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August 13, 2012

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
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RE: Docket No. UE 246 – In the Matter of PACIFICORP, dba PACIFIC POWER's Request for a General Rate Revision.

Enclosed for electronic filing in the above-captioned docket is the Public Utility Commission Staff's Reply Testimony.

/s/ Mark Brown

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cc: UE 246 Service List (parties)

CERTIFICATE OF SERVICE

UE 246

I certify that I have this day served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 13th day of August, 2012, at Salem, Oregon.

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PUBLIC UTILITY COMMISSION
OF OREGON

UE 246

STAFF REPLY TESTIMONY OF

STEVE SCHUE
ERIK COLVILLE

In the Matter of
PACIFICORP, dba PACIFIC POWER's
Request for a General Rate Revision.

<u>REDACTED VERSION</u>
August 13, 2012

CASE: UE 246
WITNESS: STEPHEN SCHUE

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1400

Reply Testimony (PCAM Issues)

August 13, 2012

Q. PLEASE STATE YOUR NAME, OCCUPATION, AND BUSINESS ADDRESS.

A. My name is Stephen Schue. My business address is 550 Capitol Street NE Suite 215, Salem, Oregon 97301-2551.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. My Witness Qualification Statement is found in Exhibit Staff/501.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I summarize various arguments made by PacifiCorp in Exhibits PAC/1700 and PAC/1800. I then explain why I agree with some of the Company's arguments, but disagree with others. I also make further recommendations as appropriate.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. I previously submitted Exhibits Staff/500-502 in this proceeding. My qualifications were included in Exhibit Staff/501.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

I. PREDICTABILITY OF WIND INTEGRATION COSTS.......................... 2
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I. PREDICTABILITY OF WIND INTEGRATION COSTS

Q. PLEASE SUMMARIZE THIS SECTION OF YOUR TESTIMONY.

A. In this Section, I summarize the Company's arguments in Exhibits PAC/1700 and PAC/1800 concerning the nature of wind integration costs and how the Company uses these arguments to support its proposal for a power cost adjustment mechanism (PCAM), which would simply pass through to customers all prudently incurred power costs. I then refute these arguments.

Q. PLEASE PROVIDE A GENERAL SUMMARY OF THE COMPANY'S POSITION ON THE NATURE OF WIND INTEGRATION COSTS AND HOW THIS LENDS SUPPORT TO THE COMPANY'S PROPOSAL FOR A PCAM STRUCTURE WHICH IS ESSENTIALLY A STRAIGHT PASS-THROUGH TO CUSTOMERS OF ALL PRUDENTLY INCURRED POWER COSTS.

A. From reading Exhibits PAC/1700 and PAC/1800, my summary of PacifiCorp's position is as follows. Wind has become a substantial portion of the Company's supply portfolio. Approximately nine percent of customer load is now met by wind generation. However, this percentage varies greatly from hour to hour, as the output from any particular wind resource can range from zero to approximately three times its average output. The costs to absorb this variability have grown with the level of wind penetration and are difficult to forecast. They are also difficult to measure after the fact, as they are part of overall net power costs, the nature of which is that "everything depends on everything else." Therefore, the only appropriate way for the Company to recover wind integration costs is through a "straight pass-through of all prudently incurred net power costs" PCAM mechanism.

Q. PLEASE PROVIDE EXAMPLES FROM THE COMPANY'S TESTIMONY TO SUBSTANTIATE YOUR SUMMARY.

A. Figure 1 on Page 8 of Exhibit PAC/1800 illustrates the substantial hour to hour wind generation variability, using actual 2011 data for the Company's wind resources. On Page 4 of Exhibit PAC/1700, the Company states that "In 2011, the production from the Company's total portfolio of owned and contracted wind generation fluctuated hourly from zero to 27.4 percent of the Company's total system retail loads throughout the year, and from zero to over 90 percent of the Company's total wind capacity." (Exhibit PAC/1700, Bird/4, Lines 5-9) On Page 9 of Exhibit PAC/1800, the Company first states that "Because of their inherent volatility, the variable and indirect costs of intermittent renewable resources are difficult to isolate and quantify," and then goes on to state that "an automatic adjustment clause would permit full recovery of these costs in a manner that normalized, forecast ratemaking currently does not." (Exhibit PAC/1800, Duvall/9, Lines 9-10 and 15-16)

Q. DO YOU AGREE THAT IT IS NOT POSSIBLE TO ACCURATELY FORECAST WIND INTEGRATION COSTS AND INCLUDE THEM IN THE COMPANY'S ANNUAL NET POWER COST (NPC) FORECAST?

A. No. As I stated in Exhibit Staff/500, PacifiCorp has, through its wind integration study, "done a solid job of analyzing and forecasting its wind integration costs." (Exhibit Staff/500, Schue/6, Lines 19-20) This allows for an accurate forecast of annual wind integration costs, which do, as the Company explains and illustrates, vary considerably from hour to hour. The Company itself has stated in Docket UE 245 that "The Company continues to believe that the level of reserves required to integrate wind generation net of system load, as identified in the Wind Integration Study [2010 Wind Integration Study from the 2011 Integrated Resource Plan] is appropriate." (UE 245, PAC/100, Duvall/15)

Q. THE COMPANY STATES THAT "STAFF PROVIDES NO SUPPORT FOR THIS STATEMENT" THAT WIND INTEGRATION COSTS, WHICH ARE VOLATILE ON AN HOUR TO HOUR BASIS, "CAN BE FORECAST WITH A REASONABLE DEGREE OF ACCURACY ON AN ANNUAL BASIS." (EXHIBIT PAC/1700, BIRD/9, LINE 10, AND BIRD/10, LINES 1-2) PLEASE PROVIDE SUPPORT FOR YOUR STATEMENT.

A. Rainfall in Salem, Oregon, provides a useful analogy. Average rainfall in Salem is approximately 36.5 inches per year, or 0.1 inches per day. It is very difficult to accurately forecast rainfall from day to day, as this fluctuates widely. One day it might be zero and the next day a full inch or more. In a percentage sense, the change from zero one day to an inch the next day is infinite. However, changes in overall rainfall do not vary greatly in percentage terms from year to year. Therefore, it is possible to provide a reasonably accurate forecast of rain on an annual basis. A similar argument holds for hourly rain forecasting vs. annual rain forecasting, as well as for hourly wind integration costs vs. annual wind integration costs. The Company's Wind Integration Study is a good example of this principle.

Q. WHAT DOES THE POSSIBILITY OF ACCURATELY FORECASTING WIND INTEGRATION COSTS ON AN ANNUAL BASIS IMPLY ABOUT THE NEED FOR SPECIAL MECHANISMS, "STRAIGHT PASS-THROUGH OF ALL PRUDENTLY INCURRED NET POWER COSTS" OR OTHER, TO CAPTURE THESE COSTS?

A. The ability to make accurate annual wind integration forecasts implies that special mechanisms, such as a "straight pass-through of all prudently incurred net power costs," are not necessary. The Company can simply include its wind integration cost forecast in its overall annual Generation and Regulation Initiative Decision Tools (GRID) model-based NPC forecast.

II. VARIANCES IN THE VALUE OF WIND OUTPUT

Q. PLEASE SUMMARIZE THIS SECTION OF YOUR TESTIMONY.

A. In this Section, I first discuss the Company's exposition and analysis of variances between the value of wind output as modeled in GRID (for rate setting purposes) and the actual value of wind output (as measured by actual wind generation and actual market electric prices). I then summarize the Company's position that these substantial variances justify a PCAM without dead bands. Next, I explain why the Company's analysis is misdirected, incomplete, and not relevant to setting the parameters for a PCAM. Finally, I explain what the Company might do in its final round of testimony if it still wants to make the point that certain variances between forecast and actual figures have been substantial in recent years.

Q. PLEASE DISCUSS THE COMPANY'S PRESENTATION OF VARIANCES IN WIND OUTPUT VALUE AND RESULTING RECOMMENDATIONS FOR A PCAM STRUCTURE.

A. On Pages 4-7 of Exhibit PAC/1800, the Company makes the point that, in the five-year period from 2007-2011, the forecast and actual values of wind output have differed substantially. It appears that the forecast figures are based on forecast output and forward market prices at the time of the final GRID runs for rate setting purposes. The actuals are based on actual wind output and actual market prices. The Company provides quantification of these differences for each of the years 2007-2011 in Tables 1 and 2 on Page 5 of Exhibit PAC/1800. Table 3 on Page 6 factors up the figures based on expected wind penetration in 2025. Table 3 should be ignored, as it is based on projections 12 years in the future with respect to the 2013 test year for this proceeding. However, the figures in Tables 1 and 2 are still substantial, and supported by details in Exhibit PAC/1801. The Company then concludes that "Given the magnitude of the wind variance risk, the Commission should adopt a PCAM for the Company without deadbands (both recovery and earnings). Otherwise, the Company will be forced to absorb direct wind generation variance risk as part of its "normal" business risk, contrary to the mandate of SB 838." (Exhibit PAC/1800, Duvall/1800, Lines 7-10)

Q. WHAT APPEARS TO BE THE PRIMARY FACTOR BEHIND THE COMPANY'S CALCULATION THAT, IN EACH OF THE YEARS 2007-2011, THE ACTUAL VALUE OF WIND OUTPUT WAS LOWER, AND IN SOME CASES, MUCH LOWER, THAN THE FORECAST VALUE OF WIND OUTPUT?

A. As shown in Exhibit PAC/1801, market prices were trending down over the five-year analysis period. The Company's measurement of forecast market prices went from approximately $60 per MWh for 2007 to approximately $33 per MWh for 2011. Measurements of actual market prices went from approximately $48 per MWh in 2007 to approximately $26 per MWh in 2011. Market price forecasts were generally behind actuals, resulting in the value of wind output variances pointed out by the Company. (Quantity of wind output variances were relatively small.) Hence, generally speaking, actual wind output was approximately the same as forecast, but the value of the actual output was substantially lower than the forecast value because actual market prices were lower than forecast, i.e. market price decreases were consistently "ahead" of the forward curves used in the Company's GRID modeling.

Q. WHY IS THE COMPANY'S DEMONSTRATION THAT THE DOWNWARD TREND IN MARKET PRICES OVER THE 2007-2011 PERIOD (AND THE FACT THAT FORWARD CURVES APPEAR TO HAVE BEEN "BEHIND" ACTUAL MARKET PRICE DECREASES) INCOMPLETE OR NOT RELEVANT?

A. Actual market prices being lower than forecast resulted in variances in all sorts of things, not simply the value of wind output. The same price movements resulted in lower than forecast values for the output of the Company's coal and gas plants, as well as the value of power needed to serve customer loads.

The Company focuses on the value of wind output variances, which is only one element in a complete picture. A more complete conceptual framework is the following. It is sometimes useful to think of valuing all elements at market prices. Without any generating resources, the cost to serve load is simply the market value of the power required to do so. Then the Company's generating resources can be viewed as offsets, i.e., customers need to be credited with the market value of the output, less the fuel cost, of these generating resources. Various other firm sales and purchases already set at the time of the Company's final November GRID runs need to be valued in a similar way. What is then left over is a net open position, short-term market purchases net of short-term market sales. In PacifiCorp's case, the net open position is a surplus.[1] This is the relevant quantity to which it is appropriate to apply differences in forecast vs. actual prices.

The Company's net surplus position was subject to market price decreases being "ahead" of the forward curves used to set rates over the 2007-2011 period. This was a substantial contributing factor to the $134 million under-recovery figure (for the five-year period) mentioned on Page 10 of Exhibit PAC/1800. Again, differences in the value of the net open position are relevant, but individual components of that overall net position are not, on a stand-alone basis, relevant. In particular, the differences between the forecast and actual values of wind output calculated by the Company are not relevant.

Q. WHAT MIGHT THE COMPANY PRESENT IN ITS FINAL ROUND OF TESTIMONY WHICH WOULD BE RELEVANT TO THE COMMISSION'S CONSIDERATION OF AN APPROPRIATE PCAM STRUCTURE?

A. The Company could discontinue its focus on the differences between forecast and actual values of wind output, and instead focus on differences between forecast and actual values of its net open (surplus in this case) position, which is what is subject to divergences between forecast and actual market prices. From the evidence presented by Company, these differences between forecast and actual values of net short term sales appear to have been substantial over the 2007-2011 period. These are relevant to the PCAM discussion.

Q. WOULD THIS CHANGE STAFF'S VIEW THAT THE COMPANY SHOULD HAVE A PCAM WITH DEAD BANDS?

[1] System balancing sales are greater than system balancing purchases.

A. No. These net short term sale value differences are only one element (although a substantial one)[2] of the $134 million figure mentioned on Page 10 of Exhibit PAC/1800. Given that the entire $134 million figure was not persuasive to Staff, a subset of that would also not be persuasive.

Q. YOU STATE ABOVE THAT A LARGE FACTOR IN THE GRID MODEL'S UNDERESTIMATION OF NPC DURING THE 2007-2011 PERIOD WAS THAT THE COMPANY'S NET SHORT-TERM POSITION IS SURPLUS AND FORWARD CURVES TRAILED ACTUAL MARKET PRICE DECREASES OVER THIS PERIOD, RESULTING IN GRID OVERESTIMATING THE VALUE OF NET SHORT-TERM SALES. DOES THIS ALSO EXPLAIN HOW PACIFICORP'S AND PORTLAND GENERAL ELECTRIC COMPANY'S (PGE) RESULTS DIFFERED OVER THIS SAME PERIOD?

