PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

September 5, 2012

***VIA ELECTRONIC FILING***
***AND OVERNIGHT DELIVERY***

Public Utility Commission of Oregon
550 Capitol Street NE, Suite 215
Salem, OR 97310-2551

Attn: Filing Center

**Re: UE 246 – Surrebuttal Testimony & Exhibits**

PacifiCorp d.b.a. Pacific Power submits for filing an original and eight copies of the surrebuttal testimony and exhibits of Cathy S. Woollums, Chad A. Teply, R. Bryce Dalley, and Gregory N. Duvall.

Please direct informal correspondence and questions regarding this filing to Bryce Dalley, Director, Regulatory Affairs & Revenue Requirement, at (503) 813-6389.

Confidential material in support of the filing has been provided to parties under the protective order in this docket (Order No. 12-060).

Sincerely,

William R. Griffith /RBD

William R. Griffith
Vice President, Regulation

Enclosures

cc: UE 246 Service List

## CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document, in Docket UE 246, on the date indicated below by email and overnight delivery, addressed to said parties at his or her last-known address(es) indicated below.

Kurt J. Boehm (W)(C)
Boehm Kurtz & Lowry
36 E. Seventh St., Suite 1510
Cincinnati, OH 45202
kboehm@bkllawfirm.com

Jody Kyler (W)(C)
Boehm Kurtz & Lowry
36 E. Seventh St. Ste 1510
Cincinnati, OH 45202
jkyler@bkllawfirm.com

OPUC Dockets (W)
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland, OR 97205
dockets@oregoncub.org

Robert Jenks (W)(C)
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland, OR 97205
Bob@oregoncub.org

G. Catriona McCracken (W)(C)
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland, OR 97205
catriona@oregoncub.org

Irion A Sanger (W)(C)
Davison Van Cleve
333 SW Taylor – Ste 400
Portland, OR 97204
mail@dvclaw.com

Melinda J. Davison (W)(C)
Davison Van Cleve PC
333 SW Taylor, Suite 400
Portland, OR 97204
mail@dvclaw.com

Kevin Higgins (W)(C)
Energy Strategies
215 State St., Suite 200
Salt Lake City, UT 84111-2322
Khiggins@energystrat.com

Michael T. Weirich (W)(C)
Department of Justice
Regulated Utility & Business Section
1162 Court St. NE
Salem, OR 97301-4096
Michael.weirch@doj.state.or.us

John W. Stephens (W)(C)
Esler Stephens & Buckley
888 SW 5th Ave Ste 700
Portland, OR 97204 - 2021
stephens@eslerstephens.com
mec@eslerstephens.com

Johanna Riemenschneider (W)(C)
PUC Staff – Dept of Justice
Business Activites Section
1162 Court St NE
Salem, OR 97301-4096
Johanna.riemenschneider@doj.state.or.us

Wendy Gerlitz (W)(C)
NW Energy Coalition
1205 SW Flavel
Portland, OR 97202
wendy@nwenergy.org

Jeremy Fisher (W)(C)
Synapse Energy
485 Massachusetts Ave, Ste 2
Cambridge, MA 02139
jfisher@synapse-energy.com

Bryce Dalley (W)(C)
Pacific Power
825 NE Multnomah St., Suite 2000
Portland, OR 97232
Bryce.dalley@pacificorp.com

Sarah Wallace (W)(C)
Pacific Power
825 NE Multnomah St Ste 1800
Portland, OR 97232
Sarah.wallace@pacificorp.com

Oregon Dockets (W)
Pacific Power
825 NE Multnomah St., Suite 2000
Portland, OR 97232
oregondockets@pacificorp.com

Donald W Schoenbeck (W)(C)
Regulatory & Cogeneration Services, Inc
900 Washington St, Ste 780
Vancouver, WA 98660-3455
Dws@r-c-s-inc.com

Gloria D. Smith (W)(C)
Sierra Club Law Program
85 Second St
San Francisco, CA 94105
Gloria.smith@sierraclub.org

Randall Dahlgren (W)
Portland General Electric
121 SW Salmon St., 1WTC0702
Portland, OR 97204
Pge.opuc.filings@pgn.com

Douglas C. Tingey (W)
Portland General Electric
121 SW Salmon St., 1WTC13
Portland, OR 97204
doug.tingey@pgn.com

Deborah Garcia (W)(C)
Oregon Public Utility Commission
PO Box 2148
Salem, OR 97308-2148
deborah.garcia@state.or.us

Megan Walseth Decker (W)(C)
Renewable Northwest Project
421 SW 6th Ave #1125
Portland, OR 97204-1629
megan@rnp.org

Jimmy Lindsay (W)(C)
Renewable Northwest Project
421 SW 6th Ave #1125
Portland, OR 97204-1629
jimmy@rnp.org

Derek Nelson (W)(C)
Sierra Club Law Program
85 Second St, 2nd Floor
San Francisco, CA 94105
derek.nelson@sierraclub.org

Stuart Robertson (W)
Robertson-Bryan, Inc
9888 Kent Street
Elk Grove, CA 95624
stuart@robertson-bryan.com

Kevin E. Parks (W)
Parks Law Offices LLC
310 SW 4th Ave.m Ste 806
Portland, OR 97204
kevin@parks-law-offices.com

William Ganong (W)(C)
514 Walnut Avenue
Klamath Falls, OR 97601
wganong@aol.com

Hollie Cannon (W)(C)
Klamath Water and Power Agency
735 Commercial St Ste 4000
Klamath Falls, OR 97601
Hollie.cannon@kwapa.org

DATED: September 5, 2012

Carrie Meyer
Coordinator, Regulatory Operations

Docket No. UE-246
Exhibit PAC/1900
Witness: Cathy S. Woollums

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF THE STATE OF OREGON**

**PACIFICORP**

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**Surrebuttal Testimony of Cathy S. Woollums**

**September 2012**

**Introduction and Purpose of Testimony**

**Q. Are you the same Cathy S. Woollums who previously submitted testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power ("the Company")?**

A. Yes, I am.

**Q. What is the purpose of your surrebuttal testimony in this proceeding?**

A. My testimony responds to issues raised by the Sierra Club and the Citizens' Utility Board of Oregon ("CUB") regarding the environmental compliance obligations faced by the Company, and the prudence of the Company's decision-making process for emissions control investments at its coal fueled-generation plants. Mr. Chad A. Teply will also respond to CUB's and Sierra Club's arguments in his surrebuttal testimony.

My testimony will respond to specific arguments raised in the rebuttal[1] testimony of Messrs. Bob Jenks and Gordon Feighner on behalf of CUB and Drs. William Steinhurst and Jeremy Fisher on behalf of Sierra Club. CUB and Sierra Club avoid the real issue in this case by focusing on irrelevant hypothetical analyses and misinterpretations of the applicable legal standard. CUB confounds the issue further by applying integrated resource planning principles to a rate case prudence determination. But CUB's and Sierra Club's arguments are irrelevant to the question facing the Commission in this case: Were the Company's environmental control investments objectively reasonable given the information available at the time the decision was made?

[1] Sierra Club mistakenly titled its testimony "surrebuttal." To avoid confusion, the Company refers to Sierra Club's testimony as rebuttal.

The goal of my surrebuttal testimony is to help the Commission answer this question by focusing on the relevant evidence and the relevant time period. The Company made the decision to invest in the environmental controls at issue in this case in 2008 and 2009. Given the Company's environmental compliance obligations at that time, and based on the best information available at that time, the Company's decision to make these investments was prudent, and ensured that the Company could continue to meet its obligation to serve using low-cost, safe, and reliable resources. Contrary to CUB's assertions, the continued operation of these plants was part of the resource portfolio in the Company's acknowledged integrated resource plans, and without the environmental controls at issue in this case, the plants could not continue to operate. My surrebuttal testimony focuses on responding to particular arguments raised in rebuttal regarding the compliance obligations facing the Company.

**The Company's Emissions Control Investments were Made to Comply with Existing Environmental Obligations**

**Q. Please summarize CUB's and Sierra Club's rebuttal positions regarding the Company's obligations to install the emissions controls.**

A. CUB's primary contention in rebuttal is that the Company did not fully assess compliance alternatives or develop analyses that could be used to support the phase-out of coal plants as economic and in the best interests of customers. CUB further argues that the Company should have waited before making these investments.

Sierra Club contends in its rebuttal testimony that the Company's economic analyses supporting its emissions control investments at the Naughton plant were insufficient and erroneous. Sierra Club also contends that the investments were permitted and implemented prematurely, prior to a federally enforceable legal requirement, and were ultimately insufficient to mitigate pollution at Naughton.

**Q. Why did the Company invest in emissions controls at its coal-fueled generating facilities?**

A. The reason is simple—the Company had environmental compliance obligations that had to be met to continue to legally operate its generating facilities. With a fleet the size of the Company's, these obligations cannot be met by waiting until the end of the compliance period. Cutting through all the competing financial analyses, CUB's reliance on Portland General Electric's decision-making regarding the Boardman facility (which was not found to be reasonable until 2010, after the Company's investment decisions and well after the preparation of the Company's BART analyses), and all the other ancillary assertions, the question at issue in this case is whether the Company's environmental control investment decisions were prudent given the Company's compliance obligations and the information available at the time the decisions were made.

**Q. Was it prudent for the Company to make compliance-related investments?**

A. Yes. While both CUB's and Sierra Club's testimonies continue to support the proposition the coal-fueled resources should be phased out, Mr. Teply's testimony indicates that in addition to being necessary to meet current and reasonably foreseeable environmental requirements, the Company's evaluations demonstrate that the Company appropriately considered costs and risks at the time the decisions were made.

**Q. What were the environmental laws or regulations the Company was required to comply with?**

A. As addressed in more detail in my reply testimony, the underlying obligations were: (1) the Regional Haze regulations; (2) the Clean Air Act's National Ambient Air Quality Standards; and (3) the Mercury and Air Toxics Standards (and its predecessor rules).

**Q. These compliance obligations are effectively federal regulations. Sierra Club witness Dr. Fisher indicates that there was no legal obligation to install controls, and suggests that unless the obligation is federally enforceable, there is no requirement to comply. How do you respond?**

A. State regulations and permit requirements place enforceable obligations on the Company. The effort to distinguish these obligations as irrelevant or non-existent because they may or may not have been *federally* enforceable at any point in time is a red herring; if a state implements and enforces a legal obligation, it is a legal obligation regardless of whether it is federally enforceable. States retain the primary responsibility for choosing how to implement the Clean Air Act's required emission reductions with respect to sources in their borders, a principle that was recently upheld by the D.C. Circuit Court of Appeals.[2] A State Implementation Plan ("SIP") is enforceable by the state regardless of whether the

[2] *EME Homer City Generation, L.P. v. U.S. Environmental Protection Agency et al.*, No 11-1302, (D.C. Cir.) August 21, 2012.

United States Environmental Protection Agency ("EPA") takes timely action on that SIP, as affirmed by the 5th Circuit in a case where the state of Texas operated under a SIP for 16 years prior to EPA taking action on it.[3]

It is interesting that Dr. Fisher asserts in his testimony that there is no compliance requirement, particularly since his assertions are in direct conflict with other positions he has taken. In January 2011, in a report prepared for the Western Grid Group to estimate the order in which 108 existing coal plants in 11 states in the Western Electric Coordinating Council might become uneconomic using 2008 data under existing and proposed environmental regulations, Dr. Fisher stated:

> In recent years, the EPA has announced a series of proposed and forthcoming regulations to control emissions of criteria pollutants and reduce damages to society and the environment from the electricity sector. <u>Already enacted and now reaching enforcement deadlines, the BART rule</u> (Best Available Retrofit Technologies) <u>requires power plants</u> which negatively impact visibility in public Class 1 lands (such as National Parks) <u>to control</u> of primary and secondary particulates, <u>primarily through the application of new sulfur dioxide controls.</u>[4]

**Q. Can Wyoming legally implement Regional Haze rules without formal approval of its SIP by EPA?**

A. Yes. While the Regional Haze rules have been in place for quite some time, in Wyoming a serious effort to implement the requirements began in 2006. In June 2006, each of the Company's facilities received letters (Exhibit PAC/1901)

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[3] *See State of Texas, et al. v. U.S. EPA*, No. 10-60614, August 13, 2012 (5th Cir.).
[4] Fisher, Jeremy and Biewald, Bruce, "Environmental Controls and the WECC Coal Fleet: Estimating the forward-going economic merit of coal-fired power plants in the West with new environmental controls," January 23, 2011 (emphasis added). Available at http://www.synapse-nergy.com/Downloads/SynapseReport.2011-01.EF+WGG.WGG-Coal-Plant-Database.10-077-Report.pdf.

requesting an analysis of BART options to be provided to the Wyoming Air Quality Division by October 15, 2006. The Air Quality Division was concurrently developing mercury control requirements and encouraged facilities to consider them at the same time: "[A]s the control strategies for the visibility impairing pollutants may overlap with Hg, you may wish to consider this fact in developing your BART control strategies." The letter also indicated that the Air Quality Division was proposing a state BART rule "which will define how the BART process will be applied in Wyoming." The first draft of the Wyoming BART rules, dated June 14, 2006 (Exhibit PAC/1902), was presented to the Wyoming Air Quality Advisory Board at its July 2006 meeting and, with minor changes, final rules became effective December 5, 2006 (see Exhibit PAC/1903) and have been in full force and effect since that time. With an underlying regulatory requirement, Wyoming was poised to move forward with additional steps to implement the Regional Haze requirements and develop its SIP.

**Q. Was implementation of the Wyoming BART rule and its requirements contingent upon approval of the SIP by EPA?**

A. No. The only reference to EPA in the Wyoming BART rule was the fact that "any control equipment required under a permit issued in this section shall be installed and operating as expeditiously as practicable but in no event later than five years after the EPA's approval of Wyoming's State Implementation Plan revision for Regional Haze." In other words, the date of installation of the required control equipment was dictated by the state in accordance with what it determined met its "expeditiously as practicable" standard.

**Q. Sierra Club states that it was "disconcerting" that the Company indicated in reply testimony that the sulfur dioxide ($SO_2$) controls were installed largely to address nonattainment of the $SO_2$ National Ambient Air Quality Standards (NAAQS), suggesting that the reason given was a post-project rationalization for the large capital investments at Naughton Units 1 and 2. How do you respond?**

A. Contrary to what Sierra Club implies, the Company has always been forthcoming about its compliance with the NAAQS at the Naughton facility. The Company was required by the Wyoming Department of Environmental Quality to conduct air dispersion modeling as part of the process of obtaining permits to install sulfur trioxide (SO3) injection systems at Naughton Units 1 and 2.[5] This is a common practice among environmental regulators to ensure that the controls to be installed do not create unintended consequences on air quality and that all emissions are accounted for and properly reflected in what ultimately become the plant-operating permits.

As demonstrated in Exhibit PAC/1904, the modeled $SO_2$ emissions at Naughton Units 1 and 2 were predicted to exceed the NAAQS in one area west of the Kemmerer mine. The Company discussed these modeled results with the Wyoming Department of Environmental Quality. Because the Company was also required to meet the requirements of the Western Backstop Trading Program for $SO_2$, which utilized an emission rate of 0.15 lb/mmBtu for $SO_2$ at all the BART-eligible units, including the Naughton units, the Wyoming Department of Environmental Quality determined that addressing the potential modeling concern

[5] Please note that my reply testimony mistakenly states that the controls were low $NO_x$ burners.

under the Regional Haze program was sufficient and that no further action was necessary.

**Q. Is it true, as Sierra Club asserts, that under a modeled exceedance of the NAAQS, "the Company would have knowingly violated air quality standards for nearly six years prior to the installation of the flue gas desulfurization"?**

A. No. Air quality modeling data is predictive and, when the model predicts an exceedance, additional (and perhaps more refined) modeling is typically conducted, and ambient air quality monitoring data may be utilized to confirm or refute the modeled results. Sierra Club suggests the Company is in noncompliance to cast a negative shadow on the Company, but at the same time minimizes the likelihood of an enforcement action by Sierra Club or others because there was no air quality monitoring data to confirm an actual exceedance or to discredit the Company's basis for installing the controls.

