Rocky Mountain Power
Docket No. 13-035-184
Witness: Chad A. Teply

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

REDACTED
Direct Testimony of Chad A. Teply

Generation Capital Additions

January 2014

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 84116. My position is vice president of resource development and construction for PacifiCorp Energy. I report to the president of PacifiCorp Energy. Both Rocky Mountain Power and PacifiCorp Energy are divisions of PacifiCorp.

Qualifications

Q. Please describe your education and business experience.

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

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the prudence of capital investments in the new Lake Side 2 combined cycle combustion turbine ("CCCT") natural gas fueled resource, certain pollution control equipment retrofits on existing coal fueled resources, and other significant generation plant projects being placed in service during the test period in this docket, July 1, 2014 through June 30, 2015 ("Test Period").

Background

Q. Please provide a general description of the Lake Side 2 CCCT project being placed in service during the Test Period and the benefits gained from the investment.

A. The Lake Side 2 Significant Energy Resource Decision was approved by the Public Service Commission of Utah ("Commission") in Docket No. 10-035-126 on April 20, 2011, following a comprehensive review of the project need and the Company's 2008 Request for Proposals ("RFP") by the Commission, the Division of Public Utilities, the Office of Consumer Services and other interested parties. The Lake Side 2 project was determined to be the lowest reasonable cost option to meet additional electricity needs of customers, taking into account costs and risks. The Commission Order in Docket No. 10-035-126 contemplates a June 2014 in-service date at a projected cost of [redacted], including transmission, to acquire, construct and integrate the project into PacifiCorp's system. Rather than repeating what is already on record in Docket No. 10-035-126, I recommend that the Commission take administrative notice of that docket for additional evidence supporting the acquisition of the Lake Side 2 project.

The Lake Side 2 project remains on schedule to be placed in service by June 2014 and is currently projected to be completed with a capital cost of approximately [redacted], excluding transmission; approximately [redacted] when including the Lake Side 2 transmission service project also included in this docket. In each case, the project costs are trending favorably for customers to the Company's previous forecasts and economic assessments originally utilized to support the investment decision.

Q. Please provide a general description of the emissions control equipment investments being placed in service during the Test Period and the benefits gained from the investments.

A. The emissions control equipment investments included in this case are required to comply with environmental laws, including the Clean Air Act Regional Haze Rules and the Mercury and Air Toxics Standards ("MATS"), being administered by the respective state agencies in which the units reside, as well as the U.S. Environmental Protection Agency ("EPA"). The emissions control investments primarily result in the reduction of nitrogen oxides ("NO_X"), particulate matter ("PM"), sulfur dioxide ("SO_2"), and mercury ("Hg") emissions, depending upon the individual installation at the retrofitted facilities.

The investments include a baghouse conversion (approximately [redacted], Company share) and low NO_X burners ("LNB") installation (approximately [redacted], Company share) at Hunter Unit 1, and a selective catalytic reduction ("SCR") system installation (approximately [redacted], Company share) at Hayden Unit 1. The Hunter Unit 1 projects are required to be installed by spring 2014 by the state of Utah Regional Haze State Implementation Plan ("SIP") and have been determined to be the least cost compliance alternative for the unit when incorporating costs for potential greenhouse gas ("GHG") regulatory outcomes, other emerging environmental regulations, and potential long-term incremental emissions reduction strategies into the economic assessments of the projects.

The Hayden Unit 1 SCR is required by the state of Colorado's Regional Haze SIP to be installed by December 31, 2016. The Hayden Unit 1 SCR is also a key component of the NO_X reduction plan required to have been submitted by Public Service Company of Colorado (the operator of Hayden Unit 1) to the Colorado Public Utilities Commission under the Colorado Clean Air Clean Jobs Act. The Colorado Public Utilities Commission ultimately approved Public Service Company of Colorado's NO_X reduction plan, including the Hayden Unit 1 SCR project, on December 9, 2010. Public Service Company of Colorado has since received a Certificate of Public Convenience and Necessity ("CPCN") for the SCR project from the Colorado Public Utilities Commission after having demonstrated that the investment was in the best interests of customers. PacifiCorp is a minority owner of Hayden Unit 1, with an interest of 24.5 percent. The Participation Agreement governing that ownership interest mandates the installation of capital improvements that are required by applicable law. The Participation Agreement also places an independent obligation on Public Service Company of Colorado, as Operating Agent, to operate Hayden Unit 2 in accordance with applicable law. The applicable laws requiring the Hayden Unit 1 SCR investment are mentioned above and discussed in detail later in this testimony.

In each case, installation of these major emissions control retrofit projects have been aligned with scheduled major maintenance outages for the affected units to mitigate replacement power cost impacts while benefiting from overlapping major maintenance outage time frames. These environmental compliance investments constitute approximately [redacted] (approximately [redacted]) of the total capital investments projected to be placed in service within the Test Period. These environmental compliance investments will allow the retrofitted facilities to continue to operate as low-cost generation resources for the benefit of customers.

Q. Please provide a general description of the other significant generation plant projects being placed in service during the test period and the benefits gained from the investments.

A. The other significant generation plant projects being placed in service during the test period include the Blundell geothermal resource well integration project and the Naughton Unit 3 natural gas conversion project.

The Blundell geothermal resource well integration project integrates two new geothermal resource wells into the Blundell generation system. One production well and one injection well, along with associated appurtenances, have been drilled and will be placed in service to support continued reliable electricity production at the site.

The Naughton Unit 3 natural gas conversion project is being pursued as the least cost compliance alternative to the state of Wyoming Regional Haze SIP requirements for Naughton Unit 3. The natural gas conversion project was identified as the least cost alternative to installing an SCR and baghouse on Naughton Unit 3 via a CPCN docket in Wyoming. The Company is currently awaiting EPA approval of the natural gas conversion project as part of EPA's review and final action on the state of Wyoming Regional Haze SIP. EPA's final action in this regard is currently expected by January 10, 2014.

These investments constitute approximately [redacted] (approximately [redacted]) of the total capital investments projected to be placed in service within the test period for this docket.

Lake Side 2 Generation Resource Addition

<u>Lake Side 2 Project Overview</u>

Q. Please describe the Lake Side 2 project.

A. Lake Side 2 is located on a 63.6 acre site in Vineyard, Utah. It is a 645 MW natural gas-fired electric generation facility, consisting of a 2x1 combined-cycle configuration, using two combustion turbine generators and a single steam turbine generator. More specifically, Lake Side 2 is nominally rated at 548 MW base load and 97 MW of duct firing for a total net capacity of 645 MW at the average ambient temperate of 52 degrees Fahrenheit. Each combustion turbine exhausts into its own heat recovery steam generator which then commonly supply a single steam turbine generator. The electrical energy generated by Lake Side 2 will be delivered to a new 345 kV point of interconnection substation (Steel Mill) where it will tie into the PacifiCorp transmission system. Lake Side 2 is currently scheduled to reach substantial completion to generate and provide energy and capacity to customers by June 2014.

Q. Please describe the characteristics of Lake Side 2.

A. Lake Side 2 is located in the Company's east balancing authority. The Company can dispatch power and energy from Lake Side 2 on a forward, day-ahead basis, with real-time optimization of the plant's usage. This dispatch flexibility will give the Company an additional system resource with the ability to provide operating reserves, load-following reserves, and automatic generation control. The added system flexibility will provide increasing benefit to PacifiCorp as (1) load grows, (2) PacifiCorp's existing flexible contracts expire, and (3) new wind and solar resources are added to the system.

<u>Total Currently Projected Cost of Lake Side 2</u>

Q. What was the total projected cost of Lake Side 2 as evaluated in the Company's 2008 RFP?

A. The total projected cost of Lake Side 2 as evaluated in the 2008 RFP was [redacted].

Q. Please describe the components of the total projected cost associated with the development and engineering, procurement, and construction of Lake Side 2 as evaluated in the 2008 RFP.

