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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR APPROVAL OF CHANGES TO ITS ELECTRIC SERVICE SCHEDULES AND A PRICE INCREASE OF $32.7 MILLION, OR APPROXIMATELY 15.0 PERCENT	))))))))	**CASE NO. PAC-E-11-12** **Direct Testimony of Chad A. Teply**

ROCKY MOUNTAIN POWER

CASE NO. PAC-E-11-12

May 2011

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

Qualifications

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 the role of project manager for the 790-megawatt Walter Scott 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 the PacifiCorp team as vice president of resource development and construction, at PacifiCorp Energy. In my current 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 supporting the prudence of capital investments in pollution control equipment, generation plant, and hydro projects being placed in service during the test period; and

- support the prudence of incremental generation operations and maintenance costs associated with certain new resources, new pollution control equipment, and other generation fleet operational changes impacting this case.

Background

Q. Please provide a general description of the pollution control equipment and additional capital investments being placed in service, and the benefits gained from the investments.

A. The pollution control equipment investments included in this case primarily result in the reduction of sulfur dioxide ("SO_2"), nitrogen oxides ("NO_x"), mercury ("Hg"), and particulate matter ("PM") emissions from the retrofitted Naughton Unit 2, Wyodak, Huntington Unit 1, Hunter Unit 2 and Jim Bridger Unit 3 facilities. These investments are required to comply with current, proposed, and probable environmental regulations as further discussed in the direct testimony of Ms. Cathy S. Woollums. These investments constitute approximately 60 percent of the Company's capital investments placed in service or projected to be placed in service from January 2011 through December 2011.

Hydro generation plant investments, which constitute approximately 4 percent of the Company's capital investments placed in service or projected to be placed in service from January 2011 through December 2011, are primarily new license implementation measures required by the Federal Energy Regulatory Commission to allow continued operation of these low-cost generation assets.

The generation plant turbine upgrade investment enhances the Company's overall generation capability and cycle efficiency without increasing emissions for the large thermal unit that receives this equipment.

Other generation plant investments during the test year support asset safety, reliability, and cost effectiveness via reduced risk of equipment and component failures, enhanced control systems, and improved security provisions.

Q. Please describe the primary environmental regulation requiring the pollution control investments included in this case.

A. Through the 1977 amendments to the Clean Air Act, Congress set a national goal for visibility to remedy impairment from manmade emissions in designated national parks and wilderness areas; this goal resulted in development of the Regional Haze Rules, adopted in 2005 by the U.S. Environmental Protection Agency ("EPA"). The first phase of these rules trigger Best Available Retrofit Technology ("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 direct testimony of Ms. Woollums includes additional discussion regarding the Regional Haze Rules and other environmental drivers behind the pollution control investments included in this case.

Q. Please describe the efforts taken to evaluate available 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. Once the appropriate BART technology was identified, the Company moved forward with its competitive bidding process to evaluate and ultimately select the preferred provider for the projects.

Q. Does the Company focus solely on environmental compliance factors when determining which capital investments to make?

A. No. As part of the Company's coal fueled units compliance planning efforts, consideration is given to selection of appropriate pollution control technologies as well as alternate compliance options such as market purchases of replacement power, re-powering to natural gas, and the procurement of replacement generation. Examples of these analyses are discussed further in my testimony.

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 ongoing compliance with existing operating requirements factored into planning of pollution control investments?

A. The Huntington Unit 1 and Hunter Unit 2 baghouse projects and the waste handling phases of the Huntington Unit 1 and Hunter Unit 2 scrubber projects presented in this case are good examples of how ongoing compliance with current regulations factors into the company's pollution control investment planning process. The addition of the baghouse will significantly reduce PM emissions and improve compliance with existing opacity standards. The scrubber waste handling systems will ensure that the final waste product will not contain any free liquids and can properly be disposed of in the onsite landfill.

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

A. The Hunter Unit 2 scrubber project is a good example of how fuel supply flexibility has factored into the Company's pollution control investment planning process. As the Company contemplated BART requirements for Hunter Units 1 and 2, pollution control equipment that would meet required emission limits and would permit utilization of coal with higher coal sulfur content was evaluated. The ability to fuel the Hunter units on coal with higher sulfur content while meeting new emission limits will help to maintain competitive fuel and generation costs at this facility.

Q. How have existing pollution control equipment end of life replacement considerations factored into planning of new pollution control investments?

A. The replacement of various scrubber system elements at Hunter Unit 2 is an example. These elements include scrubber vessel work scope, scrubber recycle pump replacements, and scrubber reagent injection nozzle replacements, as well as the scrubber reagent preparation system replacement. By planning the Hunter Unit 2 scrubber project tie-in to coincide with a planned maintenance outage cycle for the unit, the project was able to replace equipment and components that had exhausted their useful life, and at the same time address system capacity and compliance requirements.

Q. How have operational considerations factored into planning of pollution control investments?

A. Operational considerations are included in the technical specifications for each of the Company's pollution control projects. The material handling phases of the Huntington Unit 1 and Hunter Unit 2 scrubber projects are two key examples of the Company's efforts to improve operational efficiencies. These projects result in the installation of scrubber waste dewatering equipment that eliminates the manual management of fly ash blending processes. Thus, in addition to addressing system capacity concerns and maintaining waste disposal compliance, these projects improve operational efficiencies allowing plant staff to focus on other operational responsibilities.

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

A. The existing integrated resource planning ("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 retirement and replacement and repowering. 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.

Q. Has the Company compared the cost of continued operation of the retrofitted coal fueled generation units contemplated in this case to its other generation sources, including natural gas fueled generation?

A. Yes. The Company has developed Confidential Exhibit No. 22 to compare the cost of retrofitted coal fueled generation units to other generation resource classes.

Confidential Exhibit No. 22 presents the 2009 embedded generation bus bar cost per megawatt-hour differences of the various generation resources within the Company's generation fleet, including re-powered and combined-cycle natural gas fueled generation. Confidential Exhibit No. 23 provides the incremental revenue requirement associated with the pollution control equipment retrofits in this case on a dollars per megawatt-hour basis adjusted to 2009 dollars.

In general terms, the capital cost on a dollars per megawatt basis to retrofit pollution controls on existing coal fueled generation is approximately the same or less than the capital cost to build a new combined cycle natural gas generation unit. However, fuel costs of a combined cycle natural gas unit will overwhelm capital cost competitiveness when compared to a retrofitted coal fueled facility. Natural gas on a dollars per million Btu basis is approximately triple the cost of coal, and even when considering the efficiency differences, the cost of electricity generated by an emission controlled coal fueled facility will be significantly less than the cost of electricity from a new combined cycle.

These exhibits demonstrate that maintaining the ability to operate the existing coal units by retrofitting the units with the pollution control equipment represents the least-cost option for customers. 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 Wyoming, the loss of fuel diversity in the generation portfolio, and the impact on system reliability.

Q. Has the Company applied least cost principles to selection of its pollution control investments?

A. Yes. Various project revenue requirement analyses have determined the lower cost alternative to customers for achieving the target level of emission reduction or control. These take the form of comparing the present value revenue requirement impact of one technology to another and determining the present value revenue requirement differential ("PVRR(d)") benefit to customers. I will further explain these analyses in the following testimony.

Q. Has the Company assessed the costs of continuing to invest in individual coal fueled generation assets versus replacing the lost generation with market purchases?