**Q. Were the processes to develop BART or other emission control permits, the Regional Haze rules, and Wyoming's SIP public?**

A. Yes. The state actions in issuance of permits, developing rules, and developing a SIP are all subject to public review and comment and, given that this process has extended over six years, there were multiple opportunities for any member of the public or any organization to participate in the processes. Likewise, the EPA's proposed actions on the SIP are public processes in which private individuals, organizations, state agencies, and other federal agencies may participate.

**Q. Did Sierra Club participate in the public process relating to the Wyoming Regional Haze SIP?**

A. Yes. Sierra Club's position in this case is surprising given its comments during the SIP process. Along with other organizations, the Sierra Club submitted comments at various points in the public process, most recently on August 2, 2012, in EPA's docket on its proposed action to partially approve and partially disapprove the Wyoming Regional Haze SIP. According to the "Conservation Organizations," including Sierra Club, comments were submitted on August 4, 2009, August 24, 2010, December 7, 2010, and February 14, 2012—none of which asserted that the controls proposed under the Wyoming Regional Haze SIP were not required or were being required too early, nor did the Conservation Organizations assert that the SIP could not be enforced by the state or was irrelevant because it was not federally enforceable. Rather, these comments consistently asserted that the requirements of the SIP, and even the EPA's proposed Federal Implementation Plan (FIP), were not stringent enough. The Conservation Organizations' comments dated August 2, 2012, submitted through Ms. Andrea Issod and Ms. Gloria Smith, state that "EPA must require <u>additional</u> reductions of haze-causing pollution [beyond Wyoming's requirements] <u>to comply with the law</u> and to achieve the national goal of eliminating anthropogenic visibility impairment in Wyoming and the western United States" and that "requiring antiquated facilities to install pollution control technologies is a job-creating mechanism in itself."[6]

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[6] Available at: http://www.regulations.gov/#!documentDetail;D=EPA-R08-OAR-2012-0026-0056 (emphasis added).

**Q. Does this conclude your surrebuttal testimony?**

A. Yes.

Docket No. UE-246
Exhibit PAC/1901
Witness: Cathy S. Woollums

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF THE STATE OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Surrebuttal Testimony of Cathy S. Woollums**

**Wyoming Department of Environmental Quality BART Analysis Request for Naughton**

**September 2012**

Exhibit PAC/1901
Woollums/1

# Department of Environmental Quality

To protect, conserve and enhance the quality of Wyoming's environment for the benefit of current and future generations.

Dave Freudenthal, Governor

John Corra, Director

June 14, 2006

orig: K. Edrington ✓
c: Skinner w/o attach
c: Steinbrenner w/o attach

RECEIVED
P. STEINBRENNER
NAUGHTON PLANT

Peter Steinbrenner, Plant Managing Director
PacifiCorp
P.O. Box 191
Kemmerer, WY 83101

Re: Naughton Plant

Dear Mr. Steinbrenner:

This letter is being directed to you because your facility has been determined to be "Subject to BART (Best Available Retrofit Technology)" per the U.S. Environmental Protection Agency regulations contained in 40 CFR Part 51, Appendix Y: Guidelines for BART Determinations under the Regional Haze Rule. The specific documents containing the complete text of the regulations are found in 40 CFR Part 51, Appendix Y, as published on July 6, 2005 in the Federal Register beginning on Page 39104, not including later amendments (copy included).

The Regional Haze Rule requires states to submit State Implementation Plans (SIP's) to address visibility impairment in 156 Federally-protected parks and wilderness areas (Class I Areas). While the Regional Haze Rule directs states to examine visibility impairment resulting from a variety of emission sources, the rule specifically requires states to look at the contribution from BART sources. Between now and December 2007, the Air Quality Division will be preparing a Regional Haze SIP which will include, among other things, a section identifying BART Eligible sources, a determination as to whether such sources cause or contribute to visibility impairment in a Class I area, and for those sources that are "Subject to BART", identification of the appropriate type and level of BART control. The general process of applying Appendix Y is described below.

Section II of Appendix Y (Page 39158) provides guidelines for identifying BART Eligible Sources using a three step procedure. Facilities that are BART Eligible are those: (Step 1) belonging to one of the 26 listed categories, (Step 2) "in existence" on August 7, 1977, but not "in operation" before August 7, 1962 and (Step 3) with the potential to emit greater than 250 tons per year of any single visibility impairing pollutant.

Once a source is determined to be "BART Eligible", Section III of Appendix Y (Page 39161) provides guidelines for determining whether that source is "Subject to BART". The Air Quality Division has established a threshold of 0.5 deciviews for determining that sources "contribute" to visibility impairment in any Class I area according to Section III A.1 of the July 6th BART

Guidelines. We then looked at $SO_2$, $NO_X$, and direct particulate matter (PM) emissions in making this determination according to Section III A.2. of the Guidelines; and followed Option 1 using the CALPUFF model according to Section III A.3. in analyzing the impact of BART Eligible sources contributing to visibility impairment.

This screening procedure shows that your facility has been determined to be "Subject to BART" (report attached). Therefore under §35-11-110 of the Wyoming Environmental Quality Act, I am requesting that your organization now conduct an analysis of BART options according to the guidelines in Section IV of Appendix Y (Page 39163), and report back the "best" alternative (Section IV E.) to the Air Quality Division by October 15, 2006.

Upon receipt, the Air Quality Division will review your analysis for all three pollutants, $SO_2$, $NO_X$, and Particulate Matter. We will base our control requirements on the final BART analyses for $NO_X$ and PM. For $SO_2$ we will either use the BART analysis to show that an alternative Trading Program shows "Greater Reasonable Progress than BART" if the trading program survives, or to institute $SO_2$ BART controls if the program fails. For BART implementation, we will accept or amend your proposed emission controls, and set enforceable emission limits for your facility according to Section V of Appendix Y.

Also you should know that the Air Quality Division is concurrently developing Mercury control requirements, and as the control strategies for the visibility impairing pollutants may overlap with Hg, you may wish to consider this fact in developing your BART control strategies.

The Division recognizes that applying these federal guidelines will be challenging. In order to assist facility owners and establish a level playing field for all affected sources, the Division is proposing to establish a state BART rule which will define how the BART process will be applied in Wyoming. This proposal will be considered by the Air Quality Advisory Board on July 10 and 11, 2006 in Gillette, Wyoming. Owners and operators of sources subject to BART are encouraged to attend. Additional information on this meeting, including a draft BART rule will be available on the Air Quality Website http://deq.state.wy.us/aqd/index.asp?pageid=8 after June 14, 2006.

If you have any additional questions regarding this requirement, please feel free to call me at 307-777-7391 or contact Lee Gribovicz at 307-777-6993 for further assistance.

Sincerely,

D Finley

Dave Finley, Administrator
Air Quality Division

| | | | |
|---|---|---|---|
| cc: | District Engineers | Lee Gribovicz | Bernie Dailey |
| | Robert Gill | Tina Anderson | Mike Stoll |

Bill Lawson, PacifiCorp, 1407 W. North Temple, Salt Lake City, Utah 84140

Enclosure #1: July 6, 2005 Federal Register Regional Haze BART Guidelines
Enclosure #2: June 9, 2006 Don Watzel Memo – "BART Screening Analysis"
Enclosure #3: April, 2006 McVehil-Monnet Draft Final Report – "BART Air Modeling; Individual Source Visibility Impairment Analysis"

Docket No. UE-246
Exhibit PAC/1902
Witness: Cathy S. Woollums

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF THE STATE OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Surrebuttal Testimony of Cathy S. Woollums**

**Wyoming Department of Environmental Quality, Air Quality Division, Draft BART Rules**

**September 2012**

WYOMING DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION
STANDARDS AND REGULATIONS
CHAPTER 6, Section 9, BART

Section 9. Best available retrofit technology (BART).

***(a) Applicability.*** The provisions of this regulation apply to existing stationary facilities, as defined in Section 9(b) of this chapter.

***(b) Definitions.***

***"Adverse impact on visibility"*** means visibility impairment which interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of the Federal Class I area. This determination must be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency and time of visibility impairments, and how these factors correlate with 1) times of visitor use of the Federal Class I area, and 2) the frequency and timing of natural conditions that reduce visibility. This term does not include effects on integral vistas.

***"Applicable technology"*** means a commercially available control option that has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type or a technology that has been used on a pollutant-bearing gas stream that is the same or similar to the gas stream characteristics of the source.

***"Available technology"*** means that a technology is licensed and available through commercial sales.

***"Average cost effectiveness"*** means the total annualized costs of control divided by annual emissions reductions (the difference between baseline annual emissions and the estimate of emissions after controls). For the purposes of calculating average cost effectiveness, baseline annual emissions means a realistic depiction of anticipated annual emissions for the source. The source or the Division may use State or Federally enforceable permit limits or estimate the anticipated annual emissions based upon actual emissions from a representative baseline period.

***"BART alternative"*** means an alternative measure to the installation, operation, and maintenance of BART that will achieve greater reasonable progress toward national visibility goals than would have resulted from the installation, operation, and maintenance of BART at BART-eligible sources within industry source categories subject to BART requirements.

***"Best available retrofit technology (BART)"*** means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant that is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source or unit, the remaining useful life of the source or unit, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

***"Deciview"*** means a measurement of visibility impairment. A deciview is a haze index derived from calculated light extinction, such that uniform changes in haziness correspond to uniform incremental changes in perception across the entire range of conditions, from pristine to highly impaired. The deciview haze index is calculated based on the following equation (for the purposes of calculating deciview, the atmospheric light extinction coefficient must be calculated from aerosol measurements):

Deciview haze index = $10 \ln_e (b_{ext}/10 \text{ Mm}^{-1})$

Where $b_{ext}$ = the atmospheric light extinction coefficient, expressed in inverse megameters ($\text{Mm}^{-1}$).

***"Existing stationary facility"*** means any of the following stationary sources of air pollutants, including any reconstructed source, which was not in operation prior to August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any visibility impairing air pollutant. In determining potential to emit, fugitive emissions, to the extent quantifiable, must be counted.

(i) Fossil fuel-fired steam electric plants of more than 250 million British thermal units (BTU) per hour heat input that generate electricity for sale.

(A) Boiler capacities shall be aggregated to determine the heat input of a plant.

(B) Includes plants that co-generate steam and electricity and combined cycle turbines.

(ii) Coal cleaning plants (thermal dryers).

(iii) Kraft pulp mills.

(iv) Portland cement plants.

(v) Primary zinc smelters.

(vi) Iron and steel mill plants.

(vii) Primary aluminum ore reduction plants.

(viii) Primary copper smelters.

(ix) Municipal incinerators capable of charging more than 250 tons of refuse per day.

(x) Hydrofluoric, sulfuric, and nitric acid plants.

(xi) Petroleum refineries.

(xii) Lime plants.

(xiii) Phosphate rock processing plants. Includes all types of phosphate rock processing facilities, including elemental phosphorous plants as well as fertilizer production plants.

(xiv) Coke oven batteries.

(xv) Sulfur recovery plants.

(xvi) Carbon black plants (furnace process).

(xvii) Primary lead smelters.

(xviii) Fuel conversion plants.

(xix) Sintering plants.

(xx) Secondary metal production facilities. Includes nonferrous metal facilities included within Standard Industrial Classification code 3341, and secondary ferrous metal facilities in the category "iron and steel mill plants".

(xxi) Chemical process plants. Includes those facilities within the 2-digit Standard Industrial Classification 28, including pharmaceutical manufacturing facilities.

(xxii) Fossil fuel boilers of more than 250 million BTUs per hour heat input.

(A) Individual boilers greater than 250 million BTU/hr, considering federally enforceable operational limits.

(B) Includes multi-fuel boilers that burn at least fifty percent fossil fuels.

(xxiii) Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels.

(A) 300,000 barrels refers to total facility-wide tank capacity for tanks put in place after August 7, 1962 and in existence on August 7, 1977.

(B) Includes gasoline and other petroleum-derived liquids.

(xxiv) Taconite ore processing facilities.

(xxv) Glass fiber processing plants.

(xxvi) Charcoal production facilities. Includes charcoal briquette manufacturing and activated carbon production.

***"Incremental cost effectiveness"*** means the comparison of the costs and emissions performance level of a control option to those of the next most stringent option, as shown in the following formula:

> Incremental Cost Effectiveness (dollars per incremental ton removed) = [(Total annualized costs of control option) - (Total annualized costs of next control option)] ÷ [(Next control option annual emissions) - (Control option annual emissions)]

***"In existence"*** means that the owner or operator has obtained all necessary preconstruction approvals or permits required by Federal, State, or local air pollution emissions and air quality laws or regulations and either has 1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or 2) entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time.

***"In operation"*** means engaged in activity related to the primary design function of the source.

***"Integral vista"*** means a view perceived from within the mandatory Class I Federal area of a specific landmark or panorama located outside the boundary of the mandatory Class I Federal area.

***"Natural conditions"*** means naturally occurring phenomena that reduce visibility as measured in terms of light extinction, visual range, contrast, or coloration.

***"Plant"*** means all emissions units at a stationary source.

***"Potential to emit"*** means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

***"Visibility-impairing air pollutant"*** includes the following:

(i) Sulfur dioxide ($SO_2$);

(ii) Nitrogen oxides ($NO_x$); and

(iii) Particulate matter. ($PM_{10}$ will be used as the indicator for particulate matter. Emissions of $PM_{10}$ include the components of $PM_{2.5}$ as a subset).

***(c) Guidelines for BART Determinations.***

***(i)*** The U.S. Environmental Protection Agency regulations contained in 40 CFR part 51, Appendix Y, are incorporated by reference into these regulations. The specific documents containing the complete text of the regulations are found in 40 CFR part 51, Appendix Y, as published on July 6, 2005 in the Federal Register beginning on page 39104, not including later amendments. Copies of the July 6, 2005 materials can be obtained from the Department of Environmental Quality, Division of Air Quality, 122 W. 25th Street, Cheyenne, Wyoming 82002.

***(ii)*** The owner or operator of a fossil fuel-fired steam electric plant with a generating capacity greater than seven hundred fifty megawatts of electricity shall comply with the requirements of 40 CFR part 51, Appendix Y. All other facility owners or operators shall use Appendix Y as guidance for preparing their best available control retrofit technology determinations.

***(d) Identification of Sources Subject to BART.***

***(i)*** Identification of sources subject to BART shall be performed by the Air Quality Division in accordance with EPA's guidelines for BART determinations under the regional haze rule 40 CFR part 51, Appendix Y, and incorporated by reference under Section 9(c). A BART-eligible source is subject to BART unless valid air quality dispersion modeling demonstrates that the source will not cause or contribute to visibility impairment in any Class I area.

(A) A single source that is responsible for a 1.0 deciview change or more is considered to "cause" visibility impairment in any Class I area.

(B) A single source that is responsible for a 0.5 deciview change or more is considered to "contribute" visibility impairment in any Class I area.

(C) A single source is exempt from BART if the 98th percentile daily change in visibility, as compared against natural background conditions, is less than

0.5 deciviews at all Class I federal areas for each year modeled and for the entire multi-year modeling period.

***(ii)*** The Division will provide written notice to each source determined to be subject to BART.

***(e) BART Requirements.***

***(i) Submission of Best Available Retrofit Technology (BART) Permit Application.*** The owner or operator of each source subject to BART as determined under Section 9(d), shall submit a BART permit application to the Division. The permit application shall be submitted within 3 months of being notified by the Division that the source is subject to BART. Sources with a potential to emit less than 40 tons per year $SO_2$ or $NO_x$ or less than 15 tons per year $PM_{10}$ may exclude those de minimis level pollutants from the BART analysis. The BART permit application shall include:

(A) The name and address (physical location) of the existing stationary facility subject to BART.

(B) A brief description of the source and identification of any listed source categories in which it is included.

(C) Information on de minimis levels if pollutants are excluded from the analysis.

(D) An analysis of control options performed in accordance with 40 CFR part 51, Appendix Y, IV.

(E) A proposal and justification for BART emission limits and control technology that reflect the BART requirements established in 40 CFR part 51, Appendix Y.

(F) A description of the proposed emission control systems, including the estimated control efficiencies.

(G) A schedule to install and operate BART.

(H) Additional relevant information as the Administrator may request.