A. The total estimated capital investment of [redacted] included the following estimated costs:

- A transfer to in-service cost of [redacted] for the generation asset including:
  - [redacted] for engineering, procurement, and construction
  - [redacted] for sales tax
  - [redacted] for owner's cost

- [redacted] for allowance for funds used during construction ("AFUDC")
- [redacted] for property taxes during construction

- [redacted][1] for transmission upgrade costs required to integrate the plant into the Company's east balancing authority.

Q. Have there been any changes in the Lake Side 2 generation asset cost forecast to be placed in service in 2014?

A. Yes, the Company has reduced its forecast of the generation asset's costs to be placed in service in 2014 by approximately [redacted]. This reduction is primarily due to a restructuring of the water purchases required for the project from the Central Utah Water Conservancy District ("CUWCD"). Instead of purchasing all of the water needed to meet the long-term requirements of Lake Side 2 during the construction period, the water purchases from the CUWCD have been phased in to align with expected generation and cooling water needs of Lake Side 2. This phasing in of water purchases is currently estimated to reduce revenue requirement on a present value basis by approximately [redacted] due to deferred capital payments and avoided fixed "take or pay" O&M costs for water under the CUWCD water supply agreement. Future water purchases, amounting to approximately [redacted], will be phased in over the 2015 to 2019 time period.

In addition to changes in the timing of water purchases, the Company's current Lake Side 2 generation asset cost forecast reflects reductions of

[1] PacifiCorp Transmission estimated the integration costs for each delivery point in Attachment 13 of the 2008 RFP. An initial estimate of [redacted] was updated on July 29, 2010, to [redacted] in 2010 dollars escalated at 1.89 percent annually through 2014 for a nominal cost of [redacted]. These two estimates are available at http://www.oasis.pacificorp.com/oasis/ppw/main.htmlx. The [redacted] estimate was used in the Final Shortlist evaluation process.

approximately [redacted] associated with changes in sales tax, owner's costs, AFUDC, property taxes, and other internal costs. The combination of these updates results in a reduction of the total capital investment forecast for Lake Side 2 from [redacted] to approximately [redacted].

Q. Have there been any changes to the estimated transmission upgrade costs to integrate the plant into the Company's east balancing authority from the [redacted] used in the final shortlist evaluation process?

A. Yes. The Company's forecast for the transmission upgrade costs is currently estimated to be approximately [redacted].

Q. What is the updated total forecasted capital investment for Lake Side 2?

A. The combination of the updated forecast of generation asset to be placed in service in 2014, the updated transmission upgrade costs to be placed in service 2014, and deferred water purchases results in reducing the total forecasted capital investment for Lake Side 2 from [redacted] to approximately [redacted].

<u>Contract Terms and Conditions</u>

Q. Please describe key engineering, procurement, and construction ("EPC") contract terms and conditions related to contractor performance risk.

A. If the EPC contractor does not achieve substantial completion of Lake Side 2 by June 1, 2014, the EPC contract for the project provides for delay liquidated damages. Any delay in achieving substantial completion that is greater than [redacted] following June 1, 2014, will entitle the Company to terminate the Agreement and to seek additional appropriate remedies. The EPC contractor's performance is secured by a parent guarantee and retainage or a retainage letter of credit equal to [redacted] percent of all payments made (other than the final payment).

The warranty under the EPC contract is effective for [redacted] beginning June 1, 2014; provided that any repairs (other than the power generation equipment) made during the warranty period will be warranted for a period that is the greater of one year or the balance of the warranty period. The EPC contractor has agreed to obtain insurance and assume risk of loss at the customary levels requested by the Company. The EPC contractor will not be liable for consequential damages; but, with a few exceptions, will be liable for losses under the EPC contract up to the aggregate amount of 100 percent of the contract price.

In addition, the Company has secured an additional warranty on the power generation equipment (the combustion turbines, steam turbine and associated generators) for the earlier of the [redacted] of the substantial completion date, [redacted] equivalent operating hours, or [redacted] months following delivery of the equipment.

<u>Lake Side 2 Project Implementation</u>

Q. What is the current status of Lake Side 2 project construction?

A. Construction of Lake Side 2 plant facilities and installation of plant equipment is complete. Piping, electrical, instrumentation and control systems installation work is approximately 85 percent complete. Commissioning of major equipment and systems has begun and will continue through the first quarter of 2014. First fire of Combustion Turbine 21 (the first combustion turbine in the commissioning queue) is expected in January 2014, followed by commissioning of the heat recovery steam generators and finally the steam turbine and all supporting systems. Tuning and testing of the plant is currently scheduled for April and May 2014 to support commercial operation by June 2014.

Pollution Control Investment Projects - Hunter Unit 1

Hunter Unit 1 Projects Overview

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

A. The Hunter plant is a three-unit coal-fueled power plant with a net generation capacity of approximately 1,320 MW and a currently approved depreciable life for ratemaking purposes of 2042 in Utah. The plant is located approximately 158 miles south of Salt Lake City, Utah near the town of Castle Dale, Utah, and is operated under a base load generation regime. Unit 1 is 93.8 percent owned by the Company and 6.2 percent owned by the Utah Municipal Power Agency, with the Company responsible for operation and maintenance of the unit and the Hunter plant as a whole. The Hunter plant site includes the main power station buildings for Units 1 through 3, water storage reservoirs, coal stock piles, ash disposal, and a small research farm to reclaim wastewater and a portion of storm water.

Units 1 and 2 are basically identical units when considering their base design and originally installed boiler and steam turbine generator equipment. Unit 3 is identical in layout to Units 1 and 2 except the boiler and turbine are from different manufacturers.

Water for plant use is released into the Cottonwood Creek from Joe’s Valley and conveyed by a direct pipeline from the Millsite Reservoir to the plant. Potable water is piped from the cities of Castle Dale, 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 on the adjacent research farm. 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.

The Hunter plant currently employs approximately 220 personnel, including approximately 170 union craft personnel represented by the International Brotherhood of Electrical Workers Local 57.

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

A. The Hunter Unit 1 baghouse conversion project replaces the originally installed particulate matter ("PM") control equipment (electrostatic precipitator) on the unit with a best available retrofit technology baghouse to meet the Company's emissions compliance obligations required by the Regional Haze Rules and incorporated into the state of Utah's Regional Haze SIP and associated permits by spring 2014. The baghouse will capture PM and mercury from the flue gas stream as it passes through the equipment. Capturing mercury in the baghouse allows the unit to comply with the EPA's MATS requirements for mercury capture by the prescribed deadline of April 16, 2015, without installing incremental stand-alone mercury emissions control equipment. The dry particulate waste stream captured in the baghouse is transported to an on-site landfill for disposal.

An additional emissions control benefit that the baghouse brings to Unit 1 is the ability to close the scrubber bypass currently installed on the unit, which when considered in conjunction with the Hunter Unit 1 scrubber, reagent preparation, and waste handling projects completed on the unit in 2012 allows the unit to meet a reduced SO_2 emissions limit required by the state of Utah Regional Haze SIP and associated permits by spring 2014.

Other equipment to be installed as part of the baghouse project includes upgraded booster fans, boiler reinforcement, new ductwork, modifications to the existing chimney, relocation of the stack opacity monitors, electrical infrastructure, controls, and other miscellaneous appurtenances and support systems.

The Company's share of the capital investment for the baghouse conversion project included in this case is approximately [redacted]. Construction of the project began in 2013, and the baghouse conversion is scheduled to be completed and placed in service following a planned major maintenance outage on the unit in spring 2014. The project cost is trending favorably to the cost initially assessed during the economic analysis and authorization for expenditure stage of the project.