A. Yes. Whereas PacifiCorp has a net surplus position, PGE has a net deficit position. PacifiCorp's short-term market-priced sales exceed its corresponding purchases. However, PGE's situation is the opposite. PGE's short-term market-priced purchases exceed its corresponding sales. With market price decreases "running ahead" of forward curves, PGE's actual NPC generally were less than forecast over the 2007-2011 period. This was, in substantial part, due to differences between forecast and actual values of PGE's net short-term market-priced purchases. PGE's PCAM-related filings indicate that

[2] If the Company wants to pursue this approach in its final round of testimony, it could present calculations of the net short term sale value differences over the 2007-2011 period.

actual NPC were less than forecast for all but one of the years in the 2007-2011 period.[3]

Q. HOW ARE MARKET PRICES EXPECTED TO CHANGE OVER THE NEXT FEW YEARS?

A. According to current forward curves, market prices are expected to increase during the next few years.

Q. WHAT DOES THIS IMPLY ABOUT PACIFICORP'S NPC RESULTS AND POSSIBLE PCAM RESULTS OVER THE NEXT FEW YEARS?

A. If forward curves used to set power cost rates lag actual market price increases, then the actual value of net short-term market-priced sales will generally be greater than forecast. This will tend to make actual NPC less than forecast, and could result in refunds to customers, depending on the size of the NPC over-forecast and the size of the possible dead bands and earnings test. It is ironic that the Company's request might result in a PCAM "just in time to give refunds to customers." However, the PCAM request should be viewed in a longer-term context. Over a longer period of time, market prices will sometimes be going up and sometimes be going down, and forward curves may or may not accurately predict these movements.

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[3] PGE's actual NPC exceeded forecast NPC only in 2009.

III. DEAD BAND CONSTRUCTION

Q. PLEASE SUMMARIZE THIS SECTION OF YOUR TESTIMONY.

A. In this Section, I discuss the Company's proposed dead band (if its PCAM has to have one at all). I first give my understanding of the Company's proposal and why the Company thinks it is appropriate. I then explain why I disagree and continue to support a dead band construct, under which the end points are calculated based on 75 and 150 basis points of pre-tax return on equity (ROE).

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL.

A. The Company continues to favor no dead band at all. However, if it has to have one, the Company feels that it should mirror PGE's current construct, rather than the construct that PGE started with under Order No. 07-015. Order No. 07-015 required a power cost dead band bounded by 75 basis points of pre-tax ROE (when actual power costs are less than forecast) and 150 basis points of pre-tax ROE (when actual power costs are greater than forecast). This is the construct Staff supports for PacifiCorp in this docket.

Parties to Docket UE-215 agreed to a Stipulation that was approved in Order No. 10-478. Under the terms of the Stipulation, PGE's power cost dead band became bounded by fixed dollar figures, and no longer increased with increases in rate base. For PGE's 2010 PCAM filing, the relevant power cost dead band was calculated under the Order No. 07-015 construct, resulting in bounds of $17.3 million and $34.6 million. Then, for PGE's 2011 PCAM filing, the relevant power cost dead band was calculated under the Order No. 10-478 construct, under which the bounds are simply $15 million and $30 million.

PacifiCorp proposes a dead band of $7 million and $14 million, approximately half the size of PGE's, because its Oregon-allocated NPC are approximately half of PGE's.

Q. HOW DOES THE COMPANY SUPPORT THIS PROPOSAL?

A. On Page 4 of Exhibit PAC/1800, the Company provides rough calculations to illustrate that the Order No. 07-015 construct would result in a power cost dead band with bounds of approximately $43.2 million and $21.6 million, i.e., much wider than the $14 million and $7 million that the Company advocates. On Page 13 of Exhibit PAC/1800, the Company states that the "deadband increases as the Company's rate base expands." (Exhibit PAC/1800, Duvall/13, Line 3) The Company implies that it disagrees with this "the dead band increases with the size of the rate base" construct. On Page 20 of Exhibit PAC/1800, the Company states that "PGE's PCAM from Order No. 07-015 Is Obsolete" and that "in Order No. 10-478, the Commission adopted a stipulation in PGE Docket UE 215 that moved to a smaller, dollar-defined recovery deadband." (Exhibit PAC/1800, Duvall/20, Lines 11-14)

Q. PLEASE EXPLAIN WHY YOU DISAGREE WITH THE COMPANY'S REASONING.

A. I disagree with the Company's reasoning for three reasons. First, PGE's current construct is the result of a Stipulation, under which it gave up various considerations to obtain the fixed dollar dead band. PacifiCorp wants to get the fixed dollar dead band without giving up anything. Second, PacifiCorp's approach would lead to, at the time of implementation, a very different result than what would occur under an Order No. 07-015 construct. This was not the case for PGE when it implemented its stipulated approach under Order No. 10-478. Finally, the Company only looks at PGE's power cost dead band, ignoring the dead band applicable to Idaho Power Company (Idaho Power) under Order No. 08-238. Idaho Power's dead band is bounded by 125 and 250 basis points of pre-tax ROE.

Q. PLEASE EXPLAIN IN MORE DETAIL THE STIPULATION APPROVED IN ORDER NO. 10-478.

A. Parties to Docket UE 215 agreed to a Stipulation which included many elements, some favorable to PGE, some not favorable to PGE. Parties agreed to the fixed dollar power cost dead band, which was favorable to PGE, as part of a package, which included elements not favorable to PGE. PacifiCorp wants a fixed dollar power cost dead band without giving up anything. Whereas parties to the UE 215 Stipulation agreed to a balanced package, PacifiCorp wants a package containing only one element which is favorable to the Company.

Q. PLEASE COMPARE IN MORE DETAIL THE RESULTS OF PGE'S IMPLEMENTATION OF THE ORDER NO. 10-478 CONSTRUCT AND WHAT WOULD OCCUR UNDER PACIFICORP'S PROPOSAL.

A. For its 2010 PCAM filing (UE 232), PGE calculated a power cost dead band bounded by $17.3 million and $34.6 million.[4] For its 2011 PCAM filing, PGE

[4] See page 9 of Exhibit PGE/100 in Docket UE 232.

then transitioned to the fixed bounds of $15 million and $30 million. There was not a huge change in the size of the dead band at the point of transition from one construct to another. On the other hand, on Page 4 of PAC/1800, the Company favors a dead band construct with bounds of $7 million and $14 million, which is much smaller than its approximation of an Order No. 07-015 construct, the latter having bounds of $21.6 million and $43.2 million. If PacifiCorp were to obtain a fixed-dollar dead band, it should start at approximately the same size as an Order No. 07-015 construct.

Another argument against the Company's proposed bounds of $7 million and $14 million is that they are based on NPC, rather than on a more direct measure of the Company's ability to absorb differences between forecast and actual costs. Specifically, the Company argues that PacifiCorp's Oregon-allocated NPC are approximately half of PGE's and therefore PacifiCorp should have a dead band which is approximately half the size of PGE's. However, for PacifiCorp, NPC are a significantly lower fraction of overall costs than is the case for PGE. A better measure of PacifiCorp's ability to absorb NPC differences is allowed pre-tax return on equity, which is specifically tied to rate base via three set factors – equity capital share, authorized return on equity, and income tax rates. Since PacifiCorp's Oregon-allocated rate base is approximately equal to PGE's, PacifiCorp's dead band should not, in any case, be significantly smaller than PGE's.[5]

[5] Note that PacifiCorp and PGE have approximately the same equity capital shares, authorized returns on equity, and income tax rates.

Q. PLEASE EXPLAIN IN MORE DETAIL IDAHO POWER'S POWER COST DEAD BAND.

A. Consistent with Order No. 08-238, Idaho Power has a PCAM structure, under which the power cost dead band is bounded by 125 and 250 basis points of pre-tax ROE. PacifiCorp ignores this construct, as it would result in a larger dead band than under an Order No. 07-015 construct. In fact, Order No. 08-238 bounds are 67 percent larger than Order No. 07-015 bounds. Also, Idaho Power's expected hydro power generation is somewhat more than half of its load. This can result in substantial deviations between expected and actual power costs that Idaho Power must absorb.[6]

Q. DO YOU THEN CONTINUE TO ADVOCATE A POWER COST DEAD BAND FOR PACIFICORP BOUNDED BY 75 AND 150 BASIS POINTS OF PRE-TAX ROE?

A. Yes. Given the Idaho Power example, it could be argued that this structure is too favorable to PacifiCorp. Noting also that PacifiCorp has not expressed a willingness to give up anything, through a stipulation or other means, in return for a narrow fixed dollar dead band, the Company's proposal for a dead band bounded by $7 million and $14 million should be rejected. Instead, the dead band should be bounded by 75 and 150 basis points of pre-tax ROE.

[6] On the other hand, Idaho Power can retain substantial variances when actual hydro output is much higher than forecast.

IV. SENATE BILL 838 AND RELATED CONSIDERATIONS

Q. PLEASE SUMMARIZE THIS SECTION OF YOUR TESTIMONY.

A. In this Section, I first discuss the Company's argument that Senate Bill 838's (SB 838) renewable resource cost recovery provisions require a PCAM with no dead band, i.e., direct pass-through to customers of all prudently incurred net power costs. I then refute the Company's argument, in part referring back to various parts of my Opening Testimony (Exhibit Staff/500), to show that the Company's proposed direct pass-through of all prudently incurred net power costs is "overkill" for a minor theoretical issue with wind integration costs, which the Company has already acknowledged is impossible to measure.

Q. PLEASE DISCUSS THE COMPANY'S POSITION.

A. The Company states that "Noticeably absent from Staff's criteria is that the PCAM should be consistent with the law, including SB 838 …." (Exhibit PAC/1800, Duvall/18, Lines 14-15) This overall conclusion is supported by various statements on Page 9 of Exhibit PAC/1800. For example, the Company states that "Because of their inherent volatility, the variable and indirect costs of intermittent renewable resources are difficult to isolate and quantify. For this reason, a PCAM that will true-up the difference between forecasted and actual NPC is an effective way to ensure that utilities recover their [Renewable Portfolio Standard] RPS compliance costs under SB 838." (Exhibit PAC/1800, Duvall/9, Lines 9-13) The Company goes on to state that "Every dispatchable resource in the Company's portfolio at some point in time is likely to be used to provide integration, shaping, and firming. This is exactly why the Company is requesting a dollar-for-dollar PCAM under SB 838." (Exhibit PAC/1800, Duvall/9, Line 23 through Duvall/10, Line 2)

Q. WHY DO YOU DISAGREE WITH THIS POSITION?

A. First, every dispatchable resource in the Company's portfolio is at some point in time performing many different functions, not simply providing wind integration. For example, every dispatchable resource is likely, at some point in time, to be following customer load or providing reserves. In a system in which "everything depends on everything else," it is not possible to isolate the costs incurred to integrate intermittent resources. As I noted on Page 8 of Exhibit Staff/500, the Company has acknowledged that a "modeled redispatch of the Company's system cannot reasonably simulate what would have occurred if wind, low-impact hydro, or solar were not present in real-time." (Exhibit PAC/900, Duvall/26, Lines 6-9) This is consistent with the Company's statement noted above that "Because of their inherent volatility, the variable and indirect costs of intermittent renewable resources are difficult to isolate and quantify." (Exhibit PAC/1800, Duvall/9, Lines 9-10)

Although it is impossible to perfectly measure the costs of integrating intermittent resources, for the most part wind, it is possible to forecast these costs with a good degree of accuracy. This is what the Company has done in its Wind Integration Study. The Company has then incorporated this knowledge into its GRID-based NPC forecast. Particularly given that wind integration costs are less than two percent of the Company's 2013 NPC forecast, as I stated previously, "the current structure of wind integration cost recovery, through the [Transition Adjustment Mechanism] TAM proceedings, is both timely and as accurate as is practicable." (Exhibit Staff/500, Schue/10, Lines 7-9)

Q. WHAT IS YOUR SUMMARY CONCLUSION?

A. The Company cites SB 838 to support precise collection of wind (and other renewable resource) integration costs, which the Company itself acknowledges is impossible. The Company then wants to bundle these immeasurable costs, which are less than two percent of total NPC, together with the other more than 98 percent of all NPC, and make all (prudently incurred) NPC eligible for straight pass-through to customers. This tenuous reliance on SB 838 is "overkill." Current practices, which incorporate the Company's Wind Integration Study results into the GRID-based NPC forecast, remain appropriate.

Q. DOES YOUR "TWO PERCENT DRIVING THE OTHER 98 PERCENT OF COSTS" POINT HAVE OTHER IMPLICATIONS?

A. Yes. As noted on Pages 10 and 11 of Exhibit Staff/500, "Given that wind integration costs are less than two percent of all NPC, collections from or payments to customers of differences between forecasted and actual NPC would depend almost entirely on non-wind integration cost differences." (Exhibit Staff/500, Schue/10, Line 21 through Schue/11, Line 2) This leads to results that do not make sense. For example, "In a year in which wind integration costs, however imperfectly measured, were higher than forecasted, but overall NPC were lower than forecasted, then customers would receive a refund of the entire NPC delta, although wind integration costs, the basis for the pass-through mechanism, would, in fact, be higher than expected." (Exhibit Staff/500, Schue/11, Lines 2-6)

This is another reason why impossible to measure differences between forecasted and actual wind (and other renewable resource) integration costs are not a good basis for a PCAM mechanism incorporating a straight pass-through to customers of all differences between forecasted and actual prudently incurred NPC.