***(ii) Administrative Procedures for Review of a BART Permit Application.*** The administrative procedures for review shall follow the procedures specified in Chapter 6, Section 2(g) of these regulations.

***(iii) Proposed Permits.*** The Administrator shall prepare a proposed permit following the Division's review of the BART permit application. The

Administrator may approve, or amend the proposed emission limits, BART technology, and compliance schedule. Any proposed permit shall specify any notification, operation and maintenance, performance testing, monitoring, reporting and recordkeeping requirements determined by the Administrator to be reasonable and necessary.

***(iv) Opportunity for Public Comment.*** The opportunity for public comment shall follow the procedures specified in Chapter 6, Section 2(m) for permit review.

***(v) Modifications to BART Permits.*** Any source seeking to modify the BART determination for that facility must obtain the Administrator's approval.

***(vi) Operating Permit Requirements.*** BART requirements established pursuant to any BART permit issued under this section shall be included in a Chapter 6, Section 3 Operating Permit according to the procedures established in Chapter 6, Section 3.

***(vii) Fees.*** Persons applying for a permit under this section shall pay a fee to cover the Department's cost of reviewing and acting on permit applications in accordance with Chapter 6, Section 2(o).

***(viii) Installation of Best Available Retrofit Technology.*** The owner or operator of any source required to operate under a BART permit issued under Section 9(e)(iii), shall install and operate best available retrofit technology unless an alternative to the installation of BART as specified under Section 9(f) has been approved by the Division. Any control equipment required under a permit issued in this section shall be installed and operating as expeditiously as practicable but in no event later than five years after the United States Environmental Protection Agency's approval of Wyoming's State Implementation Plan revision for Regional Haze.

***(ix) Operation and Maintenance of Best Available Retrofit Technology.*** The owner or operator of a facility required to install best available retrofit technology under Section 9(e)(viii) shall establish procedures to ensure such equipment is properly operated and maintained.

***(f) BART Alternative.***

***(i)*** The Administrator may implement or require participation in an emissions trading program or other alternative measures developed in accordance with 40 CFR 51.308(e) rather than to require sources subject to BART to install, operate and maintain BART.

***(g) Monitoring, Recordkeeping and Reporting.*** The owner or operator of any existing stationary facility that is required to install best available retrofit technology or an approved BART alternative shall conduct monitoring, recordkeeping and reporting sufficient to show compliance or noncompliance on a continuous basis.

Docket No. UE-246
Exhibit PAC/1903
Witness: Cathy S. Woollums

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF THE STATE OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Surrebuttal Testimony of Cathy S. Woollums**

**Wyoming Department of Environmental Quality, Air Quality Division, Final BART Rules**

**September 2012**

# F O R W A R D

## AUTHORITY

In accordance with the provisions of Section 35-11-106 of the Wyoming Environmental Quality Act 1973, Standards and Regulations adopted by the Air Resources Council pursuant to Section 5, Wyoming Air Quality Act, Chapter 186, Session Laws of Wyoming 1967 were adopted as Standards and Regulations of the Department effective July 1, 1973.

Rules and Regulations adopted subsequent to July 1, 1973, are adopted under the authority of Sections 35-11-110, 112, 114, and 202 through 212 of the Wyoming Environmental Quality Act, 1993 and in accordance with the provisions of Sections l6-3-101 through 16-3-115 of the Wyoming Administrative Procedures Act.

## APPLICATION

The following table lists the effective dates for specific sections and subsections of **Chapter 6, Permitting Requirements**.

| Section | Effective Date |
|---|---|
| Section 1 - Introduction to permitting requirements | |
| New section | October 29, 1999 |
| Revised to describe all sections in chapter | September 7, 2010 |
| Language added to describe Section 5 now being covered under Chapter 5, Section 3 | March 28, 2012 |
| Section 2 - Permit requirements for construction, modification, and operation | |
| New section | May 29, 1974 |
| (d) Revised stack height limits | May 10, 1988 |
| (c) Added significance levels | February 13, 1989 |
| (c) Revisions | October 30, 1990 |
| (n) Revisions | October 30, 1990 |
| (a)(ii)-(iv) Revised | October 26, 1993 |
| (a)(v) Permit fees | October 26, 1993 |
| (c)(ii)(B) City of Sheridan | October 26, 1993 |
| (k)(vi) Revised | October 26, 1993 |
| (o) Entire subsection | October 26, 1993 |
| (a)(vi) Entire subsection | October 15, 1998 |
| (h) Added case-by-case | October 15, 1998 |
| Entire section restructured | October 29, 1999 |
| (c) Removed TSP 24-hr significance level | March 30, 2000 |
| Section 3 - Operating permits | |
| New section | October 26, 1993 |
| Revisions to address EPA comments | August 19, 1997 |
| Entire section restructured | October 29, 1999 |
| Revisions to incorporate CAM | December 8, 2000 |
| (b) Definitions - major source | February 7, 2003 |

(e) Permit review............................................................ February 7, 2003
(b) Added new definitions for "Alternative Operating
Scenario (AOS)" and "Approved Replicable
Methodology (ARM)" ............................................ March 28, 2012

Section 4 - <u>Prevention of significant deterioration</u>
New section........................................................................ January 25, 1979
Revisions ($PM_{10}$).......................................................... February 13, 1989
Revisions.......................................................................... October 30, 1990
Revisions ($PM_{10}$ Increments)........................................... February 13, 1995
Revisions (Electric utilities)............................................. February 13, 1995
Baseline area established ................................................ February 13, 1995
Entire section restructured ................................................ October 29, 1999
Revisions (NSR Reform) .................................................... October 6, 2006
Revisions ($PM_{2.5}$, "regulated NSR pollutant",
condensables)..................................................... September 7, 2010
$PM_{2.5}$ Increments................................................................ March 28, 2012

Section 5 - <u>Permit requirements for construction and modification of NESHAPs sources</u>
New section........................................................................ August 19, 1997
Entire section restructured ................................................ October 29, 1999
Removed applicability language; now covered under
Chapter 5, Section 3................................................ March 28, 2012

Section 6 - <u>Permit requirements for case-by-case maximum achievable technology (MACT) determination</u>
New section........................................................................ October 15, 1998
Entire section restructured ................................................ October 29, 1999
Cross references to Chapter 5 corrected .............................. March 28, 2012

Section 7 - <u>Clean air resource allocation</u>
New section........................................................................ April 17, 1986
Entire section restructured ................................................ October 29, 1999

Section 8 - [Reserved]

Section 9 - <u>Best available retrofit technology (BART)</u>
New section........................................................................ December 5, 2006

Section 10 - [Reserved]............................................................ September 7, 2010

Section 11 - [Reserved]............................................................ September 7, 2010

Section 12 - [Reserved]............................................................ September 7, 2010

Section 13 - <u>Nonattainment permit requirements</u>
New section (incorporates by reference
40 CFR 51.165)................................................. September 7, 2010

Section 14 - <u>Incorporation by reference</u> - Consolidation
New section (adoption by reference 7/1/2008)............... September 7, 2010
Revised (adoption by reference 7/1/2010)........................... March 28, 2012

reclamation obligations" under the regulations of the Land Quality Division of the Department.

(b) (i) In a case where an owner or operator permanently and purposefully ceases operation with no expressed intent to operate the facility in the future, the associated clean air resource allocation is not reserved to the owner or operator and immediately reverts to the state.

(ii) Prior to such revocation the Administrator shall provide notice to the affected owner or operator and if requested by such owner or operator will hold a public hearing pursuant to Chapter III of the Rules of Practice and Procedure of the Department.

(c) Start-up and operation of a facility after a period of non-use which lasts at least 5 years shall be considered to represent the operation of a new facility and shall be subject to the permit requirements of Chapter 6, Section 2. The provisions of Chapter 6, Section 4 may also be applicable.

(d) Brief periods of facility operation which are clearly designed to circumvent the intent of this section shall not be considered as operation under the provisions of subsections (a) and (b) above. For purposes of this section, operation must be for commercial purposes (which does not include temporary operation for period testing or maintenance of the facility in a standby status).

Section 8. **[Reserved.]**

Section 9. **Best available retrofit technology (BART).**

(a) Applicability. The provisions of this regulation apply to existing stationary facilities, as defined in Section 9(b) of this chapter.

(b) Definitions.

***"Adverse impact on visibility"*** means visibility impairment which interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of the Federal Class I area. This determination must be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency and time of visibility impairments, and how these factors correlate with 1) times of visitor use of the Federal Class I area, and 2) the frequency and timing of natural conditions that reduce visibility. This term does not include effects on integral vistas.

***"Applicable technology"*** means a commercially available control option that has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type or a technology that has been used on a pollutant-bearing gas stream that is the same or similar to the gas stream characteristics of the source.

***"Available technology"*** means that a technology is licensed and available through commercial sales.

***"Average cost effectiveness"*** means the total annualized costs of control divided by annual emissions reductions (the difference between baseline annual emissions and the estimate of emissions after controls). For the purposes of calculating average cost effectiveness, baseline annual emissions means a realistic depiction of anticipated annual emissions for the source. The source or the Division may use State or Federally enforceable permit limits or estimate the anticipated annual emissions based upon actual emissions from a representative baseline period.

***"BART alternative"*** means an alternative measure to the installation, operation, and maintenance of BART that will achieve greater reasonable progress toward national visibility goals than would have resulted from the installation, operation, and maintenance of BART at BART-eligible sources within industry source categories subject to BART requirements.

***"Best available retrofit technology (BART)"*** means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant that is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source or unit, the remaining useful life of the source or unit, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

***"Deciview"*** means a measurement of visibility impairment. A deciview is a haze index derived from calculated light extinction, such that uniform changes in haziness correspond to uniform incremental changes in perception across the entire range of conditions, from pristine to highly impaired. The deciview haze index is calculated based on the following equation (for the purposes of calculating deciview, the atmospheric light extinction coefficient must be calculated from aerosol measurements):

Deciview haze index = $10 \ln_e (b_{ext}/10 \text{ Mm}^{-1})$

Where $b_{ext}$ = the atmospheric light extinction coefficient, expressed in inverse megameters ($\text{Mm}^{-1}$).

***"Existing stationary facility"*** means any of the following stationary sources of air pollutants, including any reconstructed source, which was not in operation prior to August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit

250 tons per year or more of any visibility impairing air pollutant. In determining potential to emit, fugitive emissions, to the extent quantifiable, must be counted.

(i) Fossil fuel-fired steam electric plants of more than 250 million British thermal units (BTU) per hour heat input that generate electricity for sale.

(A) Boiler capacities shall be aggregated to determine the heat input of a plant.

(B) Includes plants that co-generate steam and electricity and combined cycle turbines.

(ii) Coal cleaning plants (thermal dryers).

(iii) Kraft pulp mills.

(iv) Portland cement plants.

(v) Primary zinc smelters.

(vi) Iron and steel mill plants.

(vii) Primary aluminum ore reduction plants.

(viii) Primary copper smelters.

(ix) Municipal incinerators capable of charging more than 250 tons of refuse per day.

(x) Hydrofluoric, sulfuric, and nitric acid plants.

(xi) Petroleum refineries.

(xii) Lime plants.

(xiii) Phosphate rock processing plants. Includes all types of phosphate rock processing facilities, including elemental phosphorous plants as well as fertilizer production plants.

(xiv) Coke oven batteries.

(xv) Sulfur recovery plants.

(xvi) Carbon black plants (furnace process).

(xvii) Primary lead smelters.

(xviii) Fuel conversion plants.

(xix) Sintering plants.

(xx) Secondary metal production facilities. Includes nonferrous metal facilities included within Standard Industrial Classification code 3341, and secondary ferrous metal facilities in the category "iron and steel mill plants".

(xxi) Chemical process plants. Includes those facilities within the 2-digit Standard Industrial Classification 28, including pharmaceutical manufacturing facilities.

(xxii) Fossil fuel boilers of more than 250 million BTUs per hour heat input.

(A) Individual boilers greater than 250 million BTU/hr, considering federally enforceable operational limits.

(B) Includes multi-fuel boilers that burn at least fifty percent fossil fuels.

(xxiii) Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels.

(A) 300,000 barrels refers to total facility-wide tank capacity for tanks put in place after August 7, 1962 and in existence on August 7, 1977.

(B) Includes gasoline and other petroleum-derived liquids.

(xxiv) Taconite ore processing facilities.

(xxv) Glass fiber processing plants.

(xxvi) Charcoal production facilities. Includes charcoal briquette manufacturing and activated carbon production.

***"Incremental cost effectiveness"*** means the comparison of the costs and emissions performance level of a control option to those of the next most stringent option, as shown in the following formula:

Incremental Cost Effectiveness (dollars per incremental ton removed) = [(Total annualized costs of control option) - (Total annualized costs of next control option)] ÷ [(Next control option annual emissions) - (Control option annual emissions)]

***"In existence"*** means that the owner or operator has obtained all necessary preconstruction approvals or permits required by Federal, State, or local air pollution emissions and air quality laws or regulations and either has 1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or 2) entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time.

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(ii) The Division will provide written notice to each source determined to be subject to BART.

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(i) Submission of Best Available Retrofit Technology (BART) Permit Application. The owner or operator of each source subject to BART as determined under Section 9(d), shall submit a BART permit application to the Division. The permit application shall be submitted according to a schedule determined by the Division. Sources with a potential to emit less than 40 tons per year $SO_2$ or $NO_x$ or less than 15 tons per year $PM_{10}$ may exclude those de minimis level pollutants from the BART analysis. The BART permit application shall include:

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(C) Information on de minimis levels if pollutants are excluded from the analysis.

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(E) A proposal and justification for BART emission limits and control technology that reflect the BART requirements established in 40 CFR part 51, Appendix Y.

(F) A description of the proposed emission control systems, including the estimated control efficiencies.

(G) A schedule to install and operate BART.

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(iv) Opportunity for Public Comment. The opportunity for public comment shall follow the procedures specified in Chapter 6, Section 2(m) for permit review.

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(i) The Administrator may implement or require participation in an emissions trading program or other alternative measures developed in accordance with 40 CFR 51.308(e) rather than to require sources subject to BART to install, operate and maintain BART.

(g) Monitoring, Recordkeeping and Reporting. The owner or operator of any existing stationary facility that is required to install best available retrofit technology or an approved BART alternative shall conduct monitoring, recordkeeping and reporting sufficient to show compliance or noncompliance on a continuous basis.

Section 10. **[Reserved.]**

Section 11. **[Reserved.]**

Section 12. **[Reserved.]**

Docket No. UE-246
Exhibit PAC/1904
Witness: Cathy S. Woollums

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF THE STATE OF OREGON**

**PACIFICORP**

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**Exhibit Accompanying Surrebuttal Testimony of Cathy S. Woollums**

**NAAQS Preliminary $SO_2$ Modeling Results**

**September 2012**

## Woollums, Cathy S

| | |
|---|---|
| **From:** | Lawson, Bill |
| **Sent:** | Tuesday, September 12, 2006 10:40 AM |
| **To:** | Steinbrenner, Peter; Skinner, Angeline |
| **Cc:** | Peterson, Sam; Mansfield, Mark; Woollums, Cathy S |
| **Subject:** | FW: Naughton SO2: plots for Iteration #1 |
| **Attachments:** | 3hr.doc; 24hr.doc; SO2_Naughton.xls |
| **Follow Up Flag:** | Follow up |
| **Flag Status:** | Flagged |

Pete/Angie:

We've run into a modeling snag we are trying to work through. When modeling SO2 emissions, we are showing impacts that exceed the national ambient air quality standards (NAAQS). These impacts are occurring west of the plant. The highest impacts appear to be on mine property, but there still appear to be exceedances occurring west of the mine. The attached word documents show the isopleths for the SO2 concentrations.

The excel spreadsheet shows the different scenarios I have asked the modelers to run. It appears that the two factors contributing to these exceedances are Unit 1 and Unit 2's SO2 concentrations and stack heights. I have only been able to eliminate the modeled NAAQS exceedances by scrubbing units 1 and 2 to 0.45 lb/mmBtu (I assume this would be an 80-85% scrub rate). I'm asking the modelers to run the model with taller stacks to see how that may affect the outcome, but I'm running out of options that we have available to us. If you have any thoughts on how we may address this SO2 issue I'd appreciate hearing from you. We need to figure out how we will address this issue before we can proceed with your permitting.