A. Yes. The Company has developed economic analyses that provide an overview of the PVRR(d) benefits associated with its pollution control investments, with consideration given to potential CO_2 costs and resulting market pricing assumptions. Confidential Exhibit No. 24 and Confidential Exhibit No. 25 provide the results of said analyses at various points in time and with various CO_2 costs and market pricing assumptions. Confidential Exhibit No. 24 provides a PVRR(d) view of the projects presented in this case at the time of planning and approval of the pollution control investments, utilizing then current CO_2 cost and market pricing assumptions. Confidential Exhibit No. 25 provides a PVRR(d) view of the units that received the pollution control investments on a going-forward basis, utilizing CO_2 cost and market pricing assumptions and the System Optimizer Coal Utilization Case Studies referenced below. These PVRR(d) analyses provide positive results for the various scenarios presented and further demonstrate prudence of the pollution control investments. The PVRR(d) analyses also offer insight into the potential impacts of various CO_2 cost and market pricing scenarios on investment recovery periods.

Q. Has the Company assessed the costs of continuing to invest in individual coal fueled generation assets versus the cost of converting the units to natural gas as fuel source?

A. Yes. The Company has developed economic analyses intended to provide an overview of the PVRR(d) benefits associated with its pollution control investments, with consideration given to potential CO_2 costs and resulting market pricing assumptions, versus natural gas repowering scenarios. Confidential Exhibit No. 26 provides the PVRR(d) results of said natural gas repowering analyses. The results of these PVRR(d) analyses provide positive results for the various scenarios presented and further demonstrate prudence of the pollution control investments presented in this case, and also offer insight into the potential impacts of various CO_2 cost and market pricing scenarios on investment recovery periods.

Q. Does the Company believe that it has appropriately assessed the cost effectiveness of the pollution control investments?

A. Yes. In assessing when and whether to proceed with pollution control investments, the Company has considered cost effectiveness of reasonable options.

Measures of capital cost on a dollars per kilowatt basis have been reviewed during studies of alternatives, as well as the cost to remove a ton of a pollutant, which is applied specifically as part of the BART determination process. Recently, BART determinations issued by the EPA and other state agencies for SO_2 and NO_x emission control projects have demonstrated that removal costs of up to $7,500 per ton are not considered cost prohibitive. PM emission reductions cannot typically be compared to this same cost per ton removal standard since the incremental emissions improvement will be much smaller due to the relatively high removal efficiency level of existing PM removal equipment. It should also be noted that when ongoing compliance and/or equipment end-of-life issues must be addressed, the dollar per incremental ton removed evaluation is not applicable. A listing of representative costs per ton removed for the pollution control projects presented in this case is included in Confidential Exhibit No. 27.

Q. Has the Company accounted for pollution control investments in its forward-planning cycles?

A. Yes. The Company makes every effort to identify, quantify and include forward-looking environmental compliance projects in its planning processes.

Q. Is the Company obligated to install pollution 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 BART permits and construction permits issued by the respective state agencies for the pollution control investments contemplated in this case include stand-alone requirements enforceable by the laws of the respective states. These requirements are enforceable independent of whether EPA has approved the respective state implementation plans.

Q. **Are the pollution control investments in this case required to comply with existing regulations?**

A. Yes. The pollution control investments in this case are required to comply with existing regulations including Regional Haze Rules, National Ambient Air Quality Standards, the Regional SO_2 Milestone and Backstop Trading Program developed in alignment with existing federal regulations and administered in Utah and Wyoming, state issued construction and operating permits, and state implementation plans. Exhibit No. 28 provides an overview of existing regulations with which the projects will be in compliance.

Q. **Do the pollution control investments also support compliance with anticipated likely regulations?**

A. Yes. In many cases the investments are also expected to support compliance with anticipated likely regulations as currently proposed. Exhibit No. 28 provides an overview of anticipated likely regulations with which the projects presented in this case are anticipated to support compliance.

Q. **Are the pollution control investments in this case based on anticipated regulations that do not exist, may never be implemented, and if implemented, may require technologies other than those installed by the Company?**

A. The pollution control investments in this case are required to comply with existing regulations being administered by the respective state departments of environmental quality.

Q. Does the Company anticipate that final EPA approval of the respective state implementation plans will require alternate pollution control equipment to be installed, making the equipment contemplated in this case obsolete?

A. No. While it is possible that the EPA will require more stringent emission limits, any such requirement will be in addition to – not in place of – the pollution 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 pollution 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 pollution 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.

Q. Has the Company communicated to the Commission its knowledge and understanding of additional costs required to maintain compliance with current and anticipated environmental regulations?

A. Yes. As the Company becomes aware of known or anticipated environmental regulations, the Company begins assessment of requirements and incorporation of appropriate project completion timelines and cost estimates into its business planning processes. The Company's IRP and IRP updates filed with this

Commission also include extensive discussion regarding the business planning considerations given to current and anticipated environmental regulations.

Q. Has the Company developed other information regarding the Company's overall emission reduction plans through 2023?

A. Yes. The Company has provided additional information including an overview of the Company's long-term emission reduction commitment, project installation schedules and compliance deadlines, emission reduction priorities, anticipated customer impacts, and brief descriptions of other environmental initiatives that are also expected to impact future operating costs of the Company in its recent filings in other states. A copy of this additional information is provided for reference in Exhibit No. 29.

Q. Does the Company continue to improve its analysis of market risk associated with emerging environmental regulations, particularly risks associated with greenhouse gases?

A. Yes. In support of the Company's 2011 IRP development process, the Company incorporated System Optimizer Coal Utilization Case Studies 20-24. These case studies were designed to investigate the impacts of CO_2 cost and gas price scenarios on the Company's existing coal fleet after accounting for coal plant incremental costs. This study used new modeling functionality that enables representation of existing plant repowering and retrofitting as future resource options. Additionally, the Company acquired and used customized enhancements to the model for estimating carbon dioxide emissions and regulatory costs associated with spot market balancing sales and purchases. These case studies include capital expenditures for planned and/or ongoing pollution control equipment investments included in the Company's business plan, including mercury HAPs MACT compliance costs. Due to the timing of these case studies in 2010, the Company's preliminary capital cost estimates for compliance with the EPA's proposed coal combustion residuals ("CCR") rules and Clean Water Act Section 316(b) cooling water intake rules were not incorporated. CCR compliance costs have since been incorporated into the Company's business plan, and preliminary estimates for future Clean Water Act Section 316(b) cooling water intake compliance projects are being developed and will be incorporated into the Company's next business plan cycle. These data sets will be incorporated into future updates of the coal utilization case studies. Exhibit No. 29, Table 1 lists the Company's planned air emissions related pollution control projects included in the case studies, with the exception of activated carbon injection projects for mercury emissions control.

Q. Do the results of the Company's coal utilization case studies included in the 2011 IRP process result in the Company requesting accelerated depreciation treatment of pollution control investments contemplated in this case?

A. No. The results of the Company's coal utilization case studies do, however, identify certain CO_2 cost and gas price scenarios that would lead the Company to re-evaluate strategic asset planning for certain units. Re-evaluation of strategic asset planning would be vetted via the Company's depreciable life studies that are completed every five years, with the next due in 2013.

Q. Will the Company continue to include System Optimizer Coal Utilization Case Studies in its IRP process?

A. Yes. The Company will continue to include and refine System Optimizer Coal Utilization Case Studies in its future IRP processes.

Q. Has the Company installed the pollution control investments in an efficient manner?

A. Yes. As further discussed in Exhibit No. 29, emission reduction projects of the number and size described above take many years to engineer, plan, and build. When considering a fleet the size of 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. Does the Company believe that the pollution control investments contemplated in this case meet the "used and useful" standard?

A. Yes. Each of these investments achieves its original intent, provides benefit to customers, and allows the Company to maintain compliance with state issued permits, state implementation plans, and regional SO_2 milestones and backstop trading programs.

Customer Considerations

Q. What are the benefits to customers of installing the pollution control equipment and why should Idaho customers pay the costs related to this project?