Q. Please describe the Hunter Unit 1 LNB installation project.

A. The LNB installation project on Hunter Unit 1 includes the installation of NO_X combustion controls that replace originally installed equipment. The new burners utilize improved combustion characteristics and a separated over-fire air supply to the boiler to reduce NO_X emissions.

The Company's share of the capital investment for the project is approximately [redacted]. The project is scheduled to be completed and placed in service following the same spring 2014 planned major maintenance outage on the unit referenced above. The project cost is trending favorably to the cost initially assessed during the economic analysis and authorization for expenditure stage of the project.

Q. Have Hunter Units 2 and 3 been equipped with LNB and baghouse retrofit technologies that provide emissions reductions consistent with those being installed on Hunter Unit 1?

A. Yes. Pursuant to Utah Regional Haze SIP requirements, Unit 2 was equipped in 2011 with the same LNB and baghouse retrofit technologies contemplated in this docket for Hunter Unit 1. The same post-retrofit emissions limits for NO_X (0.26 pounds per million Btu) and particulate matter ("PM") (0.015 pounds per million Btu) are required for each unit. The Commission reviewed the Unit 2 emissions control equipment investments for ratemaking purposes in a past general rate case docket. The Unit 2 equipment is included in the Company's rate base.

Unit 3 was equipped with a fabric filter baghouse (1983) when the unit was originally constructed and was retrofitted with LNB technology in 2007. The Commission reviewed the Unit 3 LNB investment for ratemaking purposes in a past general rate case docket. The Unit 3 LNB equipment is included in the Company's rate base.

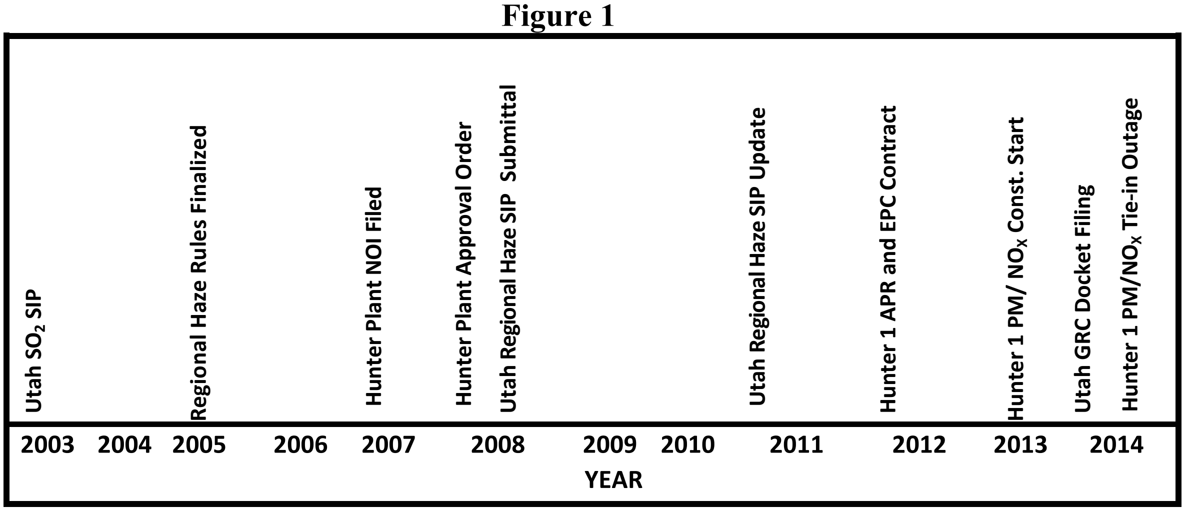
All three Hunter units are equipped with wet lime scrubbers to control sulfur dioxide emissions to a rate of 0.12 pounds per million Btu.

Hunter Unit 1 Projects Drivers and Alternatives Assessments

Q. What are the key permits and/or regulations requiring the Hunter Unit 1 baghouse and LNB projects to be installed?

A. To continue compliant operation of Hunter Unit 1, the Company must install the projects described herein to control emissions of NO_X, PM, and SO_2 criteria pollutants as required by Regional Haze Rules, the state of Utah's §309(g) Implementation Plan, the state of Utah's Best Available Retrofit Technology ("BART") review process, and the state of Utah's Approval Order (DAQE-AN0102370012-08) dated March 2008. Figure 1 below is a general timeline of the significant regulatory actions and regulations that have established the course of events.

Figure 1



The state of Utah Regional Haze SIP and permit requirements for the Hunter Unit 1 projects were finalized in 2008; detailed economic assessment of compliance alternatives and competitive procurement activities were completed in 2012; construction of the project began in 2013; and the baghouse conversion project is scheduled to be completed and placed in service following a planned major maintenance outage on the unit in spring 2014. Additional background regarding the Regional Haze compliance obligations facing Hunter Unit 1 is provided in Exhibit RMP___(CAT-1).

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

A. The Utah Regional Haze SIP and associated permit for the projects require that emissions control equipment for the unit be installed and operated in compliance with the following emissions limits.

Pollutant	**Emissions Limit (lb 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)
CO	0.34 (30-day rolling)

(a) Filterable portion only
(b) See Permit DAQE-AN102370012-08, Article 10

Q. Did the Company consider alternative technologies to the Hunter Unit 1 control projects included in this case when working with the state of Utah to assess Regional Haze compliance requirements incorporated into the Utah Regional Haze SIP?

A. Yes. The Company completed two technical studies of note to evaluate NO_X, SO_2, and PM control technology alternatives for Hunter Units 1. In October 2002, Sargent and Lundy completed a coal fleet-wide *Multi-Pollutant Control Report* (under attorney work product privilege); and in January 2005, Sargent and Lundy completed the *NO_X Emission Reduction Technologies Study,* and in November

2003, EPSCO International Inc. completed a *Phase III Recommendations* study of the original PM control equipment on the unit. See Exhibit RMP___(CAT-2) for additional discussion regarding study details.

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 electrostatic precipitators, polishing baghouses and full-scale fabric filter replacements.

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

The *Phase III Recommendations* study of the electrostatic precipitators ("ESP") and was used as the basis for the decision to convert the Hunter Unit 1 ESP to a baghouse. The decision making process began when the same type of conversion was made at Huntington Unit 2 (2004-2006). The ESP at Hunter Unit 1 and Unit 2 and Huntington Unit 1 and Unit 2 are identical, and in 2003 it had become apparent that the Huntington Unit 1 and Unit 2 ESP's were having operational difficulties. EPSCO International, Inc. was retained to study the situation, identify options and make recommendations for the Huntington and Hunter units.

Q. Has the Company updated its review of alternative technologies to the Hunter Unit 1 control projects included in this case to support the state of Utah with its ongoing assessment of Regional Haze compliance requirements in the Utah Regional Haze SIP?

A. Yes. In 2012, the Company contracted with CH2M Hill to complete updated BART analyses for Hunter Units 1, 2 and 3 for criteria pollutants NO_X, PM_{10} and SO_2. In completing these BART analyses, technology alternatives were investigated and potential reductions in emissions were quantified.

Q. Did the Company explore compliance flexibility, if any, with the environmental agencies having jurisdiction (i.e. state of Wyoming and/or EPA)?

A. Yes. As a result of negotiations with the Utah Division of Air Quality, the Company was allowed to delay the installation of the emission control equipment included in this case until the unit's planned major maintenance overhaul in 2014, in lieu of attempting to complete the project during the unit's 2010 planned major maintenance overhaul (which fell within the 2008 to 2013 Regional Haze planning period originally prescribed by the state of Utah). Please refer to Exhibit RMP___(CAT-1) for additional information regarding the Company's efforts to explore compliance timeline flexibility for the Hunter Unit 1 Regional Haze compliance projects.