V. RISK AND INCENTIVES

Q. PLEASE SUMMARIZE THIS SECTION OF YOUR TESTIMONY?

A. In this Section, I respond to various Company assertions regarding risk and incentives.

Q. ON PAGE 10 OF EXHIBIT PAC/1800, THE COMPANY STATES THAT IT "HAS ADDED SIGNIFICANT NATURAL GAS-FIRED RESOURCES SINCE 2007, WHICH HAS INCREASED ITS EXPOSURE TO THE VOLATILITY OF NATURAL GAS." (EXHIBIT PAC/1800, DUVALL/10, LINES 5-6) PLEASE COMMENT ON THIS STATEMENT.

A. When the Company makes its final GRID run in mid-November to forecast NPC for the next year, expected natural gas requirements are already hedged. Therefore, differences between the mid-November natural gas forward curve and actual gas prices do not result in as large of variances between forecast and actual NPC as might be inferred by the Company's statement. However, significant changes in natural gas prices from year to year can potentially make both forecast and actual NPC vary substantially from year to year.

Q. ON PAGE 14 OF EXHIBIT PAC/1800, THE COMPANY STATES THAT "NPC HAVE ALWAYS BEEN MORE VOLATILE THAN OTHER EXPENSES AND THIS VOLATILITY HAS INCREASED UNDER SB 838. FINALLY, THE COST DRIVERS THAT COMPRISE NPC ARE LARGELY OUTSIDE OF PACIFICORP'S CONTROL, SUCH AS FUEL EXPENSE AND PURCHASE POWER …." **(EXHIBIT PAC/1800, DUVALL/14, LINES 1-4) PLEASE COMMENT ON THIS STATEMENT.**

A. As with the previous Company statement, this is more true from year to year than from the final mid-November forecast to actual NPC for any particular year. Expected natural gas requirements are hedged by the time of the final forecast. Coal prices are largely set by contract. Firm purchased power and sales are set by contract. On the other hand, the effects on NPC of short term market priced sales and purchases are in substantial part outside of the Company's control.

Q. ON PAGE 10 OF EXHIBIT PAC/1700, BIRD/10, THE COMPANY STATES THAT "A SHARING BAND CANNOT CREATE AN INCENTIVE FOR THE COMPANY TO 'MINIMIZE' COSTS OVER WHICH IT HAS NO CONTROL." (EXHIBIT PAC/1700, BIRD/10, LINES 8-9) PLEASE COMMENT ON THIS STATEMENT.

A. The Company's claim is exaggerated. It is, however, true to some extent. For example, the Company cannot control hydro flows. On the other hand, the Company can respond in many ways to changing circumstances. For example, it can dispatch gas plants when they come "into the money." It can also proactively respond to changes in wind output, thereby keeping integration costs as low as is practicable and approximately equal to forecast.

Similar observations apply to the Company's assertions on Page 15 of Exhibit PAC/1800 that Company decision makers "do not have the ability to refuse to procure or dispatch power if it is needed" and that "sharing bands and deadbands have no impact on that and provide no incentive." (Exhibit PAC/1800, Duvall/15, Lines 14-15 and 18-19) These claims are also exaggerated. The Company does have an obligation to serve load. However, this obligation does not preclude proactive responses by the Company to minimize net costs as conditions change. For example, the obligation to serve load does not preclude running an “in the money” gas plant and selling the output into the market.

Q. ON PAGE 18 OF EXHIBIT PAC/1800, THE COMPANY STATES THAT “STAFF HAS NOT RECOGNIZED THAT FAILURE TO ADHERE TO THE MATCHING PRINCIPLE MEANS THAT CUSTOMERS ARE NOT RECEIVING THE CORRECT PRICE SIGNALS REGARDING THE COST OF SERVING THEIR REQUIREMENTS.” (EXHIBIT PAC/1800, DUVALL/18, LINES 17-19) DO YOU AGREE WITH THIS STATEMENT?

A. No. First, the statement is in the context of the Company’s position that it is important that forecast and actual costs to integrate intermittent resources are different. As discussed above, these differences, which are impossible to measure, are very small. Given that overall wind integration costs are less than two percent of all NPC, any potential price signal impacts are very small. Second, under a PCAM mechanism, customers pay or receive their share of the difference between forecast and actual NPC after the fact. To the extent that prices do not reflect actual costs, price signals are simply inaccurate. An after the fact true up does not alleviate price signal problems.

VI. ANNUAL TRANSITION ADJUSTMENT MECHANISM (TAM) FILINGS

Q. ON PAGES 21 AND 22 OF EXHIBIT PAC/1800, THE COMPANY REPLIES TO INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES' (ICNU) ARGUMENTS AGAINST ANNUAL TAM FILINGS. DO YOU SUPPORT ANNUAL TAM FILINGS?

A. Yes.

Q. WHY?

A. Annual filings are necessary to ensure that power cost rates are set to match actual costs as accurately as possible. Natural gas and market electric prices can vary substantially from year to year. Contractual prices for coal, firm power purchases, and firm power sales can change as well. Finally, the Company is obligated to purchase the output of new Public Utility Regulatory Policies Act (PURPA) resources, which are priced substantially above the Company's average net power costs. It would be unfair to systematically subject the Company to "PURPA regulatory lag."

Q. DO ANNUAL TAM FILINGS WORK WELL WITH A PCAM STRUCTURE?

A. Yes. A PCAM mechanism works with differences between forecast and actual NPC on an annual basis. It does not make sense to potentially increase these differences by setting the forecast less accurately than is possible. The most accurate option is an annual forecast. The 2013 TAM forecast is almost the same as the 2012 TAM forecast. However, this is an exception. Power prices should be based on the most recent information available.

VII. OTHER POLICY ISSUES

Q. PLEASE SUMMARIZE THIS SECTION OF YOUR TESTIMONY.

A. In this Section, I respond to various assertions made by the Company on policy issues.

Q. ON PAGES 19 AND 20 OF EXHIBIT PAC/1800, THE COMPANY OBJECTS TO STAFF'S RECOMMENDATION THAT COLLECTIONS BE LIMITED TO SIX PERCENT, AND ASSERTS THAT STAFF DOES NOT PROVIDE A BASIS FOR THE RECOMMENDED LIMITATION. PLEASE RESPOND.

A. As noted on Page 17 of Exhibit Staff/500, Staff's recommendation that "amortization of amounts deferred (for collection) under the mechanism should be limited in any one year to six percent of PacifiCorp's Oregon revenues for the proceeding calendar year"[7] is based on the provisions of Order No. 07-015.

Q. ON PAGE 16 OF EXHIBIT PAC/1800, THE COMPANY ASSERTS THAT "DEADBANDS AND SHARING BANDS ARE PUNITIVE BECAUSE THEY PENALIZE THE COMPANY WHEN IT HAS DONE NOTHING WRONG." (EXHIBIT PAC/1800, DUVALL/16, LINES 2-3) PLEASE COMMENT.

A. The Company's statement is incomplete. Dead bands and sharing bands also sometimes "give the Company a windfall when it has done nothing right." The dead band is designed to reflect the Company's ability to absorb modest under-recovery of prudently incurred power costs. The Company should then also be allowed to retain the benefits of modest over-recovery. The sharing

[7] See Exhibit Staff/500, Schue/17, Lines 11-14.

bands are designed to give the Company an incentive to keep power costs as low as possible under all circumstances.[8]

[8] See Exhibit Staff/500, Schue/18, Lines 12-18.

VIII. OTHER TECHNICAL ISSUES

Q. PLEASE SUMMARIZE THIS SECTION OF YOUR TESTIMONY.

A. In this Section, I respond to various assertions made by the Company on technical issues.

Q. ON PAGE 14 OF EXHIBIT PAC/1800, THE COMPANY ASSERTS THAT "STAFF'S ARGUMENT IS REDUNDANT; THERE IS NO REASON TO HAVE BOTH TWO DEADBANDS (RECOVERY AND EARNINGS) AND A SHARING BAND TO ENCOURAGE THE COMPANY TO MANAGE ITS NPC …." (EXHIBIT PAC/1800, DUVALL/14, LINES 9-11) PLEASE RESPOND.

A. Staff recommends a structure which meets Staff's three criteria for a good PCAM.[9] If the Company thinks that this structure could be improved by "fine tuning," it can suggest modifications in its final round of testimony.

Q. PLEASE COMMENT ON THE EXAMPLES ON PAGES 14 AND 15 OF EXHIBIT PAC/1800.

A. The first example assumes that actual NPC are potentially $200 million greater than forecast, but through extraordinary efforts, the Company reduces this difference to $50 million. The Company then asserts the "The proposed deadband and sharing "incentives" would deny the Company recovery of the entire $50 million in increased costs, even though the Company went through extraordinary efforts to mitigate these cost increases." (Exhibit PAC/1800, Duvall/15, Lines 1-4) If the $50 million is on a system basis, then the Oregon-allocated portion would be approximately $13 million, and the

[9] For a discussion of Staff's criteria, see Exhibit Staff/500, Schue/15, Lines 1-8.

Company would absorb the entire $13 million, as this is less than the $43.2 million upper bound of the dead band, as calculated and shown by the Company on Page 4 of Exhibit PAC/1800. However, this $13 million figure is only approximately one percent of the Company's Oregon revenue requirement, or 45 basis points of pre-tax ROE.[10] If the $50 million is an Oregon-allocated figure, the Company would absorb most or all of it, depending on an earnings test. However, the impact on earnings would not be much more than 150 basis points. Also, if the $50 million is an Oregon-allocated figure, it is substantially larger than any of the actual under-recovery figures for the years 2007-2011 listed in Table 4 on Page 12 of Exhibit PAC/1800.

The second example assumes that actual NPC are $200 million less than forecast. The Company then asserts that "The proposed deadbands and sharing bands would allow shareholders to retain the entire $200 million for the Company doing nothing." (Exhibit PAC/1800, Duvall/15, Lines 6-8) If the $200 million is a system figure, then the Oregon-allocated portion is approximately $50 million, which is well in excess of the $21.6 million lower bound of the dead band, as calculated and shown by the Company on Page 4 of Exhibit PAC/1800. Therefore, absent very extraordinary events impacting the earnings test, customers would receive a substantial refund. If the $200 million is an Oregon-allocated figure, most of it would be refunded to customers, as the lower dead band bound is only $21.6 million. However, a $200 million

[10] According to the Company's estimate on Page 4 of Exhibit PAC/1800, $43.2 million corresponds to 150 basis points. Then 13/43.2 x 150 results in 45 basis points.

difference between Oregon-allocated actual and forecast NPC would be extraordinary, as the Company is requesting less than $370 million in its 2013 TAM filing (UE 245).

Q. DOES THIS CONCLUDE YOUR TESTIMONY

A. Yes.

CASE: UE 246
WITNESS: ERIK COLVILLE

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 1500

Reply Testimony (Coal Issues)

August 13, 2012

PAGES 5-6, 12, 15-16, 18-19, 30, 32, 34-36 IN

STAFF EXHIBIT 1500

ARE CONFIDENTIAL

AND SUBJECT TO PROTECTIVE

ORDER NO. 12-060 IN UE 246.

YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER

TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

Q. ARE YOU THE SAME ERIK COLVILLE WHO PREVIOUSLY TESTIFIED IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. My rebuttal testimony responds to issues raised in Sierra Club's direct testimony (Sierra Club/100 and Sierra Club/200), Citizens' Utility Board of Oregon response testimony (CUB/100), and PacifiCorp's reply testimony (PAC/1500).

Q. DID YOU PREPARE EXHIBITS FOR THIS DOCKET?

A. Yes. I prepared:

- Staff/1501 "PVRR(d) Comparison" (consisting of one page);
- Staff/1502 "Changes Noted by Sierra Club in the Changes Tab of Excel Spreadsheet Files" (consisting of two pages);
- Staff/1503 "Capital Cost Comparison" (consisting of one page);
- Staff/1504 "PacifiCorp Response to DR No. 340" (consisting of one page);
- Staff/1505 "PacifiCorp Response to DR No. 336" (consisting of four pages);
- Staff/1506 "PacifiCorp Response to DR No. 335" (consisting of one page);
- Staff/1507 "Sierra Club Response to DR No. 1" (consisting of four pages);
- Staff/1508 "PacifiCorp Response to DR No. 338" (consisting of one page); and
- Staff/1509 "PacifiCorp Response to DR No. 337" (consisting of one page).

