Introduction and Purpose of Testimony

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

A. My name is Chad A. Teply. My business address is 1407 West North Temple, Suite 210, Salt Lake City, Utah. My position is vice president of resource development and construction for PacifiCorp Energy. I report to the president of PacifiCorp Energy. Both Rocky Mountain Power and PacifiCorp Energy are divisions of PacifiCorp.

Q. Please describe your education and business experience.

A. I have a Bachelor of Science Degree in Mechanical Engineering from South Dakota State University. I joined MidAmerican Energy Company in November 1999 and held positions of increasing responsibility within the generation organization, including project manager for the 790-megawatt Walter Scott Jr. Energy Center Unit 4 completed in June 2007. In April 2008, I moved to Northern Natural Gas Company as senior director of engineering. In February 2009, I joined PacifiCorp as vice president of resource development and construction, at PacifiCorp Energy. In this role, I have responsibility for development and execution of major resource additions and major environmental projects.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission with information regarding proposed capital investments in emissions control equipment, namely selective catalytic reduction ("SCR") systems, at the Company's Jim Bridger Units 3 and 4 facilities in support of the Company's Request for Approval (the "Request") of those investments. My testimony also discusses the Company's long-term emissions control plan.

Q. Please summarize the results of the economic analyses performed on the environmental investments.

A. As further discussed by Company witness Mr. Rick T. Link in the Docket, the base case results of the Company's economic analyses show a [redacted] present value revenue requirement differential ("PVRR(d)") favorable to investment in the emissions control investments that are the subject of the Request, namely SCR systems, and other incremental environmental compliance projects required to continue operating Jim Bridger Units 3 and 4 as coal-fueled assets. Mr. Link's testimony and exhibits support the economic analyses completed in support of the Request.

Q. Please summarize the topics your testimony addresses.

A. My testimony addresses the following:

1. the reason why the Company is filing the Request;
2. the need for the proposed emissions control equipment;
3. the alternatives considered;
4. the drivers, risks and planning processes associated with the Company's long-term emissions control plan; and
5. why the proposed emissions control investments are in the best interest of customers and in the best interest of the state of Utah.

Q. Has the Company filed a similar application in Wyoming in support of these same proposed investments?

A. Yes. The Company has recently filed an application for public convenience and necessity ("CPCN") with the Wyoming Public Service Commission. That application was filed in accordance with paragraph 13.b of the Stipulation and Agreement ("Stipulation") approved by the Wyoming Public Service Commission in Docket 20000-384-ER-10 as it pertains to Major Plant Investments: Environmental Projects (Stipulation Article 13.b).

Q. Which Rules apply to this Request?

A. Utah Admin. Code R746-440 applies to this Request. The information required by this Rule is found in the exhibits to my testimony described below and the testimony of Mr. Link.

Q. What exhibits are provided in support of your testimony?

A. The following exhibits are provided in support of my testimony:

- Confidential Exhibit RMP___(CAT-1) – including associated exhibit subparts:
    - Confidential Exhibit RMP___(CAT-1.1) – EPC Contract Technical Specification B-6964, including Appendix 1: Conceptual Design Drawings, February 1, 2012, Bid Issue
    - Confidential Exhibit RMP___(CAT-1.2) – Initial Capital Cost Estimates
    - Confidential Exhibit RMP___(CAT-1.3) – Incremental Operational and Maintenance and Ongoing Capital Costs
- Exhibit RMP___(CAT-2) – including associated exhibit subparts:

- Exhibit RMP___(CAT-2.1) – Jim Bridger Plant Property Ownership Key Plan
- Exhibit RMP___(CAT-2.2) – Surrounding Site Information
- Exhibit RMP___(CAT-2.3) – Permits

- Exhibit RMP___(CAT-3) – including associated exhibit subparts:
  - Exhibit RMP___(CAT-3.1) – Soil Engineering and Geologic Investigations for Jim Bridger Power Plant, Woodward-Clyde and Associates, Volumes I, II and III, September 30, 1970
  - Exhibit RMP___(CAT-3.2) – Jim Bridger Power Plant Geology/Hydrogeology
  - Exhibit RMP___(CAT-3.3) – Operating Mineral Deposits
  - Exhibit RMP___(CAT-3.4) – Topography of Site and Surrounding Area
- Confidential Exhibit RMP___(CAT-4) – including associated exhibit subparts:
  - Exhibit RMP___(CAT-4.1) – Overview of PacifiCorp's Environmental Control Plan
  - Exhibit RMP___(CAT-4.2) – Known Regulatory Drivers and Environmental Projects
  - Exhibit RMP___(CAT-4.3) – Mercury and Air Toxics Standards Projects
  - Exhibit RMP___(CAT-4.4) – Coal Combustion Residuals Projects
  - Exhibit RMP___(CAT-4.5) – Potential Impacts of Environmental Regulation on the U.S. Generation Fleet
  - Exhibit RMP___(CAT-4.6) – Jim Bridger Units 3 and 4 Projected

Emissions Reductions

- Exhibit RMP___(CAT-5) – Resolution on the Role of State Regulatory Policies in the Development of Federal Environmental Regulations
- Confidential Exhibit RMP___(CAT-6) – 2011 Integrated Resource Plan Supplemental Coal Replacement Study, September 21, 2011
- Confidential Exhibit RMP___(CAT-7) – 2011 Integrated Resource Plan Update, March 30, 2012
- Confidential Exhibit RMP___(CAT-8) – Major Contracts
- Confidential Exhibit RMP___(CAT-9) – Template Turnkey Contract for Engineering, Procurement and Construction Services For Selective Catalytic Reduction System Project for Jim Bridger Plant Units 3 and 4, Revision: RFP Version – PAC Rev. 2-17-2012.

Background Information and Basis for the Projects

Q. Did the Company recently seek authorization in Wyoming, similar to this Request, for SCR and baghouse systems to be installed at the Company's Naughton Unit 3?

A. Yes. The Company filed a similar CPCN application for SCR and baghouse systems to be installed at the Naughton Unit 3 in Wyoming. That docket is Wyoming Docket No. 20000-400-EA-11 (Record No. 12953). Ultimately, however, given that project's particular economics, the Company withdrew that application and is instead pursuing natural gas conversion of that unit.

Q. What are the key drivers that result in a recommendation to invest in emissions control equipment at Jim Bridger Units 3 and 4, versus pursuing gas

conversion as proposed for Naughton Unit 3?

A. The key drivers resulting in a different decision are:

1. There is a significant difference in capital investment costs associated with the required emissions control retrofit projects for Jim Bridger Units 3 and 4. Significantly, the cost on a dollars per kilowatt basis is approximately half of that required for the Naughton Unit 3 retrofits because of the lack of baghouse requirements for Jim Bridger Units 3 and 4 and the larger generation capacity of the Jim Bridger units.
2. There are also differences in levelized annual operating costs and run-rate capital costs between the individual units. The differences in ongoing costs between gas conversion and continued coal operation for Naughton Unit 3 as compared to Jim Bridger Units 3 and 4 are primarily driven by lower operational and maintenance costs at the Jim Bridger units when fueled by coal as compared to Naughton Unit 3.

Each of these drivers is also discussed in Mr. Link's testimony.

Q. What significant developments have occurred regarding environmental regulations affecting Jim Bridger Units 3 and 4 since the Naughton Unit 3 CPCN filings?

A. The U.S. Environmental Protection Agency ("EPA") has proposed action on Wyoming's Regional Haze State Implementation Plan ("SIP") as it pertains to oxides of nitrogen ("NO_x"). EPA recommends approval of the SCR and low NO_x burner installations on Jim Bridger Units 3 and 4 as Best Available Retrofit Technology ("BART") within the deadlines prescribed in the state's SIP as associated permits. EPA's proposed action on Wyoming's Regional Haze SIP as it pertains to sulfur dioxide ("SO_2"), recommends approval of the state's SIP in this regard, which incorporates the established emissions limits assigned to the Jim Bridger Units 3 and 4 scrubbers as currently configured.

The final Mercury and Air Toxics Standards ("MATS") were published in the *Federal Register* on February 16, 2012, with an effective date of April 16, 2012, and require that new and existing coal-fueled facilities achieve emission standards for mercury ("Hg"), acid gases and other non-mercury hazardous air pollutants. Existing sources are required to comply with the new standards by April 16, 2015. Individual sources may be granted up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls or for transmission system reliability reasons.

The Company believes that its emissions reduction projects completed to date on Jim Bridger Units 3 and 4 are consistent with the EPA's MATS and will support the Company's ability to comply with the final rule's standards for acid gases and non-mercury metallic hazardous air pollutants. The Company will be required to take additional actions to reduce mercury emissions through the installation of controls and use of reagent injection at Units 3 and 4 to otherwise comply with the final rule's standards. Budgeted costs for these additional actions have been incorporated into the financial analyses supporting the Request.

In April 2012, the EPA proposed new source performance standards for <u>new</u> fossil-fueled generating facilities that would limit emissions of CO_2 to 1,000 pounds per megawatt hour. The EPA indicated in its proposal that it does not have sufficient information to establish greenhouse gas ("GHG") new source performance standards for existing, modified or reconstructed units and has not established a schedule for when these units, or other existing sources, will be regulated. Until standards for existing, modified or reconstructed units are finalized, the impact on the Company's existing facilities cannot be determined.

On July 24, 2012, the EPA provided notice that the final rule affecting power plant cooling water intake structures has been delayed. The EPA had been under court order to issue a final rule by July 27, 2012; however, a modified settlement agreement has delayed issuance of the final rule until June 27, 2013. The rulemaking pertains to the protection of aquatic wildlife affected by the operation of cooling water intake structures.

Q. Do any of the environmental regulation developments described above alter the Company's recommendation and request in the Request to invest in the emissions control retrofits described herein?

