX. EPA's Proposed Action

EPA is proposing to partially approve and partially disapprove a regional haze SIP revision submitted by the State of Wyoming on January 12, 2011. Specifically, we are proposing to disapprove the following:

- The State's NO_X BART determinations for PacifiCorp Dave Johnston Unit 3 and Unit 4, PacifiCorp Naughton Unit 1 and Unit 2, PacifiCorp Wyodak Unit 1, and Basin Electric Laramie River Units 1, 2, and 3.
- The State's NO_X reasonable progress determination for PacifiCorp Dave Johnston Units 1 and 2.
- Wyoming's RPGs.
- The State's monitoring and recordkeeping requirements in Chapter 6.4 of the SIP.
- Portions of the State's LTS that rely on or reflect other aspects of the regional haze SIP we are proposing to disapprove.
- The provisions necessary to meet the requirements for the coordination of the review of the RAVI and the regional haze LTS.

We are proposing to approve the remaining aspects of the State's January 12, 2011, SIP submittal. We are also seeking comment on an alternative proposal related to the State's NO_X BART determination for PacifiCorp Jim Bridger Units 1 and 2.

We are proposing the promulgation of a FIP to address the deficiencies in the Wyoming regional haze SIP that we have identified in this proposal. The proposed FIP includes the following elements:

- NO_X BART determinations and limits for PacifiCorp Dave Johnston Unit 3 and Unit 4, PacifiCorp Naughton Unit 1 and Unit 2, PacifiCorp Wyodak Unit 1, and Basin Electric Laramie River Units 1, 2, and 3.
- NO_X reasonable progress determination and limits for PacifiCorp Dave Johnston Units 1 and 2.
- RPGs consistent with the SIP limits proposed for approval and the proposed FIP limits.
- Monitoring, record-keeping, and reporting requirements applicable to all BART and reasonable progress sources for which there is a SIP or FIP emissions limit.
- LTS elements pertaining to emission limits and compliance schedules for the proposed BART and reasonable progress FIP limits.
- Provisions to ensure the coordination of the RAVI and regional haze LTS.

X. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is not a ''significant regulatory action'' under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011). As discussed in section C below, the proposed FIP applies to only five facilities. It is therefore not a rule of general applicability.

B. Paperwork Reduction Act

This action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq*. Burden is defined at 5 CFR 1320.3(b). Because the proposed FIP applies to just five facilities, the Paperwork Reduction Act does not apply. See 5 CFR 1320(c).

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's proposed rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

After considering the economic impacts of today's proposed rule on small entities, I certify that this action will not have a significant economic impact on a substantial number of small entities. The Regional Haze FIP that EPA is proposing for purposes of the regional haze program consists of imposing federal controls to meet the BART requirement for NO_X emissions on specific units at five sources in Wyoming, and imposing controls to meet the reasonable progress requirement for NO_X emissions at one additional source in Wyoming. The net result of this FIP action is that EPA is proposing direct emission controls on selected units at only five sources. The sources in question are each large electric generating plants that are not owned by small entities, and therefore are not small entities. The proposed partial approval of the SIP, if finalized, merely approves state law as meeting Federal requirements and imposes no additional requirements beyond those imposed by state law. *See Mid-Tex Electric Cooperative, Inc. v. FERC,* 773 F.2d 327 (D.C. Cir. 1985)

We continue to be interested in the potential impacts of the proposed rule on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act (UMRA)

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for federal agencies to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under section 202 of UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to State, local, and Tribal governments, in the aggregate, or to the private sector, of $100 million or more (adjusted for inflation) in any one year. Before promulgating an EPA rule for which a written statement is needed, section 205 of UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of section

205 of UMRA do not apply when they are inconsistent with applicable law. Moreover, section 205 of UMRA allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments, it must have developed under section 203 of UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

Under Title II of UMRA, EPA has determined that this proposed rule does not contain a federal mandate that may result in expenditures that exceed the inflation-adjusted UMRA threshold of $100 million by State, local, or Tribal governments or the private sector in any one year. In addition, this proposed rule does not contain a significant federal intergovernmental mandate as described by section 203 of UMRA nor does it contain any regulatory requirements that might significantly or uniquely affect small governments.