Thanks
Bill Lawson

---

**From:** Josh.Nall@ch2m.com [mailto:Josh.Nall@ch2m.com]
**Sent:** Thursday, September 07, 2006 2:46 PM
**To:** Lawson, Bill
**Cc:** Marshall, Gene; Randal.Cook@ch2m.com
**Subject:** RE: Naughton SO2: plots for Iteration #1

Bill, Randal has produced plots of the modeled SO2 impacts for iteration #1 (attached). Please let us know if you need more information. Thanks, Josh.

---

**From:** Lawson, Bill [mailto:Bill.Lawson@PacifiCorp.com]
**Sent:** Thursday, September 07, 2006 7:18 AM
**To:** Nall, Josh/DEN
**Subject:** RE: Naughton SO2: results for 5th iteration

Josh - In the past, I think I've seen modeling results represented on a map that showing concentrations in a format similar to the way topo lines represent elevation - Is this something you could provide for iteration 1?

Bill

**From:** Josh.Nall@ch2m.com [mailto:Josh.Nall@ch2m.com]
**Sent:** Wednesday, September 06, 2006 12:06 PM
**To:** Lawson, Bill; Marshall, Gene
**Cc:** wendy.longley-cook@ch2m.com; Clay.Hinkle@ch2m.com; Randal.Cook@ch2m.com
**Subject:** Naughton SO2: results for 5th iteration

Bill and Gene, Randal has run the 5th iteration for Naughton SO2 (U1/2 at 0.45 lb/MMbtu, U3 at 0.40), and we are below the WAAQS/NAAQS. I've attached the updated results spreadsheet. Please let me know if you have any questions.
Thanks, Josh.

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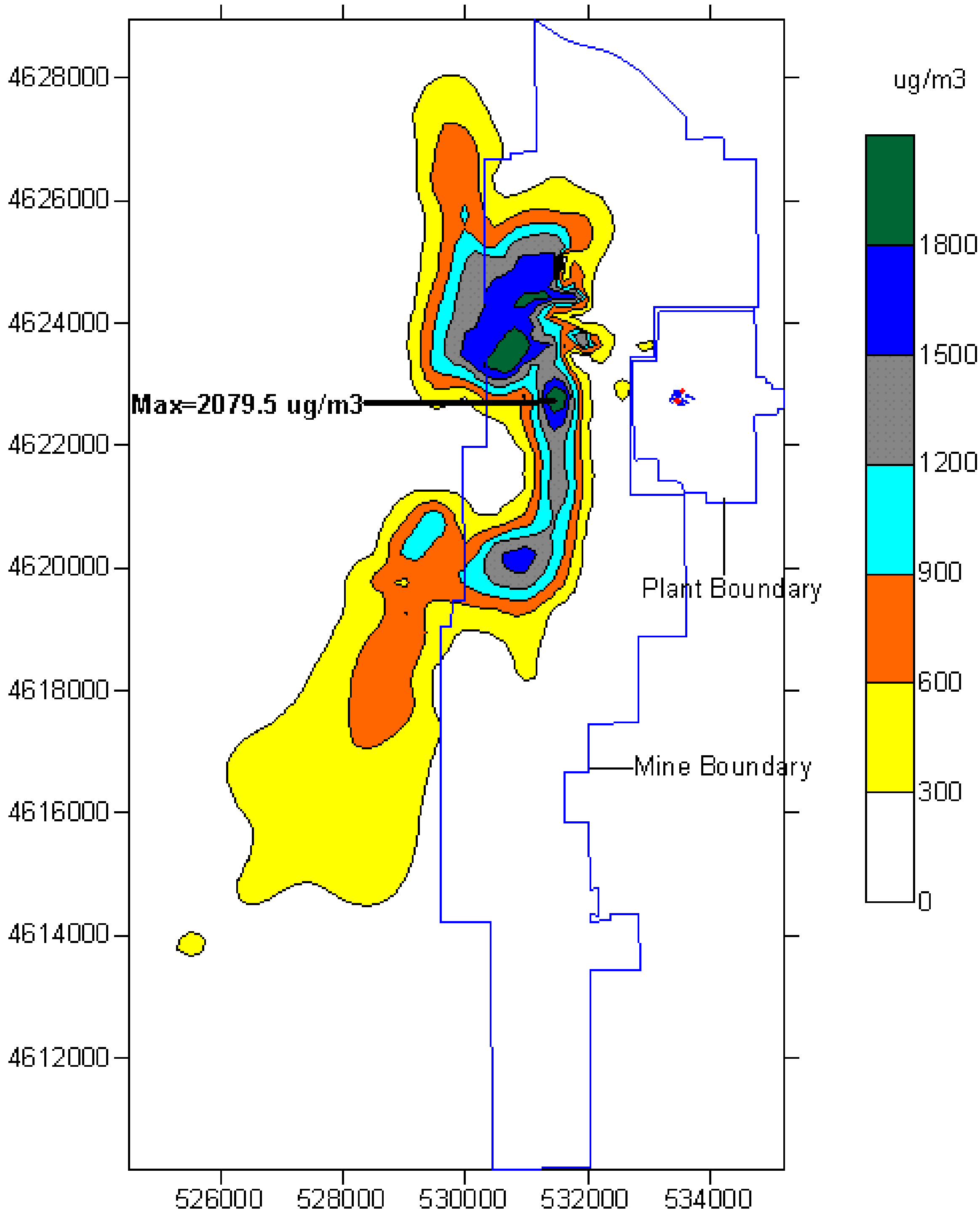
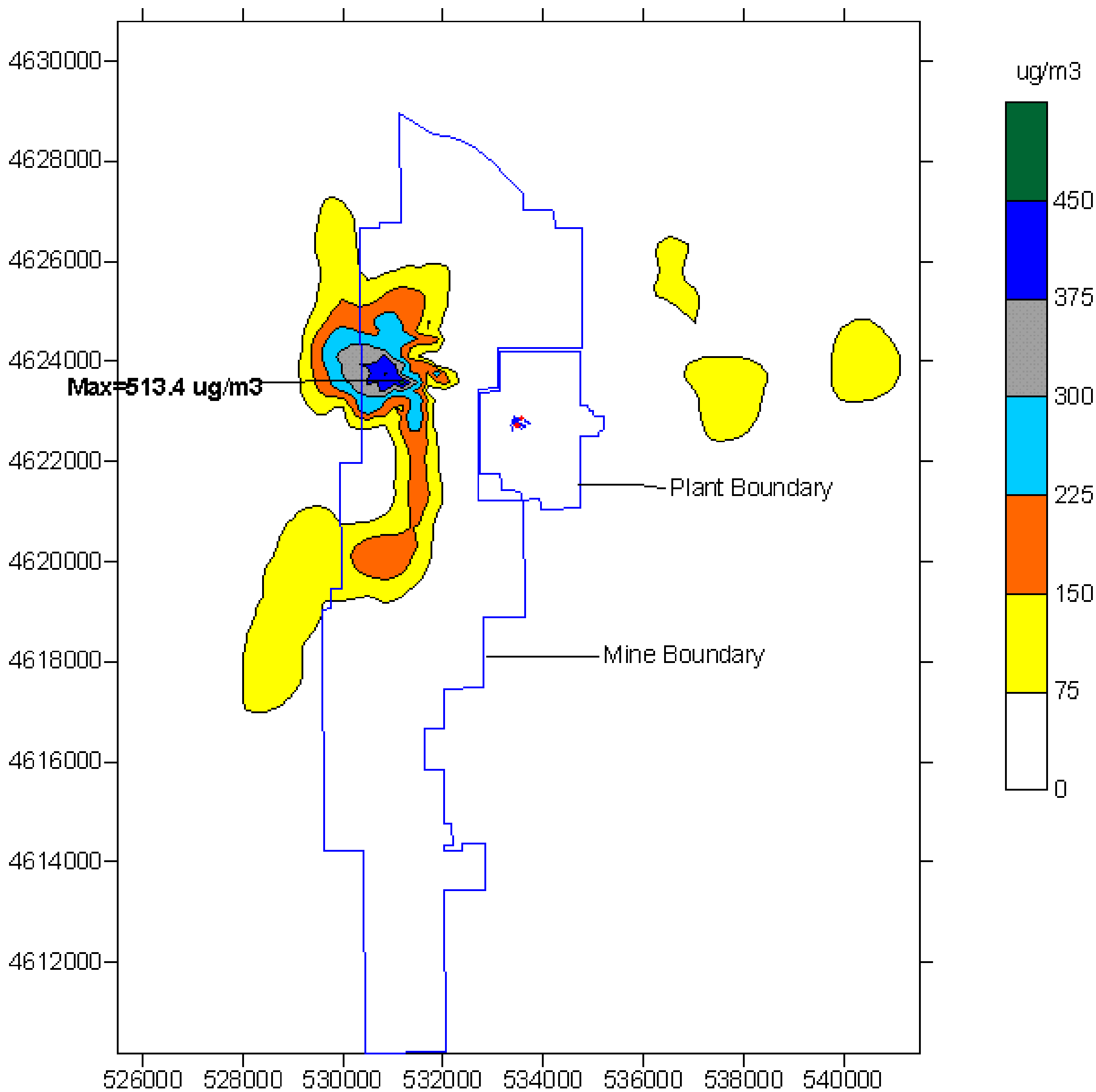
===

Naughton 3-Hour (High 2nd High) SO2 Preliminary Analysis - Iteration #1
U1=1.2 lb/mmbtu, U2=1.2 lb/mmbtu, U3=0.45lb/mmbtu



Naughton 24-Hour (High 2nd High) SO2 Preliminary Analysis - Iteration #1
U1=1.2 lb/mmbtu, U2=1.2 lb/mmbtu, U3=0.45lb/mmbtu



## PacifiCorp - Naughton Plant
## Preliminary $SO_2$ Modeling Results (various emission rates)

| | | | | |
|---|---|---|---|---|
| Original Iteration | **Base Receptor Grid (U1=1.2 lb/mmbtu, U2=1.2 lb/mmbtu, U3=0.5 lb/mmbtu)** | | | |
| | Averaging Period | Modeled Impact (µg/m$^3$) | National Ambient Air Quality Standard (µg/m$^3$) | Wyoming Ambient Air Quality Standard (µg/m$^3$) |
| | 3-Hour (High 2nd-High) | 1969.8 | 1300 | 1300 |
| | 24-Hour (High 2nd-High) | 418.1 | 365 | 260 |
| | Annual (High) | 24.7 | 80 | 60 |
| Original Iteration | **Fine Receptor Grid (U1=1.2 lb/mmbtu, U2=1.2 lb/mmbtu, U3=0.5 lb/mmbtu)** | | | |
| | Averaging Period | Modeled Impact (µg/m$^3$) | National Ambient Air Quality Standard (µg/m$^3$) | Wyoming Ambient Air Quality Standard (µg/m$^3$) |
| | 3-Hour (High 2nd-High) | 2079.5 | 1300 | 1300 |
| | 24-Hour (High 2nd-High) | 513.4 | 365 | 260 |
| | Annual (High) | 25.4 | 80 | 60 |
| Iteration 1 | **Fine Receptor Grid (U1=1.2 lb/mmbtu, U2=1.2 lb/mmbtu, U3=0.45 lb/mmbtu)** | | | |
| | Averaging Period | Modeled Impact (µg/m$^3$) | National Ambient Air Quality Standard (µg/m$^3$) | Wyoming Ambient Air Quality Standard (µg/m$^3$) |
| | 3-Hour (High 2nd-High) | 2073.1 | 1300 | 1300 |
| | 24-Hour (High 2nd-High) | 512.5 | 365 | 260 |
| | Annual (High) | 25.4 | 80 | 60 |
| Iteration 2 | **Fine Receptor Grid (U1=1.2 lb/mmbtu, U2=1.2 lb/mmbtu, U3=0.40 lb/mmbtu)** | | | |
| | Averaging Period | Modeled Impact (µg/m$^3$) | National Ambient Air Quality Standard (µg/m$^3$) | Wyoming Ambient Air Quality Standard (µg/m$^3$) |
| | 3-Hour (High 2nd-High) | 2067.3 | 1300 | 1300 |
| | 24-Hour (High 2nd-High) | 511.8 | 365 | 260 |
| | Annual (High) | 25.3 | 80 | 60 |
| Iteration 3 | **Fine Receptor Grid (U1=1.1 lb/mmbtu, U2=1.1 lb/mmbtu, U3=0.40 lb/mmbtu)** | | | |
| | Averaging Period | Modeled Impact (µg/m$^3$) | National Ambient Air Quality Standard (µg/m$^3$) | Wyoming Ambient Air Quality Standard (µg/m$^3$) |
| | 3-Hour (High 2nd-High) | 1899.8 | 1300 | 1300 |
| | 24-Hour (High 2nd-High) | 469.8 | 365 | 260 |
| | Annual (High) | 23.3 | 80 | 60 |
| Iteration 4 | **Fine Receptor Grid (U1=1.2 lb/mmbtu, U2=0.45 lb/mmbtu, U3=0.40 lb/mmbtu)** | | | |
| | Averaging Period | Modeled Impact (µg/m$^3$) | National Ambient Air Quality Standard (µg/m$^3$) | Wyoming Ambient Air Quality Standard (µg/m$^3$) |
| | 3-Hour (High 2nd-High) | 1474.3 | 1300 | 1300 |
| | 24-Hour (High 2nd-High) | 365.9 | 365 | 260 |
| | Annual (High) | 18.2 | 80 | 60 |
| Iteration 5 | **Fine Receptor Grid (U1=0.45 lb/mmbtu, U2=0.45 lb/mmbtu, U3=0.40 lb/mmbtu)** | | | |
| | Averaging Period | Modeled Impact (µg/m$^3$) | National Ambient Air Quality Standard (µg/m$^3$) | Wyoming Ambient Air Quality Standard (µg/m$^3$) |
| | 3-Hour (High 2nd-High) | 806.5 | 1300 | 1300 |
| | 24-Hour (High 2nd-High) | 196.1 | 365 | 260 |
| | Annual (High) | 9.8 | 80 | 60 |

Docket No. UE-246
Exhibit PAC/2000
Witness: Chad A. Teply

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF THE STATE OF OREGON**

**PACIFICORP**

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**REDACTED**
**Surrebuttal Testimony of Chad A. Teply**

**September 2012**

# CONFIDENTIAL SURREBUTTAL TESTIMONY OF CHAD A. TEPLY

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## ATTACHED EXHIBITS

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Exhibit PAC/2003 – BART Analyses and Applicable Permits for Hunter Units 1 and 2

Exhibit PAC/2004 – BART Analyses and Applicable Permits for Jim Bridger 3

Exhibit PAC/2005 – BART Analyses and Applicable Permits for Dave Johnston Unit 4

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Exhibit PAC/2007 – $NO_x$ Reduction Technologies Study

**Introduction and Purpose of Testimony**

**Q. Are you the same Chad A. Teply who previously submitted testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power ("the Company")?**

A. Yes.

**Q. What is the purpose of your surrebuttal testimony in this proceeding?**

A. My testimony responds to the rebuttal testimony of Messrs. Bob Jenks and Gordon Feighner on behalf of the Citizens' Utility Board of Oregon ("CUB") and Drs. Jeremy Fisher and William Steinhurst on behalf of the Sierra Club[1] regarding the prudence of the Company's investments in emissions control projects at some of the Company's coal-fueled generation plants.

As discussed at length in the Company's testimony and exhibits previously filed in this case, and contrary to the CUB's and Sierra Club's repeated contentions, the emissions control projects included in this case were: (1) appropriately developed, evaluated, and implemented as required to comply with existing regulations and using information available at the time that the decisions to make the investments were made; and (2) support the Company's ability to continue to cost effectively and reliably serve its customers.

**Q. Will another Company witness also respond to CUB's and Sierra Club's testimony and discuss the prudence of the Company's emissions control investments at issue in this docket?**

A. Yes. Ms. Cathy S. Woollums will also respond to arguments raised by CUB and Sierra Club in rebuttal testimony.

[1] Sierra Club mistakenly titled its testimony "surrebuttal." To avoid confusion, the Company refers to Sierra Club's testimony as rebuttal.