A. Customers directly benefit from the continued availability of low-cost generation produced at the facilities while also achieving environmental improvements from these resources, resulting in cleaner air. In addition, the tie-in of these necessary 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 permits

Postponing installation of the pollution control equipment included in this case 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.

Description of Pollution Control Investment Projects

Q. Please describe the Naughton Unit 2 scrubber addition project and associated equipment.

A. The scrubber addition project at the Naughton Unit 2 power plant includes the installation of SO_2 controls. The capital investment for the project being placed in service during the test period is approximately $152 million. Construction began in 2010, and the project is expected to be placed in service by November 2011. The new pollution control equipment will be tied into the existing unit during a scheduled plant maintenance outage. The project will install a flue gas desulfurization ("FGD") system. The FGD system injects reagent slurry containing sodium carbonate and sodium bicarbonate in the top of an absorber vessel ("scrubber") with a network of spray nozzles. The distribution of spray nozzles and trays causes the sodium carbonate slurry to intermix with the flue gas passing through the absorber vessel. The SO_2 in the flue gas reacts with the sodium carbonate in the slurry to form waste slurry of sodium sulfite and sodium sulfate. The liquid waste slurry is then captured and transported to a scrubber waste pond for disposal. The scrubber waste will ultimately be dewatered and retained in a closed and capped scrubber waste cell on the Naughton plant site.

Other equipment to be installed as part of the project includes induced draft fans, boiler reinforcement, new ductwork and a new chimney, sodium carbonate slurry reagent preparation systems, waste material handling systems, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems.

Q. Is the Company also installing scrubber facilities at the Naughton Unit 1 power plant?

A. Yes. The Naughton Unit 1 scrubber project is being constructed concurrently with the Naughton Unit 2 scrubber project, but on a different schedule. The description of the Naughton Unit 1 scrubber project is for the most part identical to that provided above.

Q. Will the Naughton Unit 1 scrubber addition project also be placed in service during the test period used in this case?

A. No. The Naughton Unit 1 scrubber project is expected to be placed in service during the next planned major maintenance outage for that unit, expected to be complete by May 2012. The planned major maintenance outages for the Company's generation assets are scheduled on a control area basis, considering optimal frequency between overhauls and to minimize the number of major units off line at any one time. The Company completed its most recent overhaul to Naughton Unit 1 in 2008 and is scheduled for its next overhaul in the spring of 2012. The Company's intent in establishing the tie-in schedules for the Naughton Unit 1 and Naughton Unit 2 pollution control equipment was to balance the aggregated construction costs and schedules for the pollution control equipment projects against the established planned maintenance overhaul schedules, work plans, and budgets for the respective units.

Q. Are common facilities costs associated with the Naughton Unit 1 and Naughton Unit 2 scrubber addition projects included in this case?

A. Yes. The cost of all common facilities that are required to be placed in service to allow prudent operation of either unit's new emission control equipment are incorporated into the Naughton Unit 2 capital investment being placed in service by November 2011. Common facilities include reagent preparation, waste disposal, electrical supply, and ancillary utility systems, as well as site preparation and the chimney.

Q. **Please describe the Wyodak power plant stand-alone bag house project and associated equipment.**

A. A stand-alone bag house was installed at the Wyodak power plant for control of PM, SO_2, and Hg emissions consistent with requirements. In order to increase the SO_2 removal efficiency of the unit above 90 percent as required to comply with environmental requirements, a bag house must be utilized in conjunction with the existing dry spray dryer absorbers ("SDAs"). Without a bag house, the best SO_2 removal efficiency a SDA on the unit can achieve with Wyodak coal is between 70 and 80 percent. Adding the bag house is necessary to achieve the permitted SO_2 removal requirements.

The Company's share of the capital investment for the Wyodak bag house project being placed in service during the test period is approximately $104 million. Construction began in 2010, and the project was placed in service at the end of April 2011. The new pollution control equipment was tied into the existing unit during a scheduled plant maintenance outage.

The bag house captures PM from the flue gas stream as it passes through the bag house and will improve the unit's efficiency in removing SO_2 and Hg from the flue gas. The dry particulate waste stream containing both fly ash and scrubber waste will then be transported to an ash collection pond on adjacent coal mine property for disposal.

Other equipment to be installed as part of the project includes induced draft fans, boiler reinforcement, new ductwork, waste material handling systems, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems.

Q. Please describe the Huntington Unit 1 power plant scrubber project, and associated equipment.

A. The scrubber project at the Huntington Unit 1 power plant provides required SO_2 controls for the unit, as well as a new scrubber waste material handling system and conversion of the chimney to wet operation. The new waste handling equipment will be designed to manage the increase in waste product from the higher removal efficiency and increased throughput of the scrubber.

The capital investment for the scrubber waste material handling project being placed in service during the test period is approximately $29 million. Construction began in 2010, and the scrubber waste handling project was placed in service in March 2011. Installation of the waste handling portion of the project will be completed with the plant in service. The portion of the Hunter 2 scrubber project that resulted in increased flue gas desulfurization ("FGD") system slurry delivery system capacity, by replacing recycle pumps and reagent supply piping and appurtenances, was placed in service prior to the test period for this docket. The wet stack conversion was also completed prior to the test period.

The scrubber waste material handling project includes forced oxidation compressors to allow the full conversion of calcium sulfite to calcium sulfate, larger absorber agitators, hydroclones as a replacement for the existing thickener, vacuum drum filters with associated transfer tanks and pumps, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems. Installation of this equipment will allow the scrubber slurry waste stream to be more effectively dewatered to maintain compliance with scrubber waste landfill disposal requirements. Installation of this new equipment also addresses equipment end-of-life issues for existing equipment including the absorber agitators and the thickener. These particular equipment items were nearing their end-of-life stage and would have required capital replacement in the near future.

Q. Please describe the Hunter Unit 2 power plant bag house conversion project, scrubber project, and associated equipment.

A. The bag house conversion project at the Hunter Unit 2 power plant will convert an existing electrostatic precipitator to a bag house to meet PM and Hg emissions control requirements. The bag house will capture PM and help remove Hg from the flue gas stream as it passes through the bag house. The dry particulate waste stream is then transported to an on-site landfill for disposal. Other equipment to be installed as part of the project includes upgrading the scrubber booster fans, boiler reinforcement, new ductwork, modifications to the existing chimney to accommodate wet operation, relocation of the stack opacity monitors, waste material handling systems, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems. The Company's share of the capital investment for the bag house conversion project being placed in service during the test period is approximately $54 million. Construction began in 2010, and the project was placed in service at the end of April 2011. The bag house conversion was completed during a scheduled plant maintenance outage.

The scrubber project at the Hunter Unit 2 power plant will result in improved SO_2 controls for the unit and will install a new scrubber reagent preparation system and an improved scrubber waste material handling system to meet environmental requirements. The scrubber project will increase unit's existing FGD slurry delivery system capacity by replacing recycle pumps and reagent supply piping and appurtenances, effectively increasing the liquid ("slurry") to flue gas ratio within the absorber vessels ("scrubbers"); installing a new higher capacity scrubber reagent preparation system, and expanding waste material handling system capacity with a new system. The FGD system injects lime slurry in the top of a scrubber with a network of spray nozzles and trays. The distribution of spray nozzles and trays causes the lime slurry to intermix with the flue gas passing through the absorber vessel. The SO_2 in the flue gas reacts with the calcium in the slurry to form a slurry waste of calcium sulfite and calcium sulfate. The waste material handling portion of the project will add oxidation air blowers to the system to ensure conversion of the calcium sulfite to calcium sulfate. Calcium sulfate is easier to dewater and the change will allow the slurry waste stream to be more effectively dewatered, and transported to a scrubber waste landfill for disposal.