E. Executive Order 13132: Federalism

Federalism (64 FR 43255, August 10, 1999) revokes and replaces Executive Orders 12612 (Federalism) and 12875 (Enhancing the Intergovernmental Partnership). Executive Order 13132 requires EPA to develop an accountable process to ensure "meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications." "Policies that have federalism implications" is defined in the Executive Order to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government." Under Executive Order 13132, EPA may not issue a regulation that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the federal government provides the funds necessary to pay the direct compliance costs incurred by state and local governments, or EPA consults with state and local officials early in the process of developing the proposed regulation. EPA also may not issue a regulation that has federalism implications and that preempts state law unless the Agency consults with state and local officials early in the process of developing the proposed regulation.

This rule will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132, because it merely addresses the State not fully meeting its obligation to prohibit emissions from interfering with other states measures to protect visibility established in the CAA. Thus, Executive Order 13132 does not apply to this action. In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and state and local governments, EPA specifically solicits comment on this proposed rule from state and local officials.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Executive Order 13175, entitled *Consultation and Coordination with Indian Tribal Governments* (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." This proposed rule does not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments. Thus, Executive Order 13175 does not apply to this rule.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

EPA interprets EO 13045 (62 FR 19885, April 23, 1997) as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the EO has the potential to influence the regulation. This action is not subject to EO 13045 because it implements specific standards established by Congress in statutes. However, to the extent this proposed rule will limit emissions of NO_X, SO_2, and PM, the rule will have a beneficial effect on children's health by reducing air pollution.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 ("NTTAA"), Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This proposed rulemaking does not involve technical standards. Therefore, EPA is not considering the use of any voluntary consensus standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994), establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

We have determined that this proposed action, if finalized, will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. This proposed rule limits emissions of NO_X from five facilities in Wyoming.

The partial approval of the SIP, if finalized, merely approves state law as meeting Federal requirements and imposes no additional requirements beyond those imposed by state law.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 et seq., as added by the Small Business Regulatory Enforcement Fairness Act of 1996, does not apply because this action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Intergovernmental relations, Nitrogen dioxide, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides, Volatile organic compounds.

Dated: May 23, 2013.

Shaun L. McGrath,

Regional Administrator Region 8.

40 CFR part 52 is proposed to be amended as follows:

PART 52—[AMENDED]

■ 1. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart ZZ—Wyoming

■ 2. Add section 52.2636 to read as follows:

§ 52.2636 Federal implementation plan for regional haze.[61]

(a) *Applicability.* This section applies to each owner and operator of the following emissions units in the State of Wyoming for which EPA proposes to approve the State's BART determination:

FMC Westvaco Trona Plant Units NS–1A and NS–1B (PM and NO_X);

TATA Chemicals Partners (previously General Chemical) Boilers C and D (PM and NO_X);

Basin Electric Power Cooperative Laramie River Station Units 1, 2, and 3 (PM);

PacifiCorp Dave Johnston Power Plant Unit 3 (PM);

PacifiCorp Dave Johnston Power Plant Unit 4 (PM);

PacifiCorp Jim Bridger Power Plant Units 1, 2, 3, and 4 (NO_X and PM);

PacifiCorp Naughton Power Plant Unit 3 (PM and NO_X);

PacifiCorp Naughton Power Plant Unit 1 and Unit 2 (PM); and

PacifiCorp Wyodak Power Plant Unit 1 (PM).

This section also applies to each owner and operator of the following emissions units in the State of Wyoming for which EPA proposes to disapprove the State's BART determination and issue a NO_X BART Federal Implementation Plan:

Basin Electric Power Cooperative Laramie River Station Units 1, 2, and 3;

PacifiCorp Dave Johnston Power Plant Unit 3;

PacifiCorp Dave Johnston Power Plant Unit 4;

PacifiCorp Naughton Power Plant Unit 1 and Unit 2; and

PacifiCorp Wyodak Power Plant Unit 1.

This section also applies to each owner and operator of the following emissions units in the State of Wyoming for which EPA proposes to disapprove the State's reasonable progress determinations and issue a reasonable progress determination NO_X Federal Implementation Plan: PacifiCorp Dave Johnston Power Plant Units 1 and 2.

(b) *Definitions.* Terms not defined below shall have the meaning given them in the Clean Air Act or EPA's regulations implementing the Clean Air Act. For purposes of this section:

(1) *BART* means Best Available Retrofit Technology.