**The Company's Investments were Appropriately Developed, Evaluated, and Implemented**

**Q. Please summarize CUB's and Sierra Club's positions regarding the Company's analysis of its emissions control investments**.

A. CUB's primary contention in rebuttal is that the Company did not fully assess compliance alternatives or develop economic analyses that could be used to support the phase-out of coal plants as economic and in the best interests of customers. CUB further argues that the Company should have waited before making these investments.

Sierra Club contends in its rebuttal testimony that the Company's economic analyses supporting its emissions control investments at the Naughton plant were insufficient and erroneous. Sierra Club also contends that the investments were permitted and implemented prematurely, prior to a federally enforceable legal requirement, and were ultimately insufficient to mitigate pollution at Naughton.

**Q. Was the Company's financial evaluation of the emissions control investments in question appropriate?**

A. Yes. The Company's financial evaluation appropriately considered then-current information and applied reasonably foreseeable rulemaking outcomes and appropriate risk sensitivities (including $CO_2$ emissions cost assumptions and forward market price sensitivities) available at the time the economic analyses were completed.

Both CUB and Sierra Club continue to show a predisposition to phasing out coal-fueled resources in their critiques of the Company's economic analyses. CUB broadly applies the Boardman example as its minimum expectation to establish the prudence of a Company's assessment of environmental compliance alternatives. As the Company has discussed in its previously filed testimony, there is no "one-size-fits-all" approach to analyzing investment decisions at coal-fueled plants, and unique circumstances surrounded the Boardman negotiations and settlement reached by Oregon stakeholders. In addition, the negotiations and settlement of the Boardman plant occurred *after* the Company's investment decisions at issue in this case.

Both CUB and Sierra Club also continue to make selective adjustments to the Company's economic analyses, often based on hindsight and incorporating arguments about emerging environmental regulations and after-the-fact market trends to reach results that support their positions. But at the same time, Sierra Club and CUB completely discount the risk sensitivities that the Company embedded in its original analyses.

CUB's and Sierra Club's selective adjustments to the Company's economic analyses do not demonstrate that the Company was imprudent. The prudence standard judges a utility's decision based on the information available at the time the decision was made.

**Q. What role does the present value revenue requirement differential ("PVRR(d)") analysis play in the Company's decision-making process?**

A. The PVRR(d) analysis is one part of a complex decision-making process. The Company must consider a multitude of complex, and often inter-related and inter-dependent factors, to determine whether to move forward with a particular investment. PVRR(d) analyses are developed with assumptions intended to numerically reflect known and reasonably foreseeable changes to existing circumstances and contingencies, including changes to environmental regulations, the regulatory environment generally, market prices, and customer loads. However, the Company's decision-making process is also influenced by the realities and challenges of forecasting policy-making outcomes and litigation results that recognizably change the decision-making landscape over multi-year implementation timelines for major projects.

**Q. What effect do marginally positive or marginally negative PVRR(d) results have on the Company's decision-making?**

A. Contrary to the assertions of CUB and Sierra Club, marginally positive or marginally negative PVRR(d) results do not necessarily indicate that shutting down a particular unit is the best outcome for customers. To rely solely on PVRR(d) results to determine prudence is overly simplistic. These results are one element of the analysis, but the Company has shown that it is a far more complex decision-making process.

Under the market conditions and load forecasts at the time of the Company's analyses, a favorable PVRR(d) for emissions control retrofits, as compared to market purchases, provides a reasonable indicator of the viability of retirement and replacement options as well. The Company's PVRR(d) analyses at the time would also have typically shown that a new replacement generation resource's all-in costs were significantly unfavorable when compared to forward market price curves. Thus, the Company's PVRR(d) analyses use the conservative assumption that the resource would be shut down and its output replaced with market purchases.

**Q. Sierra Club asserts that the Company conceded in reply testimony that there were errors in its original economic analyses. How do you respond?**

A. The Company did not concede that there were errors in its original analyses. To the contrary, the Company merely responded to the parties' retirement date critiques to demonstrate that, even under the parties' preferred assumption scenarios, the economic analyses continued to support the Company's decisions to invest in the emissions control equipment at issue in this case. In rebuttal, both CUB and Sierra Club recognize these alternate assessments, but take issue with also updating the corresponding forward price curves. But updating the forward price curves would be an expected and logical adjustment under the parties' proposals requiring reconsideration immediately prior to contract release and continual reassessment thereafter.

To be clear, the Company has consistently stated, and still believes, that after-the-fact adjustments to its economic analyses are inappropriate in this prudence review. The question is whether the Company's decision was objectively reasonable based on the information it knew or reasonably could have known at the time of the decision.

**Q. Does the Company assume "that there is one objective right answer that can be determined in this proceeding" as CUB alleges?**

A. No. To the contrary, it is CUB and Sierra Club who appear to believe that there is one objective "right" answer—discontinuing coal-fueled generation. But the issue here is not whether the Company's decision was "right"; the question is whether it was prudent. And the prudence standard recognizes that it is unreasonable to examine a utility's decision using information that was not available at the time of the decision, and instead appropriately bases the determination on the objective reasonableness of the decision, not on a subjective opinion of the decision.

**Q. Were the Company's emissions control projects at issue in this case installed within the appropriate timelines given the Company's compliance obligations?**

A. Yes. As also discussed in Ms. Woollums' surrebuttal testimony, the emissions control projects were installed in accordance with compliance obligations set forth in the permits and implementation plans of the respective states responsible for administering environmental compliance of the individual units. The Regional Haze planning period that applies to the Company's compliance obligations under review in this case was 2008 through 2013. The requirement to install controls as expeditiously as possible has been discussed at length in the Company's previous testimony in this docket.

Sierra Club in particular remains incorrect in its assessment of the Company's compliance obligations and in its attempts to distinguish federal enforceability from state mandated requirements. The Company did not "make a series of ill-timed and unsupported investments that are ultimately insufficient," as alleged by the Sierra Club (Sierra Club 300, Fisher/2). Nor did "the Company work to preempt proper regulatory authority," as further charged by the Sierra Club (Sierra Club 300, Fisher/3). Such statements demonstrate that Sierra Club lacks a thorough understanding of the actual process and interactions required to manage the multiple parallel path activities and overlapping timelines to effectuate successful and timely evaluation, development, permitting, and completion of major retrofit projects. Environmental compliance permitting and implementation plans, although ratified via the formal issuance of permits and plans, are developed over years of coordination between responsible companies and the agencies that regulate their operations. The Company's projects under review in this case are no exception.

**Q. CUB states that the Company "still refuses to consider any options that include a phase-out of the plant." Is this an accurate assessment of the Company's planning processes?**

A. No. This statement is inaccurate. In fact, the Company currently anticipates retiring two coal-fueled generation units (Carbon Units 1 and 2) before the expiration of the current depreciation life used for ratemaking, after analysis demonstrated that accelerated closure appears to be the least cost compliance option for the units.

The Company is also pursuing natural gas conversion of one of its coal-fueled facilities (Naughton Unit 3) after analysis demonstrated that solution to be the least cost compliance approach for the facility.

Accelerated retirement and replacement of the Company's coal-fueled generation units are considerations in the Company's planning processes, including its ongoing integrated resource planning ("IRP") process; however, that scenario may not be the risk-adjusted, least-cost option for a specific unit.

**Q. Is the Company's IRP process intended to provide project-specific economic analysis and investment authorization as CUB asserts?**

A. No. The Company's IRP process provides a stakeholder-involved planning environment to analyze and address ongoing investment in the Company's coal units versus alternatives including retirement, replacement, and repowering. However, the IRP process is not intended to provide project-specific economic analysis and investment authorization (whether that investment is a new turbine or an environmental control on a coal-fueled facility).

**Q. Is the Company's IRP being managed in accordance with IRP Guideline 8, adopted on June 30, 2008?**

A. Yes.

**Q. Does IRP Guideline 8 require individual unit-specific environmental investments to be analyzed, reviewed, and authorized in the IRP setting?**

A. No, in fact none of the regulatory commissions that review the IRP, including this Commission, approve or authorize anything as an outcome of the IRP review.

<u>Naughton Units 1 and 2</u>

**Q. Sierra Club lists a series of proposed adjustments that you did not directly contest in your reply testimony in this docket. By not contesting specific arguments and modifications proposed by Sierra Club (or CUB), is the Company indicating acceptance of the parties' arguments?**

A. No. As repeatedly stated in the Company's testimony, the Company's financial analyses completed in support of the emissions control projects under review in this case were properly executed and produced meaningful results. While Sierra Club and CUB have proposed a myriad of evolving analytical adjustments, modifications, and preferences to cast doubt on the Company's assessment, the Company has focused its testimony on non-hypothetical scenarios and key assumptions underlying the Company's analyses.

For example, Sierra Club's proposed additional modifications to the Company's projected capacity factors, "parasitic load" changes, and degradation of unit capacity either do not align with the Company's planning assumptions for those parameters at the time of decision-making, do not impact the results of the financial analyses as dramatically as Sierra Club alleges, or are simply inaccurate. Engaging in rebuttal of these numerous hypothetical scenarios on an item-by-item basis would likely have the undesirable result of further confusing the key issues for the Commission to consider in the case. Notwithstanding that concern, the Company does address the following specific critiques.

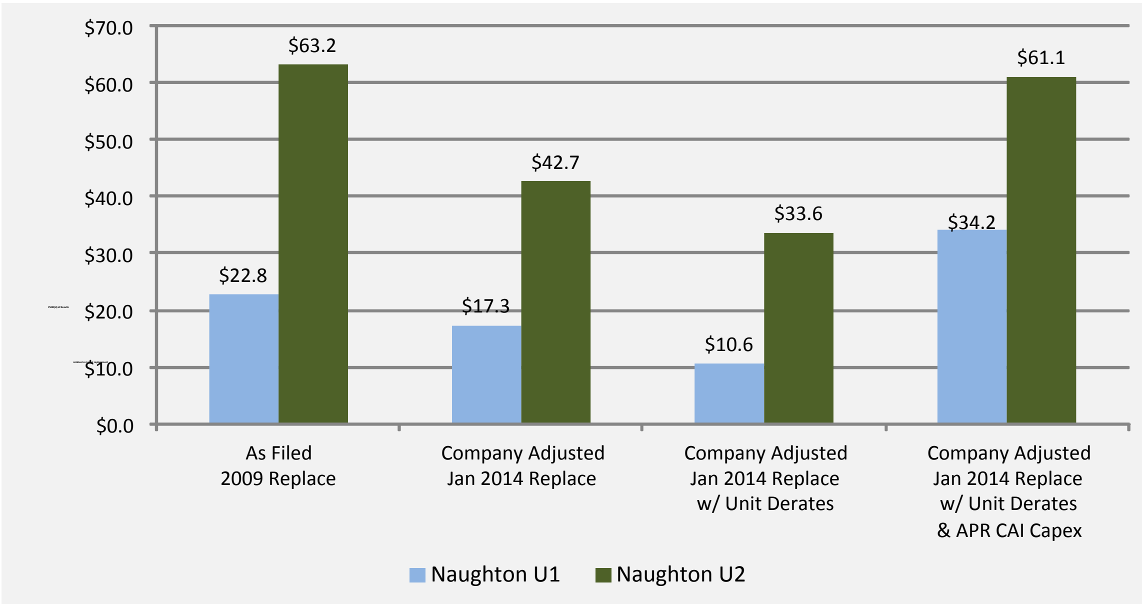
**Q. Did the Company act prudently by relying upon its February 2009 analysis supporting the Naughton environmental retrofits?**

A. Yes. As stated in the Company's reply testimony, the financial analysis for Naughton Units 1 and 2 was completed appropriately within the project implementation timeline.

**Q. Do the PVRR(d) results shown in Figures 1 and 2 of Sierra Club/300 appropriately represent the evaluated economics of the Naughton Units 1 and 2 emissions control projects?**

A. No. Sierra Club used assumptions inconsistent with information known to the Company at the time of decision making and applied biased adjustments to the original analysis. Figure 1 below represents a more appropriate picture of the results of the hypothetical modeling scenario Sierra Club has argued for, including an adjustment for "parasitic load" as discussed in Sierra Club's rebuttal testimony, building upon the Company's adjusted January 2014 replacement analysis included in the Company's reply testimony. As shown (see "Company Adjusted Jan 2014 Replace w/ Unit Derates" columns), the results of Sierra Club's requested adjustments remain positive and continue to support the emissions control investment.

**Figure 1**




**Q. If, as Sierra Club and CUB argue, the Company had updated its models just before signing the contracts in May 2009, would the Company's PVRR(d) results have been affected?**

A. Yes. The Company's PVRR(d) results would have even more strongly supported installation of the emissions control equipment on the two Naughton units. The capital expenditures for the Naughton Units 1 and 2 emissions controls projects as authorized in the Company's appropriations request ("APR") documents were reduced significantly from the amounts used in the economic analyses. Naughton Unit 1 was reduced by [redacted], and Naughton Unit 2 was reduced by [redacted], an approximate 15 percent cost reduction for each project.

**Q. Would such a PVRR(d) adjustment have further supported the Company's investment decision?**

A. Yes. As shown in Figure 1 (see "Company Adjusted Jan 2014 Replace w/ Unit Derates & APR CAI Capex" columns), even when including adjustments to respond to parties' requested analysis modifications (for example, a hypothetical 2014 replacement date, March 2009 market prices, and unit de-rates) the adjustment associated with authorized APR project costs increase the positive PVRR(d) results for the Naughton Units 1 and 2 emissions control investments, further supporting the Company's investment decision.

**Q. Would it be reasonable for the Company to continually update the financial analyses relied upon for project implementation any time forward looking market conditions change?**

A. No. Considering the dynamics of a major generation system and major project implementation timelines, movements in individual analysis sensitivities are common. Typically, re-evaluation of economic analysis sensitivities such as $CO_2$ cost loadings, market projections, and actual project costs would not occur unless a given project were affected by significant project or market events.

In the case of the Naughton Units 1 and 2 projects for example, while market projections declined over the course of the project implementation timeline, changes realized in other analysis considerations such as actual project costs and $CO_2$ cost projection planning assumptions would have resulted in positive movements in project economic assessments. Most notably, the overall project capital costs associated with the Naughton Unit 1 emissions control projects placed in service in June 2012 have decreased in aggregate by approximately [redacted] since the time of the Company's financial analysis. The overall project costs associated with the Naughton Unit 2 emissions control projects placed in service in November 2011 have decreased in aggregate by approximately [redacted] since the time of the Company's financial analysis. These significant movements alone counter the proposed continual reassessment and other PVRR(d) adjustment concepts being proposed by CUB and Sierra Club.

**Q. Does the Company negotiate cancellation provisions into its major procurement contracts to support continual financial reassessment of market trends and project assumption sensitivities?**

A. No. Similar to the concept discussed above, cancellation without cause provisions are included in major procurement contracts to protect the Company and its customers from significant changes in circumstances affecting the project or unforeseeable market events likely to cause unrecoverable hardship to the project or purchase. When invoked, these provisions can result in significant costs, impacts, and lost opportunities that are difficult for the contractor to mitigate. The successful negotiation of these clauses is dependent on a market expectation that these clauses will be used to address the above-described Company risks. Over-using such clauses will impact the Company's ability to negotiate these clauses, impact the proposal pricing for major procurement contracts, and potentially expose the Company to litigation.

**Q. Did the trends in forward market price curve information discussed by CUB in rebuttal testimony prompt the Company to enact the contract cancellation provisions it had prudently negotiated into its contracts?**

A. No. The trends in forward market price curve information discussed by CUB in rebuttal testimony did not provide a high level of certainty that the Naughton Units 1 and 2 emissions reduction projects were facing unrecoverable hardship.

As discussed above, while market projections were declining, other analysis considerations such as actual project costs and $CO_2$ cost projection planning assumptions were trending favorably in support of continued investment. The Company's analyses of its emissions control investments under review in this case continue to support those investments.

