Oregon

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July 6, 2012

Via Electronic Filing and U.S. Mail

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX 2148
SALEM OR 97308-2148

RE: Docket No. UE 250 – In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Power Cost Update Tariff for 2013

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

/s/ Kay Barnes

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c: UE 250 Service List (parties)

PUBLIC UTILITY COMMISSION
OF OREGON

UE 250

Staff Opening Testimony

Of

Stephen Schue

In the Matter of
PORTLAND GENERAL ELECTRIC COMPANY
Annual Power Cost Update Tariff for 2013

July 6, 2012

CASE: UE 250
WITNESS: Stephen Schue

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

July 6, 2012

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

A. My name is Stephen Schue. I am a Senior Economist in the Electric and Natural Gas Division of the Oregon Public Utility Commission (OPUC). 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/101.

Q. WHAT ARE THE PURPOSES OF YOUR TESTIMONY?

A. I first summarize Portland General Electric Company's (PGE or Company) 2013 Annual Update Tariff (AUT) request. I then recommend that three cost components totaling $7.4 million not be included in the 2013 net variable power cost (NVPC) forecast.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized as follows:

I. INTRODUCTION

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this Section, I summarize the Company's 2013 AUT filing and outline $7.4 million in recommended reductions.[1]

Q. PLEASE SUMMARIZE THE COMPANY'S REQUEST FOR THE 2013 TEST YEAR.

A. PGE requests $674.8 million in NVPC, based on February 23, 2012, forward curves. Compared to the 2012 AUT, this is a decrease of $1.54 per MWh at the busbar, which translates into an average rate decrease of 1.6 percent. Lower gas and electric hedging losses more than off-set increases associated with coal and hydro resources. Coal costs are somewhat higher and hydro output is both lower and more costly.

Q. WERE YOU SATISFIED WITH THE DOCUMENTATION PROVIDED?

A. Yes. I found the documentation in most cases to be extensive and well organized. The Company met both the letter and spirit of the Minimum Filing Requirements (MFR), which are in fact quite extensive. Also, the Company was responsive both formally and informally to Staff's Data Requests in the Docket.

Q. DID YOUR REVIEW OF THE MFRS FOCUS, IN PART, ON AREAS WHICH MOST AFFECT THE OVERALL NVPC RESULT?

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[1] $1.5 million of this is currently covered by a stipulated deferral mechanism, consistent with Order Nos. 10-478 and 11-153. In this filing, the Company proposes a change in collection methodology, from the current deferral structure, to inclusion in the AUT. Therefore, Staff's recommendations might be considered to total only $5.9 million. ($7.4 million - $1.5 million = $5.9 million)

A. Yes. Assumptions concerning the output and costs of hydro resources and forced outages at coal plants can substantially impact the NVPC forecast. Contracts with Grant County Public Utility District (Grant County or County) for output shares of the Priest Rapids and Wanapum hydro projects on the Columbia River are becoming less favorable over time. Costs are increasing, but the shares of output going to parties other than Grant County are decreasing with the County's increased needs. The MFR materials related to the Grant County contracts are extensive and appear to Staff to be accurate. The Company will also include more up-to-date figures as the case proceeds.

I also examined the MFR calculations and supporting documentation related to output decreases at some of the Company's hydro facilities on the Clackamas River. These decreases are the result of relicensing requirements. I found that the documentation was complete and the calculations accurate.

Docket UM 1355 focused on the calculation of assumed forced outage rates, particularly for coal-fired resources. Order No. 10-414 then set out the approved methodology. PGE's MFRs included extensive documentation and calculations associated with Order No. 10-414 compliance. I found the documentation to be complete and the calculations accurate.

Q. DID YOU EXAMINE THE COMPANY'S RESPONSES IN THIS DOCKET TO ISSUES RAISED IN DOCKET UE 228, THE 2012 AUT PROCEEDING?

A. Yes. I examined how the Company modeled Rockies-Sumas gas arbitrage opportunities in MONET (PGE's NVPC model). I also examined how the

Company documented market liquidity for gas hedges, an issue which resulted in a $2.6 million disallowance in UE 228.[2]

Q. PLEASE EXPLAIN THE ROCKIES-SUMAS GAS ARBITRAGE ISSUE.

A. Under certain conditions (positive Rockies-Sumas basis differential, available pipeline capacity, etc.), PGE can realize arbitrage gains. In the Stipulation approved by Order No. 11-432,[3] the Company agreed to explicitly model these opportunities.