(2) *BART unit* means any unit subject to a Regional Haze emission limit in Table 1 and Table 2 of this section.

(3) *CAM* means Compliance Assurance Monitoring as required by 40 CFR part 64.

(4) *Continuous emission monitoring system or CEMS* means the equipment required by this section to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of NO_X emissions, diluent, or stack gas volumetric flow rate.

(5) *FIP* means Federal Implementation Plan.

(6) *Lb/hr* means pounds per hour.

(7) *Lb/MMBtu* means pounds per million British thermal units of heat input to the fuel-burning unit.

(8) *NO_X* means nitrogen oxides.

(9) *Operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the BART or RP unit. It is not necessary for fuel to be combusted for the entire 24-hour period.

(10) The *owner/operator* means any person who owns or who operates, controls, or supervises a unit identified in paragraph (a) of this section.

(11) *PM* means filterable total particulate matter.

(12) *RP unit* means any Reasonable Progress unit subject to a Regional Haze emission limit in Table 3 of this section.

(13) *Unit* means any of the units identified in paragraph (a) of this section.

(c) *Emissions limitations.*

(1) The owners/operators of emissions units subject to this section shall not emit, or cause to be emitted, PM or NO_X in excess of the following limitations:

TABLE 1—EMISSION LIMITS FOR BART UNITS FOR WHICH EPA PROPOSES TO APPROVE THE STATE'S BART DETERMINATION

Source name/BART unit	PM Emission limits	NO_X Emission limits
	lb/MMBtu	lb/MMBtu
FMC Westvaco Trona Plant/Unit NS–1A	0.05	0.35
FMC Westvaco Trona Plant/Unit NS–1B	0.05	0.35
TATA Chemicals Partners (General Chemical) Green River Trona Plant/Boiler C	0.09	0.28
TATA Chemicals Partners (General Chemical) Green River Trona Plant/Boiler D	0.09	0.28
Basin Electric Power Cooperative Laramie River Station/Unit 1	0.03	N/A
Basin Electric Power Cooperative Laramie River Station/Unit 2	0.03	N/A
Basin Electric Power Cooperative Laramie River Station/Unit 3	0.03	N/A
Pacificorp Dave Johnston Power Plant/Unit 3	0.015	N/A
Pacificorp Dave Johnston Power Plant/Unit 4	0.015	N/A

[61] The proposed regulatory language only reflects our proposed action. If EPA's final action differs from our proposed action, the regulatory language will be amended, as necessary, to reflect the Agency's final decision.

TABLE 1—EMISSION LIMITS FOR BART UNITS FOR WHICH EPA PROPOSES TO APPROVE THE STATE'S BART DETERMINATION—Continued

Source name/BART unit	PM Emission limits lb/MMBtu	NO_X Emission limits lb/MMBtu
Pacificorp Jim Bridger Power Plant/Unit 1	0.03	0.07
Pacificorp Jim Bridger Power Plant/Unit 2	0.03	0.07
Pacificorp Jim Bridger Power Plant/Unit 3	0.03	0.07
Pacificorp Jim Bridger Power Plant/Unit 4	0.03	0.07
Pacificorp Naughton Power Plant/Unit 1	0.04	N/A
Pacificorp Naughton Power Plant/Unit 2	0.04	N/A
Pacificorp Naughton Power Plant/Unit 3	0.015	0.07
Pacificorp Wyodak Power Plant/Unit 1	0.015	N/A

TABLE 2—EMISSION LIMITS FOR BART UNITS FOR WHICH EPA PROPOSES TO DISAPPROVE THE STATE'S BART DETERMINATION AND IMPLEMENT A FIP

Source name/BART unit	NO_X Emission limit (lb/MMBtu)
Basin Electric Power Cooperative Laramie River Station/Unit 1	0.07
Basin Electric Power Cooperative Laramie River Station/Unit 2	0.07
Basin Electric Power Cooperative Laramie River Station/Unit 3	0.07
Pacificorp Dave Johnston Power Plant/Unit 3	0.07
Pacificorp Dave Johnston Power Plant/Unit 4	0.12
PacifiCorp Naughton Power Plant/Unit 1	0.07
PacifiCorp Naughton Power Plant/Unit 2	0.07
Pacificorp Wyodak Power Plant/Unit 1	0.17

TABLE 3—EMISSION LIMITS FOR RP UNITS FOR WHICH EPA PROPOSES TO DISAPPROVE THE STATE'S RP DETERMINATION AND IMPLEMENT A FIP

Source name/RP unit	NO_X Emission limit (lb/MMBtu)
Pacificorp Dave Johnston Power Plant/Unit 1	0.22
Pacificorp Dave Johnston Power Plant/Unit 2	0.22

(2) These emission limitations shall apply at all times, including startups, shutdowns, emergencies, and malfunctions.