A. No.

Q. What is the status of the Company's procurement effort underlying this request?

A. In February 2012, the Company transmitted engineer, procure, construct ("EPC") contract request for proposal ("RFP") packages to approximately 26 potential technology providers, engineers and constructors that were prequalified by the Company as being capable of completing various components of the EPC contract scope. The RFP packages included a template contract and exhibits, RFP instructions, and a comprehensive technical specification. In order to execute the full EPC contract scope, the invited entities generally formed teams to respond that include a technology provider, a "balance of project" engineer and a constructor. A copy of the template contract is attached as Confidential Exhibit RMP___(CAT-9).

Q. What is the Company's anticipated schedule for completing this major procurement effort?

A. The Company is currently evaluating the proposals received from the five EPC contract teams that responded to the Company's RFP and expects that it will be able conclude the evaluation and subsequent negotiations with the least cost evaluated contractor by [redacted]. The contract will be negotiated such that notice to proceed to the selected contractor will be released by [redacted] upon receipt of internal Company approvals, necessary permits, and Commission orders from the states of Utah and Wyoming, including the order expected to result from this Request. The Company believes that Spring 2013 is the latest time in which it can begin work on the Project and effectively meet its deadlines.

Q. How has the Company calculated the estimated project capital cost used to support this Request and its underlying analyses?

A. The Company's estimated project capital cost used to support this Request and its underlying analyses includes line item project execution costs based on engineer's estimates and a "calibrated" cost for the EPC contract based on initial bids received from the competitive RFP process. The various estimate components were compiled line by line and are provided in Confidential Exhibit RMP___(CAT-1.2) for reference and the cost analysis is discussed at Confidential Exhibit RMP___(CAT-1). In addition to the EPC contract, a list of other major contracts necessary to complete the Project is attached as Confidential Exhibit RMP___(CAT-8).

[redacted]

Q. Will the Company confirm that the final negotiated contract cost remains aligned with the Company's estimated project capital cost assumptions used to support this Request prior to completion of this Docket?

A. Yes. Pursuant to the anticipated procurement schedule described above, the Company will confirm that the final negotiated contract cost remains aligned with the Company's estimated project capital cost assumptions used to support this Request prior to completion of this Docket.

Description of Jim Bridger Plant and Projects

Q. Describe the Jim Bridger plant and the operating features of Units 3 and 4.

A. The Jim Bridger plant consists of four coal fueled units which are two-thirds co-owned by PacifiCorp and one-third co-owned by the Idaho Power Company. The plant is maintained and operated by PacifiCorp Energy. Water for operation is conveyed approximately 40 miles through a pipeline originating at a diversion from the Green River. Unit 3 began commercial operation in 1976 and Unit 4 followed in 1979. Unit 3 and Unit 4 have nominal net (or "net reliable") generation capacities of 523[1] and 530 megawatts ("MW") respectively, of which the corresponding PacifiCorp two-thirds share 349 and 353 MW. Both units are configured with Alstom (formerly Combustion Engineering) controlled circulation, tangentially fired, pulverized coal boilers and General Electric steam turbine-generators. Nominal steam conditions are 2,400 pounds per square inch gauge pressure at 1,000 degrees Fahrenheit ("F") at the turbine-generator throttle valve. Both units are configured with closed loop circulating water cooling systems that include mechanical draft cooling towers and electrostatic precipitators. Unit 4 was originally equipped with a sodium-based wet flue gas desulfurization ("FGD") system, and Unit 3 was retrofitted in 1985 with a sodium-based wet FGD system.

The Plant has been, and remains, integral to the Company's charge of providing electrical service to its customers, not only in Wyoming, but also in Utah and the other states served by the Company. The Rocky Mountain Power Jim Bridger substation is contiguous to the plant and connects six transmission lines: Populus #1 at 345 kilovolts ("kV"), Populus #2 at 345 kV, Threemile Knoll at 345 kV, Rock Springs at 230 kV, Point of Rocks at 230 kV and Mustang at 230 kV. The Plant is dispatched on a system wide basis to serve PacifiCorp customers, including Utah customers.

The plant is adjacent to PacifiCorp's and Idaho Power's co-owned Jim Bridger mine, which supplies approximately six million tons per year of sub-bituminous coal to the plant along a 2.4-mile long, 42-inch wide overland belt

[1] On February 22, 2012, a Unit 3 re-rating from 530 to 523 MW was executed. The economic evaluation represented herein was based on an assumed Unit 3 total net reliable capacity of 530 MW and accounting for the incremental increase in auxiliary power consumption by the addition of the SCR system on each unit.

conveyor at a rate of approximately 1,500 tons per hour. An additional approximately three million tons per year of sub-bituminous coal is delivered to the plant from other mines in southwestern Wyoming via rail or truck. Coal combustion residuals ("CCR") are disposed of on plant property in a solid waste landfill and a FGD waste surface impoundment.

The Plant currently employs approximately 327 personnel, including approximately 262 union craft personnel represented by the Utility Workers Union of America Local 127.

Q. Please provide a general description of the emissions control investments included in the Company's long-term emissions control plan and the benefits gained from the investments.

A. The emissions control equipment investments included in the Company's long-term emissions control plan primarily result in the reduction of SO_2, NO_X, Hg, and particulate matter ("PM") emissions from generation facilities subject to federal and state emissions requirements. The Company has developed and executed its emissions control plan with a focus on maintaining a reasonable balance between protecting the interests of customers, meeting the obligation to be in a position to serve the current and reasonably projected demands of our customers, and complying with environmental requirements, all in the face of an uncertain regulatory environment.

The Company's environmental projects are required to comply with existing Regional Haze Rules, Regional SO_2 Milestone and Backstop Trading Programs, National Ambient Air Quality Standards, and New Source Review requirements. The projects are also required to comply with stand-alone requirements in state SIPs, BART permits, construction permits, and approval orders enforceable by the laws of the respective states. The projects completed to date and/or currently permitted also position the Company well to comply with the EPA's recently finalized MATS standards.

Q. Please describe the specific emissions control investments planned at Jim Bridger Units 3 and 4 for which the Company is seeking approval.

A. The Jim Bridger Units 3 and 4 emissions control investments proposed in the Request are SCR systems and associated ancillary equipment for each unit. Each SCR system would be comprised of two separate universal reactors, with multiple catalyst levels; inlet and outlet ductwork; a shared ammonia reagent system; an economizer upgrade; structural reinforcement of the boiler and flue gas path ductwork and equipment; and extension of the existing plant distributed control system ("DCS"). An induced draft ("ID") fan upgrade and an associated auxiliary power system variable frequency drive ("VFD") insertion is required on Unit 4 only. Details are further described in Confidential Exhibit RMP___(CAT-1) to my testimony.

Q. Please explain the decision on timing of the emissions control equipment investments at Jim Bridger Units 3 and 4.

A. Pursuant to the Regional Haze Rules, Wyoming has imposed environmental standards under which the SCR systems are required to be installed at Bridger Units 3 and 4 for those Units to be able to continue to operate beyond 2015 and 2016 respectively. The Company's "Best Available Retrofit Technology" permit for the Bridger facility issued by Wyoming's Department of Environmental Quality on December 31, 2009 (the "BART Permit) required the Company to submit permit applications for the installation of SCR on Jim Bridger Units 3 and 4 by 2015 and 2016, respectively, under the state of Wyoming's Regional Haze Long-Term Strategy. The Company appealed these requirements; ultimately reaching a settlement agreement with the Wyoming Department of Environmental Quality, Air Quality Division in November 2010 (the "BART Settlement Agreement"). The BART Settlement Agreement requires the Company to install SCR or alternative add-on NOx control systems on Unit 3 by the end of 2015 and on Unit 4 by the end of 2016 to comply with required NOx emission limits. The Wyoming Regional Haze 309(g) State Implementation Plan (the "Wyoming SIP") issued on January 7, 2011, also includes these requirements. Specifically, the BART Settlement Agreement and the Wyoming SIP require NOx emission limits of 0.07 pounds per million British thermal units ("lb/mmBtu) to be achieved on Unit 3 by the end of 2015 and on Unit 4 by the end of 2016 via the installation of SCR or alternative add-on NOx control systems; with SCR being the emissions control technology solution identified during the state's BART-determination process as producing the required results. The Company has filed its construction permit applications with the WDEQ reflecting these requirements.

Moreover, the EPA proposed to approve these requirements in a notice published in the *Federal Register* on June 4, 2012. Final action by the EPA is expected by mid-October 2012; EPA's expected final approval would make these emission reduction requirements at Jim Bridger Units 3 and 4 federally enforceable as well.

Q. Has the Company provided analyses of the Jim Bridger Units 3 and 4 emissions control investments versus other compliance alternatives to demonstrate that the projects are the least-cost, adjusted for risk, outcome for its customers?

A. Yes. The analyses completed by the Company support retrofitting Jim Bridger Units 3 and 4 with emissions control equipment to allow ongoing coal fueled energy production from this facility through the depreciable life currently approved for ratemaking as the least-cost, adjusted for risk, outcome for customers. The testimony of Mr. Link provides additional detail in this regard.

Jim Bridger Units 3 and 4 Alternatives and Regulations

Compliance Alternatives

Q. Does the Company focus solely on investment in emissions control equipment as a means of environmental compliance?

A. No. As part of the Company's compliance planning efforts, consideration is given to selection of appropriate emissions control technologies as well as alternate compliance options such as retirement of a unit and replacing it with market power purchases, procurement of replacement generation, and converting a unit to be fueled with natural gas. The results of these analyses are discussed further in the testimony of Mr. Link.

Q. Does the Company believe that it has appropriately assessed the cost effectiveness of the emissions control technologies selected?

