REDACTED
Docket No. 20000-___-ER-11
Witness: Chad A. Teply

BEFORE THE WYOMING PUBLIC SERVICE COMMISSION

ROCKY MOUNTAIN POWER

REDACTED Direct Testimony of Chad A. Teply

December 2011

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

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 PacifiCorp Energy 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. How is your testimony organized?

A. My testimony is organized as follows:

1. Introduction and Purpose of Testimony
2. Comprehensive Air Initiative Overview
3. Emerging Environmental Regulations Overview
4. Planning
5. Alternatives, Cost Effectiveness and Benefits

6. Customer Considerations

7. Project-specific Discussion

8. Conclusion

Introduction and Purpose of Testimony

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 emissions control equipment being placed in service during the test period at four of the 19 coal fueled generation units the Company operates. My testimony will specifically focus on emissions control equipment investments at Naughton Unit 1, Dave Johnston Unit 4, and Hunter Units 1 and 2. These investments will be placed in service between January 2012 and March 2013 and have not been considered by this Commission in past rate case Dockets. As can be seen in Company witness Mr. Brian S. Dickman's Exhibit RMP___(BSD-2), Tab 8, these investments constitute a significant portion of the new capital investments that will be placed in service by March 31, 2013.

Overview of Testimony

Q. Please provide a general description of the emissions targeted for reduction by the control equipment included in this case.

A. The emissions control equipment investments included in this case will result in the reduction of sulfur dioxide ("SO_2"), nitrogen oxides ("NO_X"), and particulate matter ("PM") emissions from the retrofitted facilities as required to comply with current environmental regulations. In certain instances, it is also anticipated that emissions control equipment investments will support improved mercury ("Hg") emissions control, as well as compliance with proposed and anticipated likely environmental regulations such as the Mercury and Air Toxins Standards ("MATS"), formerly referred to in industry as hazardous air pollutants ("HAPs") maximum achievable control technology ("MACT") regulations.

Q. Please provide a general description of the benefits gained from the investments.

A. The Company has developed and executed its emissions control plan, including the investments presented in this case, with a focus on maintaining a reasonable balance between protecting the interests of customers, meeting the obligation 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.

Q. Please provide an overview of the primary environmental regulations requiring the emissions control investments included in this case.

A. The primary environmental regulations requiring the emissions control investments included in this case are Regional Haze Rules and National Ambient Air Quality Standards ("NAAQS"). The specific environmental requirements affecting individual investments will be discussed in detail later in my testimony.

Q. Has the Company provided analyses of the emissions control investments included in this case versus other compliance alternatives to demonstrate that the investments provide the risk adjusted, least-cost outcome for its customers?

A. Yes. The analyses completed by the Company and described in this testimony and accompanying exhibits support the emissions control equipment investments included in this case. These emissions control equipment investments will allow ongoing energy production from the retrofitted facilities through the currently approved depreciable life for ratemaking as the risk adjusted, least-cost outcome for customers.

Comprehensive Air Initiative Overview

Q. When did the Company begin development and implementation of its emissions control plan?

A. Through the Western Regional Air Partnership, the Company worked with states, tribes, and federal agencies to develop and implement regional planning processes to improve visibility in national parks and wilderness areas in the western United States. The Company's early efforts with Utah and Wyoming led to the development of the Company's Comprehensive Air Initiative ("CAI"). The CAI was designed to reduce power plant emissions in accordance with Regional Haze and other air quality regulations that would require emission reductions.

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 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 Company has 14 units that meet the construction and emissions threshold criteria and are, therefore, "BART-eligible units." Pursuant to federal regulations at 40 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 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

Since 2005, the CAI has been updated to include additional controls that the states have required. The Regional Haze State Implementation Plans initially submitted by Utah in 2008 and Wyoming in 2010, and updated since those initial filings, reflect the emissions controls in the CAI.

Q. Please provide an overview of the Company's long-term emissions compliance plan and other environmental compliance plans up to and including December 31, 2022.

A. Currently, PacifiCorp's long-term emissions control plan consists of those projects and implementation timelines identified in Exhibit RMP___(CAT-1), Overview of PacifiCorp's Environmental Control Plan. A summary of key assumptions regarding anticipated regulatory requirements and environmental control technologies is provided in Exhibit RMP___(CAT-2), Known Regulatory Drivers and Environmental Projects. Exhibit RMP___(CAT-3), Mercury Control Projects, provides similar project planning and environmental drivers for currently planned mercury control projects. Exhibit RMP___(CAT-4), List of CCR Projects Included in 10-Year Plan, provides similar project planning and environmental drivers for proxy coal combustion residuals ("CCR") projects.

Q. How many of the Company's coal fueled facilities are potentially impacted by current and emerging environmental regulations?

A. The Company owns or has a partial 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, 14 of which are BART-eligible units under the Regional Haze Rules. The Company's CAI has been developed and maintained to ensure compliance with environmental regulations governing each of the coal fueled generation facilities it operates. The current and emerging environmental regulations discussed in this testimony will potentially impact all 26 of the Company's coal fueled facilities in some fashion.

Q. Does the Company need to make the emissions control equipment investments included in this case if it expects to continue operating the affected facilities?

A. Yes. The emissions control equipment investments included in this case are required to comply with existing regulations including Regional Haze Rules, the Regional SO_2 Milestone and Backstop Trading Program developed in alignment with existing federal regulations and administered in Utah and Wyoming, National Ambient Air Quality Standards, and New Source Review requirements. In order to comply with the requirements that result from those regulations and that are set forth in the Company's air quality permits and the state implementation plans of Utah and Wyoming , it is necessary to install and operate the emissions controls presented in this case. The Company believes that the emissions control projects included in this case and those currently permitted are also consistent with the EPA's proposed MATS and will support the Company's ability to comply with the proposal's standards for acid gases and non-mercury metallic HAPs at the facilities receiving said controls. Installing and operating the emissions control equipment included in this case allows the affected facilities to continue operating as the risk adjusted, least-cost option while meeting all applicable requirements, as proven by the Company's analyses.

Q. What has been the initial focus of the Company's CAI?

A. The initial focus of the Company's CAI has been on installing controls to reduce SO_2 emissions, which are the most significant contributors to regional haze in the western United States. In addition, the Company continues to rely on installation of low NO_X burners to significantly reduce NO_X emissions. The Company also anticipates completing installation of five selective catalytic reduction systems ("SCRs") (or similar NO_X-reducing technologies) at its owned and operated facilities by 2022, reducing NO_X emissions even further. The Company's CAI also includes the installation or retrofit of several baghouses to control particulate matter emissions. For certain units which utilize dry scrubbers, baghouses have the added benefit of improving SO_2 removal. Baghouses also significantly improve mercury emissions control capability.

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 CAI?

A. The following figures represent the reductions in SO_2 and NO_X emissions that are expected to occur at units owned by the Company in Wyoming, Utah, and Arizona as a result of the Company's CAI.

Figure 1

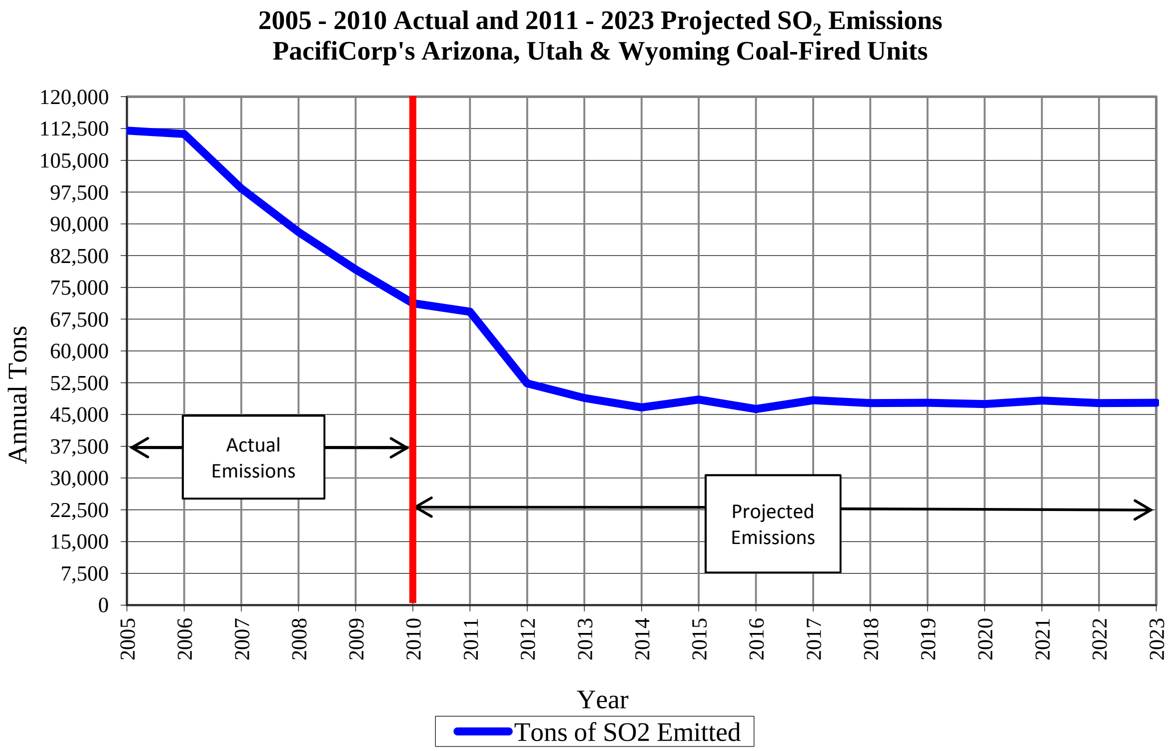
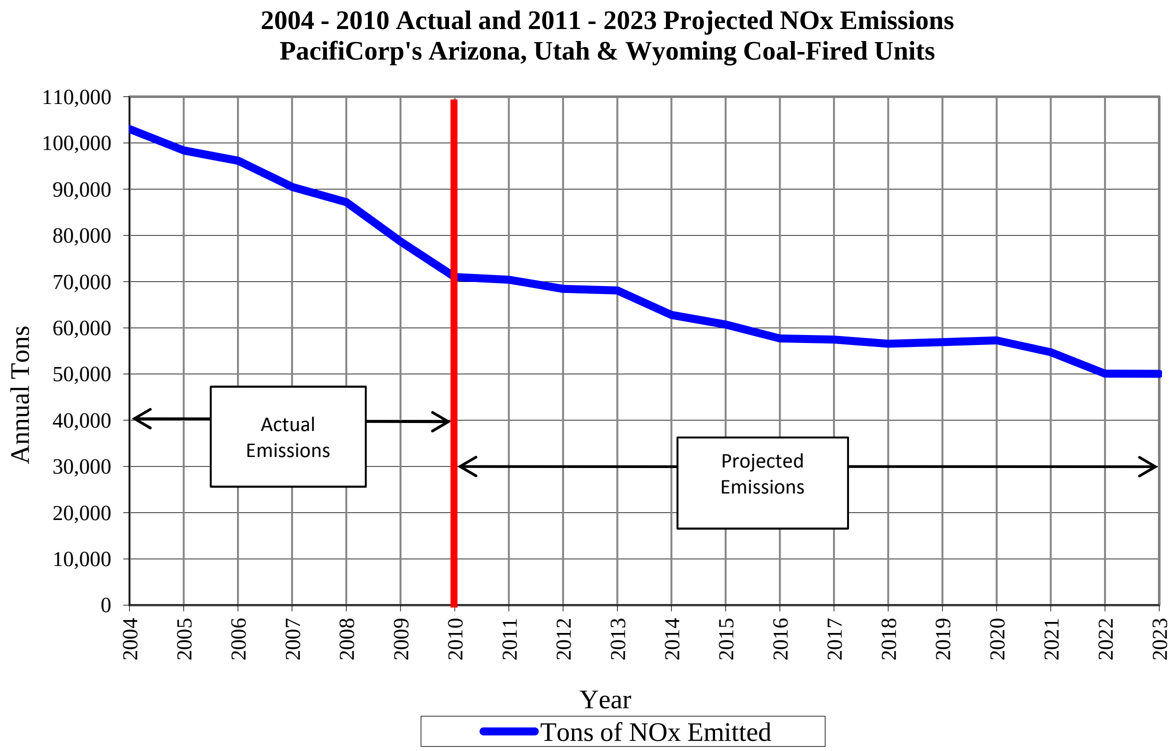