The Company's share of the capital investment for the scrubber FGD system and scrubber waste material handling portions of the project being placed in service during the test period is approximately $23 million. Construction began in 2010, and the scrubber FGD system project activities were completed and placed in service at the end of April 2011. The scrubber waste material handling portion of the project is expected to be completed by July 2011. The scrubber reagent preparation system portion of the project is expected to be placed in service by March 2012. Costs for the scrubber reagent preparation system portion of the project are not included in this case. The scrubber FGD system scope of work was completed during a scheduled plant maintenance outage. Installation of the reagent preparation system upgrade and the waste handling portion of the project will be completed later, and will not require an extended plant maintenance outage for tie-in.

Equipment to be installed as part of the various portions of the scrubber project includes lime slurry reagent preparation equipment; waste material handling system equipment including hydroclones, as a replacement for the existing thickener, and vacuum drum filters; electrical infrastructure; controls; and other miscellaneous appurtenances and support systems.

Q. Is the Company also completing a scrubber project at the Hunter Unit 1 power plant?

A. Yes. The Hunter Unit 1 scrubber project is being constructed concurrently with the Hunter Unit 2 scrubber project, but on a different schedule. The project is being constructed concurrently with the Hunter Unit 2 project to benefit from installation and operational costs synergies achieved through the use of common facilities between the two units.

Q. Please describe the Hunter Unit 1 power plant scrubber project and associated equipment.

A. The scrubber project at the Hunter Unit 1 power plant will result in improved SO_2 controls for the unit and will install a new scrubber reagent preparation system and an improved scrubber waste material handling system to meet environmental requirements. The detailed description of the Hunter Unit 1 scrubber project is for the most part identical to that provided for Hunter Unit 2 above.

Costs associated with the capital investment for the Hunter Unit 1 scrubber project ARE NOT included in the revenue requirement in this case due to the projected in-service dates of the respective portions of the project. Construction began in 2011, and the scrubber FGD system portion of the project is expected to be fully placed in service by May 2014 following a scheduled plant maintenance outage on the unit. The scrubber reagent preparation portion of the project is scheduled to be placed in service by March 2012. The scrubber waste material handling portion of the project is expected to be placed in service by March 2013. Installation of the reagent preparation and waste handling portions of the project will be completed while the plant is in service, and will not require an extended plant maintenance outage for tie-in.

Q. Please describe the Jim Bridger Unit 3 power plant scrubber project and associated equipment.

A. The scrubber project at the Jim Bridger Unit 3 power plant will result in improved SO_2 controls for the unit by allowing the scrubber bypass dampers to bypass less flue gas. The scrubber project will increase the unit's existing FGD slurry delivery system capacity by replacing recycle pumps and reagent supply piping and appurtenances, effectively increasing the liquid ("slurry") to flue gas ratio within the absorber vessels ("scrubbers"); install new scrubber vessel internals ("trays, piping and nozzles"); replace induced draft fans; install variable frequency drives; and install the associated power distribution, controls and appurtenances. The FGD system injects sodium-based slurry in the top of a scrubber with a network of spray nozzles and trays. The distribution of spray nozzles and trays causes the slurry to intermix with the flue gas passing through the absorber vessel. The SO_2 in the flue gas reacts with the sodium in the slurry to form a slurry waste of sodium sulfite and sodium sulfate. The scrubber waste, in slurry form, is sent to a waste pond where the waste liquor is allowed to evaporate and the solids are ultimately impounded in the landfill.

The Company's share of the capital investment for the scrubber project being placed in service during the test period is approximately $17 million. Construction began in 2010, and the scrubber project activities are expected to be completed in June 2011. The scrubber waste material handling portion of the project is expected to be completed by July 2011. The scrubber project scope of work is being completed during a scheduled plant maintenance outage.

Q. Please describe the other major pollution control projects and associated equipment contemplated in this case.

A. The other major pollution control projects to be placed in service during the test period include:

(1) the Naughton Unit 2 low NO_x burners installation project;

(2) the Wyodak low NO_x burners installation project; and

(3) the Hunter Unit 2 low NO_x burners installation project.

The low NO_x burners projects referenced above will install new burners that utilize improved combustion characteristics and a separated over-fire air supply to the boiler to reduce NO_x emissions.

Q. Please describe the emissions improvements that will be achieved with the pollution control projects described above.

A. The pollution control equipment investments described above are required by the permit terms and conditions issued in response to the environmental requirements described herein and support the Company's ongoing commitment to reduce SO_2 emissions from the Company's generation fleet by approximately 50 percent compared to 2005 levels. In addition to reducing SO_2 emissions, the projects support the Company's ongoing commitment to reduce NO_x emissions from the Company's generation fleet by approximately 40 percent compared to 2005 levels. The Company believes that these investments are complementary to and consistent with BART Regional Haze planning requirements intended to improve the visibility in certain national parks and wilderness areas, and that they exemplify a reasonable approach to achieving emission reductions in our operating territory. The emission reductions that result from these projects have been incorporated into the approved operating permits for the respective units.

Q. Have the costs of the projects been prudently managed by the Company?

A. Yes. The scrubber and bag house projects described above have been contracted under lump-sum, turnkey, engineer, procure and construct ("EPC") contract terms which resulted from competitive bidding processes. The burner replacement projects have been contracted under multiple lump-sum contracts which resulted from competitive bidding processes or job-specific work releases under established service level agreement rate structures. PacifiCorp management continues to provide oversight of the projects and closely manages any project execution plan changes or potential contract scope changes. PacifiCorp believes that the permitted and constructed pollution control projects and their timing appropriately balance the need for emission reductions over time with the costs and other concerns of our customers, our state utility regulatory commissions, and other stakeholders.

Q. Are there additional operating costs that will be incurred as a result of the installation of pollution control equipment?

A. Yes. Unfortunately, but unavoidably, the operation of the new pollution control equipment results in increased operation and maintenance costs associated with reagent, waste disposal, and equipment maintenance. Incremental operation and maintenance costs associated with the Dave Johnston Unit 3 scrubber and baghouse project placed in service in May 2010, the Wyodak pollution control project placed in service in April 2011, and the Naughton Unit 2 scrubber project to be placed in service in November 2011 are included in this case. These costs, as well as the capital investments identified above, are included in the revenue requirement calculations for this case as explained in Mr. Steven R. McDougal's direct testimony.

Description of Generation Plant Turbine Upgrade Investment

Q. Please describe the Hunter Unit 2 power plant turbine upgrade project presented in this case.

A. The Hunter Unit 2 power plant high pressure ("HP"), intermediate pressure ("IP"), and low pressure ("LP") turbine sections were replaced as part of this project. The project was placed in service in April 2011.

Q. Please describe the efficiency improvements that will be achieved with the turbine upgrade project described above.

A. The Company expects the Hunter Unit 2 turbine upgrade to allow more efficient turbine performance without increasing emissions, such that approximately 9 megawatts (Company share, adjusted for pollution control equipment auxiliary load) of incremental capacity can be generated by the unit. Mr. Gregory N. Duvall has included incremental capacity upgrade in the net power cost analysis associated with these projects in his direct testimony.

Q. What is the basis for justification of this investment?

A. As part of the Company's efforts to meet the growing demand for generation, and given the advancing technological improvements in steam turbine design and manufacturing, the Company has initiated a turbine upgrade initiative. This turbine upgrade initiative will further enhance PacifiCorp's overall generation capability and cycle efficiency for the large thermal units being provided with this equipment.

Description of Other Generation Plant Investments

Q. What other generation plant capital investments are included in this application?

A. Generation plant repair and replacement investments and a coal unloading facility addition at the Hayden power plant are the remaining projects included in this case. The repair and replacement projects fall primarily within three major categories: (i) boiler section replacements; (ii) control system upgrades; and (iii) other. The revenue requirement impact of these investments has been included in Mr. McDougal's direct testimony.