A. Yes. Beyond the analyses described in Mr. Link's testimony and before determining to proceed with the proposed emissions control investments, the Company considered the cost effectiveness of alternate compliance technologies. Measures of capital cost on a dollars per ton of pollutant removed have been reviewed, which is applied specifically as part of Wyoming's BART determination process.

Q. Has the Company applied least-cost, risk adjusted, principles to selection of its emissions control investments?

A. Yes. The various analyses discussed in my testimony and in the testimony of Mr. Link all demonstrate application of least-cost, risk adjusted, principles by the Company in support of the Request.

Q. Does the Company need to make the investments for Jim Bridger Units 3 and 4 if it expects to continue operating these Units?

A. Yes. In order to comply with the requirements that are set forth in the facility's air quality permit applications and the state of Wyoming's Regional Haze SIP, it is necessary to install and operate the controls in question. The Company has an obligation to operate its facilities in compliance with its permit requirements and the applicable laws and regulations, as well as satisfy the Company's other statutory and regulatory requirements. Installing and operating the proposed emissions control equipment that allows the units to continue operating is the least-cost, adjusted for risk, option to meet all the applicable requirements, as indicated by the Company's analyses.

Q. What is the currently approved depreciable life for ratemaking purposes of Jim Bridger Units 3 and 4?

A. Both Unit 3 and 4's currently approved depreciable life, for ratemaking purposes, is through 2037, except for in Oregon which utilizes 2025. The Company currently reviews the depreciable lives of its assets every five years.

Q. What other factors does the Company consider?

A. Factors such as ongoing compliance with existing operating requirements, fuel supply flexibility, equipment end of life considerations, and operational efficiencies are also factors typically included in the Company's investment decisions.

Q. How has fuel supply flexibility factored into planning of emissions control investments?

A. Since the Jim Bridger plant is primarily a mine-mouth facility, fuel supply design flexibility has been focused on establishing appropriate fuel quality design ranges representative of potential fuel quality to be received from the mine. It is expected that secondary coal reserves in the area of the Jim Bridger facility demonstrate similar fuel quality characteristics. In addition to primary and secondary coal sources, the Company is incorporating design parameters into the Jim Bridger SCR systems to accommodate Power River Basin ("PRB") coals to allow future PRB coal switching to remain a viable long-term planning alternative with limited modifications required to the SCR systems.

Q. What other operational considerations have factored into planning of emissions control investments?

A. The Company has considered several other operational factors in its project planning including the following: planned maintenance outage cycles, local weather conditions, urea costs, ammonia handling safety, ammonia injection grid tuning, ammonia slip effects, catalyst activity testing, catalyst lifecycle, catalyst cleaning, ash particle sizes, long-term operational and maintenance ("O&M") costs, run-rate capital costs, and emerging CCR disposal requirements.

Regional Haze Rules

Q. Please describe the primary environmental regulation requiring emission control investments at the Jim Bridger Units 3 and 4.

A. Through the 1977 amendments to the Clean Air Act, Congress set a national goal for visibility to remedy impairment from man-made emissions in designated national parks and wilderness areas; this goal resulted in development of the Regional Haze Rules, adopted in 2005 by EPA. The first phase of these rules trigger BART reviews for all coal-fired generation facilities built between 1962 and 1977 that emit at least 250 tons of visibility-impairing pollution per year. Visibility-impairing pollutants include SO_2, NO_x and PM. The Company owns and operates 14 units that meet the construction and emissions threshold criteria and are, therefore, "BART-eligible units." Pursuant to federal regulations at 40 *Code of Federal Regulations* ("CFR") 51.308(e)(1)(ii), each state is required to determine which BART-eligible sources are also "subject to BART." BART-eligible sources are subject to BART if they emit any air pollutant that may reasonably be anticipated to cause or contribute to impairment of visibility in any designated national park or wilderness area. The investments in emissions control equipment at the Company's BART-eligible units, including Jim Bridger Units 3 and 4, have been determined by the state environmental regulators to be necessary after considering available technology; costs of compliance; energy and non-air quality environmental impacts; existing control equipment and the remaining useful life of the facility; and the degree of improvement in visibility reasonably anticipated to result from the use of such technology.

Q. Has the Company undertaken reasonable efforts to ensure that environmental regulators consider the risks associated with requiring investments in certain emissions controls prior to knowing the nature and extent of control requirements for other emissions?

A. Yes. The Company filed an appeal of certain BART permits in Wyoming for this exact reason, including those requiring SCR for NO_x emissions control on Jim Bridger Units 3 and 4. Wyoming was the first state to make the determination that BART required the installation of SCR controls for NO_x emissions, and also to impose long-term strategy requirements for SCR in a BART permit. The Company disagreed with the determination that SCR was BART and asserted that Appendix Y of 40 CFR Part 51 did not contemplate the installation of post-combustion controls. The Company further disagreed that a long-term strategy requirement could be included in a BART permit.

Additionally, the Company was concerned that other environmental laws and or regulations could impact the Company's facilities affected by Wyoming's BART determinations in a way that impacted the economic analysis associated with the installation of the contemplated controls. These requirements not only include greenhouse gas reduction requirements, but also a host of regulatory initiatives underway by EPA, including the outcome of pending CCR regulation and MATS for mercury and non-mercury hazardous air pollutants ("HAPS"). Due to the uncertainty associated with the potential impact of these rules on the Company's facilities, the Company appealed the BART permits to ensure that these and other issues were considered in the agency's decision and, to the extent these issues had an impact on long-term viability of the facilities, the economic analysis of adding emission reduction equipment was properly reflected.

Q. Has this appeal been resolved?

A. Yes. In November 2010, PacifiCorp settled the Wyoming BART appeal to resolve the matter in a way that did not require more controls and impose additional costs earlier than originally proposed in the Wyoming Department of Environmental Quality's ("Wyoming DEQ") BART permits. To provide maximum flexibility in the event that other environmental requirements or uncertainties arose, PacifiCorp and the Wyoming DEQ included terms in the Bart Settlement Agreement to address a modification if future changes in either federal or state requirements or technology would materially alter the emissions controls and rates that would otherwise be required.

Q. Please describe the efforts taken to evaluate available emissions control technologies.

A. As part of the BART review of each facility, the Company evaluated several technologies on their ability to economically achieve compliance and support an integrated approach to control criteria pollutants (*e.g.* SO_2, NO_X, and PM for the facility), if it were to continue to operate and to burn coal. The BART analyses reviewed available retrofit emission control technologies and their associated performance and cost metrics. Each of the technologies was reviewed against its ability to meet a presumptive BART emission limit based on technology and fuel characteristics. The BART analyses outlined the available emission control technologies, the cost for each and the projected improvement in visibility which can be expected by the installation of the respective technology. For each unit or source subject to BART, the state environmental regulatory agencies identify the appropriate control technology to achieve what the air quality regulators determine are cost-effective emission reductions. The state's BART determination for Jim Bridger Units 3 and 4, including the SCR projects as discussed herein, is discussed further in Confidential Exhibit RMP___(CAT-4) and has been incorporated into the BART permits issued for the facility as well as the Wyoming Regional Haze SIP. Once the appropriate BART technology was identified, the Company moved forward with its permitting and competitive bidding processes to specify, evaluate and ultimately select the preferred provider for the projects. Evaluation and selection of the preferred provider for the projects has not yet been completed.

Q. Have emerging environmental regulations been factored into the evaluation of Jim Bridger Units 3 and 4 emissions control investments?

A. Yes. Emerging environmental regulations; specifically MATS regulations, proposed CCR regulations, proposed Clean Water Act 316(b) water intake rulemaking, and CO_2 emissions costs sensitivities have been considered in the Jim

Bridger Units 3 and 4 analyses. Proxy compliance costs associated with potential effluent guidelines have not been incorporated, as information that would offer insight into the reasonably anticipated requirements of that proposed rulemaking effort has not been made available.

Mercury and Air Toxics Standards - MATS

Q. What is the Company's current assessment of potential impacts of MATS regulations on Jim Bridger Units 3 and 4?

A. The Company believes that its emissions reduction projects completed to date on Jim Bridger Units 3 and 4 are consistent with the EPA's MATS and will support the Company's ability to comply with the final rule's standards for acid gases and non-mercury metallic HAPS. The MATS standards (in general terms):

- 1.2 pounds per trillion British thermal unit ("lb/TBtu") for mercury;
- 0.0020 pounds per million British thermal unit ("lb/mmBtu") (0.02 pounds per megawatt-hour ("lb/MWh")) for acid gases or a surrogate 0.20 lb/mmBtu SO_2 limit; and
- individually prescribed limits for non-mercury metals or a surrogate 0.030 lb/mmBtu (0.3 lb/MWh) filterable particulate matter limit.

While the Jim Bridger Units 3 and 4 SCR projects required by the state of Wyoming's permits and Regional Haze SIP will not directly control emissions required to support MATS compliance, the units are otherwise positioned well to comply with the standards for acid gases and non-mercury metallic HAPS. As discussed previously, the Company will be required to take additional actions to reduce mercury emissions through the installation of controls and use of reagent injection at Jim Bridger Units 3 and 4 to otherwise comply with the final rule's standards.

Q. What is the Company's current assessment of additional actions the Company will need to take to comply with MATS mercury emissions regulations on Jim Bridger Units 3 and 4?

A. The Company's current assessment of MATS mercury emissions regulations suggests that for Jim Bridger Units 3 and 4 it will be necessary to add a coal additive, namely calcium bromide ("$CaBr_2$"), to oxidize mercury and then add a scrubber additive to prevent readmission of mercury in the scrubber system. The potential exists to reduce the coal additive requirements due to the SCR and the SCR catalyst oxidizing the vapor phase mercury, but that potential is not currently being counted on as a compliance mechanism. Current plans do not anticipate changing waste disposal practices after installation and use of the above additives. The SCR is not expected to affect the need for a scrubber additive. The costs of the mercury emissions control systems have been incorporated into the financial analyses completed in support of the Request.