2005 - 2010 Actual and 2011 - 2023 Projected SO2 Emissions
PacifiCorp's Arizona, Utah & Wyoming Coal-Fired Units
Annual Tons
120,000
112,500
105,000
97,500
90,000
82,500
75,000
67,500
60,000
52,500
45,000
37,500
30,000
22,500
15,000
7,500
0
Actual Emissions
Projected Emissions
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
Year
Tons of SO2 Emitted

Figure 2



Q. Does the Company believe that its CAI properly balances stakeholder interests?

A. Yes. Environmental benefits, including visibility improvements, will flow from the projects installed under the Company's CAI. The Company believes that the emission reduction projects and their timing appropriately balance the need for emission reductions with the concerns of our customers for low-cost energy, concerns of state utility commissions, and concerns of other stakeholders. The Company believes this plan is complementary to, and consistent with, BART and Regional Haze planning requirements of the states in which the facilities operate. Furthermore, it is a reasonable approach to achieving required emission reductions pursuant to state requirements in Wyoming, Utah and other states. It is anticipated that upon completion, the Company's CAI will have supported emissions control projects at 15 of 19 Company-operated coal fueled units, affecting approximately 6,700 net Megawatts ('Mw") of generation capacity (approximately 5,300 net Mw Company share). Nonetheless, the Company will also continue to review all CAI projects prior to execution to ensure that they remain economically justified given any environmental, regulatory or policy changes that may occur going forward.

Q. Have the costs of the Company's CAI projects been prudently managed?

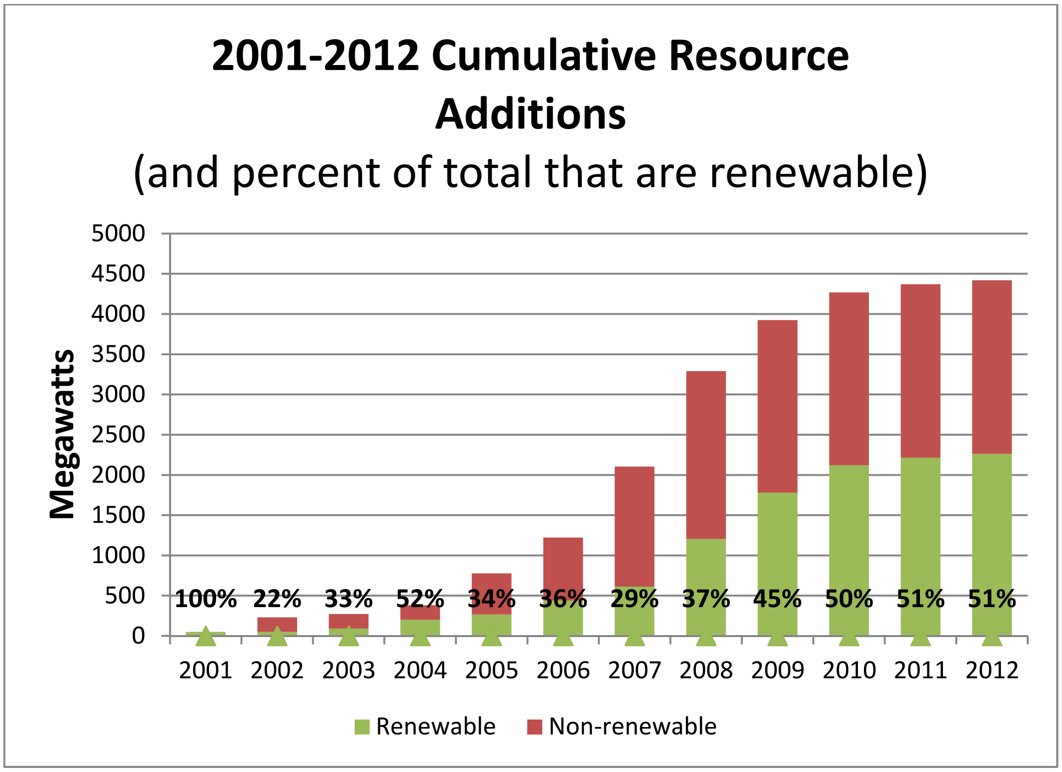
A. Yes. The Company's scrubber and baghouse projects have typically been contracted under lump-sum, turnkey, engineer, procure, and construct ("EPC") contract terms which resulted from competitive bidding processes. The Company's low NO_X burners ("LNB") projects have typically been contracted (1) under multiple lump-sum contracts which resulted from competitive bidding processes; or (2) job-specific work releases under established service level agreement rate structures. Company management continues to provide oversight of the projects and closely manages any project execution plan changes or potential contract scope changes.

Q. In addition to the Company's emissions control plan investments, what actions has the Company taken to avoid increasing emissions while diversifying its generation resource portfolio?

A. In addition to reducing emissions at existing facilities, the Company has also avoided increasing emissions by adding more than 1,400 Mw of non-emitting renewable wind generation between 2006 and 2010. Figure 3 below depicts the

Company's cumulative resource additions from 2001 through 2012 along with the percentage of the total that are from renewable generation.

Figure 3



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

A. The non-renewable generation resource additions depicted in Figure 3 are primarily natural gas resources. The most significant of these resources are the Company's Currant Creek block 1 combined cycle combustion turbine ("CCCT") facility that was placed in service in March 2006, the Company's Lake Side block 1 CCCT facility that was placed in service in September 2007, and the Chehalis CCCT facility acquired in September 2008. The Company has also recently begun construction of the Lake Side block 2 CCCT facility that is scheduled to be placed in service in 2014. In total, those projects will add more than 2,200 Mw of new gas fueled generation to the Company's generation mix.

Q. Does the Company's fleet of generation assets continue to face changing environmental compliance obligations?

A. Yes. The Company's fleet of generation assets faces a constantly changing landscape with regard to environmental regulations. Although the extent and effect of these changes remains uncertain, they are expected to impact the Company's future operating costs. See Exhibit___(CAT-6) for additional discussion regarding emerging and changing environmental regulations.

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 BART permits and construction permits issued by the respective state agencies for the emissions 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. What is the Company's current assessment of potential impacts of EPA's proposed MATS on the Company's facilities?

A. The Company's current assessment of the proposed MATS suggests that scrubbers, baghouses, electrostatic precipitators, and activated carbon and/or reagent injection systems are contemplated by EPA to be readily available, cost effective controls to meet the following proposed 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) total particulate matter limit. Until a final rule is promulgated, which is expected in December 2011, the cost, timing, equipment, monitoring, and recordkeeping to comply with the rule cannot be fully ascertained. However, the Company believes that the emissions control projects included in this case and those currently permitted are consistent with the EPA's proposed MATS and will support the Company's ability to comply with the proposal's standards for acid gases and non-mercury metallic HAPs at the facilities receiving said controls. The Company does, however, anticipate having to take additional actions to reduce mercury emissions and otherwise comply with the proposal's standards. The Company has incorporated costs for mercury emissions control equipment into its business planning processes. Other compliance costs will be incorporated as the rules are finalized.

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 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 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.

Emerging Environmental Regulations Overview

Proposed CCR Regulations

Q. What is the Company's current assessment of potential impacts of proposed EPA CCR regulations on it existing facilities?

A. As the Company assesses options regarding continued investment 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 periodically updates its CCR-related costs and asset retirement obligations in its planning processes. In response to the rulemaking regarding CCR proposed by EPA in June 2010, 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 in its business planning processes, which will serve as a planning proxy for the Company until such time as EPA completes its CCR rulemaking process. It is currently anticipated that compliance with final CCR rules will be required five years after final rulemaking, or by late-2017. 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 Company's business plans.

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

A. Yes. The Company participated in the public hearing process and filed written comments in the EPA rulemaking on this matter, Docket ID No. EPA-HQ-RCRA-2009-0640, which are included as Exhibit RMP___(CAT-7). In general, the Company believes 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, because 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 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 the Company's facilities?