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 Unit 1?

A. Yes. Prior to executing the EPC contract for the baghouse project in June 2012, the Company evaluated alternatives to comply with environmental requirements other than to complete the project. The Company used its System Optimizer Model to evaluate multiple alternatives. In brief, the major alternatives reviewed are:

(1) Continue to operate and incur operating expenses and capital revenue requirement expenses inclusive of incremental environmental investments;

(2) Retire Hunter Unit 1 and replace with resource alternatives; or;

(3) Convert to natural gas as a compliance alternative to the incremental environmental investments planned for the unit as a coal-fueled facility.

The results of the comparison of various alternatives resulted in a PVRR(d) of [redacted] favorable to proceeding with the project to the next best alternative as selected by the System Optimizer Model. The next best alternative was to convert Hunter Unit 1 to a natural gas fueled facility. Confidential Exhibit RMP___(CAT-3) provides detailed discussion of the Company's analyses and results.

Q. Are the methods and tools used to assess the compliance alternatives for Hunter Unit 1 consistent with those utilized to support the Company's recent 2013 Integrated Resource Plan filings, as well as the Company's Jim Bridger Units 3 and 4 CPCN filing in Wyoming and its Jim Bridger Units 3 and 4 Voluntary Procurement Pre-approval filing in Utah?

A. Yes. The Company utilized consistent methods and tools (e.g. System Optimizer Model) to assess compliance alternatives for Hunter Unit 1 as has been done in the Company's other recent major filings regarding environmental compliance investments in coal-fueled resources. In fact, the Company has included the results of its Hunter Unit 1 analyses in its 2013 Integrated Resource Plan Confidential Volume III filing.

Q. Does the Hunter Unit 1 baghouse conversion project provide emissions compliance benefits beyond those required by the Utah Regional Haze SIP?

A. Yes. The Hunter Unit 1 baghouse conversion project provides emissions compliance benefits associated with the EPA's MATS regulations.

Q. Beyond directly reducing mercury emissions, how is the Hunter Unit 1 baghouse project expected to allow Hunter Unit 1 to meet other EPA's MATS regulations?

A. In addition to specific emissions requirements for mercury, MATS includes requirements for emissions of non-mercury metals. MATS non-mercury metals emissions compliance can be demonstrated via a surrogate PM emissions limit of 0.030 pounds filterable PM per million Btu. Installation of the baghouse with performance requirements described above will allow Hunter Unit 1 to comply with that portion of MATS.

With respect to mercury emissions control, the Company expects that the Hunter 1 baghouse will allow Hunter Unit 1 to comply with MATS mercury emissions limits without the need for a coal supply additive (and associated costs) to oxidize mercury as the coal is burned in the furnace or the need to install activated carbon injection equipment for mercury removal purposes, avoiding those incremental costs as well.

Hunter Unit 1 Projects Emerging Environmental Regulations Considerations

Q. Has the Company assessed the potential costs of emerging environmental regulations in its economic analyses of the Hunter Unit 1 emissions compliance projects included in this case?

A. Yes. The Company has assessed potential costs of reasonably foreseeable emerging environmental regulations including coal combustion residuals ("CCR") regulations, Clean Water Act Section 316(b) regulations, effluent limitation guidelines, and various CO_2 cost scenarios in its Hunter Unit 1 analyses. Confidential Exhibit RMP___(CAT-3) provides additional detail regarding the Company's analyses in this regard.

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 development of the Utah Regional Haze SIP and planning of the multi-year Hunter Unit 1 projects, the Company is committed to understanding and anticipating the effect of emerging environmental regulations in its economic evaluations and environmental plans. As the Company assesses options regarding continued investment in its coal fueled generation assets, 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 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 2019. 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 and the economic analyses of the Hunter Unit 1 emissions control investments in this case.

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 development of the Utah Regional Haze SIP and planning of the multi-year Hunter Units 1 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 economic analyses and those costs did not alter the outcome.

Q. Has the Company developed emerging effluent limitation guidelines compliance costs for Hunter?

A. The Hunter plant is a zero discharge facility and it is currently not anticipated that it will be materially impacted by the proposed EPA effluent limitation guidelines. As such no proxy compliance costs for emerging effluent limitation guidelines were incorporated into the Company's economic analyses.

Q. How has the Company assessed potential CO_2 regulation outcomes?

A. As further described in Confidential Exhibit RMP___(CAT-3), the Company's Hunter Unit 1 baghouse and LNB investments were assessed over a range of CO_2 and natural gas forward price scenarios.

<u>Hunter Unit 1 Projects Implementation</u>

Q. Did the Company competitively and prudently procure the Hunter Unit 1 baghouse project EPC contract, as well as the Hunter Unit 1 LNB project?

A. Yes. In 2012, the Company issued a competitive EPC contract request for proposals package to over 20 market participants for supply of the Hunter Unit 1 baghouse conversion project. Three viable proposals were received and evaluated on a technical and commercial basis. The best evaluated proposal was identified and an EPC contract awarded following the procurement process.

Q. What emissions performance guarantees are provided via the Hunter 1 baghouse project EPC contract?

A. The baghouse project was specified with contractually guaranteed performance emission threshold at the following limits to provide an appropriate compliance margin over the operating life of the equipment with established maintenance cycles:

Pollutant	Emissions Limit (lb per MMBtu)
PM/PM_{10}[(a)]	0.012

(a) Filterable portion only

Q. What emissions performance guarantees are provided via the Hunter 1 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 (lb per MMBtu)
NO_X	0.24

Q. What is the current status of the Hunter 1 baghouse project?

A. Engineering and procurement for the baghouse EPC contract are complete, and the major components of the baghouse have been fabricated and delivered to the site. The EPC contractor is currently assembling baghouse components into modules which are installed during the outage. The induced draft booster fans rotors and motors are scheduled for delivery in January 2014. The only remaining material deliveries are the bags and cages for the baghouse which will be received on site by mid-February 2014. Pre-outage construction work began in May 2013 and will be ongoing until the outage starts. Major construction work and baghouse tie-in will be completed during the planned major maintenance outage period. The project is currently forecasted to be completed at or slightly below the approved budget amount, thus ensuring ratepayers will realize the value indicated by the economic analysis.

Q. What is the current status of the Hunter 1 LNB project?

A. Engineering and procurement are complete for the LNB project, and the new burners, ancillary equipment and ductwork are scheduled to start arriving at the Hunter plant in January 2014, and deliveries will be complete by the end of February 2014. Pre-outage construction work began in November 2013 and will be ongoing until the outage starts. Major construction work and LNB tie-in will be completed during the planned major maintenance outage. The project is currently forecasted to be completed at or slightly below the approved budget amount, thus ensuring ratepayers will realize the value indicated by the economic analysis.

Pollution Control Investment Project - Hayden Unit 1

<u>Hayden Unit 1 Project Overview</u>

Q. Please describe the Hayden facility.

A. The Hayden plant is a 446 megawatt, two-unit coal-fired electrical generating facility located in Routt County, Colorado. Unit 1 is jointly owned by Public Service Company of Colorado ("PSCo") and PacifiCorp (PacifiCorp owns 24.5

percent). Unit 2 is jointly owned by PSCo, Salt River Project, and PacifiCorp (PacifiCorp owns 12.6 percent). PSCo operates the plant.