Q. HOW DOES THE COMMISSION DETERMINE PRUDENCE?

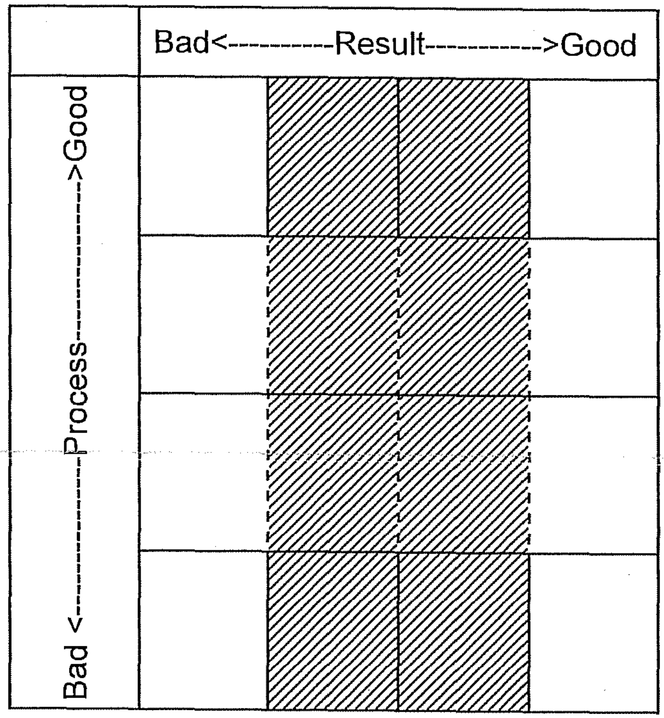
A. The Commission has set forth the following standard to be used when determining the prudence of an action: "Prudence is determined by the reasonableness of the actions 'based on information that was available (or could reasonably have been available) at the time.'" (*In re PGE*, UE 102, Order No. 99-033 at 36-37.)[1]

Q. IS IT POSSIBLE TO CONCLUDE THAT THE ENVIRONMENTAL COMPLIANCE INVESTMENTS WERE PRUDENT NOTWITHSTANDING DECISION MAKING PROCESS INFIRMITIES (i.e. A DEFICIENCY OR SHORTCOMING)?

A. Yes. The Commission has stated that "if the record demonstrates that a challenged business decision was reasonable, taking into account established historical facts and circumstances, the utility's decision must be upheld as prudent even if the record lacks detail on the utility's actual subjective decision making process." *See* Order No. 02-469 p. 5; *In re PacifiCorp* (Commission adopting PacifiCorp's description of the legal standard for determining prudence.) Under this standard, a utility's action can be prudent even if the process leading up to the action has infirmities. In other words, while a utility's decision process is probative on whether the action itself is prudent, under the Commission's prudence standard, the primary focus of the inquiry is on the reasonableness of the action, not on the process leading to it. This concept gives rise to what I informally refer to as "a

[1] *See also In re Northwest Natural Gas*, UG 132, Order No. 99-697 at 52 ("In this review, therefore, we must determine whether the NW Natural's actions and decisions, based on what it knew or should have known at the time, were prudent in light of existing circumstances.").

thinking tool" that can be illustrated as follows.



Where: Result = the decision that is made; Process = the decision making process; and the shaded area requires policy judgment.

Q. PLEASE SUMMARIZE THE COMPANY'S ACTIONS THAT ARE UNDER REVIEW.

A. PacifiCorp's actions were to make environmental compliance investments in the Naughton Units 1 and 2, Dave Johnston Unit 4, Hunter Units 1 and 2, Wyodak, and Jim Bridger Unit 3 coal fired units. The investments are listed on Staff/402, and included projects to reduce emissions of sulfur dioxide (SO2), nitrogen oxides (NOx), and particulate matter (PM). In total, the Company made 12 environmental compliance investments that collectively amounted to approximately $600 million.

Q. WERE PACIFICORP'S ACTIONS TO INVEST IN THESE ENVIRONMENTAL COMPLIANCE PROJECTS REASONABLE GIVEN WHAT THE COMPANY KNEW OR SHOULD HAVE KNOWN AT THE TIME?

A. As discussed below, the Company's actions to proceed with the environmental compliance investments in the Dave Johnston Unit 4, Hunter Units 1 and 2, Wyodak, and Jim Bridger Unit 3 coal fired plants were reasonable. As such, in accordance with the prudence standard, I conclude these actions were prudent. Related to the Naughton Units 1 and 2, after considering the information in this docket, I find the Company's actions to proceed with the environmental compliance investments were not unreasonable, and thus not imprudent. However, recognizing the Commission may draw a different conclusion, I present near the end of this testimony potential remedies for imprudence relating to Naughton Units 1 and 2.

Q. WHAT IS THE BASIS FOR YOUR CONCLUSION REGARDING THE PRUDENCE OF THE COMPANY'S ACTIONS?

A. As noted in my opening testimony, and my updates presented and discussed below, there are infirmities in the process PacifiCorp used to inform its decisions to proceed with the Naughton Units 1 and 2, Dave Johnston Unit 4, Hunter Units 1 and 2, Wyodak, and Jim Bridger Unit 3 environmental compliance projects.

Given the decision making process infirmities discussed in my opening testimony, and updated in my rebuttal testimony below, and referring to the thinking tool illustrated above, I conclude that the Company's decision making process for the Dave Johnston Unit 4, Hunter Units 1 and 2, Wyodak, and Jim Bridger Unit 3 coal plant units was "more good than bad." However, in [redacted] with the decision making process infirmities, the calculated present value revenue requirement differential (PVRR(d)) from the environmental compliance investments for Dave Johnston Unit 4, Hunter Units 1 and 2, Wyodak, and Jim Bridger Unit 3 is a [redacted] to customers ([redacted]), as shown on Staff/1501. Considering that the calculated PVRR(d) for these coal plant units is [redacted], and referring again to the thinking tool above, I rate the overall result as "good." Referring once again to the thinking tool illustrated above, for conditions where the result is "good" and the process is "more good than bad", I conclude the actions for these generating plants were reasonable and therefore were prudent.

Turning to the Naughton Units 1 and 2, I also conclude that the decision making process for these two coal plant units was "more good than bad." In addition to the decision making process infirmities discussed in my opening testimony and updated in my rebuttal testimony below, the calculated PVRR(d) benefit to customers from the environmental compliance investments is either a [redacted]

[redacted] to customers ([redacted]) or a [redacted] to customers ([redacted]), depending upon the source of the calculation (PacifiCorp or Sierra Club, respectively). Considering that the calculated PVRR(d) for these coal plant units is a [redacted], and referencing the thinking tool illustrated above, I rate the result as "somewhat good to somewhat bad." Referring again to the thinking tool illustrated above, for conditions where the result is "somewhat good to somewhat bad" and the decision making process is "more good than bad," the actions fall into the shaded policy judgment area. As described later in my rebuttal testimony, a load serving entity such as PacifiCorp, even considering the environmental compliance risks, could reasonably decide to proceed with the Naughton Units 1 and 2 environmental compliance investments.[2] This is the case because the Naughton Units 1 and 2 had proven themselves to be reliable over the long term in serving load and in meeting applicable environmental regulations. I do not find the Company's actions to proceed with the environmental compliance investments to be unreasonable. As a result, under the prudence standard, I conclude the actions were not imprudent.

Q. WHAT IS YOUR RESPONSE TO THE ISSUES RAISED BY SIERRA CLUB AND CUB IN THEIR RESPECTIVE OPENING TESTIMONIES?

A. I considered each of the issues raised in the Sierra Club and CUB opening testimonies. I note that the issues they present are primarily the same as

[2] This decision making paradigm is illustrated in PAC/1400 Woollums/4 and 5, and PAC/1500 Teply/10 and at 38-39.

those I raised as decision making process infirmities in my opening testimony. Among all the issues raised by Sierra Club and CUB there were several particularly significant issues. Those include: 1) the Company should have included environmental compliance investments in its on-going analyses rather considering them to be sunk costs; 2) the Company failed to revisit its analyses as conditions changed; and 3) the dates for idling coal plant units assumed by PacifiCorp in its analyses are earlier than the regulatory compliance dates for those units. I discuss each of these significant issues immediately below.

SIERRA CLUB/CUB ISSUE 1

Q. DISCUSS THE ISSUE OF CONSIDERING ENVIRONMENTAL COMPLIANCE INVESTMENTS AS SUNK.

A. PacifiCorp refers to its 2011 IRP Supplemental Coal Replacement Study and 2011 IRP Update Coal Replacement Study as evidence that updated capital cost estimates, market power cost forecasts, and natural gas cost forecasts, including CO2 cost sensitivities, and improved modeling techniques do not identify accelerated retirement of the coal plant units in this docket.[3] While the results of these 2011 IRP analyses are favorable to continued coal fueled operation, the updated analyses consider pre-2012 environmental compliance costs as sunk. Considering these pre-2012 costs as sunk removes them from the capital cost estimates. The result is the 2011 IRP analyses analyze a different investment than the analyses performed for decision making in this

[3] Typical of statement at PAC/500 Teply/39, and PAC/500 Teply/100.

docket. This makes the results of the 2011 IRP analyses not comparable to those performed to inform decision making.

Q. DO YOU CONSIDER PACIFICORP'S 2011 IRP ANALYSES AS VALID UPDATES IN SUPPORT OF CONTINUED COAL FUELED OPERATIONS?

A. No. Because the 2011 IRP analyses do not consider the pre-2012 environmental compliance investments I do not consider them an update of the analyses used to inform decision making. Instead, I consider them stand-alone analyses of future environmental compliance investments.

<u>SIERRA CLUB/CUB ISSUE 2</u>

Q. DISCUSS THE ISSUE OF THE COMPANY FAILING TO REVISIT ANALYSES AS CONDITIONS CHANGED.

A. As I discuss above, PacifiCorp did not update the PVRR(d) analyses in its annual business planning process or in its 2011 IRP process. I consider failing to update analyses at significant project milestones to be a decision making process infirmity. Having said that, PacifiCorp's reply testimony (PAC/1500 Teply) includes updated PVRR(d) analyses that are comparable to those prepared at the time of decision making.

Q. IS THE UPDATED PVRR(d) ANALYSIS PERTINENT IF PACIFICORP DID NOT RELY ON THIS ANALYSIS WHEN IT MADE ITS DECISIONS?

A. The updated PVRR(d) analysis shows what information was reasonably available to PacifiCorp at the time it made its decision. Given that prudence is determined by the reasonableness of the Company's actions based on information that could reasonably have been available at the time, it is pertinent to show what information was reasonably available to inform the Company's decisions. As discussed above, it is not necessary for PacifiCorp to show that it relied on this information when making its decision to proceed with the upgrade in order to show its action was prudent.

Q. WHAT WAS UPDATED IN THE PVRR(d) ANALYSES PACIFICORP PROVIDED WITH ITS REPLY TESTIMONY?

A. For each coal plant unit in this docket PacifiCorp updated the PVRR(d) analysis model used at the time of decision making so that it considers a 2014 idling date. In addition, the market power price forecast for the Naughton Units 1 and 2 analyses was updated from December 2008 to March 2009 to coincide with what was available at the time of decision making in May 2009.

SIERRA CLUB/CUB ISSUE 3

Q. DISCUSS THE ISSUE OF THE DATES PACIFICORP ASSUMED IN ITS DECISION MAKING ANALYSES FOR IDLING COAL PLANT UNITS.

A. With the exception of the Hunter Units 1 and 2, the PacifiCorp PVRR(d) analyses performed for decision making assumed each coal plant unit would be idled in the year of decision making. For the Hunter Units 1 and 2 the idling date used in analyses was the end of 2012, approximately three years after the year of decision making. The result of the assumed idling dates is to overstate the PVRR(d) benefit for each coal plant unit of making the environmental compliance investments. While Sierra Club and CUB testimony advocates for using a 2015 idling date as the basis for PVRR(d) analyses, I see the first compliance dates in the individual state permits as reasonable idling dates for use in analyses. The table below presents, by coal plant unit, the state permit compliance dates I identified.

Coal Plant Unit	State Permit Compliance Date	State Permit
Naughton Unit 1	May 2012	MD-5156
Naughton Unit 2	November 2011	MD-5156
Dave Johnston Unit 4	September 2012	MD-5098
Hunter Unit 1	2014	UDAQ 1500101 001
Hunter Unit 2	2011	UDAQ 1500101 001
Wyodak	April 2011	MD-7487
Jim Bridger Unit 3	June 2011	MD-1552A

Q. WHAT IS THE IMPACT OF THE PVRR(d) OVERSTATEMENT CAUSED BY PACIFICORP'S ASSUMED IDLING DATES FOR DECISION MAKING?

A. Sierra Club/100 Fisher/ 40 presents the results of its PVRR(d) calculation for a 2015 idling date. In response to this testimony, PacifiCorp reply testimony provides updated PVRR(d) analyses based on a 2014 idling date. Both organizations' calculations identified a multi-million dollar reduction in PVRR(d) benefit from delaying the assumed idling date compared to the date assumed in PacifiCorp's decision making analyses. However, there are significant differences between the change in PVRR(d) benefit calculated by Sierra Club and PacifiCorp. I address the differences later in this testimony.