A. Due to the preliminary status of the 316(b) rulemaking process, the Company has not completed plant-specific 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. A key element of the proposed rule is anticipated to require conducting plant-specific studies and assessments. A majority of the Company's facilities utilize cooling towers and closed cycle cooling, which we believe significantly reduces potential 316(b) rulemaking exposure. Nonetheless, modifications may still be needed at the cooling water intake structures of certain facilities to comply with the proposed impingement mortality standards. As such, the Company has developed preliminary estimates of the costs associated with potential studies and potential mitigation projects at its facilities by extrapolating results of a 2007 study completed at the Company's Dave Johnston facility prior to the suspension of the then current Phase II Section 316(b) rule. The preliminary estimates for the Company's proxy 316(b) compliance projects have been incorporated into the Company's business plans.

Q. Has the Company participated in the public comment period associated with the EPA's proposed 316(b) rulemaking?

A. Yes. The Company's filed comments in the EPA rulemaking on this matter, Docket ID No. EPA-HQ-OW-2008-0667, are included as Exhibit RMP___(CAT-

8). 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 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 limit rulemaking on its facilities?

A. The EPA's announced intention to undertake effluent rulemaking has not yet materialized into a proposed rule to regulate effluent limits for wastewater discharges from steam electric plants. The Company is, however, aware that the effluent guidelines may be revised; how the guidelines may be revised is entirely speculative. While certain Company facilities do 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 United States and was not sufficient to provide the Company with information regarding what the revised guidelines would entail and/or how the coal combustion byproduct rulemaking may impact those guidelines.

Q. Has the Company participated in the EPA's discovery process related to proposed effluent rulemaking?

A. Yes. The Company responded to EPA's effluent limitation guideline questionnaire Information Collection Request on September 15, 2010. On February 3, 2011, Eastern Research Group, Incorporated, a contractor for the EPA, contacted the Naughton plant with follow-up questions. The Company responded to those questions on February 14, 2011.

Planning

Q. Has the Company accounted for emissions 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. 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. 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 included capital expenditures for planned and/or ongoing emissions control equipment investments included in the Company's business plan, including MATS compliance costs. However, due to the timing of these case studies in 2010, the Company's preliminary capital cost estimates for compliance with the EPA's proposed CCR rules and Clean Water Act Section 316(b) cooling water intake rules were not incorporated. Proxy CCR and Clean Water Act Section 316(b) compliance project cost estimates have since been incorporated into the Company's business planning processes.

Q. Has the Company developed updated System Optimizer modeling as part of its 2011 IRP process subsequent to the case studies discussed above?

A. Yes. The Company has built upon the 2011 IRP coal utilization case studies to better evaluate the economics associated with the Company's CAI investments. The specific results of this update can be reviewed in the Company's Confidential Supplemental Coal Replacement Study ("IRP Supplement") filed in response to party comments in the 2011 IRP dockets in the various states the Company serves. A copy of the document is attached as Confidential Exhibit RMP___ (CAT-5).

Q. What improvements were made in the updated System Optimizer modeling?

A. Improvements were made in three areas. First, the Company made improvements in the study design to better capture the tradeoff in cost between existing coal resources requiring CAI investments and costs for replacement resource options. Second, the Company updated environmental compliance cost assumptions for all coal resources to reflect updated information regarding emerging regulations. Third, the Company revisited the market price and CO_2 cost scenarios that are aligned with current economic conditions and policy developments.

Q. How did the Company improve the design of the coal utilization sensitivities to better capture cost tradeoffs between existing coal resources and potential replacement resources?

A. In the original coal utilization sensitivities, the Company allowed existing coal resources to be replaced only by natural gas combined cycle resources located at the site of the coal unit being displaced. These natural gas resource replacement options were scalable in size so that the replacement option equaled the size of the coal unit it could displace. In the IRP Supplement, the Company allowed existing coal resources to be displaced by a wide range of resource options consistent with the resource alternatives used in the 2011 IRP and did not allow these resources to be scalable in size. As such, coal resources could be displaced by green field combined cycle resources, green field simple cycle resources, and demand side management ("DSM") resources in much the same way that resource portfolios were developed in the 2011 IRP process; however, the Company did not allow growth resources to fill long-term resource needs.

Q. What is a growth resource and why was it excluded as a resource replacement option in the IRP Supplement?

A. Growth resources are included as a generic resource alternative in the out years of the IRP planning horizon – beginning 2021 in the 2011 IRP. This resource is intended for capacity balancing in each load area to ensure that capacity planning margins are met in the out years of the planning horizon. Growth resources are ascribed costs that are derived from forward power market prices. Growth resources have traditionally been used in the IRP to manage simulation run time by simplifying resource selection beyond the first 10-years of the planning period. Because growth resources are generic resources with costs tied to the power market, they do not accurately reflect the true cost of a replacement resource requiring capital investment or ongoing fixed costs.[1] Allowing growth stations to replace coal resources would provide an artificial incentive for the System Optimizer model to retire units assuming they could be replaced by a generic resource option without appropriate cost metrics.

Q. Did the IRP Supplement assume that intermittent renewable resources such as wind could replace coal fueled generation?

A. No. Intermittent resources such as wind can supply system energy, but are limited in their ability to provide system capacity given the non-dispatchable and intermittent nature of wind resource generation. Because the Company's coal fueled generation provides capacity to the system, intermittent resources such as wind are not suitable replacement alternatives and were not included as a resource replacement option.

Q. What other improvements were made to the study design for the IRP Supplement?

A. To more accurately report findings for specific coal units in the IRP Supplement, the Company forced existing coal units to be idled and decommissioned at the end

[1] Growth resources, which can be added as system resources in a given load area, should not be confused with front office transactions. Front office transactions are firm forward market purchases made at market hubs that can be used to meet long-term resource needs.

of their currently established depreciable lives. To this end, the IRP Supplement forces the removal of eight coal units from the existing resource mix within the 20-year planning period. The Carbon plant is currently assumed to be idled and decommissioned at the end of its currently approved depreciable life in 2020, the Dave Johnston plant is currently assumed to be idled and decommissioned at the end of its currently approved depreciable life in 2027, and the Naughton plant is currently assumed to be idled and decommissioned at the end of its currently approved depreciable life in 2029.

Q. Please describe the environmental compliance cost assumption updates adopted for the IRP Supplement.

A. The original coal utilization sensitivities reported in the 2011 IRP were performed using then current CAI costs needed to achieve compliance with expectations for best available retrofit technology requirements under the EPA's regional haze rules and increasingly stringent NAAQS for criteria pollutants. Costs in the original sensitivities also reflected then current expectations to meet compliance with MATS technology requirements. Total costs, inclusive of Allowance for Funds Used During Construction ("AFUDC"), for all CAI in the original sensitivities totaled approximately [redacted] for the period 2011 through 2022.

In the IRP Supplement, the scope was expanded to include expected investment costs needed to meet compliance for CCR and 316(b) regulations. Costs for out-year SCR installations with proxy in-service dates beyond 2022 at the Company's Hunter, Huntington, and Wyodak facilities were also included to add conservatism to results by reflecting potential future environmental project requirements, although no such requirements or obligations currently exist. Total environmental compliance costs, inclusive of AFUDC, among all coal units in the IRP Supplement total just over [redacted] for the period 2011 through 2030.

Q. How have CO_2 cost sensitivities been incorporated into the Company's assessments of continuing to invest in individual coal fueled generating units?

A. The Company has incorporated three different CO_2 cost scenarios in the Company's IRP Supplement; a base case, a high case and a low case. The base case represents the Company's most current expectations for CO_2 price levels and timing in conjunction with the Company's most current official forward price curve. The high case captures higher CO_2 costs beginning sooner than assumed in the base case alongside a future having higher natural gas prices. The low case represents a future where no policy is effectuated that places CO_2 costs on emissions in the power sector through the 20-year study horizon and gas prices are lower than those expected under the base case. The high and low cases are variations on the base case that represent a reasonable range of high and low market conditions having potential to influence the economic viability of environmental investments required on the Company's coal fueled generation fleet. The CO_2 costs and natural gas prices assumed for these three scenarios are further described in Confidential Exhibit RMP___(CAT-5).

Q. How did the Company develop its CO_2 cost assumptions for the low and high case scenarios used in the IRP Supplement?

A. The Company compared external forecasts of CO_2 cost to develop a reasonable range around the base case representative of plausible high and low cost outcomes. The CO_2 cost assumptions used in the IRP Supplement are shown alongside these external forecasts in Confidential Exhibit RMP___(CAT-5). For the low case, the Company assumed there would be no policy developments that would impute a cost on CO_2 emissions in the power sector within the 20-year study period. This assumption is consistent with reports from PIRA who have indicated that there is real potential for a zero CO_2 cost scenario. The high CO_2 cost assumptions adopted for the IRP Supplement are higher and start sooner than any of the current projections from a variety of third party forecast services, including PIRA, Wood Mackenzie, and IHS CERA, but remain consistent with an upper limit that would have been established under the American Power Act of 2010 as proposed by Senators Kerry and Lieberman in May 2010, although the proposed legislation was not passed into law.

Q. What other cost assumption updates were made for the IRP Supplement?

A. Assumptions for the recovery of remaining depreciation costs that would be incurred as a result of an early retirement were improved. In the original coal utilization sensitivities, recovery of any remaining depreciation for the underlying resource, before accounting for incremental capital associated with CAI costs, was incorporated as a cost that encumbered the natural gas replacement resource. Because these costs are applicable regardless of whether the coal resource is kept in service or if the coal resource is retired, the IRP Supplement removed the cost of recovery for any remaining depreciation associated with the underlying resource. Rather, in the IRP Supplement, only recovery of depreciation remaining from incremental environmental compliance costs at any point in time beyond the initial investment period is included in the replacement decision being made by the System Optimizer model.

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

A. No.

Q. What project-specific factors does the Company typically consider when making its investment decisions?

A. Factors such as ongoing compliance with existing operating requirements, fuel supply flexibility, equipment end of life / performance 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 emissions control investments?

A. The waste handling phase of the Hunter Units 1 and 2 scrubber projects included in this case are good examples of how ongoing compliance with current regulations factors into the Company's emissions control investment planning process. The scrubber waste handling system will ensure that the final waste product will not contain any free liquids and can properly be disposed of in the onsite landfill in compliance with current regulations. Waste handling addition was required because the higher level of sulfur dioxide removal required by Regional Haze Regulations combined with less ash in the coal have made the previous method of waste handling (mixing scrubber waste with dry fly ash) incompatible with disposal regulations.

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

A. The Hunter Units 1 and 2 scrubber project are good examples of how fuel supply flexibility has factored into the Company's emissions control investment planning process. As the Company contemplated BART requirements for Hunter Units 1 and 2, emissions 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 contain fuel and generation costs at this facility.