Q. How will customers benefit from the repair and replacement capital expenditures contemplated in this case?

A. These capital expenditures enable the Company to maintain safe, reliable, and cost-effective operation of an aging generation fleet. The Company's plants produce energy at costs lower than market prices, enabling the Company to serve its customers at some of the lowest retail electricity prices in the United States. Prudent investment in the Company's existing generating units increases the probability of continued safe and reliable operation of these low-cost resources.

Q. Please describe the Wyodak air cooled condenser replacement project.

A. The Wyodak air cooled condenser ("ACC") has been in service for 33 years and has reached its end of useful life. This replacement project replaces all of the ACC's tube bundles and headers, both of which are experiencing failures. Failed tubes and welds are allowing air in-leakage to the ACC which increases turbine backpressure, allows for accelerated corrosion of the carbon steel tubes and headers in the ACC, and results in freeze/thaw damage during cold weather operation. The new project was placed in service in May 2011. The PacifiCorp share of the capital investment for the scrubber project being placed in service during the test period is approximately $22 million.

Q. How will customers benefit from the Wyodak air cooled condenser replacement project?

A. The Wyodak air cooled condenser replacement project is expected to result in improved unit reliability and efficiency. From a unit reliability perspective, continued operation of the ACC in its current condition has a high potential of causing progressively more unit outages and/or derates. From a unit efficiency perspective, during the winter months it is typical for the Wyodak plant to increase turbine back pressure to ensure that the ACC does not freeze. During the summer months, poor ACC performance also causes the plant to run with high turbine back pressure. Increasing unit back pressure leads to increased fuel consumption for a given megawatt output. By proceeding with the ACC replacement project, customers will benefit from improvements in the areas discussed above as well as advancements in currently available ACC technology. Technology improvements have resulted in increased equipment efficiency without increasing the size of the ACC structure. This efficiency improvement comes without increasing the power consumption of the existing cooling fans.

Q. Please describe the Hayden power plant coal unloading facility project.

A. Currently, the Hayden plant can only receive coal which is shipped by truck. The new coal unloading facility will allow the Hayden plant to also receive coal that is shipped by rail. The project includes construction of a new rail spur and loop, bridges, unloading hopper, belts, transfer points, feeders, crushers and other equipment. The project is expected to be ready for service in October 2011, at a total loaded cost of approximately $12 million (Company's share).

Q. How will customers benefit from the Hayden power plant coal unloading capital expenditure?

A. Hayden Units 1 and 2 currently consume coal produced at Peabody Energy's Twentymile mine. This coal is transported to the plant by truck over county roads. The current contract with Peabody to supply coal for Hayden expires at the end of 2011. In order to ensure a reliable, long-term supply of low-cost fuel to the plant after expiration of the Peabody contract, Hayden's owners (Public Service Company of Colorado, Salt River Project Agricultural Improvement and Power District, and PacifiCorp) requested bids from a number of regional mines that have capability to supply suitable coal to Hayden. Many of these regional mines are located too far from the Hayden plant to economically deliver coal to the facility by truck. Construction of the rail unloading facility allows these suppliers to ship coal to the plant at economic rates and to compete effectively with nearby suppliers. Ratepayers will benefit from the increased competition to supply cost-effective fuel to the plant.

Description of Hydro Investments

Q. What hydro plant capital investments are included in this application?

A. The hydro plant regulatory and new infrastructure investments contemplated in this case are primarily associated with new license implementation measures for the North Umpqua Hydroelectric Project; Federal Energy Regulatory Commission No. 1927; and dam remediation work at the Ashton Hydroelectric Project; Federal Energy Regulatory Commission No. 2381. The revenue requirement impact of these investments has been included in Mr. McDougal's direct testimony.

Q. Please describe the Lemolo Unit 2 reroute project.

A. The Company's investment in the Lemolo Unit 2 reroute project is driven by Settlement Agreement Section 6.1 of the referenced FERC license. These new reach pipe facilities will collect the outflow from the Lemolo 2 plant and transport the water to Toketee Lake. The purpose of the project is to prevent significant increases and decreases in the flow levels in the Umpqua River downstream of the plant which could have detrimental impacts on the native fishery. The project is planned to be placed into service in December 2011 and is expected to cost approximately $9 million.

Q. Please describe the Slide Creek tailrace barrier project.

A. The Company's investment in the Slide Creek tailrace barrier project is driven by Settlement Agreement Section 4.1.1(f) of the referenced FERC license. These new facilities will reduce water turbulence and prevent access to the Slide Creek plant in order to prevent delay or injury to anadromous fish during their migration up the North Umpqua River. The project is planned to be placed into service in December 2011 and is expected to cost approximately $9 million.

Q. Please describe the Ashton Dam seepage control project.

A. The Company's investment in the Ashton Dam seepage control project was driven by the need to remediate the dam embankment with a state of the art engineered fill. The project being considered by this proceeding consists of the low level flow bypass tunnel installation, which will allow for the removal and reconstruction of the dam embankment. It is a non-elective, regulatory and mandated project under the jurisdiction of the Federal Energy Regulatory Commission and a Board of Consultants. The bypass tunnel was placed into service in March 2011 at a cost of approximately $8 million.

Q. What is the basis for justification of these investments?

A. The Soda Springs hydroelectric project with a nameplate rating of 11 megawatts and the Lemolo 2 hydroelectric project with a nameplate rating of 33 megawatts are part of the eight project development comprising the North Umpqua Hydroelectric Project. The economic evaluation for the entire development was conducted in association with the FERC re-licensing process prior to the issuance of the current 2003 license. The analysis indicated that the 35-year license would provide energy for customers at rates substantially lower than market prices. The Ashton Dam seepage control project was determined to be the least cost dam remediation or dam removal alternative that would meet the approval of the FERC and the project Board of Consultants.

Customer Benefits

Q. How will customers benefit from these capital expenditures?

A. The capital expenditures described above and otherwise included in this case enable the Company to maintain safe, reliable, and cost-effective operation of an aging generation fleet. The Company's plants produce energy at costs lower than market prices, enabling the Company to serve its customers at some of the lowest retail electricity prices in the United States. Prudent investment in the Company's existing generating units increases the probability of continued safe and reliable operation of these low-cost resources.

Description of Incremental O&M Costs

Q. Are there incremental O&M costs contemplated in this case associated with recently completed wind projects?

A. Yes. Incremental O&M costs for the Company's recently completed Dunlap I wind project are included in this case. The Dunlap I wind project achieved commercial operation on October 1, 2010. The incremental O&M costs included in this case are known and measurable costs associated with ongoing operation of the facilities, including labor, contracts, parts, and consumables. These costs are summarized in Mr. McDougal's direct testimony.

Q. Are there incremental O&M costs contemplated in this case associated with operation of the Cholla Unit 4 power plant?

A. Yes. The mine which historically supplied cost-effective coal to Cholla Unit 4 was completely mined out in 2010. While also cost-effective, the new fuel being supplied to the facility contains more sulfur and ash. In order to continue to comply with environmental requirements while burning the new fuel, a new scrubber and bag house were installed on the unit in 2008. The new high-removal-rate scrubber and the higher sulfur coal have combined to raise limestone consumption significantly. Also, the new fuel has raised costs for pulverizer and boiler maintenance in the plant. Even with these changes, Cholla Unit 4 continues to provide essential energy and system regulation benefits to PacifiCorp's electric system at an attractive price. Incremental operation and maintenance costs of approximately $1.2 million associated with the operational changes described above are included in this case. These costs are summarized in Mr. McDougal's direct testimony.