Q. DESCRIBE WHAT PVRR(d) ANALYSIS METHOD SIERRA CLUB USED IN SUPPORT OF ITS DIRECT TESTIMONY.

A. As described in Sierra Club/100 Fisher/39-40, Sierra Club modified the Excel spreadsheet model used by PacifiCorp for decision making.[4] In concept, the modifications included: eliminating the endogenous comparison of continued coal plant unit operation against market power purchases; running the spreadsheet model for the case where the coal plant unit incurs the environmental compliance investments and runs through its depreciation life (2029 in the case of the Naughton Units 1 and 2, and 2042 in the case of the Hunter Units 1 and 2); running the spreadsheet model for the case where the coal plant idles in 2015, thereby avoiding the environmental compliance investments, and replacing the coal plant unit generation with market power purchases; and last, taking the difference between the continued operation model run and the 2015 idling model run to calculate the PVRR(d). Staff/1502 includes a detailed listing of other modifications Sierra Club notes

[4] Excel spreadsheet model was provided by PacifiCorp in response to Staff DR No. 220.

it made to the PacifiCorp spreadsheet model.[5]

Q. DESCRIBE WHAT WAS UPDATED IN AND THE RESULTS OF THE PVRR(d) ANALYSES PACIFICORP PROVIDED WITH ITS REPLY TESTIMONY.

A. For each coal plant unit in this rate case PacifiCorp updated its PVRR(d) analysis considering a 2014 idling date. In addition, the market power price forecast for the Naughton Units 1 and 2 analyses was updated from December 2008 to March 2009 to coincide with what was available at decision making in May 2009. The selection of a 2014 idling date is later in time than I suggest above but not as late as Sierra Club and CUB advocate for. The reason behind selecting 2014 is discussed in PacifiCorp reply testimony (PAC/1500 Teply/4-5). The 2014 idling date appears to be a reasonable analysis compromise. The updated PVRR(d) analyses provided by PacifiCorp show, compared to its decision making analyses, a [redacted] for all coal plant units from making the environmental compliance investments. The PVRR(d) analysis results for each coal plant unit, as calculated by both Sierra Club and PacifiCorp, are summarized in Staff/1501. As Staff/1501 shows, both Sierra Club and PacifiCorp calculate [redacted] PVRR(d) results ([redacted]) for all the coal plant units [redacted] Naughton Units 1 and 2.

Q. HOW DO YOU RECONCILE THE DIFFERENCE BETWEEN THE SIERRA CLUB AND PACIFICORP PVRR(d) ANALYSES RESULTS?

[5] From the Changes tab in the "Naughton 1-2 - Mod 2.4_AnalysisDate_Run_To_2029" and "Naughton 1-2 - Mod 2.4_AnalysisDate_Retire_2015" worksheet files provided in Sierra Club/100.

A. I am not able to reconcile the difference between the Sierra Club and PacifiCorp PVRR(d) analyses results. In my review of the analyses, both analyses approaches appears to be valid and I do not find errors. In response to Staff DR No. 1, Sierra Club provided instructions to configure its PVRR(d) models to prove the analysis approach and model are functioning properly. Sierra Club's response to DR No. 1 is attached as Staff/1507. A "proof" run of the model for the Naughton Units 1 and 2, configured as instructed by Sierra Club, provided PVRR(d) results the same as those calculated by PacifiCorp in PAC/500. In the data request response Sierra Club also discussed the contribution of a number of analysis assumptions to the difference between the PacifiCorp PVRR(d) results and those of Sierra Club for the Naughton Units 1 and 2. Sierra Club's response did not note errors in PacifiCorp spreadsheet calculation as a contributing factor to the differences. The Sierra Club data request response notes that it has not completed its review of the updated PacifiCorp PVRR(d) analyses and result, but would do so to support its rebuttal testimony. Until I have evidence of error (not error in analysis assumptions, but rather in spreadsheet calculations) in the PacifiCorp PVRR(d) model I am inclined to discount, but not ignore, the Sierra Club PVRR(d) results. This is because Sierra Club made significant modifications to PacifiCorp's spreadsheet model, thus introducing more opportunity for error than in the case of PacifiCorp utilizing its familiar model. My conclusion, at this time, is that because the Sierra Club and PacifiCorp PVRR(d) results differ, overall the Naughton Units 1 and 2 PVRR(d) results are inconclusive.

Q. DO THE SIERRA CLUB, CUB AND PACIFICORP TESTIMONIES RAISE OTHER ISSUES?

A. Yes. Sierra Club and CUB raised issues in addition to the three discussed above. As stated above, I considered each of the issues raised and identified several particularly significant ones for detailed discussion. Near the end of this rebuttal testimony I provide responses, by coal plant unit, to the other issues raised in the Sierra Club and CUB testimony. PacifiCorp's reply testimony also raised several issues which I reply to near the end of this rebuttal testimony.

Q. WHICH COAL PLANT UNITS ARE OF CONCERN FOLLOWING REVIEW OF SIERRA CLUB, CUB, AND PACIFICORP TESTIMONIES, AND THE UPDATED PVRR(d) ANALYSES?

A. Staff/1501 presents the various PVRR(d) analysis results for each coal plant unit. Based on the PVRR(d) analysis results, recognizing that there are infirmities in the decision making process for all the coal plant units, the units of particular concern are the Naughton Units 1 and 2. I discuss below why these coal plant units are of particular concern.

Q. WERE PACIFICORP'S ACTIONS TO INVEST IN ENVIRONMENTAL COMPLIANCE PROJECTS REASONABLE GIVEN WHAT THE COMPANY KNEW OR SHOULD HAVE KNOWN AT THE TIME?

A. As noted in my opening testimony, and its updates below, there are infirmities in the process PacifiCorp used to inform its decisions to proceed with the Naughton Units 1 and 2, Dave Johnston Unit 4, Hunter Units 1 and 2, Wyodak, and Jim Bridger Unit 3 environmental compliance projects. Referring to the thinking tool I illustrated early in this rebuttal testimony, I conclude that the decision making process for all these coal plant units was "more good than bad."

Contrasting with the decision making process infirmities, the calculated PVRR(d) from the environmental compliance investments for Dave Johnston Unit 4, Hunter Units 1 and 2, Wyodak, and Jim Bridger Unit 3 is [redacted], as shown on Staff/1501. Considering that the calculated PVRR(d) for these coal plant units is [redacted], and referring to the thinking tool I illustrated early in this rebuttal testimony, I rate the result as "good." For conditions where the result is "good" and the process is "more good than bad", I conclude the actions were reasonable and therefore were prudent.

Q. PLEASE SUMMARIZE YOUR SPECIFIC CONCERNS REGARDING NAUGHTON UNITS 1 AND 2.

A. As noted above, there are infirmities in the process PacifiCorp used to inform its decision to proceed with the Naughton Units 1 and 2 environmental compliance projects. The environmental compliance investments are summarized in the table below.

Coal Plant Unit	Project	Amount (PAC Share)	Reference
Naughton Unit1	Wet Scrubber Addition	$121 million	PAC/500 Teply/29
Naughton Unit1	Low NOx Burner Addition	$9 million	PAC/500 Teply/31
Naughton Unit 2	Wet Scrubber Addition	$155 million	PAC/500 Teply/39
Naughton Unit 2	Low NOx Burner Addition	$9 million	PAC/500 Teply/41

The decision making process infirmities identified in my opening testimony, and as updated in my rebuttal testimony, were: 1) failure to consider carbon dioxide (CO2) emission regulation at the time of decision; 2) failure to include capital cost proxies for compliance with potential coal combustion residuals (CCR), effluent limit, and cooling water intake (316b) requirements; 3) failure to include sensitivity analyses for variations in capital cost, variation in fuel and electricity costs, or variation in CO2 regulatory cost; and 4) failure to update analyses as significant milestones were reached. In addition to the decision making process infirmities, the calculated PVRR(d) from the environmental compliance investments is either a [redacted] to customers ([redacted]) or a [redacted] to customers ([redacted]), depending upon the source of the calculation (PacifiCorp or Sierra Club, respectively). These two different analyses makes the result inconclusive. Given the Naughton Units 1 and 2 decision making process infirmities and inconclusive PVRR(d) result, I reach no clear conclusion of reasonableness.

Q. WERE PACIFICORP'S ACTIONS TO INVEST IN ENVIRONMENTAL COMPLIANCE PROJECTS AT THE NAUGHTON UNITS 1 AND 2 REASONABLE GIVEN WHAT THE COMPANY KNEW OR SHOULD HAVE KNOWN AT THE TIME?

A. After considering the information offered to date in this docket I am convinced reasonableness is a matter of perspective. I also am convinced that the wording of the prudence standard allows for degrees of reasonableness – otherwise the wording would have said the action must be reasonable to be prudent rather than determined by the reasonableness of the action.

In addition to highlighting a number of PacifiCorp decision making infirmities, Sierra Club and CUB present a number of analyses assumptions that differ from those used by PacifiCorp in decision making. The Sierra Club and CUB analyses assumptions reflect and lead to a decision making paradigm where the risks posed by existing, impending, and potential environmental regulations may result in actions being reasonable if they favor early coal plant unit retirement. I conclude this is a reasonable decision making paradigm based on that particular perspective.

PacifiCorp, on the other hand, is a load serving entity. For background, a load serving entity (LSE) is an entity that serves energy to end-use customers, often also operating a distribution and transmission system. In providing this service the LSE must meet reliability, quality and safety standards. PacifiCorp, and its predecessors, have operated its coal plant units for decades as the foundation of a generation fleet to meet its service obligations. As shown in Staff/403, the environmental regulatory future for coal plant units has been complex since at least 1990, and the coal plant units have faced and met the challenges of that past.[6] When faced with an uncertain environmental compliance future and inconclusive PVRR(d) analysis results, I conclude the Company could reasonably have a decision making paradigm where it continues utilizing known and proven generation resources that have met the test of time and regulation. I conclude this is also a reasonable decision making paradigm based on that particular perspective.

In considering these matters I start by noting, as discussed above, and referring to the thinking tool illustrated early in this rebuttal testimony, that I conclude the decision making process for the Naughton Units 1 and 2 coal plant units was "more good than bad." In addition to the decision making process infirmities identified, the calculated PVRR(d) benefit to customers from the environmental compliance investments is either a [redacted] to customers ([redacted]) or a [redacted] to customers ([redacted]

[6] This decision making paradigm is illustrated in PAC/1400 Woollums/4 and 5, and PAC/1500 Teply/10 and at 38-39.

[redacted]), depending upon the source of the calculation (PacifiCorp or Sierra Club, respectively), making the results inconclusive. Considering that the calculated PVRR(d) for these coal plant units is a [redacted], and referring again to the thinking tool, I rate the result as "somewhat good to somewhat bad." For conditions where the result is "somewhat good to somewhat bad" and the process is "more good than bad," the actions fall into the shaded policy judgment area.

As I discuss above, I conclude the Company could reasonably have a decision making paradigm where it decides to continue utilizing known and proven generation resources that have met the test of time and regulation. Under this line of reasoning, I find the Company's actions to proceed with the environmental compliance investments at the Naughton Units 1 and 2 were not unreasonable. As a result, under the Commission's prudence standard I conclude the actions were not imprudent. However, recognizing the Commission may draw a different conclusion, I present below potential remedies for imprudence.

Q. WHAT REMEDIES ARE THERE FOR IMPRUDENCE?

A. Preliminarily, I wish to make two points concerning a possible prudence disallowance. First, regardless of whether the Commission reaches a conclusion of prudence or imprudence for any of the generation plants at issue, I recommend the Commission clarify in this docket its going-forward expectations regarding analyses prior a utility making environmental compliance investments at existing resource units. Second, as illustrated by CUB's reply testimony, constructing the proper prudence disallowance is a complex inquiry with consequences that must be carefully considered (*See, e.g.*, CUB/100 Jenks-Feighner/14-18). As such, Staff discusses the following two potential remedies at a somewhat high level of scrutiny. Should the Commission desire to impose a prudence disallowance for one, or more, of the coal plant units, as discussed in Remedy Option 1, Staff recommends the Commission allow more time for Staff and the parties to prepare a specific recommendation in response to whatever findings of imprudence the Commission determines. To allow for the necessary time for this inquiry, Staff recommends, in the case of a finding of imprudence, that the Commission allow the coal plant unit at issue to go into rates at the conclusion of this proceeding, but subject to a deferral and later reconciliation.

Although there are certainly more options, Staff will discuss two primary remedies for imprudence or cost disallowance in this docket:

1. Disallow the environmental compliance investments, including return of and on capital, and the associated operation and maintenance costs. Impute a shutdown date for the unit and remove all of the costs (including lost output due to the increased parasitic loads) and benefits of continued coal plant unit operation from revenue requirement.

2. Disallow certain management costs to reflect past inadequate management performance which is expected to continue while the new rates are in effect.

Q. PLEASE EXPLAIN STAFF'S FIRST POSSIBLE REMEDY SUPPORTING A PRUDENCE DISALLOWANCE OF COSTS RELATED TO THE ENVIRONMENTAL COMPLIANCE COSTS AT ISSUE.

A. If the Commission determines that PacifiCorp acted imprudently in making environmental compliance investments at one or more of the coal plant units at issue, it may exclude those investment costs from the approved revenue requirement. However, this would not be the end of the inquiry. The Commission would then have to assume the coal plant unit was closed by a certain date due to its failure to comply with applicable environmental, or other related, laws (*See, e.g.*, PAC/1400 Woollums/25-26; CUB/100 Jenks-Feighner/16-17). In this case, the Commission would then need to determine how the coal plant unit's power output would be replaced and impute the costs of the replacement resource into PacifiCorp's rates. In theory, this imputation would have the effect of disallowing the difference in total cost between the continued operation of the coal plant unit and the operation of the replacement resource during the test period of the rate case (*See, e.g.*, Commission Order No. 02-772 at 14 (Commission disallowed imprudently incurred power purchase contracts and re-priced them to more appropriate levels)). But, it would take time to perform this inquiry which is why Staff notes the need for a deferral and later reconciliation.

Q. PLEASE EXPLAIN STAFF'S SECOND POSSIBLE REMEDY SUPPORTING A DISALLOWANCE RELATED TO THE ENVIRONMENTAL COMPLIANCE COSTS AT ISSUE.