Q. How have existing emissions control equipment end of life / performance considerations factored into planning of new emissions control investments?

A. The replacement of various scrubber system elements at Hunter Units 1 and 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 Units 1 and 2 scrubber project tie-in to coincide with planned maintenance outage cycles for the units, the projects were 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 emissions control investments?

A. Operational considerations are included in the technical specifications for each of the Company's emissions control projects. The material handling phase of the Hunter Units 1 and 2 scrubber projects is a key example of the Company's efforts to improve operational efficiencies. This project results 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.

Alternatives, Cost Effectiveness and Benefits

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 idling a unit and replacing it with market power purchases. For the emissions control project investments included in this case the Company has also prepared reference cases for conversion of the units to natural gas and replacement of idled generation with in-kind CCCT technology on the existing sites. Examples of these considerations are discussed further below.

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 present value revenue requirement differential ("PVRR(d)") benefits associated with its emissions control investments versus market power purchases, with consideration given to potential CO_2 costs and resulting market pricing assumptions. The results of these analyses are discussed on a case-by-case basis in my testimony below describing the individual projects included in this case. These PVRR(d) analyses demonstrate prudence of the emissions control investments.

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 emissions control investments versus natural gas repowering scenarios, with consideration given to potential CO_2 costs and resulting market pricing assumptions. The results of these analyses are discussed on a case-by-case basis in my testimony below describing the individual projects included in this case. The results of these PVRR(d) analyses demonstrate prudence of the emissions control investments presented in this case.

Q. Has the Company assessed the costs of continuing to invest in individual coal fueled generation assets versus the cost of idling the units and replacing them with CCCT generation resources?

A. Yes. The Company has developed economic analyses intended to provide an overview of the PVRR(d) benefits associated with its emissions control investments, with consideration given to potential CO_2 costs and resulting market pricing assumptions, versus idling and replacement scenarios. The results of these analyses are discussed on a case-by-case basis in my testimony below describing the individual projects included in this case. The results of these PVRR(d) analyses demonstrate prudence of the emissions control investments presented in this case.

Q. Please summarize the findings on the Company's analyses of alternatives to the emissions control investment included in this case.

A. The Company's analyses of alternatives demonstrate that maintaining the ability to operate the existing coal units by retrofitting the units with the emissions control equipment included in this case represents the risk adjusted, least-cost option for customers. This is true even before considering factors associated with retirement of the coal units prior to their currently approved depreciation lives for ratemaking, such as the economic impact on Wyoming, the loss of fuel diversity in the generation portfolio, and the potential impact on system reliability.

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

A. In support of the BART review processes administered by the respective states, 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). The 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. Measures of capital cost on a dollars per ton of pollutant removed basis have been reviewed, which is applied specifically as part of the BART determination process. In addition, the analyses outlined the cost for projected improvement in visibility which can be expected by the installation of the respective technology. For each unit or source subject to BART, the respective 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.

Customer Considerations

Q. What are the benefits to customers of installing the emissions control equipment?

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 prior to the compliance dates specified in the respective permits.

As the compliance deadlines for existing environmental requirements and emerging environmental regulations 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, and potentially impracticable. Attempting to postpone installation of required emissions control equipment installations to later planned maintenance outages, or mid-cycle tie-in outages, would make it virtually impossible for the Company to effectively ensure that all of its affected units effectively 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.

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

A. Yes. Emission reduction projects of the number and size included in this case 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 is unduly expensive for customers, 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 emissions control investments contemplated in this case meet the used and useful standard?

A. Yes. Customers need these resources. Each of these investments 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.

Project-specific Discussion

Q. Has the Company provided the information required by the Stipulation and Agreement ("Stipulation") entered into by the Company and Parties in Docket No. 20000-384-ER-10 (the "2010 general rate case")?

A. Yes. The Company has provided in this docket the information required by the Stipulation and consistent in detail to the Company's recently filed CPCN application for its Naughton Unit 3 environmental control projects, which are subject to the Stipulation.

Naughton Unit 1

Q. Please describe the Naughton facility and Naughton Unit 1 in particular.

A. The Naughton plant consists of three coal-fueled units which are all 100 percent owned and operated by the Company. The Naughton facility is capable of producing an aggregated nominal 700 Mw of net generation. The Company also owns 100 percent of the Viva Naughton reservoir which stores water for consumptive use at the Naughton plant and provides regional recreation opportunities. Naughton Unit 1 began commercial operation in 1963 and has a nominal net generation capacity of 160 MW. The unit is configured with an

Alstom (formerly Combustion Engineering) natural circulation boiler and a General Electric steam turbine-generator. The unit configuration also includes a closed loop cooling system with a mechanical draft cooling tower, and an electrostatic precipitator. The Naughton plant property is also adjacent to Chevron Mining's Kemmerer Mine, which supplies approximately 2.8 million tons per year of sub-bituminous coal to the plant. Coal combustion residuals are currently disposed of on plant property in surface impoundments. The Naughton plant currently employs approximately 138 personnel, including 107 union craft personnel represented by the International Brotherhood of Electrical Workers Local 57.

Q. Please describe the Naughton Unit 1 scrubber addition and associated equipment included in this case.

A. The scrubber addition project on Naughton Unit 1 includes the installation of SO_2 controls. The capital investment for the project being placed in service during the test period is approximately $121 million. Construction began in 2010, and the project is expected to be placed in service by May 2012. The new emissions control equipment will be tied into the existing unit during the scheduled plant maintenance outage. The project will install a wet flue gas desulfurization ("FGD") system. The wet FGD system injects reagent slurry containing sodium carbonate and sodium bicarbonate in the top of an open spray 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 a 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 impoundment on the Naughton plant site. Other equipment to be installed as part of the project includes induced booster fans, boiler reinforcement, flue gas path reinforcement, new ductwork, a new chimney, makeup water supply upgrades, sodium carbonate slurry reagent preparation systems, waste material handling systems, a new waste disposal pond, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems.

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

A. Yes. Costs contemplated in this case include the cost of common facilities that are required to be placed in service to allow prudent operation of either unit's new emission control equipment, although the majority of common facilities were placed in service when the Naughton Unit 2 scrubber addition came online. Common facilities include reagent preparation, waste disposal, electrical supply, control system upgrades, and ancillary utility systems, as well as site preparation and the chimney.

Q. Are costs associated with ancillary projects required to support the Naughton Unit 1 scrubber addition included in this case?

A. Yes. Costs contemplated in this case include the cost of boiler reinforcement work required to maintain National Fire Protection Association ("NFPA") code compliance due to the additional flue gas fan capacity required as a result of the scrubber. New booster fans have also been installed to overcome flue gas pressure losses across the scrubber and additional ductwork.

Q. Please describe the Naughton Unit 1 low NO_X burners installation project.

A. The LNB installation project on Naughton Unit 1 includes the installation of NO_X combustion controls. The new burners utilize improved combustion characteristics and a separated over-fire air supply to the boiler to reduce NO_X emissions. The capital investment for the project being placed in service during the test period is approximately $10 million. Construction will begin in 2012, and the project is expected to be placed in service by May 2012. The new emissions control equipment will be tied into the existing unit during the scheduled plant maintenance outage.

Q. Have the emissions control project costs included in this case for Naughton Unit 1 been previously considered by this Commission with respect to prudence and used and useful standards?

A. No. However, the Company's 2010 general rate case included Naughton Unit 2 emissions control projects with the same basic scope and underlying requirements. The Naughton Unit 2 scrubber project was constructed concurrently with the Naughton Unit 1 scrubber project, but placed in service during a planned major maintenance outage for Naughton Unit 2 during the fall of 2011. The Naughton Unit 2 LNB project was placed in service at the same time. 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 Units 1 and 2 emissions control projects was to balance the aggregated construction costs and schedules for the emissions control equipment projects against the established planned maintenance overhaul schedules, work plans, and budgets for the respective units. The previously completed Naughton Unit 2 emissions control projects were deemed prudent, used and useful in the 2010 general rate case Stipulation approved by the Commission.

Q. What are the key permits and/or regulations requiring the Naughton Unit 1 wet FGD system to be installed?

A. To continue compliant operation of Naughton Unit 1, PacifiCorp must install the wet FGD ("scrubber") systems described herein to control emissions of criteria pollutants as required by NAAQS, the state of Wyoming's § 309 Implementation Plan, and the State of Wyoming's permit (MD-5156) dated May 2009.

Q. What are the key permits and/or regulations requiring the Naughton Unit 1 LNB system to be installed?

A. To continue compliant operation of Naughton Unit 1, PacifiCorp must install the LNB systems described herein to control emissions of criteria pollutants in response to Regional Haze Rules, the state of Wyoming's § 309 (g) Implementation Plan, and the state of Wyoming's BART review, decision and permit (MD-6042) dated December 2009, and the state of Wyoming's permit

(MD-5156) dated May 2009.

Q. What is the post-project SO_2 emission limit for Naughton Unit 1 as prescribed by the state of Wyoming's permit (MD-5156)?

A. The post-project SO_2 emission limit for Naughton Unit 1 as prescribed by permit (MD-5156)[2] is as follows:

Pollutant	Emissions Limit (lbs. per MMBtu[(a)])	Emissions Limit (lbs. per hr)	Emissions Limit (tons per year)
SO_2	0.15 (12-month rolling)	481 (12-month rolling)	NA

(a) Million British Thermal Units

Q. When is the Company required to demonstrate compliance with BART permit conditions?

A. The BART permit for the project requires that Naughton Unit 1 emissions control equipment be installed and operating with emissions performance test results in compliance with emissions limits before December 31, 2012.[3] The permit emissions limits[4] are as follows:

Pollutant	Emissions Limit (lbs. per MMBtu[(b)])	Emissions Limit (lbs. per hr)	Emissions Limit (tons per year)
NO_X	0.26 (30-day rolling)	481 (30-day rolling)	2,107
PM/PM_{10} [(a)]	0.040 [(b)]	74	324

[(a)] Filterable portion only
(b) Million British Thermal Units

[2] Permit MD-5156, Article 8.
[3] Permit MD-6042, Article 16.
[4] Permit MD-6042, Articles 5 and 7.