Conclusion

Q. Please summarize your testimony.

A. The pollution control equipment investments presented in this case are required to comply with current, proposed, and probable environmental regulations. The investments allow for the continued operation of low-cost coal-fired generation facilities, while achieving significant environmental improvements.

The Company is also making other prudent capital expenditures in its existing generation fleet, including hydro resources, which will benefit customers by maintaining safe, reliable, efficient, cost-effective generating resources and production facilities. The capital investments included in this case are reasonable and prudent, and the Company should be granted full cost recovery for these investments.

The Company continues to prudently manage O&M costs. The Company should be granted full recovery of the incremental O&M costs presented in this case.

Q. Does this conclude your direct testimony?

A. Yes.

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2009 Embedded Generation Bus Bar Costs

May 2011

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Comparison Bus Bar Costs with Pollution Control

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2011 Comprehensive Air Initiative – PVRR Study

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2011 Coal to Natural Gas Conversion PVRR

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NO_x, SO_2, PM Cost per Ton Removed

May 2011

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Requirements Matrix

May 2011

Rocky Mountain Power
Idaho General Rate Case - 2011
Pro Forma Pollution Control Projects

Idaho GRC - Pollution Control Projects

Proj	WBS Element	Project/WBS Short Text	Plant/Unit	In-Service	Compliance Dates	Projected Cost Included in Case	Percent of Cost Current Requirements	Date RFP Issued	APR	Date APR Approved	Planned Unit Outage Utilized	Principal Pollutant	Secondary Pollutant
1	SNAU/2008/C/C05	NAU U2 Flue Gas Desulfurization Sys	Naughton 2	Nov-11	Nov-2011 based on MD-5156 permit application. Prior to 2013 based on regional haze milestones - WY RH 309 SIP.	151,812,653	100	Sep-08	10003746	Apr-09	Yes	SO_2	N/A
2	SWDK/2007/C/724	WDK U1 SO2 and PM Emiss Control Upgrade	Wyodak 1	Apr-11	Apr-2011 based on MD-7487 permit application. Prior to 2013 based on regional haze milestones - WY RH 309 SIP. Prior to Dec 31, 2011 based on BART permit MD-6043A.	103,798,008	100	Oct-08	10004047	May-09	Yes	SO_2	Particulate
3	SHTR/2010/C/050	HTR U2 Clean Air - PM (Baghouse)	Hunter 2	Apr-11	2011 based on permit schedule dated 12/18/2009. Prior to 2012 to meet state R307-424-4 Hg rules. Spring 2011 based on Utah SIP Section XX Regional Haze.	53,436,997	100	Feb-08	10002886	Sep-08	Yes	Particulate	Mercury
4	SHTN/2007/C/273	HTG U1 SO2 & PM Em Cntrl Upgrades	Huntington 1	Mar-11	Nov-2010 based on DAQE-AN0102380019-09 permit application. Prior to 2013 based on regional haze milestones. Prior to 2012 to meet state R307-424-4 Hg rules. Fall 2010 based on Utah SIP Section XX Regional Haze.	28,770,137	100	Jun-09	10002667	Dec-09	Yes	SO_2	Particulate
5	SHTR/2007/C/DU2	HTR U2 SO2 & PM Emission Cntrl Upgrades	Hunter 2	Jul-11	2011 based on permit schedule dated 12/18/2009. Prior to 2013 based on regional haze milestones. Prior to 2012 to meet state R307-424-4 Hg rules. Spring 2011 based on Utah SIP Section XX Regional Haze.	22,521,188	100	Jun-09	10002884	Dec-09	Yes	SO_2	Particulate
6	SJIM/2007/C/207	JB U3 S02 & PM Emission Cntrl Upgrades	Jim Bridger 3	Jul-11	Jun-2011 based on MD-1552A permit application. Prior to 2013 based on regional haze milestones - WY RH 309 SIP.	17,151,525	100	Apr-08	10003390	Mar-08	Yes	SO_2	Particulate
7	SWDK/2009/C/009	WDK U1 Clean Air - NOx (LNB)	Wyodak 1	Apr-11	Apr-2011 based on MD-7487 permit application. Prior to Dec 31, 2011 based on BART permit MD-6043A.	11,858,187	100	Aug-09	10004049	Mar-10	Yes	NOx	CO
8	SNAU/2009/C/202	NAU U2 Clean Air - NOx (LNB)	Naughton 2	Nov-11	Nov-2011 based on MD-5156 permit application. Prior to Jun 30, 2012 based on BART permit MD-6042A.	9,200,272	100	Jun-10	10003744	Aug-10	Yes	NOx	CO
9	SHTR/2009/C/150	Hunter U2 Clean Air - NOx (LNB)	Hunter 2	Apr-11	2011 based on permit schedule dated 12/18/2009. Spring 2011 based on Utah SIP Section XX Regional Haze.	6,246,843	100	Sep-10	10002882	Aug-10	Yes	NOx	CO

Proj	Environmental Regulations and Requirements for Installing Control Equipment				Preliminary Assesment Proposed 40 CFR Part 63 HAPs MACT Rules Does Project Support Compliance?				Preliminary Assesment Additional Existing, Proposed, and Probable Rules Does Project Support Compliance?				
	Underlying State and Federal Regulations	State Issued Permit, Construction Permit or Approval Order	State Issued BART Permit	State Implementation Plan	Underlying Regulation	Non-Hg Metals	Acid Gases	Hg	One-Hour SO2 NAAQS Standard	One Hour NO2 NAAQS Standard	Proposed Ozone Standard	PM2.5 NAAQS Revision	Coal Combustion Residuals Regulations Under Consideration
1	40 CFR 51.309 40 CFR 52.21	MD-5156 May 2009	NA	WY Regional Haze 309 SIP	40 CFR Part 63	YES	YES	YES - with Reagent Injection	YES			YES	
2	40 CFR 51.309 40 CFR 51.309(g)	MD-7487 May 2009	MD-6043A December 23, 2010	WY Regional Haze 309 SIP WY Regional Haze 309(g) SIP Section 6.5.7	40 CFR Part 63	YES	YES	YES - with Reagent Injection	YES			YES	
3	40 CFR 51.309 Utah R307-401-8(2) 40 CFR 60.11(d) Utah R307-424-4	UDAQ Permit 1500101001 May 2008 DAQE-AN0102370012-08 March 2008	NA	Section XX Regional Haze D.6.d	40 CFR Part 63	YES	NA	YES				YES	
4	40 CFR 51.309 Utah R307-401-8(2) 40 CFR 60.11(d) Utah R307-424-4 Utah R317-1-2	UDAQ Permit 1501001003 August 2010 DAQE-AN0102380019-09 August 2009 UGW 15002	NA	Section XX Regional Haze D.6.d	40 CFR Part 63	YES	YES	YES	YES			YES	YES
5	40 CFR 51.309 Utah R307-401-8(2) 40 CFR 60.11(d) Utah R307-424-4 Utah R317-1-2	UDAQ Permit 1500101001 May 2008 DAQE-AN0102370012-08 March 2008 UGW 150001	NA	Section XX Regional Haze D.6.d	40 CFR Part 63	YES	YES	YES	YES			YES	YES
6	40 CFR 51.309 40 CFR 51.309(g)	MD-1552 April 2007 MD-1552A March 2009	MD-6040A November 24, 2010	WY Regional Haze 309 SIP WY Regional Haze 309(g) SIP Section 6.5.4	40 CFR Part 63	YES	YES	YES - with Reagent Injection	YES			YES	
7	40 CFR 51.309(g) 40 CFR 76.5, 76.11	MD-7487 May 2009	MD-6043A December 23, 2010	WY Regional Haze 309(g) SIP Section 6.5.7	NA	NA	NA	NA		YES	YES		
8	40 CFR 51.309(g) 40 CFR 76.7, 76.11	MD-5156 May 2009	MD-6042A December 23, 2010	WY Regional Haze 309(g) SIP Section 6.5.6	NA	NA	NA	NA		YES	YES		
9	40 CFR 51.309 40 CFR 76.7, 76.11	UDAQ Permit 1500101001 May 2008 DAQE-AN0102370012-08 March 2008	NA	Section XX Regional Haze D.6.d	NA	NA	NA	NA		YES	YES		