<u>Hayden Unit 1 Project Drivers and Alternatives Assessments</u>

Q. What are the key permits and/or regulations requiring the Hayden Unit 1 SCR project to be installed?

A. To continue compliant operation of Hayden Unit 1, the PSCo must install the SCR project described herein to control NO_X emissions. In December 2010, the Colorado Air Quality Control Commission ("AQCC") promulgated new BART determinations and emissions control requirements for the Hayden units in the Colorado Regional Haze SIP. These BART determinations set emissions limits of 0.08 lbs NOx/MMBtu for Hayden Unit 1, and 0.07 lbs NOx/MMBtu for Hayden Unit 2. Although the BART determinations did not specify how these limits were to be achieved, installation of SCRs is the only technically feasible method currently available. The Unit 1 SCR is expected to enter service in 2015, and the Unit 2 SCR is expected to enter service in 2016.

EPA published its approval of the Colorado Regional Haze SIP in in the Federal Register on December 31, 2012.

Q. Are the Colorado Regional Haze SIP requirements for Hayden Unit 1 currently being litigated?

A. Environmental groups National Parks Conservation Association and WildEarth Guardians filed petitions for review before the U.S. 10th Circuit Court of Appeals challenging the legality of EPA approving some aspects of the Colorado Regional Haze SIP. In general, the environmental groups are asking the court to require

EPA to make the Colorado Regional Haze SIP more stringent by requiring SCR controls at more units at a faster pace. PacifiCorp, the state of Colorado and other utilities have intervened in the appeal in support of EPA's approval of the Colorado Regional Haze SIP and against the proposition of making it more stringent.

Q. If litigation regarding Hayden Unit 1 environmental compliance requirements were to result in changes to current compliance requirements for the unit, would the Participation Agreement dictate that PSCo re-assess the SCR investment?

A. The environmental groups who filed the litigation are not seeking less stringent controls at Hayden Unit 1. Without that issue specifically before the court, it is highly unlikely that the court's decision will result in a relaxation of the SCR compliance requirements for Hayden Unit 1. If, for some reason, litigation did result in a change in SCR compliance requirements for Hayden Unit 1, the PSCo and the Company would re-assesses such changes pursuant to the terms of the Participation Agreement.

<u>Hayden Unit 1 Ownership Agreement Considerations</u>

Q. What are the primary ownership agreement considerations regarding the Company's investment in the Hayden Unit 1 SCR project?

A. The Participation Agreement requires Hayden Unit 1 to be operated in compliance with all environmental laws. The Participation Agreement also places an independent obligation on Public Service Company of Colorado, as the Operating Agent, to operate Hayden Unit 1 in accordance with all environmental laws. Considerations under the agreement fall into two primary classes. First, PacifiCorp must consider the applicable law (e.g., the Colorado Regional Haze SIP and the Colorado Clean Air Clean Jobs Act). Second, PacifiCorp must consider its contractual rights and obligations under the Participation Agreement in regard to the applicable law.

Q. Following its assessment of applicable law and its rights and obligations under the Participation Agreement for Hayden Unit 1, what position has the Company taken with respect to the SCR emissions control investment for the unit.

A. Following its assessment of applicable law and its rights and obligations under the Participation Agreement, the Company approved investment in the SCR for Hayden Unit 1 because: (i) it is required by applicable law; and (ii) Hayden Unit 1 is required to be operated in accordance with applicable law.

Q. What is the status of applicable law that applies to the Hayden Unit 1 SCR emissions control investment?

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

Further, the state of Colorado has adopted the Clean Air Clean Jobs Act that required PSCo to submit a plan to reduce NO_X emissions by 70 to 80 percent by 2017. PSCo's NO_X reduction plan, reviewed and approved by the Colorado

Public Utilities Commission, includes installation of SCR retrofits on Hayden Units 1 and 2. To comply with the Colorado Regional Haze SIP and PSCo's approved Clean Air Clean Jobs Act NOx reduction plan, PSCo as Operating Agent for the Hayden facility, is pursuing installation of SCR on Hayden Units 1 and 2.

Q. Please provide a general description of the terms and conditions of the Hayden Unit 1 Participation Agreement that governs the Company's rights and obligations regarding major capital expenditures at this jointly owned plant.

A. The Participation Agreement mandates the installation of capital improvements that are required by applicable law. The Participation Agreement also places an independent obligation on PSCo, as Operating Agent, to operate Hayden Unit 2 in accordance with applicable law. Also, the Participation Agreement requires the unanimous consent of all owners to proceed with a capital improvement. If the Operating Agent proposes a capital improvement (e.g. the installation of SCR equipment) to meet applicable law, as has occurred at Hayden Unit 1, a non-consenting owner has the option to assert that the Operating Agent (and other owners) are in default under the Participation Agreement if it cannot be demonstrated that applicable law requires the investment. In that case, whether or not a default has occurred will be decided by arbitration.

Q. Does the Company assert that the Operating Agent for Hayden Unit 1 is in default as it pertains to its proposed capital investment in the installation of SCR equipment on the unit?

A. No. The basis for the Company's position in that regard is provided above.

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

A. Yes. PSCo has found the installation of SCR on Unit 1 to be in the best interests of customers and has received approval of a CPCN from the Colorado Public Service Commission for the project.

Q. Considering the terms and conditions of the Hayden Unit 1 Participation Agreement, did the Company pursue arbitration of the Hunter Unit 1 SCR investment decision?

A. No, for the reasons explained above.

<u>Hayden Unit 1 Projects Implementation</u>

Q. What is the current status of the Hayden Unit 1 SCR project?

A. Engineering and procurement of the Hayden Unit 1 SCR project are underway, and the SCR equipment supply contract has been awarded. PSCo is completing the Hayden Unit 1 SCR project on a multiple lump sum contracts basis with PSCo staff and PSCo's owner's engineer providing engineering, procurement, and construction management. Major construction work and SCR tie-in will be completed during the planned major maintenance outage period for the unit in spring 2015.

Blundell Geothermal Well Integration Project

Q. Please describe the Blundell facility.

A. The Blundell plant is a 34-megawatt geothermal facility near Milford, Utah. Blundell Unit 1 was commissioned in 1984 and is a 24 megawatt facility using single "flash" technology. Blundell Unit 2 was commissioned in 2007 and is a 10 megawatt "bottoming" cycle which uses a binary heat-recovery process to extract additional energy from the hot geothermal brine left over from Blundell Unit 1 prior to returning the brine to the geothermal reservoir. The renewable energy source for the Blundell plant is the Roosevelt Hot Springs Reservoir which spans approximately 30,000 acres and lays thousands of feet below surface. The reservoir contains groundwater heated by magma to approximately 500°F and at a pressure of approximately 500 pounds per square inch. There are four existing supply wells that bring the high-pressure, heated liquid to the surface, where it "flashes" to steam in steam separators. The steam is separated from the geothermal liquid called "brine" and the steam is transported by above ground pipeline to Blundell Unit 1 which uses a Rankine Cycle steam turbine generator to produce electricity.

Blundell Unit 2 is a "bottoming" cycle. The steam exiting Blundell Unit 1 flows through heat exchangers to heat iso-pentane, a fluid similar to propane, to expand through a separate turbine to generate electricity in a closed-loop, binary process. The geothermal fluid, after passing through the iso-pentane heat exchangers, is further condensed and returned to the geothermal reservoir via three existing injection wells. The plant has approximately two miles of steam piping and six miles of brine piping, tying the existing seven-well geothermal supply and injection system together. With the exception of the geothermal brine, Blundell is a zero-discharge facility.

Q. Please describe the Blundell well integration project.

A. The two wells included in the Blundell well integration project were originally drilled in 2008 as part of a project to prove the Roosevelt Hot Springs Reservoir's capacity and capability to support construction on an incremental generation resource at the facility (Blundell Unit 3). The wells were drilled and tested under the premise that they could ultimately be incorporated into the existing geothermal supply and injection system for Blundell Units 1 and 2, or could ultimately be incorporated into a series of new wells required for an incremental resource at Blundell. Pursuit of an incremental generation resource at Blundell was deferred and later canceled due to cost, inability to commercially mitigate geothermal resource performance risk, and uncertainty regarding renewal of production tax credits for geothermal resources. However, these two new wells represent viable assets that are available to be placed into service for the benefit of customers. The wells will supply additional steam and injection capacity for Blundell Units 1 and 2 and improve operational reliability and flexibility.