(d) *Compliance date.*

(1) The owners and operators of PacifiCorp Jim Bridger Unit 3 and Unit 4 shall comply with the emission limitations and other requirements of this section by December 31, 2015, for Unit 3 and December 31, 2016, for Unit 4.

(2) The owners and operators of the other BART and RP sources subject to this section shall comply with the emissions limitations and other requirements of this section within five years of the effective date of this rule.

(e) *Compliance determinations for NO_X.*

(1) For all BART and RP units other than Trona Plant units:

(i) *CEMS.* At all times after the compliance date specified in paragraph (d) of this section, the owner/operator of each unit shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR part 75, to accurately measure NO_X, diluent, and stack gas volumetric flow rate from each unit. The CEMS shall be used to determine compliance with the emission limitations in paragraph (c) of this section for each unit.

(ii) *Method.*

(A) For any hour in which fuel is combusted in a unit, the owner/operator of each unit shall calculate the hourly average NO_X concentration in lb/MMBtu and lb/hr at the CEMS in accordance with the requirements of 40 CFR part 75. At the end of each operating day, the owner/operator shall calculate and record a new 30-day rolling average emission rate in lb/MMBtu and lb/hr from the arithmetic average of all valid hourly emission rates from the CEMS for the current operating day and the previous 29 successive operating days.

(B) An hourly average NO_X emission rate in lb/MMBtu or lb/hr is valid only if the minimum number of data points, as specified in 40 CFR part 75, is acquired by both the pollutant concentration monitor (NO_X) and the diluent monitor (O_2 or CO_2).

(C) Compliance with tons-per-year emission limits shall be calculated on a rolling 12-month basis. At the end of each calendar month, the owner/operator shall calculate and record a new 12-month rolling average emission rate from the arithmetic average of all valid hourly emission rates from the CEMS for the current month and the previous 11 months and the report the result in tons.

(D) Data reported to meet the requirements of this section shall not include data substituted using the missing data substitution procedures of subpart D of 40 CFR part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR part 75.

(2) For all Trona Plant BART units:

(i) *CEMS.* At all times after the compliance date specified in paragraph

(d) of this section, the owner/operator of each unit shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR part 60, to accurately measure NO_X, diluent, and stack gas volumetric flow rate from each unit, including the CEMS quality assurance requirements in appendix F of 40 CFR part 60. The CEMS shall be used to determine compliance with the emission limitations in paragraph (c) of this section for each unit.

(ii) *Method.*

(A) For any hour in which fuel is combusted in a unit, the owner/operator of each unit shall calculate the hourly average NO_X concentration in lb/MMBtu and lb/hr at the CEMS in accordance with the requirements of 40 CFR part 60. At the end of each operating day, the owner/operator shall calculate and record a new 30-day rolling average emission rate in lb/MMBtu and lb/hr from the arithmetic average of all valid hourly emission rates from the CEMS for the current operating day and the previous 29 successive operating days.

(B) An hourly average NO_X emission rate in lb/MMBtu or lb/hr is valid only if the minimum number of data points, as specified in 40 CFR part 60, is acquired by both the pollutant concentration monitor (NO_X) and the diluent monitor (O_2 or CO_2).

(C) Compliance with tons-per-year emission limits shall be calculated on a rolling 12-month basis. At the end of each calendar month, the owner/operator shall calculate and record a new 12-month rolling average emission rate from the arithmetic average of all valid hourly emission rates from the CEMS for the current month and the previous 11 months and report results in tons.