**Q. Is 2013 a reasonable Best Available Retrofit Technology ("BART") compliance timeframe for assessment and implementation of the Company's emissions control projects under review in this case?**

A. Yes. Contrary to Sierra Club's assertion, 2013 (not 2015) is an appropriate BART compliance timeframe. Sierra Club applies a hindsight adjustment based on the U.S. Environmental Protection Agency's ("EPA") lack of action on individual state Regional Haze program filings to change the planning parameters that should reasonably have been known at the time of decision-making for the projects under review in this docket. Sierra Club's proposed adjustment is simply inaccurate.

**Q. Did the Company evaluate high and low market electricity costs in the Naughton PVRR(d) analyses?**

A. Yes. The results for the high and low market electricity costs, in which the forward market prices were increased by 20 percent and decreased by 20 percent, were clearly noted on the PVRR(d) analysis results. The Company evaluated the results of these sensitivities and determined that the results should not preclude proceeding with the projects. Sierra Club's assertion that the Company included the toggle to evaluate these costs, but did not actually use it, is nothing more than inaccurate speculation.

**Q. Sierra Club criticizes the Company for changing Naughton emissions control project costs to 2014 in the Company's revised Naughton analysis, rather than maintaining the original treatment and reflecting the costs in the analysis as incurred in 2009 through 2012. Please respond.**

A. The Company's original economic analysis as referenced in direct testimony placed capital in rate base as spent, rather than at the completion of construction when the emissions control projects would actually be placed in service. Because these capital costs also included projected Allowance for Funds Used During Construction ("AFUDC") accumulated as though the Naughton projects costs were placed in service as scheduled in 201 and 2012, respectively, the resulting PVRR was higher for the retrofit projects than it would have been if the total costs of the projects had been analyzed as being added to rate base when the projects were scheduled to be placed in service. Therefore, the projected financial benefits derived from these projects were actually understated in the Company's original economic assessment.

In preparing the revised analysis included in PAC/1500, the Company was simply responding to the comments of CUB and Sierra Club. In opening testimony, Sierra Club argued that the Company should have waited until the last possible moment to install the environmental retrofit projects. Although the Company does not agree with Sierra Club's argument, the Company reflected that argument in the revised analysis by changing the in-service date to January 2014 to be responsive to parties' concerns. Accordingly, the project capital costs were shifted and escalated to reflect that later in-service date.

**Q. In other words, Sierra Club wants the PVRR(d) analysis to reflect a later in-service date, but wants to maintain the assumption that the capital for the Naughton environmental retrofit projects would be placed in rate base as the expenses were incurred from 2009 through 2012. Is that a reasonable approach?**

A. No. While the Company did understate the projected financial benefits of the Naughton projects in its original economic analysis by placing the environmental retrofit project dollars in rate base as they were incurred from 2009 through 2012, rather than when they were projected to be placed in-service (June 2012 for Naughton Unit 1; November 2011 for Naughton Unit 2), the Company's revised Naughton analysis places the capital cost in rate base when placed in service and is a more accurate projection of the benefits the retrofit projects actually provide. Arbitrarily extending the in-service date by a number of years without extending the date those capital costs would be included in rate base is an unreasonable assumption.

**Q. Sierra Club argues that the financial analysis should reflect the costs of the environmental control investments in the years 2009 through 2012, while simultaneously arguing that these investments are not needed until January 2016. Do you agree with this approach?**

A. No. The Company's revised Naughton analysis was provided to show that, even if the environmental control investments were not required to be placed in service until 2014, making the investment and continuing to operate the units would provide customer benefits. If the investments are not placed in service until 2016, the evaluation should reflect the matching of the construction spending necessary for that completion date. Sierra Club argues that a project with a 2016 in-service date should be placed in rate base during 2009 through 2012, which is inconsistent with fundamental ratemaking principles and disregards prudent construction scheduling. As Sierra Club has demonstrated, making these assumptions would certainly increase the costs to customers, but the assumptions are not reasonable. The Company adamantly opposes Mr. Fisher's modeling efforts as flawed and not representative of a reasonable outcome.

**Q. The Company's 2009 Strategic Asset Plan contained hypothetical dollars for selective catalytic reduction ("SCR") installation at Naughton Units 1 and 2. Is it appropriate to conclude from this plan that the Company was categorically anticipating SCRs being installed at those units?**

A. No. Sierra Club uses the 2009 Strategic Asset Plan to argue that potential future SCR installations on Naughton Units 1 and 2 must be considered as part of the PVRR(d) analysis. But this is not a reasonable conclusion. As explained in my reply testimony (beginning at PAC/1500, Teply/14, line 18), the Company does not anticipate installing SCRs on Naughton Units 1 or 2 in the future.

It is helpful to understand the context for the 2009 Strategic Asset Plan. The plan discusses a 30-year life projection approach without consideration of individual unit depreciable life planning periods. The plan sets forth a technically feasible investment profile, which is not adjusted to reflect established depreciable life planning periods for individual units. The SCR investment that Sierra Club interprets as a requirement for analysis of Naughton Unit 1 is discussed in the plan as a 2027 investment, two years before the currently established depreciable life of the unit. The SCR investment for Naughton Unit 2 is discussed in the plan as a 2025 investment, four years before the currently established depreciable life of the unit. Neither investment, while technically feasible, would be pursued under those circumstances. The Company's analysis, as completed in February 2009 and submitted with my direct testimony, was correct in not including costs associated with future SCR installations for those units.

**Q. CUB argues that the Company could simply phase out the Naughton plant by 2020 and thus avoid the emissions control investments under review in this case, resulting in positive PVRR(d)s for Naughton Unit 1 and Unit 2 of $75.6 million and $96.7 million, respectively. Do you agree?**

A. No. The basic premise of CUB's argument—that a prudent utility would plan for non-compliance with applicable regulations and deadlines—is not supportable. CUB argues that a prudent utility would run multiple models, assuming variable closure dates and no or reduced environmental controls, regardless of existing compliance obligations or deadlines. CUB then assumes that the Company could successfully negotiate these alternative compliance scenarios and compliance deadlines with state and federal regulators. However, it is highly unusual to be able to negotiate non-compliance with established regulations, particularly in states like Utah and Wyoming, where coal-fueled generation is an important part of the regional economy. A prudent utility plans for compliance, not non-compliance.

Secondly, the Company cannot plan to phase out generation without also planning for replacement generation. CUB's analysis results of $75.6 million and $96.7 million do not take into consideration the costs of replacement generation resources and arbitrarily suggest that the Company could operate out-of-compliance with a minimal investment of approximately $10 million for alternative compliance.

<u>Jim Bridger Unit 3</u>

**Q. Please summarize CUB's reply arguments regarding Jim Bridger Unit 3.**

A. CUB believes that the Company acted imprudently by evaluating the compliance alternative to its investment in Jim Bridger Unit 3 as an immediate shutdown of the unit versus a later shutdown date reflecting a later compliance deadline, and by not updating its study before commencing construction of the scrubber upgrade. CUB also believes that the Company was imprudent in not analyzing and considering whether a change to the expected life of the plant would produce an outcome with lower costs.

**Q. Would CUB's proposed adjustments materially change the Company's financial evaluation of the Jim Bridger Unit 3 investment?**

A. No. CUB appears to be basing its objection to the Company's Jim Bridger Unit 3 investment on the presumption that, if the Company had included the approximately $17 million in scrubber upgrade total project costs that were placed in service in June 2011 as avoidable costs in its recent assessment of future Jim

Bridger Unit 3 SCR project costs, the Company would now be choosing accelerated retirement of the unit. CUB's assumptions are simply wrong. The costs associated with the Jim Bridger Unit 3 investment, if they were to be considered avoidable costs associated with a hypothetical yet-to-be-completed project, do not materially change the financial assessment results as CUB purports.

**Q. Did the Company's updated economic assessment of the future installation of Jim Bridger Unit 3 and 4 SCRs support the conclusion that the continued operation of these units is in the best interests of customers?**

A. Yes. The Company's updated economic assessment of the future installation of Jim Bridger Units 3 and 4 SCRs, which are not part of this case, continues to support investment in those projects. The Company submitted an application in the state of Wyoming for a Certificate of Public Convenience and Necessity for those projects on August 7, 2012, and submitted an application for voluntary procurement pre-approval in the state of Utah on August 24, 2012.

**Q. Are the results of the updated analysis for Jim Bridger Units 3 and 4 consistent with the results of the analysis at issue in this case?**

A. Yes. The Company's analysis of Jim Bridger Unit 3 emissions control investments at issue in this case, which relied on reasonably available information at the time of decision-making, supported investment and continued environmentally compliant operation of this coal-fueled unit through its remaining useful life.

**Q. Did the Company's 2008 financial analysis of the Jim Bridger Unit 3 emissions reduction projects incorporate the costs of potential future SCR installations on that unit?**

A. Yes. The Company's financial analyses completed in December 2008 included costs for a potential future SCR installation on Jim Bridger Unit 3.

**Q. CUB argues that the Company could simply phase out the Jim Bridger Unit 3 by 2020, 2022, or 2025 and thus avoid the emissions control investments under review in this case, resulting in a positive PVRR(d) of $411.7 million, $680 million, or $767 million, respectively. Do you agree?**

A. No. The fundamental flaws with this argument are discussed above. The Company cannot plan to operate out-of-compliance, cannot assume successful repeated attempts to negotiate alternative compliance scenarios and compliance deadlines with state and federal regulators, and cannot phase out its generation resources without also planning for replacement generation. CUB's analysis does not take into consideration the replacement costs of phasing out the generating resource, and CUB arbitrarily suggests that the Company could operate out-of-compliance with no investment in alternative compliance.

<u>Other Plants</u>

**Q. CUB continues to argue for a 25 percent disallowance of the capital costs for all of the Company's emissions control investments in this case. Did CUB provide any evidence to support this proposal in rebuttal testimony?**

A. No. CUB continues to assert that a 25 percent disallowance of all of the Company's emissions control projects at issue in this case is appropriate, but in rebuttal testimony does not even discuss the emissions control projects at Dave Johnston Unit 4 (placed in service in April 2012), Hunter Unit 1 (placed in service in June 2012), Hunter Unit 2 (placed in service in May 2011), and Wyodak (placed in service in April 2011).

**Q. Has the Company provided workpapers and exhibits supporting the prudence of the Company's emissions control investments?**

A. Yes. In addition to the Company's previously filed testimony and exhibits, the Company has also submitted workpapers in support of all of the emissions controls at issue in this case. The relevant portions of these workpapers were referenced in my opening testimony and are attached to this testimony as:

1) Confidential Exhibit PAC/2001 – Busbar cost workpapers for Dave Johnston Unit 4, Naughton Units 1 and 2, Hunter Units 1 and 2, Jim Bridger Unit 3, and Wyodak.
2) Exhibit PAC/2002 – BART analyses applicable permits for Naughton Units 1 and 2.
3) Exhibit PAC/2003 – Technology screening studies and applicable permits for Hunter Units 1 and 2.
4) Exhibit PAC/2004 – BART analyses and applicable permits for Jim Bridger Unit 3.
5) Exhibit PAC/2005 – BART analyses and applicable permits for Dave Johnston Unit 4.
6) Exhibit PAC/2006 – BART analyses and applicable permits for Wyodak.
7) Exhibit PAC/2007 – $NO_x$ Reduction Technologies Study.

In addition, the Company's PVRR(d) analyses were included as exhibits CUB/107 (Jim Bridger Unit 3), CUB/109 (Naughton Units 1 and 2), CUB/112 (Dave Johnston Unit 4), CUB/113 (Hunter Units 1 and 2), and CUB/114 (Wyodak).

**Conclusion**

**Q. Please summarize your testimony.**

A. My testimony indicates that:

- The Company's emissions control projects included in this case and their timing appropriately balance compliance with environmental regulations with costs and customer benefits.
- These projects and the rules requiring them are highly complex. As I have indicated, the Company's considerations when making emissions control investments must include evaluation of state and federal environmental regulatory requirements, compliance deadlines, review of emerging environmental regulations and rulemaking, and analyses of alternate compliance options. Considerations must also include ongoing compliance with existing operating requirements, fuel supply flexibility, equipment end of life considerations, and operational efficiencies.
- Maintaining the ability to operate the Company's coal-fueled units by retrofitting them with the emissions controls presented in this case represents the least-cost option for customers.

**Q. Does this conclude your surrebuttal testimony?**

A. Yes.

Docket No. UE-246
Exhibit PAC/2100
Witness: R. Bryce Dalley

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF THE STATE OF OREGON**

**PACIFICORP**

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**Surrebuttal Testimony of R. Bryce Dalley**

**September 2012**

**Q. Are you the same R. Bryce Dalley who previously submitted testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power ("the Company")?**

A. Yes.

**Purpose and Overview of Surrebuttal Testimony**

**Q. What is the purpose of your surrebuttal testimony in this case?**

A. My surrebuttal testimony responds to the rebuttal testimony of Messrs. Bob Jenks and Gordon Feighner on behalf of the Citizens' Utility Board of Oregon ("CUB") and Mr. Michael C. Deen on behalf of the Industrial Customers of Northwest Utilities ("ICNU") related to the Company's request to recover its investment in the Mona-to-Oquirrh transmission line ("Mona-to-Oquirrh Project") through a separate tariff rider once the project becomes used and useful to Oregon customers. My surrebuttal testimony is limited to new arguments raised in the parties' rebuttal testimony. To the extent the parties repeat arguments raised in their opening testimony, please see my reply testimony for the Company's response (PAC/1600).

**Response to CUB**

**Q. Please summarize CUB's position regarding the Company's proposal for recovery of the Mona-to-Oquirrh Project.**

A. CUB argues that the line will not be in service until May 2013, and will therefore not be used and useful to customers when rates go into effect on January 1, 2013.[1] CUB further concurs with Staff and ICNU that "the project should not be included in rates before it comes online and is used and useful." CUB

[1] CUB/200, Jenks-Feighner/45.

recommends that the Company seek to include the project "in rates on or after the project is complete."[2]

**Q. Is the Company's proposal consistent with CUB's recommendations?**

A. Yes. The Company is proposing to delay the inclusion of the costs of the Mona-to-Oquirrh Project in rates until the project goes into service and is used and useful for Oregon customers. Although CUB is correct that the project will not be in service when the rates approved in this general rate case go into effect on January 1, 2013, this point is irrelevant because the Company is not proposing to include the Mona-to-Oquirrh project in those rates. The Company's proposal is to add the project to rates when the project goes into service. Thus, the Company's proposal is consistent with CUB's recommendation to seek to include the project "in rates on or after the project is complete."

**Response to ICNU**

**Q. Please summarize ICNU's rebuttal position regarding the Company's proposal for recovery of the Mona-to-Oquirrh Project.**

A. In its rebuttal testimony, ICNU argues that the Company has presented no justification for its proposal to "allow extraordinary early recovery of its costs."[3] ICNU states that it is Commission practice to include only those investments that are completed before the test period to be included in rates.[4] ICNU argues that the Company "had the discretion and ability to file a rate case later for a test year that would have included the project."[5] Finally, ICNU argues that the Company's

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[2] *Id.*
[3] ICNU/111, Deen/2.
[4] *Id.*
[5] *Id.* at 3.

proposal is one-sided, allowing the Company to recover "earlier than it would otherwise"[6] and to the "detriment of consumers."[7]

**Q. Is ICNU correct that the Company "had the discretion and ability to file a rate case later"?**

A. No. Under the guidelines governing the Transition Adjustment Mechanism ("TAM") adopted in Order No. 09-274, the Company must make its general rate case filing "no later than March 1 to allow for a January 1 rate effective date."[8] Thus, unless the Commission waives the guidelines, the Company could not file a general rate case later than March 1, 2012.

**Q. Do the TAM guidelines impede the Company's ability to match the time an investment begins providing service to customers with the time that the costs associated with the investment are reflected in rates?**

A. Yes. This case is the perfect example. Given the constraints of the TAM guidelines, the Company could not avoid providing service from the investment in the Mona-to-Oquirrh Project without compensation by simply filing its general rate case later, with a test period that began after the project was in service. The Company's next opportunity to file for the inclusion of the Mona-to-Oquirrh Project in rates would be March 1, 2013, with rates effective in January 2014. By the time recovery in rates would begin, the project would have already in service for at least six months.

[6] *Id.*
[7] *Id.* at 4.
[8] Order No. 09-274, Appendix A at 13 (June 16, 2009).