Proposed Coal Combustion Residuals Regulations - CCR

Q. What is the Company's current assessment of potential impacts of proposed EPA CCR regulations on Jim Bridger Units 3 and 4?

A. As the Company assesses decisions to continue to invest in its coal fueled generation assets, it is important to note that the Company will be faced with certain CCR storage, handling, and long-term management costs at its existing facilities whether the facilities continue to operate or not. Therefore, the Company continually updates its CCR-related costs and asset retirement obligations in its planning processes.

In response to the proposed EPA rulemaking regarding CCR, the Company has updated its CCR-related costs and asset retirement obligations on a preliminary basis to incorporate proposed Subtitle D or near-Subtitle D infrastructure requirements, which will serve as a planning proxy for the Company until such time as EPA responds to the completed public comment period for CCR regulations. It is currently anticipated that compliance with final CCR rules promulgated as a result of the ongoing EPA effort will be required five years after final rulemaking, or by late-2017 at the earliest, based on the EPA's current intent. Until a final rule is promulgated, the cost, timing, equipment, monitoring, and recordkeeping to comply with the rule cannot be fully ascertained. However, the costs of the Company's proxy CCR Subtitle D compliance projects have been incorporated into the analyses. The Company has also incorporated appropriate CCR design provisions and compliance planning into the technical specifications for the Jim Bridger Units 3 and 4 SCR systems.

Q. Has the Company participated in the public comment period associated with the EPA's proposed CCR regulations?

A. Yes. The Company has filed written comments in the EPA rulemaking on this matter, Docket ID No. EPA-HQ-RCRA-2009-0640, and also provided comments at one of the EPA's public hearings, held in Denver, Colorado. In general, the Company's perspective is that the Subtitle C hazardous waste regulatory approach proposed by the EPA would lead to a myriad of draconian results for all utilities and the U.S. economy, as agricultural, transportation, infrastructure, and construction benefits of CCR use would be halted. PacifiCorp vigorously supports the development of CCR as a non-hazardous waste under the Resource Conservation and Recovery Act ("RCRA") Subtitle D non-hazardous waste rule. The uncertainty surrounding the breadth of Subtitle C impacts on the industry and the economy makes attempting to analyze the associated economics unproductive. Therefore, PacifiCorp has not completed specific studies to fully ascertain the impacts of the proposed Subtitle C rulemaking outcome.

Proposed Clean Water Act 316(b) Regulations

Q. What is the Company's current assessment of potential impacts of proposed Clean Water Act 316(b) water intake regulations on Jim Bridger Units 3 and 4?

A. Due to the preliminary status of the 316(b) rulemaking process, the Company has not completed specific detailed studies to fully ascertain and verify that intake structure retrofits or new technologies are necessary to comply with the currently proposed 316(b) water intake regulations, particularly since a key element of the proposed rule is to conduct plant-specific studies and assessments. While the EPA was expected to issue a final rule by July 27, 2012, the issuance of the rule has now been deferred to June 2013. The Jim Bridger plant utilizes cooling towers and closed cycle cooling, significantly reducing potential 316(b) rulemaking exposure. Nonetheless, modifications may be needed at the Jim Bridger cooling water intake structure, located at the Green River diversion, to comply with the proposed impingement mortality standards. As such, the Company has developed a preliminary estimate of the costs associated with potential studies and potential mitigation projects at Jim Bridger by extrapolating results of a 2007 study completed at the Company's Dave Johnston facility prior to the suspension of the Phase II Section 316(b) rule. The currently estimated costs for the Jim Bridger facility have been incorporated into the analyses completed and are described in Confidential Exhibit RMP___(CAT-1) to my testimony.

Q. Has the Company participated in the public comment period associated with the proposed Clean Water Act 316(b) water intake regulations?

A. Yes. The Company has filed comments in the EPA rulemaking on this matter, Docket ID No. EPA-HQ-OW-2008-0667. In general, the Company's perspective is supportive of EPA's willingness to provide for case by case, site-specific flexibility for facilities related to the establishment of and compliance with entrainment standards. However, the Company does have concerns with:

1. the ability of regulated entities to achieve the proposed numeric limits for impingement;
2. the potentially subjective interpretation and implementation of entrainment standards by the delegated state permitting authorities;
3. the potential multiple definitions and redefinitions of Best Technology Available;
4. the proposed cost-benefit analysis process for species of concern;
5. the lack of a de minimis impact exemption;
6. the proposed monitoring and recordkeeping requirements; and

7. the proposed timing of compliance requirements. In addition, the Company asserted its position in the rulemaking docket that since closed cycle cooling already represents Best Technology Available, it should be deemed to meet compliance with the 316(b) requirements.

Proposed Effluent Rulemaking

Q. What is the Company's current assessment of potential impacts of proposed EPA effluent rulemaking on Jim Bridger Units 3 and 4?

A. The EPA's announced intention to undertake effluent rulemaking has not yet materialized into proposed guidelines to regulate effluent limits for wastewater discharges from steam electric plants. While the Company is aware that the effluent guidelines may be revised, how they may be revised is entirely speculative. While the Jim Bridger facility does have effluent outflows that may be impacted by the proposed rulemaking, attempting to analyze hypothetical scenarios with no basis for direction would not produce meaningful results. The EPA's "Steam Electric Power Generating Point Source Category: Final Detailed Study Report" dated October 2009, largely reviewed plants in the Eastern U.S. and was not sufficient to provide the Company with information regarding what the revised guidelines would entail and or how the CCR rulemaking may impact those guidelines.

CO_2 Cost Sensitivities

Q. Has the Company assessed the costs of continuing to invest in individual coal fueled generation with consideration given to CO_2 cost sensitivities?

A. Yes. As discussed further in the testimony and exhibits of Mr. Link, the Company has included various CO_2 cost sensitivities and resulting market pricing assumptions in its System Optimizer modeling efforts in support of the projects.

Future Environmental Regulations

Q. Does the Company consider future environmental requirements when planning and undertaking emissions reduction projects?

A. Yes. While the projects requested for approval in the Request are driven by current environmental requirements, the Company has also considered the need for the incremental emission reductions and the type of controls that could be required in the future when planning for these projects. There are a multitude of environmental requirements the electric industry faces over the next several years. An EPA environmental regulations development timeline provided in Confidential Exhibit RMP___(CAT-4, Figure 4.1) identifies some of the environmental requirements that are currently underway or in development. There is a great deal of uncertainty associated with future environmental requirements; however, the Company must comply with the requirements that exist today and prepare for the regulations that will be adopted in the future.

Q. Has the Company assessed the costs of continuing to invest in individual coal fueled generation assets with consideration given to increasingly more stringent National Ambient Air Quality Standards?

A. Yes. Increasingly more stringent National Ambient Air Quality Standards have been and are being adopted for criteria pollutants, including SO_2, nitrogen dioxide (“NO_2”), ozone, and PM. However, Utah and Wyoming have not yet made any determinations as to what, if any areas may be in nonattainment with respect to the new standards.[2] Implementation of the Jim Bridger Units 3 and 4 emissions control projects, as described in Confidential Exhibit RMP___(CAT-1) to my testimony, is expected to assist in meeting these more stringent standards, avoiding the negative consequences of an area being declared to be in nonattainment. Recognizing that there is a great deal of uncertainty associated with these future requirements, attempting to analyze hypothetical compliance scenarios without information pertaining to potentially affected areas and or units would not produce meaningful results. This uncertainty is highlighted by President Obama's determination on September 2, 2011, that the EPA should withdraw its pending reconsideration of the ozone standard and, instead, reconsider the standard during the 2013 scheduled review.

Greater Sage-grouse Considerations

Q. Has the Company provided specific information pertaining to potential impacts to plant and animal life in the areas surrounding the project?

A. Yes. Exhibit RMP___(CAT-2) to my testimony specifically discusses potential impacts to plant and animal life in the areas surrounding the project. In general,

[2] Portions of Lincoln, Sweetwater and Sublette Counties in Wyoming have been classified as being in marginal nonattainment areas of the 2008 ozone standard. However, the ozone nonattainment area does not currently extend to the area in which the Jim Bridger plant is located.

because the project will be executed entirely within the plant-proper boundaries of the existing Jim Bridger facility, no material impacts in this regard are expected. The Company remains aware of State of Wyoming Executive Order 2011-5 regarding protection of the greater sage-grouse core area in the state. The Jim Bridger facility is not located within a state designated greater sage-grouse core area.

Critical Nature of Request Approval

Q. Has the Company established its project development schedule to successfully complete the Jim Bridger Units 3 and 4 SCR projects in accordance with established compliance timelines and project budgets?

A. Yes. The Company has developed its project development schedule with a sufficient period of time to allow the Commission to evaluate the Request pursuant to the requirements of Utah Code Ann. 54-17-402.

Q. What construction related cost risks could result should the approval of the Request be delayed?

A. To benefit from competitive market pricing and establish an accurate project critical path schedule aligned with the planned major maintenance outage schedule for Jim Bridger Unit 3, the Company initiated a competitive procurement process for the Jim Bridger Units 3 and 4 SCR project in January 2012. The Company will negotiate in good faith with requests for proposal respondents toward establishing an EPC contract for the project. Delayed receipt of approval could result in a request from the ultimately selected contractor for additional project costs due to expired bid validity periods for subcontractors, commodity cost increases, labor cost increases, accelerated equipment deliveries, accelerated work schedules, and conditional cash flow adjustments by way of example.