Q. Are Naughton Unit 1 SO_2 emissions contemplated in the Regional SO_2 Milestone and Backstop Trading Program?

A. Yes. Naughton Unit 1emissions must comply with all requirements of the regional SO_2 Milestone and Backstop Trading program, in accordance with Chapter 14, Sections 2 and 3, of the Wyoming Air Quality Standards and Regulations ("WAQSR"). The SO_2 Backstop Trading program utilizes presumptive BART SO_2 emission rate for Naughton Unit 1 of 0.15 pounds SO_2 per MMBtu. The investment in the Naughton Unit 1 wet FGD system addition will meet this emission threshold and will also support compliance with the EPA's proposed MATS for acid gases.

Q. Are Naughton Unit 1 SO_2 and NO_X emissions considered in the development of the plant-wide applicability emission limits for the Naughton plant?

A. Yes. The state of Wyoming's permit (MD-11754) dated May 2011 establishes PALs for emissions of SO_2 and NO_X at Naughton. The SO_2 and NO_X PALs limit the annual tons of SO_2 and NO_X that may be emitted from the facility. Typically, past actual emissions are used to develop PAL limits. However, since historical data is not available for Naughton Units 1 and 2 and with the new SO_2 and NO_X control projects being placed in service, the post-project potential emissions from these units are used. The annual SO_2 potential to emit for each unit was calculated using the post-project potential emission rate of 0.15 pounds SO_2 per MMBtu, and the annual NO_X potential to emit for each unit was calculated using the post-project potential emission rate of 0.26 pounds NO_X per MMBtu. The following table summarizes the emissions from each source that was included in the development of the Naughton plant PAL emission limits:

Component Description	Annual NO_X Emissions (tons per year)	Annual SO_2 Emissions (tons per year)
Naughton Unit 1 (potential-to-emit basis)	2,107	1,215
Naughton Unit 2 (potential-to-emit basis)	2,733	1,577
Naughton Unit 3 and Non-Boiler Sources (past actual baseline)	6,233	5,958
Naughton PSD Significance Threshold	40	40
Total Annual Emissions (PALs)	11,113	8,790

Q. How is the Naughton Unit 1 scrubber addition expected to support the EPA's proposed MATS?

A. MATS emissions limits are pending before the EPA for acid gases emissions, particularly hydrogen chloride ("HCl"). A wet FGD system SO_2 emissions limit of 0.20 pounds SO_2 per MMBtu is recognized as the anticipated surrogate for the proposed MATS acid gases emissions compliance, and as such, installation of the wet FGD system with performance requirements described above is expected to support compliance with that portion of the MATS.

Q. What emissions performance guarantees are provided via the scrubber addition project engineer, procure, and construct ("EPC") contract?

A. The scrubber system is specified with contractually guaranteed performance emission thresholds at the following limits to provide an appropriate compliance margin over the operating life of the equipment with established maintenance cycles:

Pollutant	Emissions Limit
SO_2	[redacted]
PM/PM_{10}[(a)]	[redacted]

[redacted]

Q. What emissions performance guarantees are provided via the LNB supply contract?

A. The LNB supply contract includes guaranteed performance emission thresholds at the following limits to provide an appropriate compliance margin over the operating life of the equipment with established maintenance cycles:

Pollutant	Emissions Limit
NO_X	[redacted]

Q. Did the Company consider alternative technologies to the Naughton Unit 1 emissions control projects included in this case?

A. Yes. The Company completed three technical studies of note to evaluate NO_X, PM and SO_2 emission control technology alternatives for Naughton Unit 1. In October 2002 Sargent and Lundy ("S & L") completed a coal fleet-wide Multi-Pollutant Control Report; in January 2005 S & L completed the NO_X Emission Reduction Technologies Study; and in February of 2007 CH2M Hill completed the BART Analysis for Naughton Units 1 through 3.

The Multi-Pollutant Control Report investigated the cost and necessity of NO_X controls (including both boiler in-combustion and post-combustion controls), PM controls (including upgraded ESPs, polishing baghouses and full-scale fabric filter replacements), and SO_2 controls (including upgrading the existing scrubbers).

The NO_X Emission Reduction Technologies Study compared 16 emission control technologies, status of the technology development, performance, approximate initial capital costs, and approximate fixed and variable operational and maintenance costs.

The BART Analysis for Naughton Units 1 through 3 was conducted for criteria pollutants NO_X, PM_{10} and SO_2. In completing this BART Analysis, technology alternatives were investigated and potential reductions in emissions were quantified. The BART Analysis for Naughton Units 1 through 3 was considered in the state of Wyoming's BART determination, permit requirements, and SIP discussed above.

Q. Has the Company evaluated whether the risk adjusted, least cost alternative to comply with environmental requirements was to invest in the emissions control equipment included in this case or to idle Naughton Unit 1?

A. Yes. The Company evaluated whether the risk adjusted, least cost alternative to comply with environmental requirements was to add the wet FGD system and install new LNBs versus idling Naughton Unit 1 in 2009 and replacing the generation with market power purchases. The evaluation calculated a present value revenue requirement differential, PVRR(d), between the two options by subtracting fuel, O&M, environmental emissions cost, and on-going and CAI capital revenue requirement cost from revenue, similar to a merchant plant valuation. The revenue was derived using the December 31, 2008, PacifiCorp official market forward price curve at a corresponding CO_2 price of $8 per ton.

The results of the evaluation demonstrated that it was beneficial to customers to invest in emissions control equipment for Naughton Unit 1 in lieu of idling the facility and replacing the generation with market power purchases. The resulting PVRR(d) was a positive differential of [redacted]

Q. Has the Company completed any additional economic evaluations regarding the benefit of investing in the Naughton Unit 1 environmental projects included in this case?

A. Yes. Two additional economic evaluations were completed to compare the benefit of investing now in the environmental projects included in this case versus (1) conversion of the unit to natural gas; and (2) replacement ("repowering") of the unit with an in-kind, site-specific natural gas fired CCCT block. The evaluation descriptions and resulting PVRR(d) information are presented in the following table:

Evaluation Identification	**PVRR(d) Results**
Conversion to Natural Gas	[redacted]
Repowering at Naughton Unit 1	[redacted]

Q. Please describe the conversion to natural gas scenario evaluated.

A. This evaluation considered whether converting Naughton Unit 1 to natural gas in place of coal, and then operating the unit on natural gas to meet mandated emissions thresholds, would be beneficial for customers. This present value evaluation uses a macroeconomic merchant plant approach where the unit's revenue requirement is compared to the value of the unit's generation using the PacifiCorp September 30, 2011, official market forward price curve and a corresponding $16 per ton CO_2 price beginning in 2021. The evaluation established that the conversion and fueling with natural gas through 2029 is detrimental to customers, and the associated PVRR(d) was [redacted] unfavorable. This evaluation demonstrates that without a significant market pricing response to widespread coal-fueled steam electric plant idling and retrofits, high natural gas heat rates would result in low dispatching intervals of a converted unit.

Q. Please describe the repowering scenario evaluated.

A. This evaluation considered whether converting Naughton Unit 1 to a "repowered" natural gas fueled "1x1 F wet cooled" CCCT unit rated at 160 nominal MW was more economical on a market price basis. This evaluation places the CCCT at the Naughton plant. Again, this evaluation takes a macroeconomic merchant plant approach and compares the "net revenue-to-cost" using the PacifiCorp September 30, 2011 official market forward price curve and a corresponding $16 per ton CO_2 price beginning in 2021. The evaluation concluded that repowering as a CCCT resource located at Naughton Unit 1 is detrimental to customers, and the associated PVRR(d) was [redacted] unfavorable at the end of a projected CCCT depreciable life of 40 years.

Q. Has the Company evaluated the impact of the environmental projects included in this case on the bus bar cost of Naughton Unit 1?

A. Yes. The Naughton Unit 1 bus bar costs before and after installation of environmental projects included in this case, in 2010 dollars and with comparable CO_2 price impacts (2021 CO_2 cost de-escalated to 2010), are represented in the following table:

Bus Bar Cost Before Installation of Environmental Projects ($/MWh)	**Bus Bar Cost Contribution of Environmental Projects ($/MWh)**	**Bus Bar Cost After Installation of Environmental Projects ($/MWh)**	**Incremental CO_2 Price Revenue Requirement ($/MWh)**	**Bus Bar Cost After Installation of Environmental Projects and with CO_2 Price ($/MWh)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q. How do the bus bar costs referenced above compare to other generation resource types in the Company's available generation mix?

A. Comparable bus bar costs are [redacted] per MWh (excluding CO_2 cost adjustment) for PacifiCorp's combined cycle Lakeside Unit 1 and [redacted] per MWh (excluding CO_2 cost adjustment) for PacifiCorp's natural gas converted Gadsby Units 1, 2 and 3. The fuel costs associated with these bus bar cost references are [redacted] and [redacted] per MWh, respectively. Future variations in major capital and operational expenditures, changes to unit dispatch cycles, and other factors could impact these costs going forward. Variable costs include those associated with fuel, reagents, and proxy compliance costs for emerging environmental regulations.

Q. Has the Company developed emerging CCR regulations compliance costs for the Naughton facility?

A. Yes. Although information regarding the currently emerging CCR regulations was not available at the time of decision-making and planning of the multi-year

Naughton Unit 1 scrubber project included in this case, the Company is committed to understanding and anticipating the effect of emerging environmental regulations in its economic evaluations and environmental plans. As discussed previously in my testimony, the Company has developed proxy compliance project costs for emerging rules regulating CCR for use in its forward-looking business planning processes. To provide frame of reference, the aforementioned costs have been incorporated into the Company's IRP Supplement, which did not identify an accelerated retirement date for Naughton Unit 1.

Q. Has the Company developed emerging 316(b) regulations compliance costs for the Naughton facility?

A. Yes. Although information regarding the currently emerging 316(b) regulations was not available at the time of decision-making and planning of the multi-year Naughton Unit 1 scrubber project included in this case, the Company has applied the same principles as those discussed above for emerging CCR regulations and has incorporated 316(b) compliance costs into the Company's IRP Supplement. As noted above, the IRP Supplement did not identify an accelerated retirement date for Naughton Unit 1.