Rocky Mountain Power
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Exhibit Accompanying Direct Testimony of Chad A. Teply

PacifiCorp's Emission Reduction Plan

May 2011

November 2, 2010

Exhibit A

PacifiCorp's Emissions Reductions Plan

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

Summary

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

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

PacifiCorp's Long-Term Emission Reduction Commitment

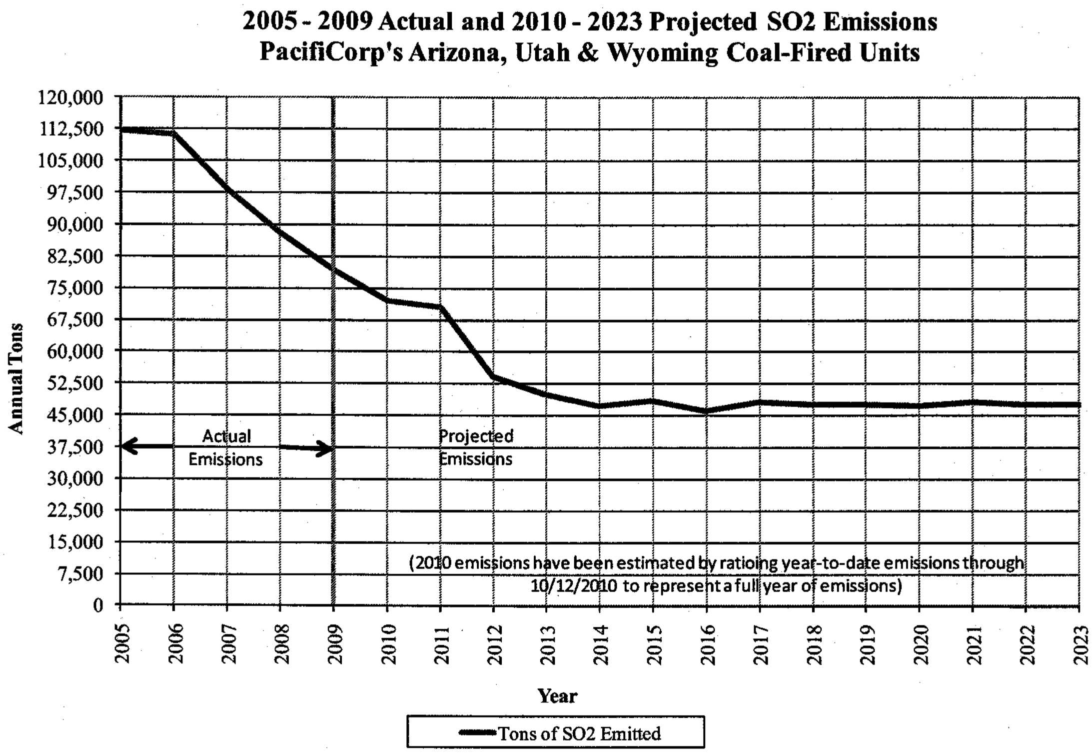
Table 1 below identifies the emission reduction projects and related construction schedules as currently included in PacifiCorp's reduction plan.

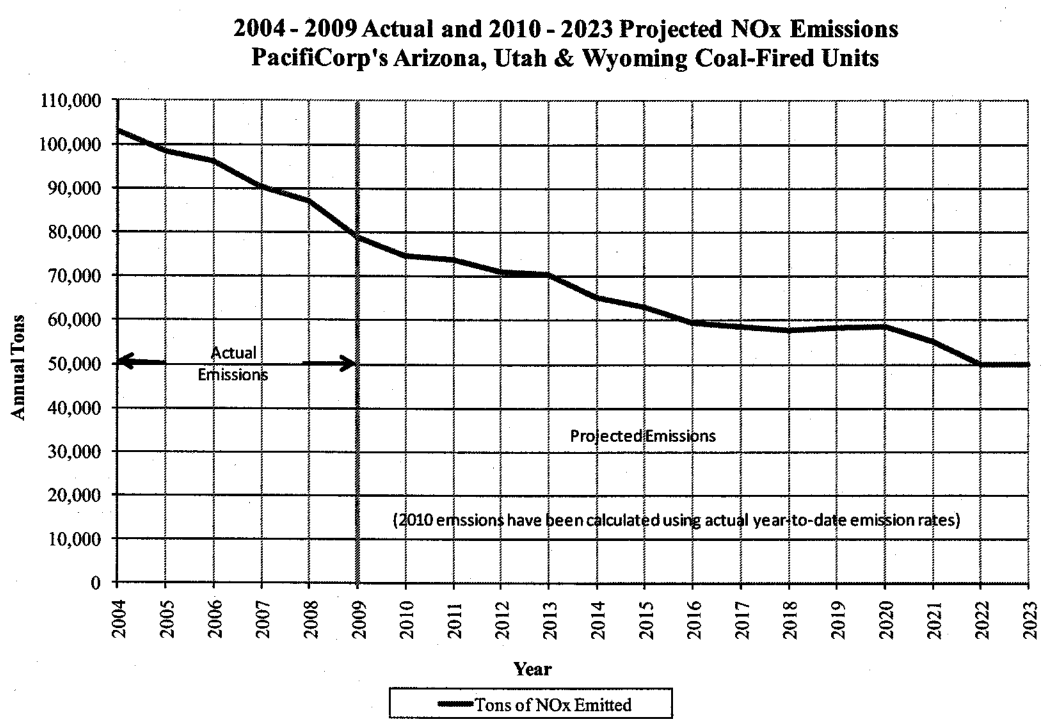
Table 1: Long-Term Reduction Plan

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

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

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


2005 - 2009 Actual and 2010 - 2023 Projected SO2 Emissions
PacifiCorp's Arizona, Utah & Wyoming Coal-Fired Units
Annual Tons
Actual Emissions
Projected Emissions
(2010 emissions have been estimated by ratioing year-to-date emissions through 10/12/2010 to represent a full year of emissions)
Year
Tons of SO2 Emitted


2004 - 2009 Actual and 2010 - 2023 Projected NOx Emissions
PacifiCorp's Arizona, Utah & Wyoming Coal-Fired Units
Annual Tons
Actual Emissions
Projected Emissions
(2010 emssions have been calculated using actual year-to-date emission rates)
Year
Tons of NOx Emitted