Q. What schedule risks could result if approval on the Request is delayed?

A. The project critical path schedule has been established to align with the planned major maintenance outage schedule for Jim Bridger Unit 3 in the spring of 2015 and subsequent performance testing thereafter to achieve emission compliance by the end of 2015. Delayed approval could result in the remaining schedule duration being unachievable, either resulting in a need to defer the planned major maintenance outage for Jim Bridger Unit 3 or potentially the inability of the contractor to meet a 2015 completion schedule. Significant risks associated with delayed approval on the Request include missing the compliance window, loss or deferral of manufacturing queue for key materials and or components, labor unavailability, inclement weather delays, costs associated with deferral of other planned major maintenance outage work, and potential seasonal replacement power cost impacts by way of example.

Long-Term Emissions Plan Discussion

Q. Has the Company provided discussion of its long-term emissions control plan up to and including December 31, 2022?

A. Yes. Confidential Exhibit RMP___(CAT-4) to my testimony presents the Company's long-term emissions control plan up to and including December 31, 2022.

Q. Does this testimony discuss the complexity in balancing stakeholder interests that the Company faces in making prudent emissions control capital investment decisions?

A. Yes. There are many different viewpoints regarding whether the Company should make investments in its coal fueled facilities. These viewpoints include:

(1) ardent opposition to continued investment in and operation of coal fueled generation,

(2) recommendations for deferred decision-making while awaiting regulatory certainty and final EPA action, and

(3) support of the Company's emissions control investments and continued utilization of coal for generation, with consideration given to regulation of its obligation to reliably and cost-effectively serve its customers, while balancing compliance with current and anticipated likely environmental requirements and regulations.

Emissions Control Plan Overview

Q. Please provide an overview of the projects included in the Company's emissions control plan, along with their costs and key regulatory drivers.

A. The Company wholly-owns or has partial ownership share in 26 coal fueled units within the states of Wyoming, Utah, Arizona, Colorado, and Montana. The Company maintains operational responsibility for 19 of those units. The

Company's emissions control plan has been developed and maintained to ensure compliance with environmental regulations governing the Company's operations. Exhibits RMP___(CAT-4.1) through RMP___(CAT-4.4) to my testimony have been prepared to provide a forward-looking overview of the projects currently included in the Company's emissions control plan and other environmental compliance plans, including current status and key regulatory drivers.

Q. What priorities have been established as part of the Company's emissions control plan?

A. The Company began implementing its emissions control plan in 2005. The initial focus of the plan has been on installing controls to reduce SO_2 emissions which are the most significant contributors to regional haze in the western United States. The Company's emissions control plan also includes the installation or retrofit of five baghouses to control particulate matter emissions. For units which utilize dry scrubbers, baghouses have the added benefit of improving SO_2 removal. Baghouses also significantly improve mercury emissions control capability. In addition to its SO_2 and PM emissions reductions, the Company continues to rely on installation of low NOx burners to significantly reduce NOx emissions. The Company's major environmental compliance projects going forward will primarily focus on the reduction of NO_X emissions, also regulated under the Regional Haze Rule. The Company currently anticipates completing installation of four SCRs (or similar NOx-reducing technologies) by 2022, further reducing NOx emissions from its Jim Bridger units. The first two of those SCRs are the subject of the Request.

Q. What level of emissions reductions are expected to occur at the Company's Wyoming, Utah, and Arizona facilities as a result of the Company's emissions control plan?

A. The following figures represent the reductions in SO_2 and NOx emissions that are expected to occur at units owned by the Company in Wyoming, Utah, and Arizona as a result of the Company's emissions control plan including the Bridger SCR Projects.

Figure 1

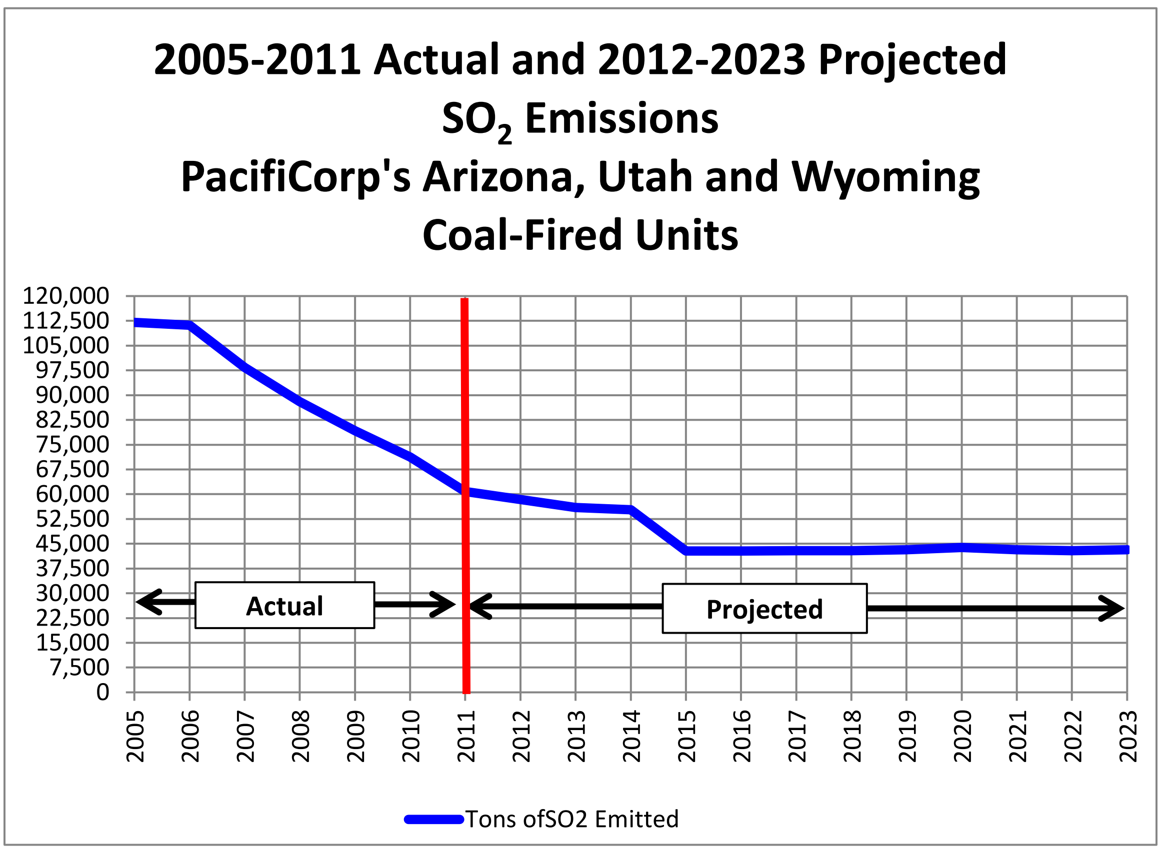
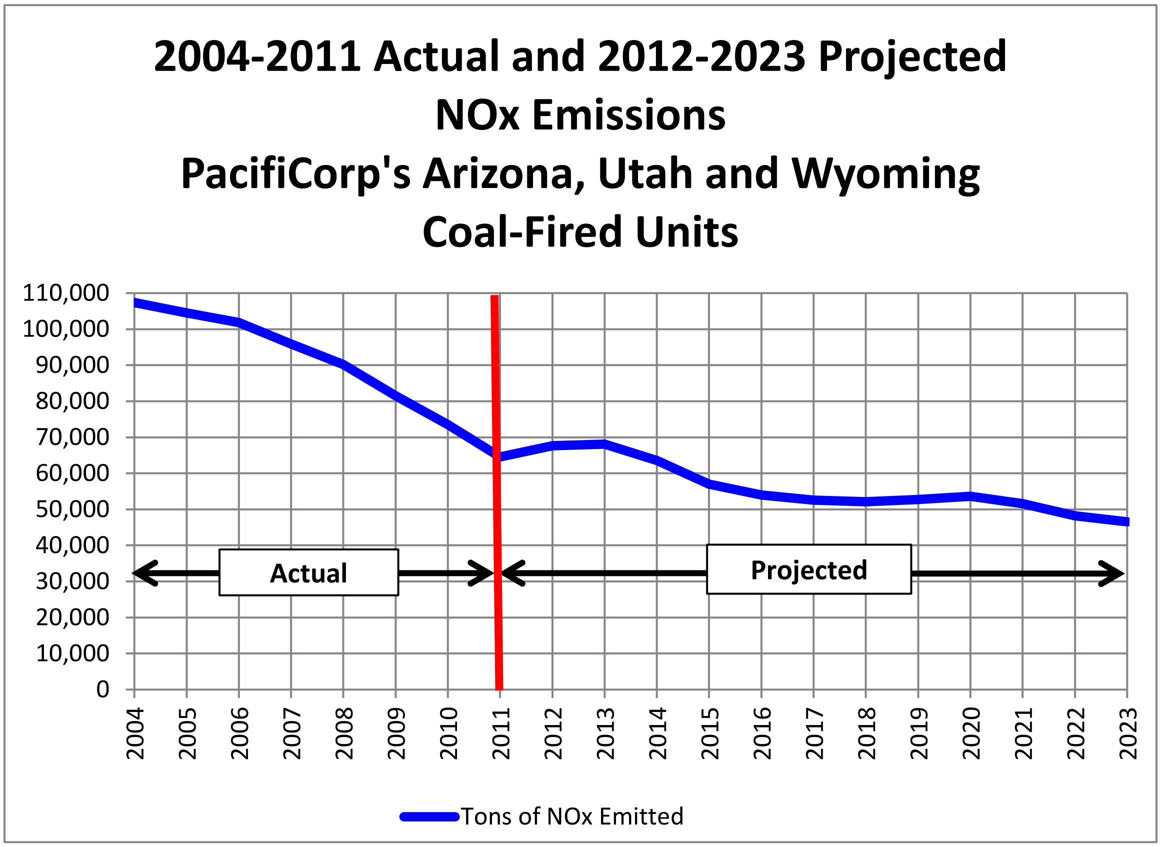


Figure 2



Q. What significant developments regarding environmental regulations have recently occurred that could impact the Company's long term emissions control plan?