**Q. Does the Company's proposal appropriately match the benefits and costs of the Mona-to-Oquirrh Project?**

A. Yes. Contrary to ICNU's arguments, the Company's proposal is not detrimental to customers. The Company's customers will begin receiving the benefits of the Mona-to-Oquirrh Project, which are discussed in detail in the opening testimony of Company witness Mr. Darrell T. Gerrard,[9] when the project goes into service in May 2013. Under the Company's proposal, recovery of the Mona-to-Oquirrh begins when the project is placed into service, which appropriately matches the costs borne by with the benefits received by customers.

**Recommendation**

**Q. What is your recommendation to the Commission?**

A. The Company recommends that the Commission approve the Company's proposal to recover its investment in the Mona-to-Oquirrh Project because it will be used and useful at the time the proposed tariff rider goes into effect. The Company's proposal appropriately matches the benefits and costs of the project for customers, while allowing the Company to timely recover an investment in a transmission line that is necessary to continue to provide safe, reliable, and adequate service for its customers.

**Q. Does this conclude your surrebuttal testimony?**

A. Yes.

[9] PAC/700, Gerrard/2-3, 9-16; PAC/705.

Docket No. UE-246
Exhibit PAC/2200
Witness: Gregory N. Duvall

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF THE STATE OF OREGON**

**PACIFICORP**

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**Surrebuttal Testimony of Gregory N. Duvall**

**September 2012**

# SURREBUTTAL TESTIMONY OF GREGORY N. DUVALL

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**Introduction and Purpose of Testimony**

**Q. Are you the same Gregory N. Duvall who previously submitted testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power ("the Company")?**

A. Yes.

**Q. What is the purpose of your surrebuttal testimony?**

A. I respond to criticisms of the Company's power cost adjustment mechanism ("PCAM") proposal presented by Mr. Stephen Schue on behalf of Oregon Public Utility Commission Staff ("Staff"), Messrs. Robert Jenks and Gordon Feighner on behalf of the Citizens' Utility Board of Oregon ("CUB"), and Mr. Michael C. Deen on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). In particular, I address issues related to the Company's proposed PCAM design and the wind risk analysis I presented in my reply testimony. I also respond to the testimony of Mr. Kevin Higgins on behalf of Fred Meyer and Quality Food Centers, divisions of The Kroger Co. ("Kroger"), which addresses ICNU's proposal to eliminate the Transition Adjustment Mechanism ("TAM").

**Q. Please summarize your surrebuttal testimony.**

A. The Company proposed a PCAM in this case to address the chronic under-recovery of prudently incurred net power costs ("NPC"). Consistent with fundamental regulatory principles, a utility customer's rates should reflect the cost to serve that customer. If the costs are reasonable and prudent, there is no basis for disallowing recovery of any portion thereof, even under the theory that it provides some incentive to be "more" prudent.

The Company has demonstrated that, as a result of the deadbands in the parties' proposed PCAMs, it would have received no portion of its unrecovered (and undisputed) Oregon NPC of $134 million over the last five years. The Company disagrees that incentives in the form of sharing bands are needed and that a sharing mechanism would operate as an effective incentive to control NPC. For these reasons and others, the proposals from Staff, CUB, and ICNU to apply Portland General Electric Company's ("PGE") old PCAM design to the Company are unreasonable. Adoption of a PCAM for the Company without deadbands is consistent with the PCAMs now in place in four of the Company's other jurisdictions, the vast majority of PCAMs now in place throughout the country, and the purchased gas adjustment mechanisms ("PGAs") now in place for Oregon's natural gas utilities.

Furthermore, SB 838 materially increased the Company's NPC business risk in Oregon and expressly assigned compliance cost responsibility to customers. It is impossible to isolate and quantify the exact NPC impacts associated with the renewable generation mandated by SB 838. However, measuring the potential cost impact of wind volatility based on variances in wind output and market prices actually experienced over the last five years demonstrates that the risks from SB 838 fully offset the deadbands previously set by the Commission to account for normal NPC business risk in a pre-SB 838 environment. No party explained in their direct or rebuttal testimony why a deadband designed to account for normal NPC business risk in 2007 should continue to apply in 2012, after SB 838 materially changed both the degree and assignment of NPC business risk.

**Staff, CUB and ICNU's Proposed Deadband, Which Would Render the PCAM Effectively Inoperative, is Inconsistent with General Regulatory Principles.**

**Q. Did Staff, CUB, or ICNU dispute the figures you provided in Table 4 of your reply testimony, showing that a PCAM with their proposed deadbands would have provided the Company zero percent recovery of its unrecovered NPC over the last five years?**

A. No. The parties did not dispute this fact in their rebuttal testimony, nor did they propose to change the size or operation of the deadband to allow the PCAM to actually operate. For reference, I have provided Table 4 from my reply testimony again below.

**Reply Testimony Table 4**

**PacifiCorp NPC Under Recovery, Oregon Allocated ($000's)**

| | 2007 | 2008 | 2009 | 2010 | 2011 | Total |
|---|---|---|---|---|---|---|
| Under Recovery | 27,983 | 30,216 | 7,777 | 34,277 | 33,808 | $134,061 |

**PCAM Recovery Under Various Scenarios ($000's)**

| | 2007 | 2008 | 2009 | 2010 | 2011 | Total |
|---|---|---|---|---|---|---|
| Staff/CUB | 0 | 0 | 0 | 0 | 0 | $0 |
| ICNU | 0 | 0 | 0 | 0 | 0 | $0 |
| Kroger | 19,588 | 21,151 | 5,444 | 23,994 | 23,666 | $93,843 |
| Current PGE Method | 574 | 14,594 | 0 | 18,250 | 17,827 | $51,245 |

**Remaining PCAM Under Recovery ($000's)**

| | 2007 | 2008 | 2009 | 2010 | 2011 | Total |
|---|---|---|---|---|---|---|
| Staff/CUB | 27,983 | 30,216 | 7,777 | 34,277 | 33,808 | $134,061 |
| ICNU | 27,983 | 30,216 | 7,777 | 34,277 | 33,808 | $134,061 |
| Kroger | 8,395 | 9,065 | 2,333 | 10,283 | 10,142 | $40,218 |
| Current PGE Method | 27,409 | 15,622 | 7,777 | 16,028 | 15,981 | $82,816 |

**PCAM % Recovery**

| | 2007 | 2008 | 2009 | 2010 | 2011 | Average |
|---|---|---|---|---|---|---|
| Staff/CUB | 0% | 0% | 0% | 0% | 0% | 0% |
| ICNU | 0% | 0% | 0% | 0% | 0% | 0% |
| Kroger | 70% | 70% | 70% | 70% | 70% | 70% |
| Current PGE Method | 2% | 48% | 0% | 53% | 53% | 31% |

**Q. Does the NPC under-recovery from 2007 through 2011 shown in Table 4 ever get past the 150/75 basis point deadband?**

A. No. In every year since 2007, the basis point deadband would have been so large that it would never have been exceeded, even though the Company's unrecovered NPC were more than $25 million in four of the five years reported. Any proposed earnings deadband or sharing bands would also have been rendered irrelevant by the large initial deadband.

**Q. How big is the basis point deadband relative to the Company's total Oregon NPC?**

A. The applicable basis point deadband for 2011 would have been $43.2 million. The Company's Oregon NPC in rates in 2011 were approximately $322 million. Consequently, the deadband would require the Company to absorb over 13 percent of its total NPC before it could recover any unrecovered NPC. To put this in perspective, the Company's 2013 proposed TAM increase is $3.4 million, approximately one percent of total NPC.

**Q. Staff testifies that the Company "advocates" for a dollar-defined deadband of $14 million/$7 million. Is this accurate?**

A. No. The Company strongly opposes any deadband in the PCAM. In response to the parties' arguments that the Company's PCAM should be the same as that first adopted for PGE, the Company has simply noted that: (1) in 2010, the Commission approved a stipulation adopting a dollar-defined deadband of $30 million/$15 million for PGE; and (2) sizing that deadband proportionately to the Company's Oregon NPC, which is less than one-half of the size of PGE's forecast

NPC of approximately $675 million in 2013,[1] would produce a deadband of $14 million/$7 million.

**Q. Staff indicates that the Company wants PGE's stipulated, dollar-defined deadband without the compromises required for a stipulation. Is this true?**

A. No. The Company testified about the 2010 update to PGE's 2007 PCAM design because parties' arguments were that PGE's original PCAM design is binding precedent on the Company and ignored the fact that the design changed and was no longer in place for PGE. The Company has consistently argued that neither PGE's original PCAM design nor the update is precedential by the express terms of the underlying orders.

**Q. Is Staff correct that PGE made compromises on its proposed design changes to the PCAM in the stipulation in Docket UE 215?**

A. Yes. PGE filed for symmetrical, dollar-defined deadbands of $10 million and the conversion of the earnings deadband to an earnings test.[2] PGE sought these changes because of a negative reaction to the large, asymmetrical deadbands from the financial community, the complexity of the design and operation of the PCAM (especially the overlapping basis point and earnings deadbands), and the volatility of results under the PCAM.[3] In support of its filing, PGE conducted a survey indicating that three percent of the utilities in its cost of capital peer group had a PCAM with a deadband only, and six percent had a deadband with some kind of sharing mechanism.[4] This is consistent with the Company's findings with

[1] *In re Portland General Electric Company*, Docket UE 250, PGE/100, Niman-Peschka-Hager/1.
[2] *In re Portland General Electric Company*, Docket UE 215, PGE/1100, Hager-Valach/7.
[3] *Id.* at PGE/1100, Hager-Valach/6; PGE/1700, Pope/2-5; PGE/1300, Fetter/17-19.
[4] *Id*. at PGE/1701, Pope/2.

respect to its cost of capital peer group, where only four of 55 companies (or seven percent) had a deadband and a sharing mechanism.[5]

**Q. How does Staff attempt to justify its deadband proposal that results in a larger deadband for the Company when its NPC are half of PGE's NPC?**

A. Staff's position is that the Company is better able to absorb differences between forecast and actual NPC than PGE. Staff states that the Company's NPC are a lower fraction of its overall costs compared to PGE and the Company's Oregon rate base is approximately the same size as PGE's rate base.

**Q. Does Staff's argument make sense?**

A. No. Rates are not set based on a utility's ability to withstand losses. Rates are set to allow a utility to recover its prudently incurred costs. Building a deadband around a utility's presumed capacity to absorb losses is inconsistent with this basic ratemaking goal. As shown on Table 4, in 2011 alone the Company was unable to recover over $33.8 million in NPC. If utilities chronically under-recover NPC outside of their control, they will be forced to cut controllable costs to make ends meet.

**Q. Would a dollar-defined deadband of $14 million/$7 million operate in a reasonable manner for the Company?**

A. No. Table 4 provided above and in my reply testimony demonstrates that the Company would have recovered less than one-third of its unrecovered NPC over the last five years if the dollar-defined deadband were in place.

[5] See PAC/901, Duvall/1.

**Q. Staff criticizes the Company for ignoring Idaho Power's PCAM design. Is this a fair criticism?**

A. No. The Company's testimony responded to Staff's, CUB's, and ICNU's PCAM proposals, which are all expressly based upon the old PGE PCAM adopted in Order No. 07-015.

**Q. Does Idaho Power's PCAM provide a good model for a the Company PCAM?**

A. No. Idaho Power's PCAM and annual NPC update were expressly designed to address Idaho Power's heavy reliance on hydro power. Staff's testimony does not discuss a key design element of this PCAM: Idaho Power is allowed to reflect the latest forecast from the Northwest River Forecast Center for its hydro forecast just two months prior to the rate effective date rather than using a normalized hydro forecast.[6] This approach allows Idaho Power to more closely match forecast and actual hydro generation outside of the PCAM, which is a significant benefit because Idaho Power meets approximately half of its load with hydro. This approach is in contrast to the Company's NPC modeling in TAM filings, which relies upon normalized hydro generation to determine forecast NPC. Staff's testimony unreasonably represents that the mechanism designed specifically around Idaho Power's resource portfolio and unique NPC forecasts is an appropriate benchmark for a the Company PCAM without addressing this material difference in hydro modeling. An examination of Idaho Power's PCAM highlights the unique design considerations that have been implemented on a utility-specific basis to address the Company's specific circumstances.

[6] *In re Idaho Power Company*, Order No. 08-238 at Appendix A, Section 11(a), Docket UE 195 (2008).

**Q. Are the PGE and Idaho Power PCAMs relevant to the design of a PCAM for the Company?**

A. Some elements are relevant. Each PCAM has been tailored to meet the unique needs of the respective company's system, and that objective should be followed for the Company also. The fact that PGE has generally over-forecast its NPC demonstrates that the Company and PGE are not similarly situated. If the Commission is seeking a PCAM model to apply in this case, it is more reasonable to look to the PCAMs the Company operates under in other states than it is to look to a PCAM designed for PGE or Idaho Power.

In fact, Staff has acknowledged that a "one-size-fits-all" approach to PCAM design is not appropriate:

> In any case, staff is not recommending a universal deadband that would be applied to all of Oregon's investor-owned electric utilities. Staff has indicated that the purpose of a deadband is to exclude a reasonable range of normal variation in power costs from triggering the PCA mechanism. This standard may result in different deadband recommendations for the different electric utilities.[7]

**Q. ICNU asserts that their proposed PCAM structure will better ensure equity between shareholders and customers. Please respond.**

A. The facts do not bear this out. As I demonstrated in my reply testimony, ICNU's proposed PCAM would have done nothing to address the chronic under-recovery of NPC borne by the Company shareholders over the last five years. Furthermore, in a situation where actual NPC are less than previously forecast, the large deadband and earnings band proposed by ICNU under the guise of protecting consumers would allow a utility to keep a significant amount of the

[7] Staff Opening Brief at 21, Docket No. UE 180.

over-collected NPC, even if the utility is over-earning. Neither outcome strikes an equitable balance between shareholders and customers. ICNU's proposed structure is instead based on arbitrary triggers that will only either enrich or harm shareholders or customers. Importantly, the Company is not seeking an opportunity to make a profit on NPC or to recover more than actual costs; the Company is simply asking the Commission to rectify a persistent mismatch between the NPC paid by customers for service provided and the actual NPC of providing that service.

**Q. ICNU argues there is no reason to provide a PCAM that is "far more generous" than the Company's other states. Please respond.**

A. The only other state in the Company's service territory that has a Renewables Portfolio Standard ("RPS") and a PCAM is California.[8] In December 2006, the California Public Utilities Commission approved the Company's Energy Cost Adjustment Clause ("ECAC"), which is a dollar-for-dollar PCAM with an annual prudence review but without sharing bands or deadbands. The Company's Oregon PCAM proposal is consistent with the California mechanism. The Company is simply asking for a PCAM that allows recovery of its prudently incurred NPC—no more, no less. Apparently ICNU believes that it is "generous" to design a mechanism in this manner and to exclude components that function as an automatic disallowance of NPC without a finding of imprudence. But the Company's proposal is not "generous," it is fair. A dollar-for-dollar PCAM

[8] Washington also has an RPS requirement but has adopted a unique cost allocation methodology that it applies to The Company's system-wide costs, including NPC, and to date that allocation method has precluded the use of a PCAM to true-up actual NPC.

ensures that neither the Company nor its customers will be unfairly enriched or harmed due to cost variances that are out of the Company's control.

**Q. ICNU testifies that the California ECAC is an unusual recovery mechanism. Do you agree?**

A. No. The dollar-for-dollar mechanism the Company has in California is more the norm. In my direct testimony, I demonstrated that the vast majority of PCAMs for utilities in the Company's cost of capital peer group do not contain deadbands, sharing mechanisms, or earnings review deadbands. In fact, only seven out of 55 had a deadband and only four out of 55 had both a deadband and sharing bands. Most telling is that only one out of 55 mechanisms contained a deadband, sharing bands, *and* an earnings review (PGE's).[9] As referenced earlier, in support of its PCAM proposal in Docket UE 215, PGE also found that three percent of the utilities in its cost of capital peer group had a PCAM with a deadband only and six percent had a deadband with some kind of sharing mechanism. The PCAMs in place in Oregon for PGE and Idaho Power are the outliers when compared to other states.