Q. Please describe the assets that will be placed into rates.

A. This project will place into service one new steam production well drilled to a depth of approximately 5,000 feet and associated ancillary equipment including a well head, steam/brine separator, emergency backup generator, brine transfer pump, control system, disposal pond, air compressors, well site control/equipment building and security fencing. It will also place into service one new injection well drilled to a depth of approximately 7,000 feet deep and associated ancillary equipment including a wellhead, disposal pond, local instrumentation and valves for operation. The wells are interconnected with Blundell Unit 1 and 2 by three new overland pipelines. One pipeline will connect the production well to the Unit 1 main steam supply line. A second pipeline will connect the production well to the Blundell Unit 2 brine supply line, and the third pipeline will connect Blundell Unit 2 brine return line to the new injection well. In addition, plant control system modifications are required to operate the new production and injection wells from the Blundell Unit 1 control room.

Q. What is the total value of the assets described above and when will they be placed in service?

A. The forecasted costs of the project, including AFUDC, are approximately [redacted] and are expected to be placed in service by September 2014.

Q. How does this project benefit customers?

A. The project will benefit customers by improving the reliability and operational flexibility of Blundell Units 1 and 2.

Q. How has the Company assessed the benefit to customers?

A. The four active production wells at Blundell have an average age of over 30 years. The three active injection wells at Blundell have an average age of over 35 years. Production and injection wells have a finite life which is very difficult to model and predict; however, a statistical analysis of Roosevelt Hot Springs Reservoir well histories indicate a 10 percent per year probability of a well failure. While statistically, an event can happen any time, it has been over 10 years since a significant well event has occurred at Blundell.

Since 1984, two production wells have failed and been abandoned. During that timeframe, three other production wells have developed issues that, while not immediately impairing their serviceability, are being monitored. With the remaining wells in service, reserve steam supply capability at Blundell is currently estimated to be less than eight percent based upon current well conditions and performance assumptions and will continue to decline as the condition of the wells continues to deteriorate. However, during peak demand months in the summer and early fall, the Company has experienced lost production due to lack of steam supply, leading to the conclusion that the reserve margin reported as less than eight percent may be overly optimistic depending upon specific operating conditions. During May through October 2012, Blundell Unit 1 operated at 6,195 megawatt-hours below nameplate capacity as a result of low steam pressure across the four production wells. This realized loss of production capability is a key driver to pursing incremental production well capacity tie-in at this point in time.

If one of the four wells were to fail, there is insufficient capacity in the remaining three production wells to maintain rated plant output. In fact, two of the four production wells deliver approximately 70 percent of the steam for Blundell. If one of those wells were to fail, output would be severely curtailed until the well could be replaced.

Regarding injection wells, the continued production of high pressure geothermal fluid from the Roosevelt resource is contingent on injection of the used geothermal brine back into the aquifer to maintain the fluid balance. The brine cools as it travels down the injection wells, and as it cools the silica suspended in the brine solution turns solid and can plug and ultimately close off the injection capability of the well. While the rate of plugging is difficult to measure, maintaining margin in total system injection well capacity to accommodate individual well performance degradation is prudent.

Of the three existing injection wells, one well is suspected to be re-injecting fluid near or just outside the limit of the geothermal field due to gradually changing subsurface characteristics of the resource, one has a partially collapsed casing and the third injection well is used to re-inject most of the fluid. Thus plant production is currently heavily dependent on a single injection well.

Based on the approximate 20-year remaining life of Blundell and a range of probabilities and circumstances, the benefit for integration of the two wells ranges from [redacted] to [redacted] on an annualized basis, with a total benefit over the remaining life of Blundell of [redacted] to [redacted].

Q. Can the Company wait to complete the Blundell well integration project?

A. No. With the increasing risk of failure due to deteriorating condition of the production and injection wells described above, as well as the realization of loss of available energy production in 2012 due to existing well conditions, pursuing integration of the production and injection wells available at Blundell is appropriate at this time. As noted above, if the Company were to wait until ultimate failure of a well prior to commencing procurement of ancillary equipment supply and installation contracts, it is reasonable to assume that the lost production and/or injection well capacity would extend 12 months or more, based upon the competitively procured equipment supply lead times and installation contract schedules currently being negotiated by the Company.

While accelerated equipment supply and installation agreements may ultimately be available in an "emergency" condition, such contracts would be reasonably expected to be significantly more costly and would not address ongoing loss of energy generation during the delivery and installation period.

Naughton Unit 3 Natural Gas Conversion Project

Q. Please describe the Naughton plant and the Naughton Unit 3 facility, in particular.

A. The Naughton plant consists of three coal fueled units that are all 100 precent owned and operated by PacifiCorp. PacifiCorp also owns 100 precent of the Viva Naughton reservoir which stores water for consumptive use at the Naughton plant and provides regional recreation opportunities. Water for plant use flows from the Viva Naughton reservoir into the Ham's Fork River, where it is diverted approximately five miles downstream and then conveyed approximately nine miles via a pipeline to an onsite raw water storage pond. National Pollutant Discharge Elimination System ("NPDES") permit WY0020311 allows release of small flows from CCR clearwater ponds. Plant sewage is treated on site in a general biosolids permitted package wastewater treatment facility that discharges effluent into a CCR pond under NPDES permit WY0020311. Potable water for plant use is obtained from the town of Kemmerer, Wyoming.

The Naughton plant property is adjacent to the Westmoreland Kemmerer Mine that supplies approximately 2.8 million tons per year of sub-bituminous coal to the plant via an overland belt conveyor. CCR are disposed of on plant property in surface impoundments.

Naughton Unit 3 began commercial operation in 1971. It has a currently approved depreciable life for ratemaking purposes of 2029, and a net reliable generation capacity of 330 megawatts ("MW"). The boiler was retrofitted in 1999 with LNB for NO_X removal. The unit configuration also includes: a closed-loop cooling water system, with a mechanical draft cooling tower; an electrostatic precipitator ("ESP") for PM removal; and a sodium-based wet flue gas desulfurization system ("FGD") for SO_2 removal that was retrofitted in 1981.

The Naughton plant currently employs approximately 140 personnel, including approximately 105 union craft personnel represented by the International Brotherhood of Electrical Workers Local 57.

Q. Please describe the Naughton Unit 3 natural gas conversion project and the associated equipment.

A. As part of the Naughton Unit 3 natural gas conversion project, the steam electric unit will be converted from a base-loaded 100 percent coal fueled unit to a 100 percent natural gas fueled slow-start peaking unit. Coal fueling equipment will be left in place except where it interferes with new natural gas fuel supply equipment. It is anticipated that natural gas supply piping to the converted Naughton Unit 3 can be modified with a new pipeline, approximately 16 inches in diameter, from the existing natural gas supplier metering station located approximately 1.8 miles east of the plant.

New boiler natural gas fuel supply equipment will include igniters, flame scanners, LNBs, and natural gas distribution piping. Five levels of LNBs will be installed in existing air compartments on each of the four corners of the boiler and will have the capability to sustain unit operation over a net reliable load range from approximately 85 to 330 MW. Modifications to the boiler burner management control systems will be completed. New process control instruments, control wiring and high performance controller modules will be installed and integrated into the plant's existing distributed control system.

A 15 to 20 percent flue gas recirculation system ("FGR") will be installed to enable the boiler to attain required operating temperatures and to provide NOx emissions reductions. Flue gas will be recirculated from the existing ductwork between the economizer outlet and the air preheater inlet. Flue gas will be re-injected into the boiler wind box. The FGR will consist of two by 50 percent capacity fans; including lubricating oil systems, fan motors, foundations, vibration monitoring, controls and interconnecting ductwork.