A. The infirmities found with PacifiCorp's decision making process underlying the environmental compliance investments it made at the coal plant units under consideration have been discussed at length in this rebuttal testimony. As a second possible remedy, the Commission could determine that, based upon these infirmities, PacifiCorp's management performed in an unsatisfactory manner and there is nothing in the record to show that the management team would perform any differently in the future. In this case, the Commission could make an adjustment in the rate case to management costs to reflect a lower quality of management expected at the Company during the time the new rates will be in effect. The Commission has made this type of determination in the past[7] (*See* Commission Order No. 11-432 ("PGE's management must ensure that the company complies with Commission orders. From the facts of this case, we find that PGE's management is not complying with our instructions in docket UE 139, and to ensure the company's future compliance, we reduce PGE's 2012 NVPC forecast by $2.6 million. This amount is the monetary equivalent of a one year, 10-basis-point reduction in PGE's authorized ROE. When PGE files its 2012 power cost

[7] Staff notes that its second remedy option operates differently from CUB's recommended "option 3" 25% penalty disallowance. *See* CUB/100 Jenks-Feighner/17-18. CUB's penalty approach seems to represent a retroactive disallowance which, if true, would be unlawful. In contrast, Staff's remedy of disallowing management costs would be prospective in that it is based upon a finding that PacifiCorp's management is expected to continue to perform in a less-than-adequate manner during the times rates would be in effect.

adjustment mechanism tariff to true-up actual 2012 NVPC with the forecast, PGE must ensure that the full $2.6 million reduction flows to customers.") and Commission Order No. 97-171 ("due to continuing USWC service problems with no quick solutions in sight, we adopted the low end of Staff's proposed reasonable range of return on equity, 10.2 percent, as USWC's approved rate of return. We adopted this rate of return in anticipation that USWC's quality of service will not rise to its pre-AFOR level while rates from this docket are in effect. The low end of the rate of return range reflects USWC's lowered service quality.")).

Q. WHAT ARE THE UPDATES TO YOUR OPENING TESTIMONY THAT YOU WISH TO HIGHLIGHT?

A. I would like to highlight the following updates to my opening testimony (Staff/400). The effect of these updates is addressed and incorporated into the remainder of my rebuttal testimony.

- Contrary to my statements on Staff/400 Colville/8, line 15, page 9 line 13, page 12 line 12, page 15 line 10, and page 19 line 9, the Company did perform a sensitivity analysis for variations in the market price of power. As a result, I remove this observation from my list of decision making process infirmities.
- On Staff/400 Colville/11, line 13, and at page 12, line 5, I state that the Company's analyses considered only one alternative to making environmental compliance investments – that being idling a coal plant unit and replacing it with market power purchases. However, I do not

conclude in my opening testimony, nor in this rebuttal testimony, that considering only one alternative to making the investments is a decision making process infirmity. Given that the market price of electricity does not generally include all the fixed and variable costs of generating electricity, had the Company considered a replacement resource such as a combined cycle combustion turbine (CCCT) or refueling the coal plant unit with natural gas, it is likely the PVRR(d) benefit may well have been significantly higher than the Company presented in its testimony. While I have not performed an analysis using replacement resources to verify this possibility, if it is true, then the Company erred on the conservative side in its choice of analyses which used only market power purchases.

- In my opening testimony I did not consider the impact of the assumed idling date on the PVRR(d) analyses. Staff issued data request (DR) No. 340 to PacifiCorp requesting the reasoning behind the assumed idling dates. The Company responded to the data request and stated that its intent was to understand the economics of the coal plant units at the time of decision making. The Company's response to DR No. 340 is attached as Staff/1504. While I can agree this reasoning was logical, in the context of decision making, I do not consider it reasonable because of the impact on the PVRR(d) results. As a result, I conclude the Company's use of the decision making dates for idling the coal plant units, rather than State permit compliance dates, in its PVRR(d) analyses is a decision making process infirmity.

- Sensitivity cases for analysis of Best Available Retrofit Technology (BART) compliance costs were not analyzed. I consider lack of sensitivity analyses to be a decision making process infirmity. Since I did not note this specific infirmity in my opening testimony, I add it to the list of decision making process infirmities on Staff/400 Colville/8, line 15, page 9, line 13, page 12, line 12, page 15, line 10, and at page 19, line 9.
- After filing my testimony I learned I had misinterpreted the Company's testimony and drawn an incorrect conclusion that its PVRR(d) analyses were updated annually in its business planning process. This misinterpretation is reflected on Staff/400 Colville/8, line 18, page 13, line 14, page 14, line 22, and at page 19, line 6-7. The Company's response to Staff DR No. 336, which refers to the response to Sierra Club data request 3.1, corrects my misinterpretation. The Company's response to DR No. 336 is attached as Staff/1505. I now conclude the Company's decision making PVRR(d) analyses were not updated annually in its business planning process.
- After filing my opening testimony I learned I had misunderstood the treatment in the Company's 2011 Integrated Resource Plan (IRP) supplemental and updated analyses of pre-2012 capital investments. The Company's response to Staff data request 335 clarified that the pre-2012 investments were not considered in its post-2011 analyses. The Company's response to DR No. 335 is attached as Staff/1506. This misunderstanding affects my earlier conclusion that the Company's

updated analyses showing a benefit to customers could be extrapolated back to the decision making time period (Staff/400 Colville16, line 8). I now conclude that the 2011 IRP analyses are stand-alone analyses of future environmental compliance investments and not updates of the decision making analyses.

Q. WERE THERE OTHER ISSUES RAISED IN THE SIERRA CLUB, CUB OR PACIFICORP TESTIMONY?

A. Yes. While I have presented my rebuttal testimony above which explains my conclusion and recommendations in this matter, I will respond to additional selected issues raised by Sierra Club, CUB and PacifiCorp. For ease of presentation, I will state each selected issue and then provide my response. I start with issues raised by Sierra Club or CUB, or both, and conclude with selected PacifiCorp issues.

SIERRA CLUB OR CUB ISSUES

1. General Issues

A. The "Boardman" *Best Available Retrofit Technology (BART)* analysis approach should have been used (CUB/100 Jenks-Feighner/22-25).

Response: The Boardman approach to BART analysis was not recognized as being beneficial until late 2010, so I do not consider it a precedent for the environmental compliance investment decisions in this docket. I do conclude the decision making process could be better informed by considering the remaining useful life to be a variable, as was done in the Boardman approach to BART analysis. I also recognize that the ability to meaningfully consider alternatives to compliance derived from varying the remaining useful life is likely dependent upon the regulatory environment where the coal plant unit is located. Going forward, I suggest it is the Company's responsibility to prove it is not reasonable to consider the remaining life as a variable in BART analyses.

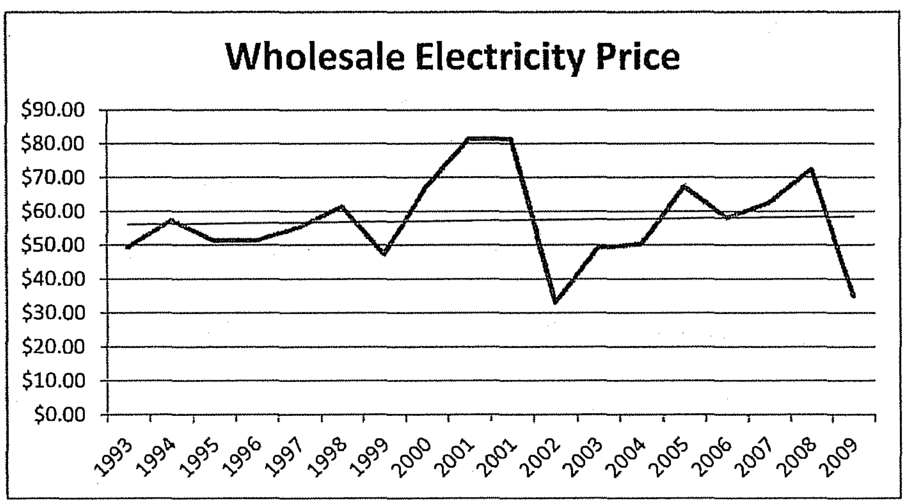
B. Environmental compliance investments should have been postponed until the Regional Haze Rule (RHR) is finalized (CUB/100 Jenks-Feighner/26, and Sierra Club/100 Fisher/57), the regulatory path was clear (Sierra Club/100 Fisher/6, and CUB/100 Jenks-Feighner/42), and the costs and risks were more clear (Sierra Club/100 Fisher/52).

Response: With state permit compliance deadlines and impending federal compliance deadlines, I would not consider postponing action while awaiting a clear regulatory path to be reasonable given what information the Company had or reasonably could have had. As a result, such a postponement would not be prudent.

C. The Company failed to revisit analyses as conditions changed (Sierra Club/100 Fisher/42, CUB/100 Jenks-Feighner/32-34, 40-41, 45-46, 51-52, and 55-56).

Response: As stated in my opening and rebuttal testimony, I consider it a decision making process infirmity to not re-evaluate decisions at significant milestones, such as beginning physical construction activities.

Specifically related to the market electricity price, looking at the market price of electricity at the time of decision making, I am not convinced PacifiCorp had a clear picture that prices were on a long term decline as Sierra Club asserts. The market electricity price figure below represents the picture available for decision making in 2009. The 2008 down turn in prices looks similar to the temporary downturn in 2001.



D. The Company should have considered whether some aspects of the Energy Gateway transmission project would still be needed if coal plant units were idled (Sierra Club/100 Fisher/50, 56).

Response: At the time of decision making the Energy Gateway transmission project was a concept without regulatory approval. As noted in PacifiCorp's reply testimony, without evidence or support that Energy Gateway transmission project configuration or costs would be affected by a decision to idle coal plant units, such a contention is speculative. Because the Energy Gateway costs are not specifically related to the environmental compliance investment decision they should not be a part of the analysis to inform that decision.

E. The Company is using a piecemeal approach to evaluate investments (CUB/100 Jenks-Feigner/18).

Response: I find the PacifiCorp decision making analyses to have infirmities but not to be a "piecemeal" approach. If the process was conducted without infirmities, the life-cycle economic analysis would include every cost reasonably foreseeable. A problem arises because no one has perfect foresight, and concluding what is reasonably foreseeable is a matter of opinion.

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

A. There was no regulatory basis for making the investments (Sierra Club/100 Fisher/14).

Response: Without second guessing the underlying motives, I see a regulatory basis for making the investments beginning with the 2002 Multi-pollutant Control Report, followed by the June 14, 2006 Wyoming Department of Environmental Quality (WDEQ) BART determination leading to the January 2007 WDEQ permit application, all possibly in an attempt to be proactive. The January 2007 WDEQ permit application then led to permit MD-5156 with compliance dates of May 2012 for Unit 1 and November 2011 for Unit 2.

B. The Company acted to mitigate risk of [redacted] without regard for regulatory requirements (Sierra Club/100 Fisher 25).

Response: My plain reading of the cited documents is that the Company developed and is following through with a plan that attempts to manage the risks of a fluid environmental regulatory situation. I conclude that managing risks is reasonable.

C. The Company should have used the System Optimizer model rather than or in addition to a spreadsheet model (Sierra Club/100 Fisher/32).

Response: Based upon PacifiCorp testimony, and my experience from the PacifiCorp 2011 IRP Docket No. LC 52, System Optimizer was not configured to do this type of analysis until 2011.

D. Capital cost estimates in the analyses were incomplete:

a. Flue Gas Desulfurization (FGD) pond closure and expansion (Sierra Club/100 Fisher/35).

Response: While I recognize some FGD pond projects are required regardless of whether the coal plant unit continues to operate, pond expansion or other residuals related projects will likely be required due to the environmental compliance investment decision. A proxy cost for these related projects should be a part of the analysis to inform the decisions.

b. Stack replacement (Sierra Club/100 Fisher/35-36).

Response: Based on the Company's response to Staff DR No. 338 the capital cost for replacement of the stack was included in the decision making PVRR(d) analysis. The Company's response to DR No. 338 is attached as Staff/1508.

c. Selective Catalytic Reduction (SCR) (Sierra Club/100 Fisher/36 and CUB/100 Jenks-Feighner/42).

Response: Based on the Naughton Units 1 and 2 BART analyses, WDEQ permit requirements, and PacifiCorp's reply testimony, SCR is not planned or expected for the Naughton Units 1 and 2 (PAC/1500 Teply/14).

d. Activated carbon injection (ACI) for mercury control (Sierra Club/100 Fisher/38).

Response: Since the likelihood of Environmental Protection Agency mercury control rules was known at the time of decision making PacifiCorp should have included a proxy cost for compliance. Based on capital cost estimates provided as part of the coal replacement study screening model[8] a proxy cost of approximately [redacted] for each coal plant unit would have been appropriate. This level of capital investment is not a significant addition to the analyses for these coal plant units.

E. The analyses failed to include generation degradation and increased parasitic load (Sierra Club/100 Fisher/37).

Response: I will respond to the parasitic load issue first. Based on PacifiCorp's response to Staff DR No. 337, the increased parasitic load from the environmental compliance equipment additions was not included in the decision making analyses. The Company's response to DR No. 337 is attached as Staff/1509. Since the increased parasitic load reduces the coal

[8] The coal screening model and associated capital cost stream was provided in Docket No. LC 52 as support for and part of the Company's March 30, 2012 Coal Replacement Study Update.

plant unit generation, it should have been included in the analysis. Having said this, considering that total coal plant unit parasitic load is generally a small percentage of generation, I could not reasonably conclude that the increased parasitic load would be a significant factor in the PVRR(d) analysis. As to the generation degradation issue, generation degradation is related to the coal plant unit age and condition. Generation degradation is not related specifically to environmental compliance investments so it should not be included in such decision making analyses.