Dave Johnston Unit 4

Q. Please describe the Dave Johnston facility and Dave Johnston Unit 4 in particular.

A. The Dave Johnston plant is a four unit, coal fueled power plant with a net maximum capacity of 762 MW located near Glenrock, Wyoming. The Company owns 100 percent of the Dave Johnston plant and adjacent reclaimed mine including the land, equipment, and infrastructure. The site consists of approximately 2,500 acres at an elevation of 4,950 feet above sea level. The plant consists of four units: two rated at 106 Mw; one rated at 220 Mw; and one rated at 330 Mw. Dave Johnston Unit 4 began commercial operation in 1972 and has a nominal net generation capacity of 330 MW. Unit 1 and Unit 2 are equipped with Babcock & Wilcox (B&W) front wall-fired steam generators, Unit 3 is equipped with a B&W opposed-wall burner steam generator, while Unit 4 is equipped with a tangentially-fired Combustion Engineering (CE) steam generator. All four units are also equipped with General Electric tandem-compound, two-casing, two-flow condensing, single-reheat turbines. All four units are designed to burn sub-bituminous coal from the local area or from the Powder River Basin. Coal for the plant is received on unit trains. Railroad access is via the Burlington Northern–Santa Fe Railway Company. The Company owns water rights in the North Platte River for plant boiler water make-up and circulating water use. Due to utilization of once-through cooling water systems the Dave Johnston plant is the most likely to be impacted by emerging 316(b) regulations. The Dave Johnston plant also utilizes various CCR landfills and retention ponds, as well as wastewater ponds for its processes. The Dave Johnston plant currently employs approximately 185 personnel, including 147 union craft personnel represented by the Utility Worker Union of America Local 127.

Q. Please describe the Dave Johnston Unit 4 emissions control project and associated equipment included in this case.

A. The emissions control project at the Dave Johnston Unit 4 power plant is being completed in conjunction with the Dave Johnston Unit 3 emissions control project that was be placed in service in 2010. The Dave Johnston Unit 4 emissions control project will upgrade and improve the unit's PM and SO_2 controls. The capital expenditure for the project during the test period is approximately $106 million. Construction began in 2008, and the project will be operational by April 2012. The new emissions control equipment is being tied into the existing unit during a scheduled plant maintenance outage. The project will install a dry flue gas desulfurization ("DFGD") system with fabric filter. A DFGD system injects lime slurry in the top of an absorber vessel with a rapidly rotating atomizer wheel. The rapid rotation of the atomizer wheel causes the lime slurry to separate into very fine droplets that intermix with the flue gas. The SO_2 in the flue gas reacts with the calcium in the lime slurry to form calcium sulfate in the form of dry PM. The dry PM is then captured in the downstream baghouse along with fly ash from the boiler. The DFGD system will produce a nonhazardous dry waste product suitable for landfill disposal. Other equipment to be installed as part of the project includes induced draft fans, boiler reinforcement, new ductwork, lime slurry reagent preparation systems, waste material handling systems, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems.

Q. Is the Dave Johnston Unit 3 emissions control project already in service and in rates?

A. Yes. As mentioned above the Dave Johnston Unit 3 emissions control project, which was constructed concurrently with the Dave Johnston Unit 4 emissions control project, including common facilities for both units, was placed in service during the 2010 planned major maintenance outage for that unit. 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's Dave Johnston Unit 4 completed its most recent overhaul in 2009 and is scheduled for its next overhaul in the spring of 2012. The Company's intent in establishing the tie-in schedules for the Dave Johnston Unit 3 and Dave Johnston Unit 4 emissions control equipment was to balance the aggregated construction costs and schedules for the emissions control equipment projects against the established planned maintenance overhaul schedules, work plans, and budgets for the respective units.

Q. Have the emissions control project costs included in this case for Dave Johnston Unit 4 been previously considered by this Commission with respect to prudence and used and useful standards?

A. No. However, the Company's 2010 general rate case included approval of the Dave Johnston Unit 3 scrubber project with the same basic scope and underlying requirements. The Dave Johnston Unit 3 scrubber project was constructed concurrently with the Dave Johnston Unit 4 scrubber project, but placed in service during a planned major maintenance outage for Dave Johnston Unit 3 in 2010. 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 Dave Johnston Unit 4 in 2009 and is scheduled for its next overhaul in the spring of 2012. The Company's intent in establishing the tie-in schedules for the Dave Johnston Units 3 and 4 emissions control projects was to balance the aggregated construction costs and schedules for the emissions control equipment projects against the established planned maintenance overhaul schedules, work plans, and budgets for the respective units. The previously completed Dave Johnston Unit 3 scrubber project was deemed prudent, used and useful in the 2010 rate case Stipulation approved by this Commission.

Q. What are the key permits and/or regulations requiring the Dave Johnston Unit 4 DFGD with fabric filter system to be installed?

A. To continue compliant operation of Dave Johnston Unit 4, the Company must install the DFGD with fabric filter system described herein to control emissions of criteria pollutants as required by Regional Haze Rules, the State of Wyoming's § 309 (g) Implementation Plan, the state of Wyoming's BART review, decision and permit (MD-6041) dated December 2009, and the state of Wyoming's Air Quality Permit (MD-5098) dated June 2008.

Q. What is the post-project SO_2 emission limit for Dave Johnston Unit 4 as prescribed by the state of Wyoming's permit (MD-5098)?

A. The post-project SO_2 emission limit for Dave Johnston Unit 4 as prescribed by permit (MD-5098)[5] is as follows:

Pollutant	Emissions Limit (lbs. per MMBtu[a])	Emissions Limit (lbs. per hr)	Emissions Limit (tons per year)
SO_2	0.15 (12-month rolling)	615 (24-hour rolling)	NA

[a] Million British Thermal Units

Q. When is the Company required to demonstrate compliance with BART permit conditions?

A. The BART permit for the project requires that emissions control equipment be installed and operating with emissions performance test results in compliance with emissions limits before December 31, 2012.[6] The permit emissions limits[7] are as follows:

Pollutant	Emissions Limit (lbs. per MMBtu[b])	Emissions Limit (lbs. per hr)	Emissions Limit (tons per year)
NO_X	0.15 (30-day rolling)	615 (30-day rolling)	2,694
PM/PM_{10} [a]	0.015 (annual testing)	61.5 (annual testing)	269

[a] Filterable portion only
[b] Million British Thermal Units

Q. Are Dave Johnston Unit 4 SO_2 emissions contemplated in the Regional SO_2 Milestone and Backstop Trading Program?

A. Yes. Dave Johnston Unit 4 emissions must comply with all requirements of the regional SO_2 Milestone and Backstop Trading program, in accordance with

[5] Permit MD-5098, Article 10.
[6] Permit MD-6041, Article 15.
[7] Permit MD-6041, Article 5.

Chapter 14, Sections 2 and 3, of the WAQSR. The SO_2 Backstop Trading program utilizes presumptive BART SO_2 emission rate for Dave Johnston Unit 4 of 0.15 pounds SO_2 per MMBtu. The investment in the Dave Johnston Unit 4 DFGD with fabric filter system will meet this emission threshold and will also support compliance with the EPA's proposed MATS for acid gases.

Q. Are Dave Johnston Unit 4 SO_2 and NO_X emissions considered in the development of the plant-wide applicability emission limits for the Dave Johnston plant?

A. Yes. The state of Wyoming's Air Quality Permit (MD-5098) establishes PALs for emissions of SO_2 and NO_X at Dave Johnston. The SO_2 and NO_X PALs limit the annual tons of SO_2 and NO_X that may be emitted from the facility. Typically, past actual emissions are used to develop PAL limits. However, since historical data was not available for Units 3 and 4 with the new SO_2 and NO_X controls projects being placed in service, the post-project potential emissions from these units are used. The annual SO_2 potential to emit for each unit was calculated using the post-project potential emission rate of 0.15 pounds SO_2 per MMBtu. The annual NO_X potential to emit for Unit 3 was calculated using the post-project potential emission rate of 0.28 pounds NO_X per MMBtu and the potential to emit for Unit 4 was calculated using the post-project potential emission rate of 0.15 pounds NO_X per MMBtu, The following table summarizes the emissions from each source that were included in the development of the Dave Johnston PAL emission limits:

Component Description	Annual NO_X Emissions (tons per year)	Annual SO_2 Emissions (tons per year)
Dave Johnston Unit 1 (actual emissions)	2,382	3,842
Dave Johnston Unit 2 (actual emissions)	2,222	3,704
Dave Johnston Unit 3 (potential-to-emit)	3,434	1,840
Dave Johnston Unit 4 (potential-to-emit)	2,694	2,694
PSD Significance Threshold	40	40
Total Annual Emissions (PALs)	10,772	12,120

Q. How is the Dave Johnston Unit 4 DFGD with fabric filter addition expected to support the EPA's proposed MATS?

A. MATS emissions limits are pending before the EPA for acid gases emissions, particularly HCl. An SO_2 emissions limit of 0.20 pounds SO_2 per MMBtu is recognized as the anticipated surrogate for the proposed MATS acid gases emissions compliance, and as such, installation of the DFGD with fabric filter system with performance requirements described above is expected to support compliance with that portion of the MATS. MATS emissions limits are also pending for non-mercury metallic HAPs. A total PM emissions limit of 0.030 pounds PM per MMBtu is recognized as the anticipated surrogate for the proposed MATS non-mercury metallic HAPs emissions compliance, and as such, installation of the DFGC with fabric filter system with performance requirements described above is also expected to support compliance with that portion of the MATS.

Q. What emissions performance guarantees are provided via the DFGD with fabric filter project EPC contract?

A. The DFGD with fabric filter system is specified with contractually guaranteed performance emission thresholds at the following limits to provide an appropriate compliance margin over the operating life of the equipment with established maintenance cycles:

Pollutant	Emissions Limit
SO_2	[redacted]
PM/PM_{10}[a]	[redacted]

[a] [redacted]

Q. Did the Company consider alternative technologies to the Dave Johnston Unit 4 emissions control projects included in this case?

A. Yes. The Company completed three technical studies of note to evaluate NO_X, PM and SO_2 emission control technology alternatives for Dave Johnston Unit 4. In October 2002 S & L completed a coal fleet-wide Multi-Pollutant Control Report; in January 2005 S & L completed the NO_X Emission Reduction Technologies Study; and in February of 2007 CH2M Hill completed the BART Analysis for Dave Johnston Units 3 through 4.

The basis of the Multi-Pollutant Control Report and the NO_X Emission Reduction Technologies Study were described earlier in my testimony.