A. The EPA has recently published its proposals to partially approve and partially disapprove Regional Haze SIPs in Utah, Wyoming, and Arizona; and has approved the Colorado Regional Haze SIP. The Company owns and operates, or has partial ownership share in, several units affected by these proposed actions.

The EPA's proposed action on Wyoming's Regional Haze SIP as it pertains to SO_2, recommends approval of the state's SIP. The EPA proposed action on Wyoming's Regional Haze SIP as it pertains to NOx is to partially approve and partially disapprove the state's SIP and issue a Federal Implementation Plan ("FIP") for those portions proposed to be disapproved. The EPA's action proposes to accelerate the installation of SCR currently required at the Company's Jim Bridger Units 1 and 2 from 2022 and 2021 to 2017, but agreed to accept comment on maintaining the schedule as the state determined in its SIP. In addition, the EPA proposes to reject the SIP for the Wyodak facility and Dave Johnston Unit 3 and require the installation of additional controls, namely a selective non-catalytic reduction system ("SNCR"), within five years, as well as requiring the installation of low-NOx burners and overfire air at Dave Johnston Units 1 and 2 by July 31, 2018. The EPA held public hearings on its proposed disapproval on June 26 and 28, 2012, and the written comment period closed August 3, 2012.

The EPA's proposed action on Utah's Regional Haze SIP as it pertains to SO_2, recommends approval of the state's SIP. The EPA's proposed action on Utah's Regional Haze SIP as it pertains to NOx and PM is to partially approve and partially disapprove the state's SIP and request five factor analyses of NOx controls be completed by the state. The Company is assisting Utah in that regard. The EPA has indicated that their action on Utah's SIP may involve requirements for the installation of additional NO_X controls, namely SCR, none of which are required by the state of Utah's SIP.

The EPA's proposed action on Arizona's Regional Haze SIP as it pertains to NOx is to partially approve and partially disapprove the state's SIP and issue a FIP for those portions proposed to be disapproved. The EPA's proposed action on Colorado's Regional Haze SIP as it pertains to NOx recommends approval of the state's SIP. The Colorado SIP requires SCR to be installed on Hayden Units 1 and

2 and Craig Unit 2, all by year-end 2016, each unit of which the Company has partial ownership share. In addition, the Colorado SIP requires installation of SNCR on Craig Unit 1, in which the Company also has partial ownership, by year-end 2017.

The Company cannot fully determine the impacts of EPA's proposals on the affected units listed above until final SIP and/or FIP actions are taken and the appropriate appeal periods pass.

Q. Has the Company participated in the public comment period associated with the proposed EPA actions described above?

A. Yes. The Company has filed comments in Docket ID No. EPA-R08-OAR-2012-0026, with respect to Wyoming's Regional Haze SIP as it pertains to NOx; Docket ID No. EPA-ROA-OAR-2011-0400, with respect to Wyoming's Regional Haze SIP as it pertains to SO_2; and Docket ID No. EPA-R08-OAR-2011-0114, with respect to Utah's Regional Haze SIP. The Company will also participate in each of the dockets associated with the other proposed EPA actions described above. In general, the Company will communicate the following concerns with the EPA's proposed actions:

1. the EPA's proposals fail to give proper deference to the individual state's regional haze determinations as required by the Clean Air Act;
2. the Company is not opposed to implementing cost-effective emissions controls to meet existing requirements and achieve environmental benefits, including perceptible regional haze improvements. However,

this effort must be balanced with the Company's ability to meet its responsibility to supply reliable, affordable electricity; and

3. the EPA's proposed actions impose costs and expenses prematurely with no perceptible benefit in visibility.

Q. Does the Company believe that its emissions control plan properly balances stakeholder interests?

A. Yes. Environmental benefits, including visibility improvements as calculated by EPA models, will flow from the projects installed under the Company's emissions control plan. The Company believes that the emission reduction projects and their timing appropriately balance the need for emission reductions over time with the cost and other concerns of our customers, our state utility regulatory commissions, and other stakeholders. PacifiCorp believes this plan is complementary to and consistent with BART and Regional Haze planning requirements of the states in which the Company operates, and that it is a reasonable approach to achieving required emission reductions in Wyoming, Utah and other states.

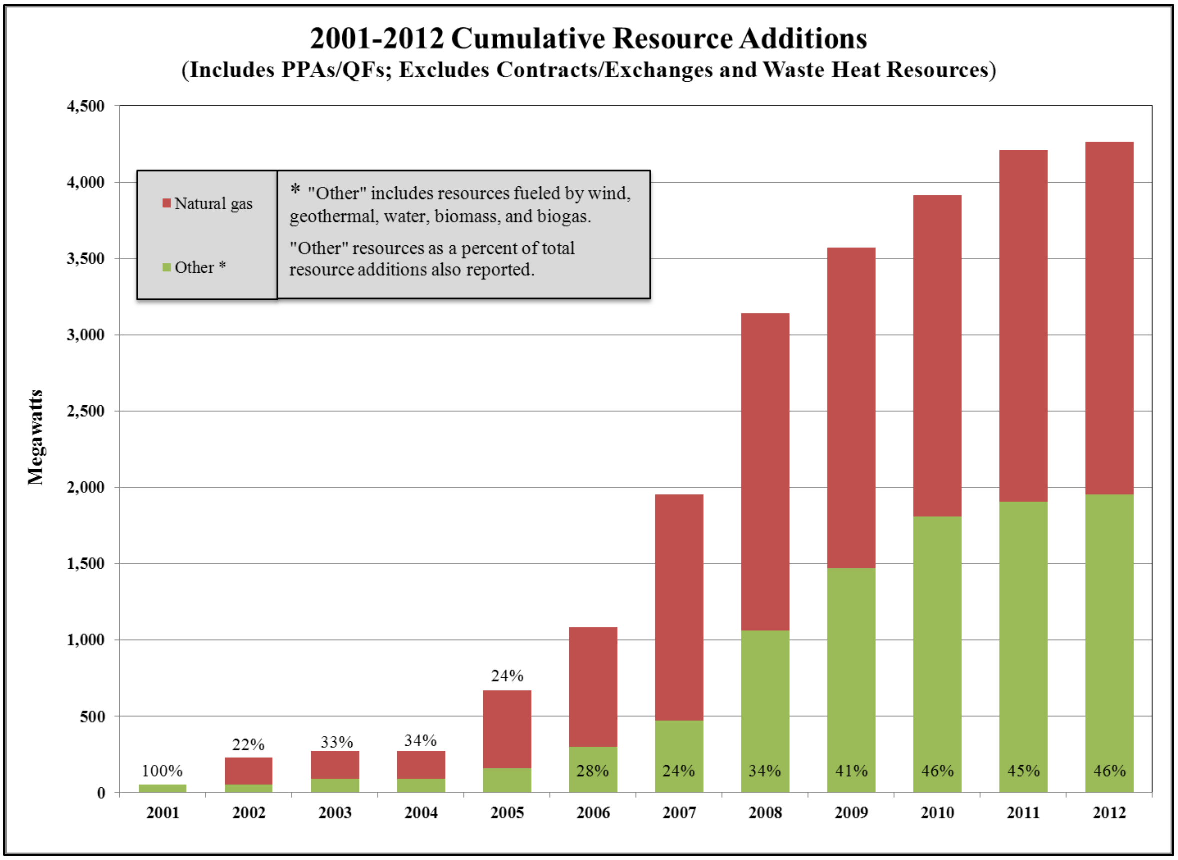
Other Company Actions

Q. In addition to the Company's emissions control plan investments, what other actions has the Company taken to address environmental stakeholder interests?

A. In addition to reducing emissions at existing facilities, the Company has also avoided increasing emissions by adding more than 1,400 megawatts of non-emitting wind generation between 2006 and 2010. Figure 3 below depicts the Company's cumulative resource additions from 2001 through 2012 along with the

823 percentage of the total that are from resources fueled by wind, geothermal, water, 824 biomass, and biogas.

Figure 3



825 **Q. What types of generation comprise the non-renewable portion of the**
826 **cumulative resource additions shown in Figure 3 above?**

827 A. The non-renewable generation resource additions depicted in Figure 3 above are 828 primarily natural gas resources, the most significant of which are the Company's 829 Currant Creek block 1 combined cycle combustion turbine facility that was placed 830 in service in March 2006, the Company's Lake Side block 1 combined cycle 831 combustion turbine facility that was placed in service in September 2007, and the 832 Chehalis combined cycle combustion turbine facility that was acquired in

September 2008.

Pending Regulations Considerations

Q. Does the Company's long-term emissions control plan support compliance with other environmental regulations beyond the Regional Haze Rules discussed in testimony above?

A. Yes. In addition to the BART requirements under the Regional Haze Rules discussed in testimony above, the EPA has promulgated MATS, also discussed above, that requires coal fueled generating facilities to reduce mercury, and other emissions of HAPs. Facilities have three years to comply with the final MATS - until April 16, 2015 - with the possibility of up to a one-year incremental extension that may be granted by the appropriate agencies on a case by case basis. The projects included in the Company's emissions control plan have positioned the Company well to meet MATS requirements.

Further, increasingly more stringent National Ambient Air Quality Standards have been and are being adopted for criteria pollutants, including SO_2, NO_2, ozone, and $PM_{2.5}$. Implementation of the emissions control projects in the Company's emissions control plan are expected to assist in meeting these more stringent standards, avoiding the negative consequences of an area being declared to be a nonattainment area.

Q. How does the Company plan for existing and future environmental requirements?

A. Existing environmental permit and regulatory requirements, such as operating within a permitted emission limit or complying with the regulatory requirements of waste management activities, are implemented through operating practices, procedures, monitoring and plans on a daily basis within the Company's operating facilities. When regulatory requirements or operating conditions change, new compliance obligations may be imposed when operating permits are applied for or renewed.