Q. DOES THE COMPANY'S MODELING MEET THE STIPULATION REQUIREMENTS?

A. Yes. The modeling includes historical data-based quantities and ties directly to the Rockies and Sumas gas forward curves in MONET.

Q. HOW DID THE COMPANY DOCUMENT LIQUIDITY FOR ITS TEST YEAR GAS HEDGES?

A. Gas hedges, whose mark-to-market values are included in the test year revenue requirement, were entered into beginning in 2008. The Company set out a standard that it "would not transact for a given delivery year if PGE's cumulative transaction volume would exceed 3% of the cumulative market volume already executed for that same delivery year . . . ." (PGE/100, Niman-Peschka-Hager/16, Lines 18-20) The three percent cumulative test is based on New York Mercantile Exchange natural gas transactions for Henry Hub, as recorded by the Intercontinental Exchange (ICE). A work paper supplied with the initial filing demonstrates that the Company has met this standard.

[2] See Order No. 11-432, Pages 1, 15, and 17.
[3] See Pages 7 and 8 of the Stipulation, which is an Attachment to Order No. 11-432.

Q. DOES STAFF RECOMMEND A CHANGE TO THE CUMMULATIVE STANDARD?

A. Yes. The three percent cumulative standard is a good start and demonstrates that the Company did respond to the criticisms and associated disallowance in Order No. 11-432.[4] However, Staff recommends an alternative, specifically a three percent incremental standard. Under an incremental standard, the size of a particular PGE transaction would be compared to the size of the relevant overall market on the day the PGE transaction is executed.[5] A particular transaction might be a substantial part of the overall market at the time it is made, although it does not trigger the three percent cumulative test. Therefore, it makes more sense to adhere to a three percent incremental standard, with documentation of special circumstances under which it is reasonable to exceed this threshold.

Q. PLEASE PROVIDE AN EXAMPLE TO ILLUSTRATE HOW CUMMULATIVE AND INCREMENTAL STANDARDS COULD LEAD TO DIFFERENT RESULTS.

A. Suppose that during the analysis period prior to the day on which transaction X takes place, PGE's cumulative transactions sum to 1,000 MW and corresponding cumulative relevant market transactions sum to 100,000 MW, implying a three percent cumulative market figure of 3,000 MW. PGE's

[4] It should be noted that the Company entered into most of the gas hedges relevant to this Docket prior to issuance of Order No. 11-432. Therefore, Staff's recommendations in this Section apply primarily to future proceedings.
[5] If a period different than one day provides a more accurate measure of liquidity, the Company can propose an alternative and explain why it is the appropriate period over which to measure liquidity.

cumulative 1,000 MW are well within the cumulative three percent bound of 3,000 MW. Then suppose that PGE's transaction X is for 100 MW and that, on the day of transaction X, relevant market transactions total 1,000 MW. Then, after transaction X, PGE's cumulative transactions are 1,100 MW (1,000 + 100), cumulative market transactions are 101,000 MW (100,000 + 1,000), and the three percent cumulative bound is 3,030 MW (101,000 x 3%). PGE's cumulative transactions of 1,100 MW are well within the 3,030 MW bound. However, on an incremental basis, on the day of transaction X, PGE's transactions are 100 MW and market transactions are 1,000 MW. The incremental three percent bound is only 30 MW (1,000 MW x 3%), which is exceeded by PGE's 100 MW transaction. On the day of transaction X, the incremental three percent bound of 30 MW is more relevant than the 3,030 MW cumulative figure. As an extreme example, one PGE transaction might be the entire market on the day it is made, but still not violate a cumulative bound.[6]

Q. DID THE COMPANY DEMONSTRATE THAT IT HAS GENERALLY MET YOUR RECOMMENDED INCREMENTAL STANDARD?

A. Yes. The Company's work paper documenting adherence to the three percent cumulative standard on a backward looking basis shows that all but one of the transactions relevant to this proceeding also met the incremental three percent standard. In future proceedings, the Company should provide documentation for every trade that may exceed the three percent incremental standard to

[6] As noted on the previous page, if a period different than one day provides a more accurate measure of liquidity, the Company can propose an alternative and explain why it is the appropriate period over which to measure liquidity.

establish that it was reasonable in light of the information that was known or knowable at the time of the transaction.