3. <u>Hunter Units 1 and 2</u>

A. Capital cost estimates in the analyses were incomplete:

a. SCR (Sierra Club/100 Fisher/54 and CUB/100 Jenks-Feighner/52).

Response: Based on PacifiCorp's reply testimony, SCR could reasonably have been considered (it was included in the Hunter Unit 2 analysis) but doing so would not have changed the Company's decision to proceed with the environmental compliance investments for the Hunter Units 1 and 2 (PAC/1500 Teply/15-16).

b. Turbine upgrade costs (Sierra Club/100 Fisher/54).

Response: Turbine upgrades are justified on their own merits and are not part of the environmental compliance investment decision. Because these costs are not specifically related to the environmental compliance investment decision they should not be a part of the analysis to inform that decision.

c. CCR proxy (Sierra Club/100 Fisher/54).

Response: While I recognize some CCR projects are required regardless of whether the coal plant unit continues to operate, other residuals related projects will likely be required as a result of the environmental compliance investment decision. A proxy cost for these related projects should be a part of the analysis to inform the decisions.

d. Capital cost is [redacted] estimated (CUB/100 Fisher/52).

Response: Both the [redacted] and [redacted] updated PVRR(d) benefits for Hunter Units 1 and 2 presented in the Company's reply testimony are larger than the alleged missing capital cost so including it would not have changed the business decision.

B. The coal cost should have been analyzed to reflect the change to the Cottonwood mine in 2020 (Sierra Club/100 Fisher/55).

Response: As discussed in PacifiCorp's reply testimony, the Company was aware of future risks associated with coal supplies but used the then-current fuel cost trajectory in the decision making analyses. This was a reasonable action.

4. Wyodak

A. Concern that PacifiCorp is withholding some costs for the complete baghouse project in this rate case to influence future rate cases (Sierra Club/100 Fisher/59-60).

Response: As stated in PacifiCorp's reply testimony, the total cost for the baghouse project was described in PAC/500 and was included in this docket.

B. Capital cost estimates in the analyses were incomplete:

a. $[redacted] investments (CUB/100 Jenks-Feighner/56).

Response: The [redacted] investments appears to represent addition of SCR. Based on the Wyodak BART analysis, WDEQ permit requirement, and the Company's BART Appeal Settlement Agreement[9], no SCR is required, planned or expected. In addition, the [redacted] updated PVRR(d) benefit presented in the Company's reply testimony is larger than the alleged missing capital cost so including it would not have changed the business decision.

5. Jim Bridger Unit 3

[9] Provided in response to Staff DR No. 269.

Capital cost estimates in the analyses were incomplete because they did not include SCR (CUB/100 Jenks-Feighner/34-35).

Response: Based on the Company's response to Staff DR No. 138, the cost for SCR was included in the decision making analyses. The Company's response to DR No. 138 is attached as Staff/1510.

6. Dave Johnston Unit 4

Capital cost estimates in the analyses were incomplete because the more recent estimate went up about $[redacted] (CUB/100 Jenks-Feighner/46)].

Response: This level of capital investment is not a significant addition to the analyses for this coal plant unit.

PACIFICORP ISSUES

I offer the following responses to selected issues raised by PacifiCorp in its reply testimony (PAC/1500).

A. The Company notes that it considered potential CO2 emissions costs in its analyses. PAC/1500 Teply/8, 12 and 14. As discussed in my opening and rebuttal testimony, consideration of CO2 regulation, and CO2 cost sensitivity analyses were not present in PacifiCorp's decision making analyses. The extent of CO2 cost consideration I was able to find is limited to the market power price forecast.

B. The Company discusses changes in capital cost estimates since decision making. PAC/1500 Teply/17, 25 and 32. My comparison of the capital cost estimates used in decision making (response to Staff DR No. 138) with the capital cost estimates derived by adding the decision making capital cost to the post-2011 capital cost stream included in the coal screening model[10] arrives at different change amounts than the Company does. My comparison is attached as Staff/1503. While I find this discrepancy, I do not conclude the differences impact the Company's decision to proceed.

C. The Company notes that capital cost estimates for compliance with CCR regulations were not known at the time of decision making. PAC/1500 Teply/22. Although I agree these costs were not known with certainty, the impending CCR regulations were known and the Company's analysis should have included proxy cost estimates, or a capital cost sensitivity analysis should have been conducted, to determine the possible impact of the regulations.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[10] The coal screening model and associated capital cost stream was provided in Docket No. LC 52 as support for and part of the Company's March 30, 2012 Coal Replacement Study Update.

CASE: UE 246
WITNESS: ERIK COLVILLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1501

Exhibits in Support
Of Reply Testimony

August 13, 2012

STAFF EXHIBIT 1501

IS CONFIDENTIAL

AND SUBJECT TO PROTECTIVE

ORDER NO. 12-060 IN UE 246.

YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER

TO RECEIVE THE

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OF THIS EXHIBIT.

PVRR(d) Comparison

Coal Plant Unit	Environmental Compliance Projects Included in PVRR(d) Analysis	PacifiCorp Decision Making PVRR(d)	Sierra Club 2015 Idling PVRR(d)	PacifiCorp Reply Testimony PVRR(d)
Naughton Unit 1	Wet Scrubber addition, LNB	[redacted]	[redacted]	[redacted]
Naughton Unit 2	Wet Scrubber addition, LNB	[redacted]	[redacted]	[redacted]
Dave Johnston Unit 4	Dry Scrubber, Fabric Filter addition, LNB, Hg controls	[redacted]	[redacted]	[redacted]
Hunter Unit 1	Wet Scrubber upgrade, Baghouse addition, LNB	[redacted]	[redacted]	[redacted]
Hunter Unit 2	Wet Scrubber upgrade, ESP conversion to Baghouse, LNB, SCR	[redacted]	[redacted]	[redacted]
Wyodak	Baghouse addition/SO2 Upgrade, LNB	[redacted]	[redacted]	[redacted]
Jim Bridger Unit 3	Wet Scrubber upgrade, Hg controls, SCR	[redacted]	[redacted]	[redacted]

LNB = low NOx burner
Hg = mercury
ESP = electrostatic precepitator
SCR = selective catalytic reduction

Positive = benefit to customers
Negative = cost to customers

CASE: UE 246
WITNESS: ERIK COLVILLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1502

Exhibits in Support
Of Reply Testimony

August 13, 2012

STAFF EXHIBIT 1502

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Modifications Noted by Sierra Club in the "Changes" Tab of Excel Spreadsheet Files Named:

- "Naughton 1-2 - Mod 2.4_AnalysisDate_Run_To_2029", and
- "Naughton 1-2 - Mod 2.4_AnalysisDate_Retire_2015"

provided with Sierra Club/100.

Run till 2029:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Run till 2015

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

CASE: UE 246
WITNESS: ERIK COLVILLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1503

Exhibits in Support
Of Reply Testimony

August 13, 2012

STAFF EXHIBIT 1503

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Nominal Dollars

Dave Johnston U4	NPV @ 7.17%	Total	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Dave Johnston U4 NOX			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			-	-	-										
DJ U4 Mercury CEMS			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			-	-	-										
U4 Mercury Controls			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]			-	-	-										
U4 CEM Equipment Replacement			[redacted]	-	-	-	-			-	-	-										
U4 Clean Air - SO2 & PM			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-										
Totals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-										
Coal Screening Upfront Coal Capital + Rate Case Capital	[redacted]	[redacted]				104,000,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Author:
In rate case

Hunter U1	NPV @ 7.17%	Total	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
HTR U1 SO2 & PM Em Cntrl Upgrades					-	-	-	-	-	-	-	-	-	-								
Hunter U1 Clean Air - SO2					[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-								
Hunter U1 Clean Air - PM						[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-								
Hunter U1 NOx LNB Development - Clean Air						-	[redacted]	-	-	-	-	-	-	-								
Hunter U1 NOx LNB Build - Clean Air						-	-	[redacted]	[redacted]	-	-	-	-	-								
301 CEM Equipment Replacement						-	-	-	-	-	-	-	-	-								
HTR U1 Mercury CEMS						-	-	-	-	-	-	-	-	-								
Totals	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-								
Coal Screening Upfront Coal Capital + Rate Case Capital	[redacted]	[redacted]				55,000,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Author:
In rate case

Hunter U2	NPV @ 7.17%	Total	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
HTR U2 SO2 & PM Em Cntrl Upgrades					-	-	-	-	-	-	-	-	-	-								
302 Clean Air - PM					[redacted]	[redacted]	-	-	-	-	-	-	-	-								
U2 Clean Air - SO2					[redacted]	[redacted]	-	-	-	-	-	-	-	-								
Hunter U2 NOx LNB Development - Clean Air					[redacted]	[redacted]	-	-	-	-	-	-	-	-								
Hunter U2 NOx LNB Build - Clean Air					[redacted]	[redacted]	-	-	-	-	-	-	-	-								
Hunter U2 NOx SCR Development - Clean Air					-	-			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]								
Hunter U2 Clean Air - SCR - Build					-	-			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]								
302 CEM Equipment Replacement					-	-			-	-	-	-	-	-								
HTR U2 Mercury CEMS					-	-	-	-	-	-	-	-	-	-								
Totals	[redacted]	[redacted]			[redacted]	[redacted]	-	-	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]								
Coal Screening Upfront Coal Capital + Rate Case Capital	[redacted]	[redacted]				27,000,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Author:
In rate case

Jim Bridger U3	NPV @ 7.17%	Total	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
JB U3 SO2 & PM Em Cntrl Upgrades Dev			[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-										
U3 Clean Air - SCR			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-										
U3 JB NOX			[redacted]	[redacted]	[redacted]	[redacted]					-	-										
U3 Mercury CEMS			[redacted]	[redacted]	[redacted]	[redacted]			-	-	-	-										
U3 Mercury Controls			[redacted]	[redacted]	[redacted]	[redacted]			-	-	-	-										
U3 CEM Equipment Replacement			[redacted]	[redacted]	[redacted]	[redacted]			-	-	-	-										
U3 SO2 & PM Emission Controls Upgrades			[redacted]	[redacted]	[redacted]	[redacted]			-	-	-	-										
Totals	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	-										
Coal Screening Upfront Coal Capital + Rate Case Capital	[redacted]	[redacted]				17,000,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Author:
In rate case

Naughton U1	NPV @ 7.17%	Total	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
U1 FGD System (Implementation)				[redacted]	[redacted]	[redacted]	[redacted]			-	-	-	-									
NAU U1 Mercury CEMS				[redacted]	[redacted]	[redacted]	-			-	-	-	-									
NAU U1 Flue Gas Desulfurization Sys				[redacted]	[redacted]	[redacted]	-			-	-	-	-									
U1 OH Clean Air - NOx				[redacted]	[redacted]	[redacted]	[redacted]			-	-	-	-									
Totals	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-									
Coal Screening Upfront Coal Capital + Rate Case Capital	[redacted]	[redacted]				130,000,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Author:
In rate case

Naughton U2	NPV @ 7.17%	Total	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
U2 OH Clean Air - NOx				[redacted]	[redacted]	[redacted]	[redacted]			-	-	-	-									
U2 FGD System (Implementation)				[redacted]	[redacted]	[redacted]	[redacted]			-	-	-	-									
NAU U2 Mercury CEMS				[redacted]	-	-	-			-	-	-	-									
NAU U2 Flue Gas Desulfurization Sys				[redacted]	[redacted]	[redacted]	-			-	-	-	-									
Totals	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]	-	-	-	-	-	-									
Coal Screening Upfront Coal Capital + Rate Case Capital	[redacted]	[redacted]				164,000,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Author:
In rate case

Wyodak U1	NPV @ 7.17%	Total	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
U1 OH Clean Air - SO2				[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-									
U1 OH Clean Air - NOX - BUILD				[redacted]	[redacted]	[redacted]			-	-	-	-	-									
U1 OH Clean Air - NOX - DEVELOPMENT				[redacted]	[redacted]	[redacted]			-	-	-	-	-									
WDK U1 Mercury CEMS				[redacted]	[redacted]	[redacted]			-	-	-	-	-									
WDK U1 SO2 and PM Emiss Control Upgrado				[redacted]	[redacted]	[redacted]			-	-	-	-	-									
U1 - CEM Equipment Replacement				[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-									
Totals	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	-	-	-	-	-	-	-									
Coal Screening Upfront Coal Capital + Rate Case Capital	[redacted]	[redacted]				114,000,000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Author:
In rate case

Wyodak U1			2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
U1 OH Clean Air - SCR - BUILD		[redacted]			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]													

CASE: UE 246
WITNESS: ERIK COLVILLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1504

Exhibits in Support
Of Reply Testimony

August 13, 2012

OPUC Data Request 340

Related to the PVRR(d) analyses referred to on page 21 of PAC/500 Teply, please describe the reasoning for selecting the idling year for each coal plant unit rather than selecting the first permit compliance year for each coal plant unit (for example, selecting 2009 for idling Naughton Unit 1 rather than May 2012, the compliance date in permit MD-5156).

Response to OPUC Data Request 340

The Company's financial evaluation was intended to understand the full economics of the units at the time of decision-making, including CAI costs and CO_2 emissions costs at the time the economic analyses were completed. However, intervening parties have taken issue with the evaluation period used. Adjusting the Company's modeled retirement dates to coincide with the anticipated BART planning period compliance timeframe of 2013, rather than the originally evaluated dates, continues to result in favorable economics in the Company's base case analyses. This updated information was provided in Mr. Teply's reply testimony (PAC/1500), filed July 19, 2012.