The BART Analysis for Dave Johnston Units 3 and 4 was conducted for criteria pollutants NO_X, PM_{10} and SO_2. In completing this BART Analysis, technology alternatives were investigated and potential reductions in emissions were quantified. The BART Analysis for Dave Johnston Units 3 and 4 was considered in the state of Wyoming's BART determination, permit requirements, and SIP discussed above.

Q. Has the Company evaluated whether the risk adjusted, least cost alternative to comply with environmental requirements was to invest in the emissions control equipment included in this case or to idle Dave Johnston Unit 4?

A. Yes. The Company evaluated whether the risk adjusted, least cost alternative to comply with environmental requirements was to add the DFGD with fabric filter system versus idling Dave Johnston Unit 4 in 2008 and replacing the generation with market power purchases. The evaluation calculated a present value revenue requirement differential, PVRR(d), between the two options by subtracting fuel, O&M, environmental emissions cost, and on-going and CAI capital revenue requirement cost from revenue, similar to a merchant plant valuation. The revenue was derived using the December 31, 2007, PacifiCorp official market forward price curve at a corresponding CO_2 price of $8 per ton. The results of the evaluation demonstrated that it was beneficial to customers to invest in emissions control equipment for Dave Johnston Unit 4 in lieu of idling the facility and replacing the generation with market power purchases. The resulting PVRR(d) was a positive differential of [redacted]

Q. Has the Company completed any additional economic evaluations regarding the benefit of investing in the Dave Johnston Unit 4 environmental projects included in this case?

A. Yes. Two additional economic evaluations were completed to compare the benefit of investing now in the environmental projects included in this case versus (1) conversion of the unit to natural gas; and (2) replacement (“repowering”) of the unit with an in-kind, site-specific natural gas fired CCCT block. The evaluation descriptions and resulting PVRR(d) information are presented in the following table:

Evaluation Identification	PVRR(d) Results
Conversion to Natural Gas	[redacted]
Repowering at Dave Johnston Unit 4	[redacted]

Q. Please describe the conversion to natural gas scenario evaluated.

A. This evaluation considered whether converting Dave Johnston Unit 4 to natural gas in place of coal, and then operating the unit on natural gas to meet mandated emissions thresholds, would be beneficial for customers. This present value evaluation uses a macroeconomic merchant plant approach where the unit's revenue requirement is compared to the value of the unit's generation using the PacifiCorp September 30, 2011, official market forward price curve and a corresponding $16 per ton CO_2 price beginning in 2021. The evaluation established that the conversion and fueling with natural gas through 2027 is detrimental to customers, and the associated PVRR(d) was [redacted] unfavorable. This evaluation demonstrates that without a significant market pricing response to widespread coal-fueled steam electric plant idling and retrofits, high natural gas heat rates would result in low dispatching intervals of a converted unit.

Q. Please describe the repowering scenario evaluated.

A. This evaluation considered whether converting Dave Johnston Unit 4 to a "repowered" natural gas fueled "1x1 G wet cooled" CCCT unit rated at 330 nominal MW was more economical on a market price basis. This evaluation places the CCCT at the Dave Johnston plant. Again, this evaluation takes a macroeconomic merchant plant approach and compares the "net revenue-to-cost" using the PacifiCorp September 30, 2011, official market forward price curve and a corresponding $16 per ton CO_2 price beginning in 2021. The evaluation concluded that repowering as a CCCT resource located at Dave Johnston Unit 4 is detrimental to customers, and the associated PVRR(d) was [redacted] unfavorable at the end of a projected CCCT depreciable life of 40 years.

Q. Has the Company evaluated the impact of the environmental projects included in this case on the bus bar cost of Dave Johnston Unit 4?

A. Yes. The Dave Johnston Unit 4 bus bar costs before and after installation of environmental projects included in this case, in 2010 dollars and with comparable CO_2 price impacts (2021 CO_2 cost de-escalated to 2010), are represented in the following table:

Bus Bar Cost Before Installation of Environmental Projects ($/MWh)	**Bus Bar Cost Contribution of Environmental Projects ($/MWh)**	**Bus Bar Cost After Installation of Environmental Projects ($/MWh)**	**Incremental CO_2 Price Revenue Requirement ($/MWh)**	**Bus Bar Cost After Installation of Environmental Projects and with CO_2 Price ($/MWh)**
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q. How do the bus bar costs reference above compare to other generation resource types in the Company's available generation mix?

A. Please refer to my earlier testimony regarding bus bar costs for Naughton Unit 1 for comparable bus bar cost references for other generation resource types.

Q. Has the Company developed emerging CCR regulations compliance costs for the Dave Johnston facility?

A. Yes. Although information regarding the currently emerging CCR regulations was not available at the time of decision-making and planning of the multi-year Dave Johnston Unit 4 DFGD with fabric filter project included in this case, the Company is committed to understanding and anticipating the effect of emerging environmental regulations in its economic evaluations and environmental plans. As discussed previously in my testimony, the Company has developed proxy compliance project costs for emerging rules regulating CCR for use in its forward-looking business planning processes. To provide frame of reference, the aforementioned costs have been incorporated into the Company's IRP Supplement, which did not identify an accelerated retirement date for Dave Johnston Unit 4.

Q. Has the Company developed emerging 316(b) regulations compliance costs for the Dave Johnston facility?

A. Yes. Although information regarding the currently emerging 316(b) regulations was not available at the time of decision-making and planning of the multi-year Dave Johnston Unit 4 DFGD with fabric filter project included in this case, the Company has applied the same principles as those discussed above for emerging CCR regulations and has incorporated 316(b) compliance costs into the Company's IRP Supplement. As noted above, the IRP Supplement did not identify an accelerated retirement date for Dave Johnston Unit 4.

Hunter Units 1 and 2

Q. Please describe the Hunter facility and Hunter Units 1 and 2 in particular.

A. The Hunter plant is a three-unit coal-fueled power plant with a net generation capacity of approximately 1,320 MW. The plant is located approximately 158 miles south of Salt Lake City, Utah near the town of Castledale, Utah. Units 1 and 2 are co-owned, while Unit 3 is 100 percent owned by the Company. Unit 1 is 93.8 percent owned by the Company and 6.2 percent owned by the Utah Municipal Power Authority. Unit 2 is 60.3 percent owned by the Company, 24.9 percent owned by Deseret Generation and Transmission Cooperatives, and 14.8 percent owned by Utah Associated Municipal Power Systems. However the entire plant is under an exclusive owner operation and maintenance contract with the Company. The site covers an area of approximately 1,000 acres at 5,644 feet above sea level, which includes the main power station buildings, storage reservoirs, coal stocks, ash disposal and a small research farm to reclaim wastewater and a proportion of storm water.

The plant consists of three coal fired boiler units with associated steam turbine generator units, operating under a base load operating regime. Unit 1 and Unit 2 are identical units. The steam generators are tangentially-fired, controlled circulation boilers supplied by Combustion Engineering. The units are designed to burn sub-bituminous coal from the local area. Each Westinghouse steam turbine is a tandem-compound, two-casing, two-flow condensing, single-reheat turbine. Each Westinghouse generator has a hydrogen cooled stator and rotor. The units were originally equipped with electrostatic precipitators to control particulate emissions. The Unit 2 electrostatic precipitator has since been converted to a fabric filter baghouse. Unit 3 is identical in layout to Units 1 and 2 except the boiler and turbines are from different manufacturers and the unit was originally equipped with a fabric filter bag house to control particulate emissions. The steam generator is a front and rear wall fired Babcock and Wilcox unit. The General Electric steam turbine is tandem-compound, two-casing, two-flow condensing, single-reheat turbines.

All three units are equipped with wet lime scrubbers to control sulfur dioxide emissions. Water for plant use is released into the Cottonwood Creek from Joe's Valley conveyed by a direct pipeline from the Millsite Reservoir to the plant. Potable water is piped from the cities of Castledale, Utah or Clawson, Utah. Hunter is a zero discharge plant. The balance of water is evaporated from a pond or used for irrigation of hay crops. Plant sewage is treated and discharged to the evaporation pond.

Coal is supplied by truck from the nearby Sufco, Cottonwood, Dugout, and Deer Creek mines. Hunter has a blending facility in the fuels preparation facility, which allows for combustion of various coal types. Fuel expense at Hunter Units 1 and 2 is shared on an energy usage basis while all other production expenses are shared on an ownership basis.

The Hunter plant currently employs approximately 221 personnel, including 171 union craft personnel represented by the International Brotherhood of Electrical Workers Local 57.

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

A. The Hunter Unit 1 scrubber project 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, especially in anticipation of an increase in sulfur content of available coal supplies. The scrubber project will increase the unit's existing wet 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; installing a new higher capacity scrubber reagent preparation system, and expanding waste material handling system capacity with a new system. The wet FGD system injects lime slurry in the top of an absorber vessel with a network of spray nozzles. The distribution of spray nozzles 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, which is easier to dewater and transport to a scrubber waste landfill for disposal. Additional reagent preparation and waste disposal capacity is critical if coal sulfur increases as anticipated.

The Company's share of the capital investment for the scrubber project being placed in service during the test period is approximately $53 million. The overall scrubber project work scope is being completed in three primary phases:

(1) scrubber vessels and associated equipment modifications and replacement, (2) reagent preparation system replacement; and (3) waste material handling system replacement. The reagent preparation and waste material handling systems being constructed for the project will serve both Hunter Units 1 and 2, with costs allocated accordingly. Hunter Unit 1 construction activities began in 2011, and all phases of the Hunter Unit 1 scrubber project are scheduled to be completed and placed in service by the end of June 2012. Installation of all phases of the Hunter Unit 1 scrubber project are being completed while the plant is in service by converting absorber vessels one at a time and will not require an extended plant maintenance outage for tie-in.

Equipment being installed as part of the various portions of the Hunter Unit 1 scrubber project includes lime slurry reagent preparation equipment; waste material handling system equipment including forced oxidation air blowers, hydroclones, as a replacement for the existing thickener, and vacuum drum filters; electrical infrastructure; controls; and other miscellaneous appurtenances and support systems.

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

A. The Hunter Unit 2 scrubber project 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. Also as noted above, the

Hunter Unit 2 scrubber project shares certain common scopes of work, with project costs allocated accordingly.