To assess the potential impacts of new environmental regulatory initiatives, the Company employs environmental professionals in the business units who coordinate with dedicated staff in the MidAmerican Energy Holdings Company ("MEHC") environmental policy and strategy group. The MEHC environmental policy and strategy group reviews proposed and final regulatory requirements and is actively engaged in the regulatory processes at both the state and at the federal level. The group seeks feedback from environmental regulators to assess their concerns, reads and analyzes legislation and regulations proposed at the state and federal levels, provides feedback on legislation, and reviews and comments on proposed regulations. MEHC and or the Company submits written comments in regulatory proceedings and participates in public hearings on the proposals, ensuring that the Company's concerns or support, as appropriate, are considered in these public forums. The Company is both well informed and engaged on these issues.

In addition, when significant environmental rulemaking or legislative proposals are released, MEHC and Company staff assesses those proposals and advises Company management of the potential impacts of the proposals. If the preliminary or final form of a proposal would alter the Company's business plan, those plans may be amended to reflect the likely impact on the Company to achieve compliance with the requirements within the relevant compliance period after considering our compliance options.

Q. When you contemplate the Company's compliance options, what factors are considered?

A. There are a multitude of factors, depending on the specific regulation. If a regulation prescribes a specific emissions limit, the Company reviews what types of controls may be available to achieve the requisite emissions limit, given the specific characteristics of each unit. As applicable, impacts on reliability, capital costs, operating and maintenance costs, the life of the controls, the life of the unit itself, cost of replacement generation, and other factors are considered. If an emissions trading mechanism is available to achieve compliance, the costs of obtaining the emissions allowances is compared to the costs to install and operate controls, considering the factors noted above.

Q. How are future environmental requirements factored into the Company's analysis of its environmental compliance options?

A. The Company updates its environmental compliance assumptions annually (or more frequently if significant regulatory changes occur) to reflect the most likely rulemaking outcome to comply with air, water and waste regulations. These environmental assumptions reflect both existing and expected requirements under the most likely scenario and are utilized as the basis for the Company's integrated resource planning ("IRP") input assumptions, as well as for the Company's 10-year business plan. We also examine the actual and potential compliance timeframes and how those timeframes may be coordinated with planned plant outage schedules. Coordinating major environmental control projects with existing outage schedules allows the Company to avoid additional outage time and reduces the need for replacement power which minimizes costs and maintains system reliability.

Q. What process is in place to explore ongoing investment in the Company's coal units?

A. The existing IRP process conducted across the six states served by the Company provides the process to analyze and address ongoing investment in the Company's coal units versus alternatives including idling, replacement and natural gas conversion. Future IRPs will increasingly focus upon the complexity in balancing factors such as:

(1) pending environmental regulations and requirements to reduce emissions in addition to addressing waste disposal and water quality concerns;

(2) avoidance of excessive reliance on any one generation technology;

(3) costs and trade-offs of various resource options including energy efficiency, demand response programs, and renewable generation;

(4) state-specific energy policies, resource preferences, and economic development efforts;

(5) the need for additional transmission investment to reduce power costs and increase efficiency and reliability of the integrated transmission system; and

(6) managing the impact on customer rates.

Timing of Investments and Consideration of Alternatives

Q. Why is PacifiCorp installing emissions control equipment at this time?

A. The Company is installing emissions control equipment at this time to comply with the Regional Haze Rules, as well as in response to more stringent National Ambient Air Quality Standards, MATS, and a number of other existing and emerging emission reduction requirements. Final installation activities and tie-in of the Company's emissions control projects are typically accomplished when the units are off-line. Meeting the timing requirements of construction permits and Approval Orders and reducing plant outage time typically necessitates completion of final installation activities and tie-in of the emissions control equipment during scheduled overhauls. Installation of the emissions control equipment and associated systems included in the Request represent a significant step for the Company's coal fueled power plant fleet toward meeting the NO_X reductions required by the Regional Haze Rules.

Q. Can installation of emissions control equipment be prudently deferred?

A. No. The Company has been engaged in Regional Haze Rule compliance planning with the respective state departments of environmental control since the initial development of the western states' regional program. During the initial 2003 to 2008 planning period, the Company was required by the Wyoming Department of Environmental Quality Air Quality Division ("WDAQ") to conduct detailed BART reviews. It was the initial expectation of the western states' Regional Haze program that individual states would establish BART emission limits for BART eligible units and would require installation of appropriate controls by 2013.

PacifiCorp originally submitted these evaluations of its BART eligible facilities in Wyoming in January 2007, with revisions submitted in October 2007. Addendums to individual facility BART reviews were developed in March 2008. WDAQ completed its final reviews of the BART evaluations and the Company's associated permit applications and issued Air Quality Permits (construction permits) for individual emissions control projects. WDAQ followed up by issuing BART permits for individual emissions control projects; the BART Appeal Settlement Agreement was executed in November 2010; followed by issuance of amendments to certain BART permits in December 2010. The emissions control projects presented in the Request support the Company's obligations in this regard.

Q. Did the Company follow a similar process for its Utah coal fueled plants?

A. Yes. As an example, the Company completed detailed scrubber technology screening studies in 2007 for the Hunter and Huntington scrubber projects and submitted its Notice of Intent (construction permit) applications to the Utah Division of Air Quality ("UDAQ") for the Hunter project in August 2006, with a final revision submitted in November 2007, and its Notice of Intent application for the Huntington project in April 2008, with a final revision submitted in January 2009. UDAQ included these projects in its Regional Haze SIP in 2008 and subsequent revisions. UDAQ completed its final reviews of the Company's permit applications for the emissions control projects and issued Approval Orders (construction permits) in March 2008 for the Hunter projects and January 2010 for the Huntington projects.

Q. Do the timelines discussed above provide a reasonable progression of

evaluation, agency coordination, and decision-making for the respective emissions control projects?

A. Yes. Emissions control projects of the types discussed above and included in the Request are extremely complex and require a significant amount of evaluation and planning to bring to fruition. The permitting processes described above are required to define the technical requirements the Company needs to move forward with establishing competitive pricing for the work and ultimately executing the projects. The timeline for securing contracts for this type of work through project completion often has a multi-year duration.

Q. What other factors impact the planning and execution timelines for the projects included in the Company's emissions control plan?

A. Emission reduction projects of the number and size included in the Company's emissions control plan take many years to plan, permit, engineer, procure, construct and commission. When considering a fleet the size of the Company's, there is a practical limitation on available construction resources and labor. There is also a limit on the number of units that may be taken out of service at any given time, as well as the level of construction activities that can be supported by the local infrastructures at and around these facilities. Additional cost and construction timing limitations include the loss of large generating resources during some parts of construction and the associated impact on the reliability of the Company's electrical system during these extended outages. In other words, it is not practical, and it is unduly expensive, to expect to build these emission reduction projects all at once or even in a compressed time period.

Q. Should the uncertainty associated with future environmental regulations weigh in favor of waiting until the regulations are final to install any controls?

A. No. The full and final scope of environmental regulations is not easily determined, particularly when rulemakings are often lengthy in their own right and just as often followed by extensive and lengthy litigation before the rule is finalized. Perfect foresight is not possible; the EPA has recently begun to acknowledge that its approach to regulation makes it difficult for companies with compliance obligations to make long-term decisions on compliance. In EPA Administrator Lisa Jackson's remarks presented on the release of the proposed Utility HAPS maximum achievable control technology ("MACT") rules (now known as MATS) on March 16, 2011, she stated:

> "The proposal and implementation of these standards will also have benefits for American utilities. For the first time in twenty years, they will have certainty about the standards they must meet. And setting national standards for mercury and air toxics will level the competitive playing field and close loopholes for big polluters. Utilities that have already put pollution control technology in place will no longer have to compete with those who have delayed those investments – a group that includes almost half of the nation's coal-fired plants, which lack advanced pollution control equipment. In fact, facilities that have already taken responsible steps to reduce the release of toxins into our air will be at a competitive advantage over their heavy-polluting counterparts. And to ensure cost-effectiveness, we have proposed flexibility in meeting the standards. The technologies being required already exist in abundance, and under the proposal, power providers have four years to comply."[3]

The lack of certainty in environmental regulation is well recognized, but does not obviate existing compliance obligations. The uncertainty of future

[3] Remarks available at: http://yosemite.epa.gov/opa/admpress.nsf/12a744ff56dbff8585257590004750b6/b7e570d651cadc03852578550057011c!OpenDocument.

environmental regulations is also acknowledged by state utility regulators. On February 16, 2011, the National Association of Regulatory Utility Commissioners Board of Directors adopted a resolution, included as Exhibit RMP___(CAT-5) to my testimony, urging the EPA to ensure that reliability, cost, compounded economic impacts of multiple environmental rulemakings, and flexibility of timeframes for compliance be considered as the agency develops public health and environmental programs.

Q. Is waiting until all the regulations are considered, finalized, and quantified to install controls a feasible approach for the Company?

A. No. Doing so would put the facilities at substantial risk of noncompliance and does not reflect the reality of the multistate operations and planning process for a utility the size of PacifiCorp. Moreover, it would be imprudent for a utility the size of PacifiCorp to assume it can install all required controls under a "just-in-time" plan. This approach to compliance poses a significant risk to the Company and its stakeholders; as a practical matter, it cannot be economically achieved on a system the size of the Company's. Emission reduction projects are complex, multi-year projects. Trying to install multiple controls within the same short time frames poses a significant risk of noncompliance with penalties that can be substantial. Even if a regulatory agency did not impose penalties for failing to achieve emission reduction deadlines, third parties have not hesitated to bring lawsuits against the operators of those facilities that miss deadlines or are otherwise not in compliance with permit and emission limits. Indeed, the federal Clean Air Act specifically allows for private citizen enforcement of air quality requirements.