Flue gas will exit the unit by flowing through: (1) the de-energized existing ESP, (2) the existing induced draft and booster fans, and (3) the FGD bypass ductwork. It will discharge to the atmosphere through the existing wet FGD chimney. All flue gas duct expansion joints between the induced draft fan inlets and the FGD outlet duct will be replaced. Other demolition work will be limited to interfering items only.

Q. Why is natural gas conversion of Naughton Unit 3 being pursued?

A. To comply with state of Wyoming Regional Haze SIP requirements, installation of SCR and a baghouse to reduce emissions of NO_X and PM on Naughton Unit 3 was required by December 31, 2014. The Company assessed the economics associated with these requirements in a CPCN docket in the state of Wyoming and determined that natural gas conversion is in the best interests of the Company's customers. A summary of the Company's CPCN filing and results is included in Exhibit RMP___(CAT-4).

Q. Please provide additional background regarding the Regional Haze compliance obligations facing Naughton Unit 3.

A. In 2007, the Company submitted required applications to the Wyoming Department of Environmental Quality ("WDEQ") Air Quality Division ("AQD") for BART permits at various BART-eligible electric generating units in Wyoming, including Naughton Unit 3. On December 31, 2009, the WDEQ AQD issued BART permit MD-6042 for the Naughton plant requiring, among other things, the installation of a SCR and a baghouse as additional environmental controls at Naughton Unit 3.

In February 2010, the Company appealed certain provisions of the Naughton BART permit to the Wyoming Environmental Quality Council ("WEQC"), including provisions requiring the installation of SCR and baghouse on Naughton Unit 3. By settlement agreement dated November 3, 2010, the Company and the WDEQ AQD resolved the appeal as to Naughton Unit 3 by the Company agreeing to abide by the original terms of the Naughton BART permit.

The WDEQ AQD finalized its Regional Haze SIP on January 7, 2011, including the requirement for the Company to install a SCR and baghouse at Naughton Unit 3. It then submitted its Regional Haze SIP to the EPA for review and approval. On June 4, 2012, EPA proposed to partially approve certain portions of the Wyoming Regional Haze SIP, including those portions that require the installation of SCR and baghouse at Naughton Unit 3 by December 31, 2014.

The EPA later determined that public comments received on its proposed action on the SIP led it to *re-propose* its rule for a new round of public comment. The EPA reported that it had conducted additional analysis on emissions control costs and the associated visibility benefits between the Wyoming Regional Haze SIP submittal and December 14, 2012, the anticipated EPA final action date. The EPA approached the original litigants and, in an unopposed motion filed December 10, 2012 with the U.S. Department of Justice on behalf of the EPA, requested a new deadline for a re-proposed rule of March 29, 2013, and a final action deadline of September 27, 2013. The court approved the EPA's request for extension on December 13, 2012.

Subsequently, on March 27, 2013, the EPA received approval from the U.S. District Court to again extend the deadlines previously agreed to for issuance of actions on the Wyoming Regional Haze SIP. In a filing made in the U.S. District Court, WildEarth Guardians, National Parks Conservation Association, and the Environmental Defense Fund agreed to allow the EPA to extend the previously extended deadlines for issuance of a re-proposal on the Wyoming Regional Haze SIP from March 29, 2013 to May 23, 2013, and to revise final action deadlines from September 27, 2013 to November 21, 2013.

The EPA re-proposed official draft rules on the Wyoming Regional Haze SIP on June 10, 2013. In its re-proposed draft rules, the EPA supported SCR and baghouse on Naughton Unit 3 and requested public comments on a natural gas conversion alternative. The Company provided comments on the EPA's re-drafted proposal on August 26, 2013, in support of the natural gas conversion alternative for Naughton Unit 3 and extension of the operating timeframe of the unit as a coal-fueled resource from December 31, 2014 to December 31, 2017.

Since August 26, 2013, EPA has again been granted an extension to take final action on the Wyoming Regional Haze SIP to January 10, 2014. Until EPA takes final action on the SIP, and the underlying state of Wyoming compliance obligations, including the Wyoming Regional Haze SIP, are modified, the Company remains obligated to comply the Wyoming Regional Haze SIP and the associated WDEQ permit documents to install SCR and a baghouse at Naughton Unit 3 by December 31, 2014.

Q. Did the Company explore compliance flexibility, if any, with the environmental agencies having jurisdiction (i.e. state of Wyoming and/or EPA)?

A. Yes. The topic of project timelines and technical requirements has been raised with representatives of the state of Wyoming and EPA Region 8 given EPA's continual extension motions regarding Wyoming Regional Haze SIP actions, and consideration that final action is now not expected until January 10, 2014. The Company has pointed out that re-proposed rules, after dates the Company must enter into contracts for timely and compliant equipment procurement and installation, affecting required emissions limits or compliance timelines make cost-effective decision-making and planning extremely difficult both for the Company and for competitive market participants. Further, due to EPA's continually delayed action, it would be impossible for the Company to complete an SCR and baghouse project within the originally prescribed compliance deadline for Naughton Unit 3, should the EPA reject the alternative compliance approach of natural gas conversion of the unit. EPA has acknowledged the dilemma to the Company and competitive market faces.

Company representatives also met WDEQ representatives on January 4, 2013 and March 27, 2013, to further discuss EPA's delayed action along with other environmental compliance planning topics. WDEQ's position regarding EPA's pending actions is that the Company is currently bound by the environmental compliance obligations included in the Wyoming Regional Haze SIP, associated WDEQ AQD permits, and settlement stipulation pertaining to Naughton Unit 3 and other Wyoming units. The WDEQ re-confirmed its position in writing on March 6, 2013.

Company representatives also met with the Wyoming Attorney General's office on January 4, 2013, to discuss deadlines and the agency's position on extending the deadlines. The Company was advised that the state of Wyoming views the deadlines as being independently legally enforceable under the Wyoming Regional Haze SIP, the Settlement Agreement, and Chapters 6 and 9 of the Wyoming Air Quality Standards and Regulations. The state's position was confirmed at the WEQC's meeting on January 10, 2013.

Q. Has the Company formally requested state of Wyoming approval of the natural gas conversion alternate Regional Haze compliance approach for Naughton Unit 3?

A. Yes. Recognizing the complexity that attempting to modify Wyoming Regional Haze SIP, Settlement Agreement, and other associated regulations and agreements regarding Naughton Unit 3 presents; as well as the uncertainty surrounding the timing and extent of EPA's final action in this regard, the Company applied for and received a permit from the WDEQ to cease coal-fueled operation of Naughton Unit 3 by December 31, 2017, and to convert the unit to natural gas fueling by June 30, 2018. WDEQ AQD Permit MD-14506 is attached as Exhibit RMP___(CAT-5) for reference.

It is expected that the terms of the natural gas conversion permit for Naughton Unit 3 will ultimately be aligned with the other Regional Haze related plans, permits, and agreements affecting the unit following final EPA action on the Wyoming Regional Haze SIP.

Q. Has the Company evaluated whether the least-cost alternative, accounting for risk and uncertainty, to comply with environmental requirements was to invest in the emissions control equipment or to idle Naughton Unit 3?

A. Yes. As part of the CPCN process described above, the Company completed an economic analysis that evaluated the trade-offs between making incremental investments to comply with then-current and emerging environmental regulations to a broad range of resource alternatives including: (1) natural gas conversion; (2)

early retirement and replacement with green field natural gas resources; (3) firm market purchases; (4) demand-side management opportunities; and or (5) renewable resources. Ultimately, the Company's evaluation established that converting the unit to 100 percent natural gas fueling and operating the unit as a slow-start peaking unit was the risk-adjusted and least-cost alternative for our customers.