Capital costs included in this case associated with the Hunter Unit 2 scrubber project include those costs allocated to the reagent preparation system phase of the project. The Company's share of the capital investment for the reagent preparation system phase of the Hunter Unit 2 scrubber project being placed in service during the test period is approximately $12 million. Capital costs associated with the other two phases of the project, namely scrubber the vessels and associated equipment modifications and replacement and the waste material handling system replacement were reviewed by the Commission in a previous rate case docket and were deemed to be prudent, used, and useful. Construction of the Hunter Unit 2 reagent preparation equipment began in 2011 and is scheduled to be placed in service by the end of March 2012. Installation of the reagent preparation system phase 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. How do the Hunter Units 1 and 2 scrubber projects benefit from concurrent construction and shared sub-systems?

A. The Hunter Units 1 and 2 scrubber projects are being constructed concurrently, but on different schedules to benefit from installation and operational costs synergies achieved through the use of common facilities between the two units.

Q. What are the key permits and/or regulations requiring the Hunter Units 1 and 2 scrubber projects to be installed?

A. To continue compliant operation of Hunter Units 1 and 2, the Company must install the scrubber projects described herein to control emissions of criteria pollutants as required by Regional Haze Rules, the State of Utah's § 309 (g) Implementation Plan, the state of Utah's BART review process, and the state of Utah's Approval Order (DAQE-AN0102370012-08) dated March 2008.

Q. What are the Company's specific obligations under the Hunter Units 1 and 2 permit conditions?

A. The permits for the project require that emissions control equipment for each unit be installed and operate with emissions performance test results in compliance with the following emissions limits:[8]

Pollutant	**Emissions Limit (lbs. per MMBtu[b])**
NO_X	0.26 (30-day rolling)
SO_2	0.12 (30-day rolling)
PM/PM_{10} [a]	0.015 (annual testing)

[a] Filterable portion only
(b) Million British Thermal Units

Q. Are Hunter Units 1 and 2 SO_2 emissions contemplated in the Regional SO_2 Milestone and Backstop Trading Program?

A. Yes. Hunter Units 1 and 2 emissions must comply with all requirements of the regional SO_2 Milestone and Backstop Trading program. Specific unit SO_2 requirements are identified in Section XX D6 Table 5 of the Utah State Implementation Plan. The SO_2 Backstop Trading program utilizes the BART SO_2 emission rates for Hunter Units 1 and 2 of 0.12 pounds SO_2 per MMBtu. The investments in the Hunter Units 1 and 2 scrubber projects will meet this emission

[8] Permit DAQE-AN0102370012-08, Article 10.

threshold and will also support compliance with the EPA's proposed MATS for acid gases.

Q. How are the Hunter Units 1 and 2 scrubber projects expected to support the EPA's proposed MATS regulations?

A. MATS emissions limits are pending before the EPA for acid gases emissions, particularly HCl. An SO_2 emissions limit of 0.20 pounds SO_2 per MMBtu is recognized as the anticipated surrogate for the proposed MATS acid gases emissions compliance, and as such, the Hunter Units 1 and 2 scrubbers are expected to support compliance with that portion of the MATS.

Q. What emissions performance guarantees are provided via the scrubber projects EPC contract?

A. The scrubber projects are specified with contractually guaranteed performance emission thresholds at the following limits to provide an appropriate compliance margin over the operating life of the equipment with established maintenance cycles:

Pollutant	Emissions Limit
SO_2	[redacted]

Q. Did the Company consider alternative technologies to the Hunter Units 1 and 2 emissions control projects included in this case?

A. Yes. The Company completed two technical studies of note to evaluate NO_X, PM and SO_2 emission control technology alternatives for Hunter Units 1 and 2. In October 2002 S & L completed a coal fleet-wide Multi-Pollutant Control Report and in August 2007 S & L submitted the Hunter Station Units 1 and 2 FGD Upgrade Study which was supplemented with additional options data in February

2008.

The basis of the Multi-Pollutant Control Report was described earlier in my testimony.

The Hunter Station Units 1 and 2 FGD Upgrade Study was conducted to evaluate SO_2 emissions control options. In completing the study, technology alternatives were investigated and potential reductions in emissions were quantified.

Q. Has the Company evaluated whether the risk adjusted, least cost alternative to comply with environmental requirements was to invest in the emissions control equipment included in this case or to idle Hunter Units 1 and/or 2?

A. Yes. The Company evaluated whether the risk adjusted, least cost alternative to comply with environmental requirements was to complete the scrubber projects versus idling Hunter Units 1 and/or 2 at the end of 2012 and replacing the generation with market power purchases. The evaluation calculated a present value revenue requirement differential, PVRR(d), between the two options by subtracting fuel, O&M, environmental emissions cost, and on-going and CAI capital revenue requirement cost from revenue, similar to a merchant plant valuation. The revenue was derived using the September 30, 2009, PacifiCorp official market forward price curve at a corresponding CO_2 price of $8 per ton. The results of the evaluation demonstrated that it was beneficial to customers to invest in emissions control equipment for Hunter Units 1 and 2 in lieu of idling the facility and replacing the generation with market power purchases. The resulting PVRR(d)s showed positive differentials of [redacted] for Hunter 1 and [redacted] for Hunter 2.

Q. Has the Company completed any additional economic evaluations regarding the benefit of investing in the Hunter Units 1 and 2 environmental projects included in this case?

A. Yes. Two additional economic evaluations were completed to compare the benefit of investing now in the environmental projects included in this case versus (1) conversion of the unit to natural gas and (2) replacement ("repowering") of the unit with an in-kind, site-specific natural gas fired CCCT block. The evaluation descriptions and resulting PVRR(d) information are presented in the following table:

Evaluation Identification	PVRR(d) Results
Conversion of Hunter Unit 1 to Natural Gas	[redacted]
Conversion of Hunter Unit 2 to Natural Gas	[redacted]
Repowering at Hunter Unit 1	[redacted]
Repowering at Hunter Unit 2	[redacted]

Q. Please describe the conversion to natural gas scenario evaluated.

A. This evaluation considered whether converting Hunter Units 1or 2 to natural gas in place of coal, and then operating the unit on natural gas to meet mandated emissions thresholds, would be beneficial for customers. This present value evaluation uses a macroeconomic merchant plant approach where the unit's revenue requirement is compared to the value of the unit's generation using the PacifiCorp September 30, 2011, official market forward price curve and a corresponding \$16 per ton CO_2 price beginning in 2021. The evaluation established that the conversion and fueling with natural gas through 2042 is detrimental to customers, and the associated PVRR(d) was [redacted] unfavorable for Hunter Unit 1 and [redacted] unfavorable for Hunter Unit 2. This evaluation demonstrated that without a significant market pricing response to widespread coal-fueled steam electric plant idling and retrofits, high natural gas heat rates would result in low dispatching intervals of a converted unit.

Q. Please describe the repowering scenarios evaluated.

A. This evaluation considered whether converting Hunter Units 1 or 2 to a "repowered" natural gas fueled "1x1 F wet cooled" CCCT unit rated at 446 nominal MW was more economical on a market price basis. This evaluation places the CCCT at the Hunter plant. This evaluation takes a macroeconomic merchant plant approach and compares the "net revenue-to-cost" using the PacifiCorp September 30, 2011, official market forward price curve and a corresponding $16 per ton CO_2 price beginning in 2021. The evaluation concluded that repowering as a CCCT resource located at Hunter is detrimental to customers at the end of a projected CCCT depreciable life of 40 years, and the associated PVRR(d) in 2042 was [redacted] unfavorable for Hunter Unit 1 and [redacted] unfavorable for Hunter Unit 2.

Q. Has the Company evaluated the impact of the environmental projects included in this case on the bus bar cost of Hunter Units 1 and 2?

A. Yes. The Hunter Units 1 and 2 bus bar costs before and after installation of environmental projects included in this case, in 2010 dollars and with comparable CO_2 price impacts (2021 CO_2 cost de-escalated to 2010), are represented in the following table:

Facility	Bus Bar Cost Before Installation of Env Projects ($/MWh)	Bus Bar Cost Contribution of Env Projects ($/MWh)	Bus Bar Cost After Installation of Env Projects ($/MWh)	Incremental CO_2 Price Revenue Requirement ($/MWh)	Bus Bar Cost After Installation of Env Projects and with CO_2 Price ($/MWh)
Hunter 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hunter 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q. How do the bus bar costs reference above compare to other generation resource types in the Company's available generation mix?

A. Please refer to my earlier testimony regarding bus bar costs for Naughton Unit 1 for comparable bus bar cost references for other generation resource types.

Q. Has the Company developed emerging CCR regulations compliance costs for the Hunter facility?

A. Yes. Although information regarding the currently emerging CCR regulations was not available at the time of decision-making and planning of the multi-year Hunter Units 1 and 2 scrubber projects included in this case, the Company is committed to understanding and anticipating the effect of emerging environmental regulations in its economic evaluations and environmental plans. As discussed previously in my testimony, the Company has developed proxy compliance project costs for emerging rules regulating CCR for use in its forward-looking business planning processes. To provide frame of reference, the aforementioned costs have been incorporated into the Company's IRP Supplement, which did not identify an accelerated retirement date for Hunter Units 1 or 2.

Q. Has the Company developed emerging 316(b) regulations compliance costs for the Hunter facility?

A. Yes. Although information regarding the currently emerging 316(b) regulations was not available at the time of decision-making and planning of the multi-year Hunter Units 1 and 2 scrubber projects included in this case, the Company has applied the same principles as those discussed above for emerging CCR regulations and has incorporated 316(b) compliance costs into the Company's IRP Supplement. As noted above, the IRP Supplement did not identify an accelerated retirement date for Hunter Units 1 or 2.

Operating Costs

Q. Are there additional operating costs that will be incurred as a result of the installation of emissions control equipment included in this case?

A. Yes. Unfortunately, but unavoidably, the operation of the new emissions 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 emissions control equipment included in this case are explained in Company witness Mr. Dana M. Ralston's direct testimony.

Conclusion

Q. Please summarize your testimony.

A. The emissions control equipment investments presented in this case are required to comply with current, proposed, and anticipated likely environmental regulations. The investments allow for the continued operation of low-cost coal-fired generation facilities, while achieving significant environmental improvements. 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 coal fueled generating units increases the probability of continued safe, compliant, and reliable operation of these low-cost resources. The capital investments included in this case are reasonable and prudent, and the Company should be granted full cost recovery for these investments.

Q. Does this conclude your direct testimony?

A. Yes.