Considering future environmental regulatory requirements when planning compliance projects for existing regulations avoids the concern many companies are expressing about the short three-year compliance period. Because MATS had its genesis in the Clean Air Mercury Rule, which was issued by the EPA in 2005 but vacated by the court in 2008, the Company was able to, and did, consider the potential impacts of a mercury rule on its equipment decisions.

Q. Why doesn't the Company wait until it knows the outcome of all air quality, waste and water rules to implement its environmental projects?

A. The structure of the EPA and the nature of its rulemaking process are not conducive to the agency producing coordinated air quality, waste and water rules for the electricity sector; these media-based rules address different issues through varying methods with different compliance timeframes. Nonetheless, the Company undertakes efforts to ensure that the potential compliance requirements for all these rulemaking activities are understood and reflected in its plans, making decisions based on the best available information at the time the decisions are made and updating that information as additional details on requirements become available.

Environmental regulations and the cost of implementation are only one factor that influences whether or not to make investments in environmental projects; the Company also must consider the cost of alternative generation. Future natural gas prices, construction costs for renewable generation, existing coal contracts, and associated transmission availability and costs are also among the factors that are contemplated in a determination of whether it is economic to install emissions control equipment at coal fueled plants.

Q. Does the Company believe that any of the emissions control equipment included in its emissions control plan will not be necessary as a result of future environmental requirements?

A. No. The Company does not anticipate that environmental regulations will become less stringent and history demonstrates that regulations become more stringent over time. The controls included in the Company's emissions control plan are necessary to allow the Company to continue operating these facilities given that increasing stringency. Further, the Company's analysis suggests that these controls place the facilities in a position to continue to generate reasonably priced electricity under contemplated environmental regulations, even if greenhouse gas legislation is adopted. The Company's analysis suggests that the cost of carbon under a regulatory regime for greenhouse gas emissions would have to approach $40 per ton on a levelized basis with gas prices sustained below the $7 to $9 per mmBtu range to begin to make replacement of coal fueled resources cost effective prior to 2030. Utilizing greenhouse gas reduction requirements as a basis for current investment decisions is highly speculative given that the current Congressional activity is focused on delay or repeal of the EPA's authority to regulate greenhouse gases, and not on a comprehensive legislative effort to reduce greenhouse gas emissions.

Additionally, in the course of applying environmental requirements to the Company's facilities, the respective state Department of Environmental Quality or the EPA consider what constitutes cost-effective emission reductions, taking the position that all cost-effective reductions are required. As discussed earlier in my testimony, in the context of the Regional Haze program's BART determinations, the reviewing environmental agency must consider:

(a) the costs of compliance;

(b) the energy and non-air quality environmental impacts of compliance;

(c) any existing emissions control technology in use at the source;

(d) the remaining useful life of the source; and

(e) the degree of visibility improvement which may reasonably be anticipated from the use of BART.

Within the foregoing mandatory BART factors are considerations such as greenhouse gas regulation and other environmental regulatory drivers that may have an impact on the remaining useful life of the source are considered.

Q. What efforts are being taken by the Company to understand and evaluate impacts of potential future environmental regulations on the Company's business?

A. PacifiCorp and its parent, MEHC, are active in the current state and federal legislative and agency activities regarding environmental rulemaking affecting virtually all coal fueled and natural gas fueled generating units. With respect to potential restrictions on greenhouse gas emissions in particular, the Company's IRP process is utilized to incorporate the impacts of CO_2 cost into its preferred portfolio results.

Q. Is the Company obligated to install emissions controls required by state permits, regardless of whether final EPA review and approval of the respective Regional Haze state implementation plans remains pending?

A. Yes. The Wyoming SIP and BART Settlement Agreement (and permits issued reflecting their requirements) constitute stand-alone requirements that are enforceable independent of whether EPA has approved the respective state implementation plans. Notwithstanding the underlying state requirements, the EPA has proposed to approve the installation of the SCR controls, which would also make the obligation federally enforceable upon final approval.

Q. Does the Company anticipate that final EPA approval of the respective state implementation plans will require alternate emissions control equipment to be installed, making the equipment included in the Company's emissions control plan obsolete?

A. No. While it is possible that the EPA will require additional emission reductions, any such requirements will be in addition to – not in place of – the emissions control technology selections completed to date, which apply best available retrofit technology, comply with existing state and federal regulations, and support Regional Haze Rule objectives. The Company also incorporates into its emissions control equipment contract specifications design considerations intended to provide appropriate levels of operating margin, equipment redundancy, and system maintainability and reliability provisions to support an expected range of process inputs, operating conditions, and system performance. Although the Company cannot predict future emissions control regulations and associated emissions limits, the Company does take steps to procure a prudent level of design flexibility to accommodate potential changes in system performance requirements, where practical.

Planning Environment

Q. Does the Company evaluate market risk associated with emerging environmental regulations, particularly risks associated with greenhouse gases?

A. Yes. The Company evaluates greenhouse gas risks in its IRP process by considering a range of CO_2 price scenarios that inform selection of a preferred resource portfolio. Through the 2011 IRP process, the Company made advancements in its modeling of incremental investments that could be required to achieve compliance with emerging environmental regulations. The modeling improvements were documented in an IRP Supplemental Coal Replacement Study filed in September 2011 and in an updated coal study analysis that was filed with the Company's 2011 IRP Update in March 2012. Moreover, the Company will continue to evaluate environmental investment costs in its 2013 IRP process.

Q. What modeling improvements were made in the System Optimizer Model ("SO Model") to support the Company's IRP Supplemental Coal Replacement Study filed in September 2011?

A. Improvements were made in three areas. First, the Company made improvements to the configuration of model inputs that more accurately capture the tradeoff in cost between existing coal resources requiring incremental environmental investments and costs for replacement resource options. Second, the Company updated environmental compliance cost assumptions for all coal resources to reflect updated information regarding environmental regulations. Third, the Company updated market price and CO_2 cost scenarios to update alignment with then current economic conditions and policy developments.

Q. Please describe the incremental environmental investment cost assumptions used in the Company's IRP Supplemental Coal Replacement Study.

A. Incremental environmental investment costs assumptions were expanded to include proxy compliance costs required for CCR and Clean Water Act Section 316(b) regulations, as well as costs for out-year SCR installations with proxy in-service dates beyond 2022 at the Company's Hunter, Huntington, and Wyodak facilities. The proxy SCR costs at these facilities were included in the model to add conservatism to results by reflecting potential future environmental project requirements, although no such requirements or obligations currently exist. With those costs included, total environmental compliance costs, inclusive of AFUDC, in the IRP Supplemental Coal Replacement Study total just over [redacted] for the period 2011 through 2030.

Q. Did the results of the IRP Supplement identify coal fueled generation assets operated by the Company as candidates for accelerated idling?

A. No. Please refer to the IRP Supplemental Coal Replacement Study attached as Confidential Exhibit RMP___(CAT-6).

Q. Did the Company further update the IRP Supplemental Coal Replacement Study as part of its 2011 IRP Update?

A. Yes. The Company included an updated coal replacement study as part of its 2011 IRP Update filed in March 2012. Please refer to Exhibit A of the 2011 IRP Update attached as Confidential Exhibit RMP___(CAT-7). The updated coal replacement study was performed using the SO Model and analyzed near term investments needed to meet compliance obligations with emerging environmental regulations for eight specific generating units under a range of natural gas prices and CO_2 costs in varying combinations.

Q. Were Jim Bridger Units 3 and 4 included on the list of eight specific generating units analyzed in the updated coal replacement study?

A. Yes.

Q. Are the SO Model input assumptions and results supporting investment in the Jim Bridger Units 3 and 4 SCRs as discussed in the accompanying testimony and exhibits of Mr. Link consistent with the information presented in the Company's 2011 IRP Update?

A. Yes.

Customer Considerations

Q. What are the benefits to customers of installing the projects included in the Company's emissions control plan?

A. Customers directly benefit from the continued availability of low-cost generation produced at the facilities while also achieving environmental improvements from these resources. In addition, the tie-in of these controls is being accomplished during planned maintenance outages, as opposed to scheduling separate outages for this work, which reduces replacement power costs. The Company has 10 BART-eligible units in Wyoming and four in Utah. The BART controls for each of these units must be installed as expeditiously as possible, but no later than five years from the date the respective SIPs are approved and prior to the compliance dates specified in the respective permits.

Postponing installation of emissions control equipment to later planned maintenance outages would make it virtually impossible for the Company to effectively ensure that all of its affected units meet compliance deadlines and would place the Company at risk of not having access to necessary capital, materials, and labor while attempting to perform these major equipment installations in a compressed timeframe. As the deadlines for environmental requirements across the country draw closer, the demand for equipment and skilled labor is likely to increase, making timely compliance more difficult without incurring significant additional cost.

Finally, maintaining the ability to operate the existing coal fueled units that have been or are planned to be retrofitted with economic emissions control equipment represents the least-cost option for customers, especially when considered in conjunction with the other generation resource addition projects that the Company has completed and intends to complete as part of its regularly updated IRP preferred portfolio implementation effort. This is even before considering factors associated with retirement of the coal units prior to their ratemaking depreciation lives, such as stranded depreciation expense, the economic impact on the respective states in which the assets reside, and the potential impact on system reliability.

Conclusion

Q. Please summarize your testimony.

A. The base case results of the Company's economic analyses show a [redacted] PVRR(d) favorable to investment in the emissions control investments that are the subject of the Request, namely SCR systems, and other incremental environmental compliance projects required to continue operating Jim Bridger Units 3 and 4 in compliance as coal fueled assets. The Company respectfully requests an Order granting the Request to construct the two SCR systems at its Jim Bridger Units 3 and 4 facilities.

Q. Does this conclude your direct testimony?

A. Yes.