Q. PLEASE SUMMARIZE THE REDUCTIONS YOU RECOMMEND.

A. I recommend three reductions. First, I recommend that the cost of chemicals related to mercury control at the Boardman coal-fired plant not be included in the AUT, but rather continue to be included in the deferred accounting mechanism approved in Order No. 11-153. This treatment in turn was based on a Stipulation approved in Order No. 10-478. This reduces the Company's 2013 AUT request by $1.5 million.[7]

Second, I recommend that the cost of chemicals for the dry sorbent injection (DSI) method of sulphur dioxide control at the Boardman plant not be included in the 2013 AUT. The Company has documented that this cost will occur beginning in July of the test year. However, the addition of this cost is outside of the scope of the AUT, which, except in general rate case (GRC) years, is strictly limited in scope. In considering a GRC, the Company must weigh cost changes which increase the revenue requirement against cost changes which decrease the revenue requirement, and then make an overall decision on whether to file. It is not appropriate to collect some new costs through the AUT without examining all revenue requirement elements in a GRC. PGE has decided not to file a GRC for the 2013 test year. Therefore, the DSI-related chemical costs should not be allowed in the 2013 AUT. This reduces the NVPC forecast by $1.6 million.

[7] Although this is a reduction in the 2013 AUT, the Company will collect the costs through the deferral mechanism, subject to the conditions of that structure.

Third, I recommend that the new day-ahead forecast error component of wind integration costs not be included. This reduces the test year NVPC estimate by $4.3 million. The new estimate comes from the September 30, 2011, PGE Wind Integration Study Phase II (Wind Integration Study).[8] The day-ahead forecast error component used for test years from 2009 through 2012 was established by Stipulation in Docket UE 198.[9] Docket UE 198 ran concurrently with Docket UE 197, a GRC proceeding. Both were based on the same 2009 test year. Making use of the Wind Integration Study will be appropriate for the Company's next GRC test year. However, this component of wind integration costs is not on the short list of elements to be updated in a non-GRC power cost proceeding. As with the DSI-related chemicals, the Company must weigh various factors in deciding on a GRC filing. It would upset the Company-customer balance to allow the Company to conclude that the "negatives outweigh the positives" for a GRC filing, but then to get some of the "positives" through means such as the AUT.

Q. DO YOU ALSO DISAGREE WITH THE COMPANY'S METHODOLOGIES OR PRESENTATION OF THESE THREE ISSUES?

A. No. The Company's documentation and calculations related to both types of chemical costs were complete and accurate.[10] In a later Section, I make recommendations on how to more accurately implement the Company's approach to calculating the day-ahead forecast error component of wind

[8] PGE included the Wind Integration Study in its Direct Testimony as Exhibit PGE 103.
[9] The Stipulation was approved in Order No. 08-505 (Page 3 and Appendix A, Page 3).
[10] The DSI-related chemical costs would likely be approximately $2.5 to 3.0 million in post-2013 test years, as the calculation above is for a six-month period beginning in July 2013.

integration costs for use in filings beginning with the next GRC test year.[11] However, I accept the Company's general approach.

The Company also pointed out these three issues in its testimony, which assured that the policy issues were clear to all parties. Staff simply disagrees with the Company's perspective that these particular costs are sufficiently unique to justify an exception to the general principle that, except in GRC years, the AUT is strictly limited in scope.

[11] These recommendations also apply to 2013, if the Commission finds the Company's arguments for inclusion in this proceeding to be persuasive.