OPUC Data Request 336

Please describe and identify dates of updates or re-evaluations of the PVRR(d) analyses referred to on page 21 of PAC/500 Teply.

Response to OPUC Data Request 336

Please refer to the Company's response to Sierra Club 3.1a.

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Pacific Power | Rocky Mountain Power
825 NE Multnomah, Suite 2000
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July 11, 2012

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RE: OR Docket No. UE-246
Sierra Club 3rd Set Data Request (1-8)

Please find enclosed PacifiCorp's Response to Sierra Club 3rd Set Data Request 3.1.

If you have any questions, please call Bryce Dalley at (503) 813-6389.

Sincerely,

Bryce Dalley/

Bryce Dalley
Director, Regulatory Affairs & Revenue Requirements

Enclosure:
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Sierra Club Data Request 3.1

Reference Exhibit 400, opening testimony of OPUC Staff witness Coleville/14-15 (lines 14/20-15/4): "The PVRR(d) analyses updates since decision making have been included in the Company's annual business planning and integrated resource planning, and have included proxy costs for CCR and 316(b) requirements and the effect of possible CO2 regulatory cost, and variation in fuel and electricity cost (PAC/500 Teply/16-19). The PVRR(d) analyses updates continue to show benefit to customers for making all the known environmental compliance investments and continuing to operate each coal plant unit."

(a) Has the Company updated PVRR(d) analyses for Hunter 1 & 2, Naughton 1 & 2, Dave Johnston 4, Jim Bridger 3, Wyodak 1, and/or Huntington 1 since the versions supplied in OPUC DR 220 and Sierra Club DR 2.3?

(b) If the answer to (a) is anything other than an unequivocal "no", please explain the Company's response to Sierra Club 2.1(i), which states: "The final economic analyses were not updated after the NTP dates for the respective projects."

(c) If the answer to (a) is anything other than an unequivocal "no," please provide any PVRR(d) analyses performed after the NTP dates that, in the words of Staff, "continue to show benefit to customers for … continuing to operate each coal plant unit." Provide analyses in original digital form, with formulas intact and unlocked.

(d) To the extent not previously provided in response to part (c) above or as part of the 2011 IRP coal utilization study and subsequent updates to the 2011 IRP, please identify any and all models or analyses used by the Company that evaluate the "benefit to customers for making all the known environmental compliance investments and continuing to operate each coal plant unit"?

(e) For any models or analyses identified in part (d) above, please provide any such analysis in original, digital form as available. If such analyses were conducted in System Optimizer or other proprietary software packages, please provide the output from these models as used by the Company and any spreadsheets or workpapers, summary, memoranda, presentations, or other documents or other products generated for internal review at the Company, or as used to inform any business plan. Provide model output and documentation in original, digital form.

(f) Please provide any PVRR(d) analyses performed as part of the Company's annual business planning process. Provide analyses in original digital form, with formulas intact and unlocked.

Response to Sierra Club Data Request 3.1

(a) No, the Company has not updated the final economic analyses utilized for decision-making since the versions supplied in the Company's responses to OPUC Data Requests 220 and Sierra Club Data Requests 2.3. However, the Company did include the subject units and associated costs in its 2011 integrated resource plan (IRP) activities, including the 2011 IRP Supplement and 2011 IRP Update, as discussed by Eric Colville, Colville/14 (lines 18-20).

(b) Not applicable.

(c) Not applicable.

(d) The quoted material in this request is taken out of context, and the Company therefore objects to this request as vague. Without waiving this objections, the Company responds as follows:

The PVRR(d) analyses updates associated with the referenced quotation have been provided as part of the Company's 2011 IRP activities, including the 2011 IRP Supplement and the 2011 IRP Update.

(e) Not applicable; previously provided in response as part of the 2011 IRP coal utilization study and subsequent updates to the 2011 IRP.

(f) The Company objects to this request as overly broad, unduly burdensome, and not reasonably calculated to lead to the discovery of admissible evidence. Without waiving these objections, the Company responds as follows:

The Company has supplied all relevant analyses.

OPUC Data Request 335

Assuming the following statement is true, please explain how it relates to the Coal Replacement Study referenced on page 100 of PAC/500 Teply:

Pre-2012 Comprehensive Air Initiative (CAI) costs are not considered to be avoidable while post-2011 costs are considered as avoidable. However, pre-2012 CAI costs are a part of the baseline costs for each coal plant unit that when combined with anticipated post-2011 costs must be overcome for the System Optimizer model to select continued coal plant unit operation instead of a replacement resource.

Whether the statement is true or false, please explain why, and fully describe how the pre-2012 CAI costs are handled in the Coal Replacement Study.

Response to OPUC Data Request 335

The Company understands the statement was made by the data requester and not made as part of the Company filings.

The statement is not correct. Pre-2012 CAI investments were treated as sunk costs and had no bearing on future CAI investment decisions analyzed in the Coal Replacement Study. Forward looking operation and maintenance expenses associated with pre-2012 CAI investments were included in the Coal Replacement Study and could be avoided in the event one of the units studied did not continue operating as a coal-fueled facility.

CASE: UE 246
WITNESS: ERIK COLVILLE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1507

Exhibits in Support
Of Reply Testimony

August 13, 2012

Via E-Mail and USPS

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97308-2148

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550 Capitol Street NE #215
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Michael Weirich
Department of Justice
1162 Court St NE
Salem, OR
97301-4096

August 6, 2012

Re: OR Docket No. UE-246 - OPUC Data Request 1

Please find enclosed Sierra Club's response to OPUC's first data request.

Please let me know if you require any additional documents or if you have any questions. Thank you.

Sincerely,

<u>/s/ Derek Nelson</u>
Derek Nelson
Program Assistant
Sierra Club Environmental Law Program
85 Second Street, 2nd Floor
San Francisco, CA 94105
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UE-246
August 6, 2012
OPUC Data Request 1

OPUC Data Request 1

For each of the Naughton Units 1 and 2 please identify and explain the differences between the PVRR(d) analysis methodologies, inputs, and results for the Excel spreadsheets entitled "OPUC 220-4 – Workpaper – Nau 1&2 – Rebuttal 2014 Close" provided with PacifiCorp reply testimony PAC/1500, and "Naughton 1-2 - Mod 2.4_AnalysisDate_Run_To_2029" minus "Naughton 1-2 - Mod 2.4_AnalysisDate_Retire_2015" provided with Sierra Club/100. For each methodology and input difference identified please describe the relative contribution of that difference to the results difference.

Response to OPUC Data Request 1

At the time that this discovery is due, we are still evaluating Mr. Teply's workpapers, and expect to be able to respond in full to this question in surebuttal testimony after we complete analysis. However, the following is our current understanding of the differences between Mr. Teply's revised analysis at Naughton 1 & 2 and the analysis supplied by Dr. Fisher in Sierra Club's direct testimony.

Dr. Fisher identified a number of errors and omissions in the original NPVRR(d) analysis supplied by the Company in OPUC 220-4. These errors in the original NPVRR(d) analysis included:

(a) an implied retirement date in 2008, rather than a later reasonable retirement deadline (Dr. Fisher suggested 2015),
(b) the use of a forecast capacity factor higher than that in the 2009 Strategic Asset Plan,
(c) the failure to examine generator degradation as predicted in the 2009 Strategic Asset Plan, and
(d) the failure to include the anticipated cost of an SCR at Naughton 1 & 2.

As Staff notes, to test error (a), Dr. Fisher created two separate workbooks entitled "Naughton 1-2 - Mod 2.4_AnalysisDate_Run_To_2029" minus "Naughton 1-2 - Mod 2.4_AnalysisDate_Retire_2015". The first of the workbooks models the gross PVRR of running the Naughton units through 2029 <u>with</u> the Comprehensive Air Initiative (CAI) retrofits. This workbook is different than the original OPUC 220-4 workbook in that it <u>excludes</u> the net benefit of running against market prices. The second workbook models the gross PVRR of running the Naughton units through 2015 and purchasing exclusively market power from 2016 through 2029.

Dr. Fisher then created additional scenarios in these workbooks to test errors (b)-(d). The first line of Dr. Fisher's workbook represents a "base case", i.e. the only change here is in the timing of the retirement (2015 instead of 2008). With this change only, Dr. Fisher found a net liability for N1 and N2 of -$49 and -$20 million, respectively, instead of +$23 and +$63 million, respectively.[1]

To replicate the results of the original PVRR(d) analysis using Dr. Fisher's version of the model, one would simply set the "Plant Calendar End Year" in tab "Data" of "Naughton 1-2 - Mod 2.4_AnalysisDate_Retire_2015" to 2008 instead of 2015, and copy the resulting values in the "Table" output tab to their respective locations in the "PVRR(d) Results – Naughton and Hunter" workbook.

In reply testimony, Mr. Teply appears to have conceded that point (a) regarding the retirement date was a valid concern, and submitted alternate PVRR(d) analyses in his rebuttal testimony. He also appears to have picked up another concern with the use of an up-to-date "official forward price curve" for the market price of electricity. The version used in the NPVRR(d) analysis was out of date by the time the Company signed contracts for the Naughton retrofits in May 2009.

To the extent that we can determine, Mr. Teply's revised workpaper ("OPUC 220-4 – Workpaper – Nau 1&2 – Rebuttal 2014 Close") makes very simple alterations to the original PVRR(d) analysis:

(a) removes all costs and benefits from years 2009-2013,
(b) sums all CAI projects from 2009 through 2013 and moves this value in 2014 instead of spread from 2009 through 2012
(c) changes market electricity prices to reflect 3/2009 forecast instead of 12/2008 forecast
(d) changes environmental costs (i.e. emissions prices) to reflect 4/2009 forecast instead of 12/2008 forecast

Mr. Teply's new analysis results in a reduced net benefit for N1 and N2 of +$17 and +$43 million, respectively, instead of +$23 and +$63 million, respectively.[2]

We are still working to analyze the differences between Dr. Fisher's re-analysis (-$49 and -$20 million for N1 & N2) and Mr. Teply's re-analysis (+$17 and +$43 million), but have identified the following areas of difference thus far (each impact evaluated singularly and subject to change as new information is uncovered):

(a) Mr. Teply's use of a higher market electricity price increases the benefit of N1 & N2 by $27 and $35 million. If he had not included this newer electricity price, the PVRR(d) of N1 & N2 would have been -$10 and +$8 million, respectively all else held the same (i.e. a shift of -$27 and -$36 million, respectively).
(b) By moving all capital expenses into the year 2014 instead of spread between 2009 and 2012, Mr. Teply's model appears to discount the capital costs (i.e. they impact the PVRR of the coal plant less and incur less tax through the analysis). Adjusting the CAI capital costs such that they are spread from 2009-2012 (as incurred) changes the PVRR(d) of N1 & N2 to -$5 and +$14, respectively, all else held the same (i.e a shift of -$22 and $-29 million, respectively).

[1] For these values, see tab "AnalysisDate" of "PVRR(d) Results – Naughton and Hunter" in Dr. Fisher's workpapers and tab "Table" in "Attach OPUC 220-4 CONF.xls".
[2] For these values, see tab "Table" in "OPUC 220-4 – Workpaper – Nau1&2 – Rebuttal – 2014 Close.xls" and tab "Table" in "Attach OPUC 220-4 CONF.xls".

(c) Dr. Fisher's analysis retires Naughton 1 & 2 in 2015, forcing the model to depreciate all <u>ongoing</u> capital expenditures from 2009 to 2014 by the year 2015; in the 2029 retirement scenario, these expenses are depreciated over an extended period. Mr. Teply's model, by excluding these costs altogether, implicitly assumes that a retired unit would not have to undergo accelerated depreciation. We have not yet quantified the impact of this difference.
(d) Mr. Teply suggests that the N1 & N2 units would have to be retired by 2013, not 2015 as suggested by Sierra Club and CUB. We have not yet quantified the impact of this difference.

Between changes to the market electricity price and Mr. Teply's consolidation of CAI costs in the year 2014, we think we capture approximately ¾ of the difference between Mr. Teply's rebuttal results and Dr. Fisher's results. Again, we will check, clarify and characterize these differences more completely in surebuttal testimony.

Both Dr. Fisher's analysis and Mr. Teply's analysis assume that capital expenses incurred prior to retirement but <u>after</u> the analysis would be incurred in full through retirement. This is likely a conservative assumption (i.e. factors in favor of the retrofit option) as in the retirement scenario an operator would likely not invest in high-cost, long-term maintenance if a plant were to be retired within a few years.

OPUC Data Request 338

Please confirm whether the costs associated with installation of a new stack as part of the Naughton flue gas desulfurization systems for Units 1 and 2 is included in the CAI capital cost estimates used in the PVRR(d) analyses referred to on pages 37 and 45 of PAC/500 Teply.

Response to OPUC Data Request 338

Yes, the costs are included.

OPUC Data Request 337

Please confirm whether the increased parasitic load from Comprehensive Air Initiative (CAI) projects is accounted for in the PVRR(d) analyses referred to on page 21 of PAC/500 Teply.

Response to OPUC Data Request 337

The increased parasitic loads were not accounted for in the PVRR(d) analyses referred to in PAC/500, Teply/21. However, including parasitic load in the calculation would not be expected to materially change the outcome of the analysis.