Project Installation Schedule

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

Priority of Emission Reductions

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

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

Emission Reductions and BART Deadlines

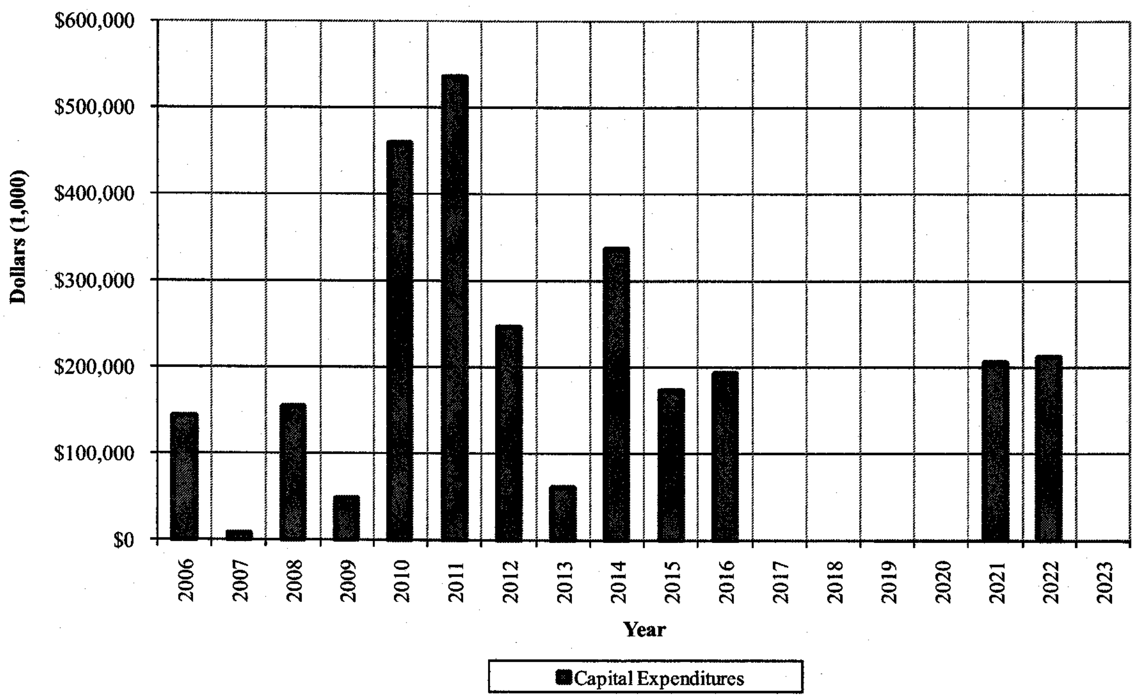
As depicted in the table and charts above, PacifiCorp began implementing its emission reduction commitments in 2005. This was well ahead of the emission reduction timelines under the regional haze rules which require BART to be installed no later than five years following approval of the applicable Regional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

Customer Impacts

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

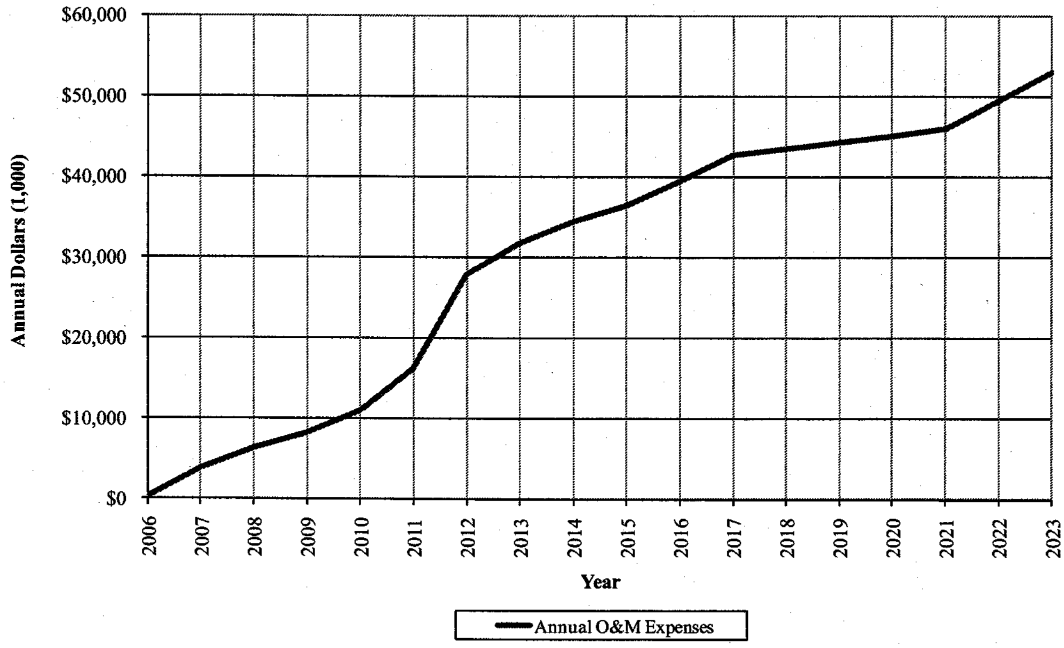
1. The timing and magnitude of the capital costs.
2. The O&M expenses that will be incurred due to these projects.
3. The expected annual costs[2] through 2023 that customers will be incur as a result of these specific pollution control projects.

Capital Expenditures to Add Pollution Control Equipment onPacifiCorp's Arizona, Utah & Wyoming Coal-Fired Units

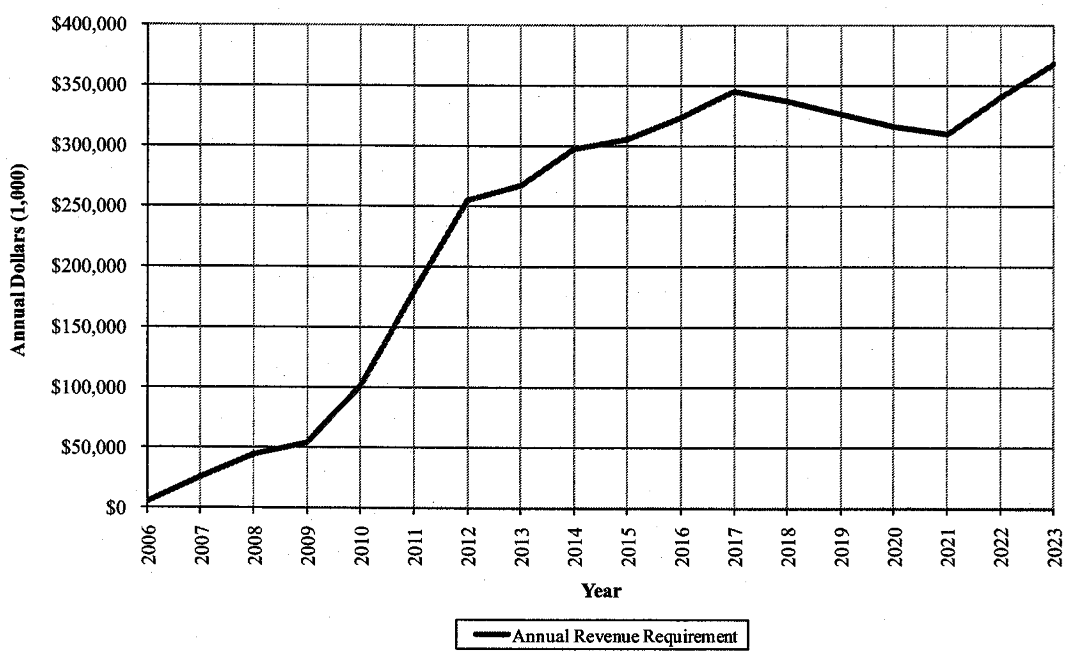


[2] PacifiCorp has made every attempt to provide an accurate estimate of the anticipated increase in annual revenue requirements that will ultimately be translated to increases in customers' electricity rates. However, there are several variables such as interest rates, inflation rates, discount rates,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

Increases In O&M Expenses Due to Additional Pollution Control Equipment on Arizona, Utah & Wyoming Coal-Fired Units



Annual Increase to Customers Due to Additional Pollution Control Equipment on Arizona, Utah & Wyoming Coal-Fired Units



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

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

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

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

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

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

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

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

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

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

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

8. Increasing escalation rates on fuel costs and other commodities

BART and Regional Haze Compliance

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

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

Conclusion

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

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

November 2, 2010