(f) *Compliance determinations for particulate matter.*

Compliance with the particulate matter emission limit for each BART and RP unit shall be determined from annual performance stack tests. Within 60 days of the compliance deadline specified in section (d), and on at least an annual basis thereafter, the owner/operator of each unit shall conduct a stack test on each unit to measure particulate emissions using EPA Method 5, 5B, 5D, or 17, as appropriate, in 40 CFR part 60, Appendix A. A test shall consist of three runs, with each run at least 120 minutes in duration and each run collecting a minimum sample of 60 dry standard cubic feet. Results shall be reported in lb/MMBtu and lb/hr. In addition to annual stack tests, the owner/operator shall monitor particulate emissions for compliance with the BART emission limits in accordance with the applicable Compliance Assurance Monitoring (CAM) plan developed and approved by the State in accordance with 40 CFR part 64.

(g) *Recordkeeping.* The owner/operator shall maintain the following records for at least five years:

(1) All CEMS data, including the date, place, and time of sampling or measurement; parameters sampled or measured; and results.

(2) Records of quality assurance and quality control activities for emissions measuring systems including, but not limited to, any records required by 40 CFR part 75. Or, for Trona Plant units, records of quality assurance and quality control activities for emissions measuring systems including, but not limited to appendix F of 40 CFR part 60.

(3) Records of all major maintenance activities conducted on emission units, air pollution control equipment, and CEMS.

(4) Any other CEMS records required by 40 CFR part 75. Or, for Trona Plant units, any other CEMs records required by 40 CFR part 60.

(5) Records of all particulate stack test results.

(6) All data collected pursuant to the CAM plan.

(h) *Reporting.* All reports under this section shall be submitted to the Director, Office of Enforcement, Compliance and Environmental Justice, U.S. Environmental Protection Agency, Region 8, Mail Code 8ENF–AT, 1595 Wynkoop Street, Denver, Colorado 80202–1129.

(1) The owner/operator of each unit shall submit quarterly excess emissions reports for NO_X BART and RP units no later than the 30th day following the end of each calendar quarter. Excess emissions means emissions that exceed the emissions limits specified in paragraph (c) of this section. The reports shall include the magnitude, date(s), and duration of each period of excess emissions, specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the unit, the nature and cause of any malfunction (if known), and the corrective action taken or preventative measures adopted. The owner/operator shall also submit reports of any exceedances of tons-per-year emission limits.

(2) The owner/operator of each unit shall submit quarterly CEMS performance reports, to include dates and duration of each period during which the CEMS was inoperative (except for zero and span adjustments and calibration checks), reason(s) why the CEMS was inoperative and steps taken to prevent recurrence, and any CEMS repairs or adjustments. The owner/operator of each unit shall also submit results of any CEMS performance tests required by 40 CFR part 75. Or, for Trona Plant units, the owner/operator of each unit shall also submit results of any CEMs performance test required appendix F of 40 CFR part 60 (Relative Accuracy Test Audits, Relative Accuracy Audits, and Cylinder Gas Audits).

(3) When no excess emissions have occurred or the CEMS has not been inoperative, repaired, or adjusted during the reporting period, such information shall be stated in the quarterly reports required by sections (h)(1) and (2) above.

(4) The owner/operator of each unit shall submit results of any particulate matter stack tests conducted for demonstrating compliance with the particulate matter BART limits in section (c) above, within 60 calendar days after completion of the test.

(5) The owner/operator of each unit shall submit semi-annual reports of any excursions under the approved CAM plan in accordance with the schedule specified in the source's title V permit.

(i) *Notifications.*

(1) The owner/operator shall submit notification of commencement of construction of any equipment which is being constructed to comply with the NO_X emission limits in paragraph (c) of this section.

(2) The owner/operator shall submit semi-annual progress reports on construction of any such equipment.

(3) The owner/operator shall submit notification of initial startup of any such equipment.

(j) *Equipment operation.* At all times, the owner/operator shall maintain each unit, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

(k) *Credible Evidence.* Nothing in this section shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with requirements of this section if the appropriate performance or compliance test procedures or method had been performed.

■ 3. Add section 52.2637 to read as follows:

§ 52.2637 Federal implementation plan for reasonable attributable visibility impairment long-term strategy.

As required by 40 CFR 41.306(c), EPA will ensure that the review of the State's reasonably attributable visibility impairment long-term strategy is coordinated with the regional haze long-term strategy under 40 CFR 51.308(g). EPA's review will be in accordance with the requirements of 40 CFR 51.306(c).

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