Q. Did the Company consider alternative technologies to the natural gas conversion?

A. Yes. Exhibit RMP___(CAT-2) is a summary of the technical studies and key study points used in the Company's consideration and analysis of technical alternatives to the Naughton Unit 3 Regional Haze compliance alternatives.

Q. Please describe the currently anticipated Naughton Unit 3 natural gas conversion project timeline from inception through final completion.

A. This testimony has been prepared under the worst-case assumption that the Naughton Unit 3 natural gas conversion will be completed and placed in service by May 2015, pursuant to the currently established Wyoming Regional Haze SIP compliance deadline for Naughton Unit 3 NO_X and PM reductions, and assuming that EPA does not support the timeline for conversion approved under the state of Wyoming construction permit discussed above. Under this scenario, the unit would operate on coal through December 31, 2014, and subsequently enter into a five-month construction and tie-in outage for conversion of the unit to natural gas as its fuel supply. EPC contract provisions are being pursued that will guarantee the project to be mechanically complete by June 1, 2015, and available thereafter to generate as dispatched during the 2015 summer peak load season and beyond.

Exhibit RMP___(CAT-6) illustrates the overall project timeline from inception to completion, including activities occurring during the early development phase of the project that were focused toward planning a SCR and a baghouse alternative instead of the natural gas conversion alternative.

Q. Has the Company aligned its competitive procurement activities for the conversion project with the emissions performance requirements of the construction permit approved for the project?

A. Yes. PacifiCorp is currently in the process of bidding the EPC contract for the Naughton Unit 3 natural gas conversion. Proposals were received from bidders on December 3, 2013. In its request for proposals, PacifiCorp requested the following emissions performance guarantees:

Parameter	Guarantee
NOx Emission Rate	**By Contractor** **(At least ≤ 0.080 lb NOx/mmBtu throughout the load range)**
Long Term NOx Emission Rate	**< 0.080 lb NOx/mmBtu AND < 250 lb NOx/hr** **(30-boiler day rolling arithmetic average)**
CO	**By Contractor** **(lb CO/mmBtu or ppm throughout the load range)**
VOC Emission	**< 0.0040 lb VOC/mmBtu**
PM Limit	**≤ 0.0070 lb PM_{10}/mmBtu**

Q. Did the Company consider all applicable emerging environmental regulations that pose risk to continued operation of Naughton Unit 3 when determining natural gas conversion was the preferred compliance alternative?

A. Yes. The Company considered MATS regulations; potential carbon dioxide ("CO_2") regulations; proposed CCR regulations; proposed Clean Water Act 316(b) regulations; and proposed effluent limitation guidelines rulemaking. Case-by-case discussion of the impacts of those emerging environmental regulations on the Company's decision to convert Naughton Unit 3 to a natural gas fueled generation resource is provided in Exhibit RMP___(CAT-7) for reference.

Q. Does the Naughton Unit 3 natural gas conversion permit issued by Wyoming address MATS compliance for the unit in the interim between April 15, 2015 and December 31, 2017?

A. Yes. A critical consideration of the Naughton Unit 3 natural gas conversion compliance schedule approved by WDEQ is the overlapping requirement to comply with MATS by April 16, 2015, through the December 31, 2017, coal-fueled operation window for the unit. In that interim period, WDEQ has prescribed enforceable operating restrictions and emissions limits on the unit consistent with MATS compliance requirements. It is proposed that the operating limits and permit conditions commence upon compliance dates required by the MATS rule (April 16, 2015), and terminate December 31, 2017.

Q. Has the EPA approved the alternate Regional Haze compliance approach of converting Naughton Unit 3 to natural gas fueling?

A. No. As discussed above, EPA is not currently expected to take final action on the Wyoming Regional Haze SIP until January 10, 2014. EPA has, however, requested public comment on the Naughton Unit 3 natural gas conversion and associated project timing approved by Wyoming. As such, the Company continues to prepare for the earlier conversion date discussed above to avoid placing the Company in a position of being unable to achieve the currently prescribed Wyoming Regional Haze SIP compliance timeline for the unit.

Q. Are the state of Wyoming compliance requirements enforceable absent final EPA action?

A. Yes. Company representatives met with WDEQ representatives on January 4, 2013 and March 27, 2013, to further discuss the EPA's delayed Wyoming Regional Haze SIP rule making action along with other environmental compliance planning topics. WDEQ's position regarding EPA's pending actions is that the Company remains currently bound by the environmental compliance obligation included in the Wyoming Regional Haze SIP, associated WDEQ AQD permits, and settlement stipulation pertaining to Naughton Unit 3 and other Wyoming units. The WDEQ re-confirmed its position in writing on March 6, 2013. See Exhibit RMP___(CAT-8).

Q. If EPA approves the revised compliance deadline for Naughton Unit 3 consistent with the state of Wyoming's requirements, what actions does the Company intend to take?

A. If EPA approves the Naughton Unit 3 compliance conditions included in the construction permit issued by WDEQ discussed above and allows the unit to operate as a coal-fueled resource through December 31, 2017, the Company will revise its natural gas conversion project implementation schedule accordingly. In that instance, the Company would support an adjustment to the capital cost associated with the natural gas conversion project and removing the capital addition from the Test Period. The impact of such an adjustment is addressed in the direct testimony of Company witnesses Mr. Gregory N. Duvall and Mr. Steven R. McDougal. Exhibit RMP___(CAT-9) provides additional context regarding permitting activities associated with EPA's review and approval.

Q. Will Naughton Unit 3 remain a low cost generation resource following implementation of the project?

A. While the implementation phase of the Naughton Unit 3 natural gas conversion has not yet started, the EPC contract is currently being bid for an early 2015 conversion. The competitive market respondents to the Company's request for proposals further inform the Company as to whether its cost estimates and performance assumptions for the project remain accurate and aligned with the assumptions used in its Naughton Unit 3 natural gas conversion alternative resource decision analysis.

The Company's current economic analysis, including sensitivity analyses, for the proposed Naughton Unit 3 natural gas conversion project demonstrates that the unit remains a valuable low cost generation resource for peaking needs following unit conversion.

Conclusion

Q. Please summarize your testimony.

A. The Lake Side 2 project was approved by the Commission as the lowest reasonable cost option to meet additional electricity needs of customers, taking into account costs and risks, in Docket No. 10-035-126. The Company's investment in and implementation of the new Lake Side 2 CCCT natural gas fueled resource project remains aligned with its original intent and is expected to deliver benefits to customers on schedule and at a lower capital cost than originally forecasted.

Investments in emissions control investments at the Company's jointly owned Hunter Unit 1 and Hayden Unit 1 are required to meet the EPA's Regional Haze rules, and the resulting BART reviews, state implementation plans, permitting processes, and in the case of Hayden, Colorado Clean Air Clean Jobs Act. The investments in pollution control equipment at the Company's Hunter Unit 1 included in this case have been assessed in conjunction with potential compliance costs associated with emerging environmental regulations, including potential regulation of carbon dioxide emissions. The investment allows for the continued operation of low-cost coal-fueled generation resources, while achieving significant environmental improvements. The Company's support of the investment in the Hayden Unit 1 environmental compliance project included in this case has been administered pursuant to applicable law and the Partnership Agreement applicable to that unit.

The Company's other major generation plant investments at Blundell and as currently planned at Naughton Unit 3 have been prudently managed and assessed as being in the best interests of customers; effectively maintaining safe, reliable, efficient, cost-effective generating resources and production facilities.

The capital investments included in this case are reasonable and prudent, and the Company should be granted full cost recovery for these investments.

Q. Does this conclude your direct testimony?

A. Yes.