**Q. Do any other state commissions apply a deadband to their PCAMs approved for the Company?**

A. No. To the extent that the Company's other commissions have concluded that something less than full dollar-for-dollar recovery is appropriate to incentivize cost control, they have accomplished this goal through a symmetrical sharing mechanism, not through a deadband. However, the Company has consistently

[9] Idaho Power's Oregon PCAM also includes these three elements, but the comparison chart includes Idaho Power's PCAM structure in Idaho because that is its primary service territory.

disagreed that sharing bands are an effective incentive. The Company must prudently dispatch its system to serve customers at the lowest cost regardless of whether there is an approved PCAM in place or whether that PCAM includes a sharing mechanism. Rather than functioning as an incentive, a sharing band functions as a pre-determined disallowance of costs without a determination of imprudence.

**Q. CUB argues that the Commission should reject the Company's proposed PCAM because it does not adhere to the four design criteria outlined in Order No. 05-1261. Please comment.**

A. In Order No. 05-1261, the Commission listed four criteria "that should be included in a *hydro-related PCA*":[10] it must be limited to unusual events, there will be no adjustments if overall earnings are reasonable, it must be revenue neutral, and it must operate in the long-term. In Order No. 07-015, however, the Commission addressed PGE's application for a more expansive PCAM mechanism, similar to the Company's application in this case, and concluded that a PCAM should "be adopted to capture power cost variations that exceed those considered part of normal business risk."[11] The Company's proposal in this case does just that. As discussed below, the Company has addressed the issue of "normal business risk" and demonstrated that the deadbands set for PGE in 2007 to assign normal business risk to the utility no longer apply after adoption of SB 838.

[10] Order No. 05-126, at 8 (December 21, 2005).
[11] Order No. 07-015, at 26.

**Q. CUB continues to argue for asymmetric deadbands based on potential changes in wholesale market prices. Does this rationale for asymmetry apply to the Company's request in this docket?**

A. No. CUB failed to address my reply testimony on this point, which is that unlike PGE, the Company is often a net seller in the wholesale markets and a decline in market prices actually increases the Company's NPC. Staff's testimony expressly recognizes this distinction between the Company and PGE and attributes much of the Company's under-recovery of NPC to this fact.[12] The asymmetrical deadbands established in Order No. 07-015 were premised on the theory that prices for PGE could increase infinitely (costing customers) but decrease finitely (benefitting customers). Because this premise works the other way around for the Company, any asymmetry should be on the cost-recovery side, not the cost-refund side of a deadband.

**Q. Do the Commission's PGAs for Avista Utilities, Northwest Natural Gas Company, and Cascade Natural Gas Corporation include deadbands?**

A. No. I understand that the PGAs rely only on sharing bands for costs and earnings (either 90/10 or 80/20 at the utility's election).[13] They do not include a deadband set on basis points, earnings, or dollars.

[12] Staff/1400, Schue/10-11.
[13] *In re Investigation into Purchase Gas Mechanisms*, Order No, 08-504, Docket UM 1286 (2008); OAR 860-022-0070.

**Staff, CUB, and ICNU's Proposed Deadband is Inconsistent With SB 838.**

**Q. Staff and ICNU criticize the analysis of the impact of wind variability on NPC included in your reply testimony. Please clarify the purpose of your analysis.**

A. The purpose of the analysis presented on pages 5 and 6 of my reply testimony is to show that normal business risk has changed with the addition of renewable resources. The analysis demonstrates that the swings in the output and value of wind generation on the Company's system can have a material impact on NPC and the Company's ability to adequately recover its prudently incurred costs. This analysis isolates and quantifies one aspect of the change in the Company's operations resulting from the addition of large amounts of renewable generation. It demonstrates that the Company's current and forecast wind generation variance risk alone is large enough to fully offset the deadband set for normal business risks in Order No. 07-015.

The supporting details in Exhibit PAC/1801 show that the Company is significantly impacted by large, uncontrollable changes in market prices and wind generation output. For example, in 2009 average market prices were 41 percent lower than previously forecast, even when the TAM relied on the Company's best price forecast as of November 2008. In that same year, wind generation was 15 percent lower than projected in the TAM. The analysis also highlights the difference between owned wind and purchased wind—when wind generation is higher than forecast the Company's owned facilities provide additional generation with no incremental cost, but the additional purchased wind is procured at the contractual rates that are often set much higher than current market prices and increase NPC. At the same time, the increased supply of wind generation reduces wholesale market prices, causing a double whammy for the Company by reducing revenue the Company can collect from wholesale sales, which are a large offset to the Company's NPC.

**Q. ICNU characterizes the Company's analysis of wind variability and its impact on NPC as misleading and irrelevant because the Company is not recovering the costs of its wind resources by selling their output in wholesale markets. Do you agree with their assessment?**

A. No. Volumes of wind generation and market prices are the relevant measure of the value of wind resources. As it relates to NPC, market prices are the primary avoided cost and are an appropriate indication of the potential impact on NPC as wind generation varies from forecast levels. Ironically, ICNU criticizes the Company for failing to specifically quantify the incremental costs and risks associated with renewable energy, but then claims that the Company's analysis that does just that is irrelevant.

**Q. Staff concludes that the primary factor driving the change in value of wind output was market prices because the wind output variances were small. Do you agree?**

A. No. Exhibit PAC/1801 shows that actual wind output varied from the static, normalized wind used in the annual TAM filings by up to 15 percent. Both market prices and wind generation output have a significant impact on the changes in the value of wind generation available to the Company and are always relevant variables in NPC calculations.

**Q. Staff also characterizes the Company's variance study as misdirected and incomplete, arguing that variances in the value of wind should be netted with variances in the value of other resources to be relevant.[14] Please respond.**

A. Staff's criticisms of the Company's variance analysis are misplaced. As previously noted, the purpose of the variance analysis was to show that the addition of a fleet of wind resources significantly increases the Company's business risk, rendering deadbands an improper component in the Company's PCAM. The Company certainly agrees that all components of NPC are affected by changes in wind generation and market prices, but the precise impact that additional intermittent renewable resources have on the entire system is not quantifiable. Staff's conceptual framework relying on the value of the net position after accounting for all NPC components actually supports the Company's proposed PCAM design as the only way to adequately recover all of the system impacts from renewable resources. Staff acknowledges that these net differences are a substantial element of the $134 million in the Company's NPC under-recovery since 2007.

**Q. Staff concludes that a dollar-for-dollar PCAM is not necessary since the Company has the ability to accurately forecast wind integration costs on an annual basis.[15] Do you agree?**

A. No. As described by Staff, the Company relies on the results of its 2010 Wind Integration Study to calculate the level of reserves needed to integrate a given

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[14] Staff/1400, Schue/6.
[15] Staff/1400, Schue/5.

level of wind penetration on the Company's system over the course of a year. For determining the level of NPC in rates, the Company relies on the GRID model to produce normalized NPC for a given set of assumptions, including wind generation and the corresponding level of reserves. Neither wind generation nor the corresponding reserve requirement can be accurately forecast for a given hour, so the Company uses normalized, or average, forecast profiles to model forecast NPC. For example, wind generation is entered as a static profile that only changes every four hours. Reserve requirements are spread evenly throughout the test period. Forecast NPC cannot capture the minute-to-minute variations in wind generation and the resulting impacts on the rest of the Company's system. In actual operations, the reserves needed vary based on wind output, and the cost of holding reserves varies with market prices and the availability of reserve carrying resources in the Company's fleet. Consequently, the full impact of variance in wind generation is *not* included in the Company's normalized NPC.

**Q. Is the Company's proposed PCAM driven solely by wind integration costs?**

A. No. The Company's request is driven by the general regulatory principle that all prudently incurred NPC should be included in rates, including the NPC impacts of renewable energy. Staff has limited its discussion on the cost of managing a large fleet of wind resources to normalized integration costs as determined by the Company's wind integration study and has ignored other costs such as firming and shaping, the impact wind generation has on market prices, and the unknown costs associated with the unpredictability of wind generation. The Company's proposed PCAM is required to ensure the actual impacts of renewable energy on

NPC are reflected in customer rates.

**Q. Does CUB concur with the provisions of ORS 469A.120(1)?**

A. Yes. On page 42 of CUB's rebuttal testimony, they concur that all prudently incurred costs associated with compliance with a renewable portfolio standard are recoverable in rates, including costs associated with using physical or financial assets used to integrate, firm, or shape renewable energy sources.

**Q. CUB suggests that SB 838 does not require, and in fact precludes, the use of a dollar-for-dollar PCAM with respect to the cost of wind variability or providing shaping, firming or integration. Is it correct?**

A. No. It is not possible to isolate and quantify the precise cost of wind variability and the related cost of shaping, firming or integration; therefore, the *only* way that "all of these costs" can be recovered is through a dollar-for-dollar PCAM that allows for recovery of all prudently incurred actual NPC. CUB's proposed PCAM certainly does not allow "all of these costs" to be recovered.

**Q. CUB argues the Company's wind integration study should not be used to true-up NPC since it is controversial and suggests that it would result in large true-ups. How do you respond?**

A. CUB's argument is illogical. The Company's wind integration study is used in its annual TAM filings to estimate the level of reserves required to be held for a given level of wind generation on the Company's system and the corresponding cost of integrating the wind resources. The true up is to actual NPC, not to the wind integration study. Once again, the *only* way to accurately include the cost of wind integration in customer rates is to establish a dollar-for-dollar true up to actual NPC. Such a true-up would also remove the source of controversy and comply with SB 838.

**Q. Staff contends that the Company's reliance on SB 838 is "overkill."[16] How do you respond?**

A. Staff has limited the impact of wind on NPC to the results of the wind integration study and concludes that it is only two percent of NPC. As noted previously, integration is only one part of the impact of wind on NPC. Staff has ignored the cost of firming, shaping, and other system impacts described by Company witness Mr. Stefan A. Bird. Moreover, the Company's reliance on SB 838 is but one part of its justification for its proposed PCAM. The chronic under-recovery of overall NPC must be addressed, but is ignored by Staff, CUB, and ICNU. The passage of SB 838 has clearly added a new dimension into the policy considerations, regarding the design of a PCAM and strongly supports the elimination of deadbands.

**Sharing Bands Do Not Provide a Cost Control Incentive and Do Not Belong in the Company's PCAM.**

**Q. Please provide an overview of the parties' sharing proposals.**

A. Staff and CUB propose a 90/10 percent sharing on all post-deadband amounts. ICNU proposes a 75/25 percent sharing, after the deadband. Kroger proposes a 70/30 percent sharing on all amounts, with no deadband.

[16] Staff/1400, Schue/19.

**Q. ICNU asserts that, without sharing, the Company's proposed mechanism provides no incentive for the Company to manage its costs. Do you agree?**

A. No. The most powerful management incentive at the Commission's disposal is a prudence review, which is part of the structure of the Company's proposal. Nearly all NPC components are out of the control of the Company, including the level and variations in customer loads, wholesale power prices, natural gas prices, hydro generation, wind generation, and the timing of forced outages. No artificially imposed incentive will enable the Company to control these factors.

**Q. In support of including a sharing band, Staff suggests the Company has control over a portion of NPC because it can dispatch gas plants when they come "into the money" or proactively respond to changes in wind output. Please respond.**

A. The Company can and does dispatch its gas plants when it is the most economic choice to do so. The Company takes such action as a matter of prudent utility operation and retains the risk of disallowances for imprudent operations. The Company has no control over the wholesale market prices that would determine if a plant is "in the money" and has no way to anticipate the moment-to-moment variations in wind generation and what the system conditions will be when actual wind generation varies from forecasts. A prudence review of the actions taken by the Company as it responds to these uncontrollable factors is the only effective tool to incentivize prudent, cost-effective system operation. Artificial sharing bands do not incentivize the Company to be "more" prudent because the sharing cannot be avoided no matter how prudently the Company acts.

**Q. CUB has argued that true-ups are rare in Oregon and they are never applied on a dollar-for-dollar basis.[17] Do you agree?**

A. No. In Order No. 10-210, the Commission ordered the Company to credit the proceeds from REC sales to a balancing account for return to customers on a dollar-for-dollar basis.[18] PGE treats REC sales in the same manner. Revenue from REC sales credited to the balancing account is not subject to deadbands or sharing bands of any type. Idaho Power's REC sales are credited to its PCAM after application of the deadbands, but before application of sharing bands.[19] The effect of this treatment is to permit Idaho Power shareholders to retain 10 percent of the proceeds of all REC sales. In either case, it is notable that revenue related to renewable energy resources is not subject to deadbands, consistent with the Company's proposal for a post-SB 838 PCAM.

**Response to Testimony on PCAM Implementation Issues and TAM**

**Q. Please explain your understanding of ICNU's position regarding the interaction between the PCAM and TAM?**

A. ICNU argues that annual TAM filings render the Company's PCAM proposal "not only unnecessary but unbalanced for consumers."[20] At the same time ICNU recommends the annual TAM filings be eliminated after this year regardless of whether a PCAM is adopted.[21]

[17] CUB/100, Jenks-Feighner/4.
[18] *In re PacifiCorp*, Order No, 10-210, UP 260 (2010). The Company only sells RECs associated with renewable resources that are ineligible for compliance with SB 838.
[19] *In re Idaho Power Company*, Order No, 11-086, UP 269 (2011).
[20] ICNU/111, Deen/9.
[21] ICNU/100, Deen/14.

**Q. Do you agree that the Company's proposal is unnecessary and unbalanced for consumers?**

A. No. It is difficult to understand how ICNU can claim the Company's proposal is unnecessary and unbalanced given the Company's undisputed NPC under-recovery since 2007. To the contrary, it is the chronic under-recovery of NPC that is unbalanced and needs to be fixed. The Company's proposed PCAM allows the Company to recover its prudently incurred costs, and ensures that customer rates reflect the cost to serve that customer.

From a practical perspective the PCAM does not make the TAM unnecessary. The TAM and PCAM serve different purposes—the TAM updates forecast NPC and the PCAM trues up the forecast to actual NPC. Under ICNU's proposal, the forecast NPC in customer rates would become stale, and known changes in actual NPC levels would be subject to automatic disallowance or enrichment through deadbands and sharing bands. In reality a PCAM makes annual TAM filings even more important in order to set the forecast NPC as accurately as possible and minimize variances that must flow through the adjustment mechanism after the fact. This forecast and true up structure is already in place for PGE and Idaho Power.

**Q. Do you agree with ICNU's proposal to eliminate or substantially revise the TAM?**

A. No. In my reply testimony I provided detailed arguments demonstrating the flaws in ICNU's proposal to eliminate or revise the TAM put forth in their direct testimony.[22] ICNU advocates for the same outcome in reply testimony but provides no additional evidence or counter arguments. The fact remains that the annual TAM filing is necessary to establish accurate transition adjustments for direct access customers and is required under statute. Furthermore, the Renewable Adjustment Clause ("RAC") mechanism established to recover costs mandated by SB 838 is tied to the TAM design and annual schedule.

**Q. Does Kroger comment on ICNU's proposal regarding elimination of the TAM?**

A. Yes. Kroger comments on ICNU's alternative approach to setting the transition credits in a general rate case should the TAM be eliminated. Kroger notes that under that approach, the demand for direct access service could be susceptible to large swings due to the use of outdated information. Finally, Kroger anticipates that ICNU's alternative would be strongly resisted by the Company.

**Q. What is the effect of using outdated information to determine the transition credits?**

A. Oregon retail customers who did not select direct access could be harmed under ICNU's proposal. For example, if a transition credit were calculated in one year when market prices were high, and if, in the following year, market prices fell and the transition adjustment did not reflect those lower market prices, then direct access customers would get a windfall at the expense of either other Oregon customers or Company shareholders. Annually updating the transition adjustment to current market prices is consistent with the intent of the direct access program,

[22] ICNU/100, Deen/13,lines l-10.

which is designed to ensure cost are not shifted from direct access customers to customers that do not participate in direct access.

**Q. Even though Kroger acknowledges the transition adjustments need to be updated on an annual basis, do they make a formal proposal on how to fix ICNU's proposal so it does not harm customers that do not elect direct access?**

A. No. Neither Kroger nor ICNU presented a detailed proposal on how to update the transition credits in the absence of annual TAM filings.

**Q. Does this conclude your surrebuttal testimony?**

A. Yes.