II. MERCURY CONTROL SYSTEM CHEMICAL COSTS

Q. PLEASE OUTLINE THIS SECTION OF YOUR TESTIMONY.

A. In this Section, I first summarize the Company's arguments for including the cost of chemicals for the Boardman mercury control system in the AUT, rather than continuing collection through a deferral mechanism established by a Stipulation in Docket UE 215.[12] I then explain why this change in collection structures should not be allowed. This reduces the NVPC forecast in this Docket by $1.5 million, although the Company can continue to include this amount in the deferral mechanism.

Q. PLEASE DESCRIBE THE COSTS AT ISSUE.

A. As stated in the Company's testimony, "PGE began activated carbon injection and calcium bromide injection to achieve mercury emissions reductions at Boardman in 2011." (PGE/100, Niman-Peschka-Hager/11, Lines 2-3) The MFR materials document the Company's estimate of $1.5 million for these costs in the 2013 test year.

Q. IS THE COMPANY CURRENTLY ABLE TO RECOVER THESE COSTS?

A. Yes. In Docket UE 215, PGE and other parties stipulated to coverage of these costs in a deferral mechanism.[13] The Company's request is for a change in how these costs are collected, rather than a change from not collecting them at all. The deferral mechanism may well include more process and conditions

[12] This mechanism was approved in Order Nos. 10-478 and 11-153.
[13] See Second Revenue Requirement Stipulation, approved in Order No. 10-478. (Appendix B, Pages 3-4) See also Order No. 11-153, (Appendix A, Page 3)

than would collection through the AUT. However, it is the cost recovery structure stipulated to by parties in Docket UE 215.

Q. DO YOU AGREE WITH THE COMPANY'S REQUESTED CHANGE IN THE METHOD OF RECOVERY FOR THE MERCURY CONTROL CHEMICALS?

A. No. Parties to Docket UE 215 agreed to the Stipulation. It is not appropriate for the Company to "unilaterally " request a change. Five parties agreed to the Stipulation, including four who are parties to this Docket – Staff, PGE, Industrial Customers of Northwest Utilities (ICNU), and the Citizens' Utility Board of Oregon (CUB). However, the fifth party to the Stipulation, Fred Meyer Stores and Quality Food Centers, Division of Kroger Co. (Kroger), is not even a party to this Docket. Approving the Company's request for a change in collection structure would be particularly unfair to Kroger.

Q. DO YOU DISAGREE WITH THE COMPANY'S PROPOSAL FOR ANOTHER REASON?

A. Yes. The proposal is also contrary to the general principle that AUT proceedings in non-GRC years are strictly limited in scope. Therefore, the additions to the list of items eligible for inclusion and revision in an AUT proceeding for a non-GRC test year included in the Company's Advice No. 12-08 should not be allowed.[14]

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[14] Advice No. 12-08 includes revised Tariff Schedules 125 and 126, which add "Chemical costs required for Boardman pollution controls, which are directly related to the plant's output." In the next Section, I address the "directly related to the plant's output" issue.

III. DRY SORBENT INJECTION CHEMICAL COSTS

Q. PLEASE OUTLINE THIS SECTION OF YOUR TESTIMONY.

A. In this Section, I first summarize the Company's arguments for including the costs of chemicals associated with the Boardman dry sorbent injection (DSI) system in the 2013 AUT. I then explain why the DSI-related chemical costs should not be included. Exclusion of these costs results in a $1.6 million decrease in the 2013 NVPC estimate.[15]

Q. PLEASE DESCRIBE THE COSTS AT ISSUE.

A. The Regional Haze Rules established by the Oregon Department of Environmental Quality set a maximum level of sulfur dioxide emissions for the Boardman plant. "DSI is a pollution control system that reduces sulfur dioxide emissions by combining a dry alkaline reagent directly with the boiler exhaust gas stream. The reagent a[b]sorbs sulfur dioxide and is then collected by the existing electrostatic precipitator." (PGE/100, Niman-Peschka-Hager/12, Lines 4-6) The Company requests inclusion of the costs of chemicals associated with the DSI system, which will become operative in July 2013.

Q. HOW DOES THE COMPANY JUSTIFY INCLUSION OF THESE COSTS?

A. The Company states that "Although not accounted for as fuel costs, the chemical costs of DSI are variable with the plant's production and, thus, appropriately included in PGE's 2013 net variable power cost forecast." (PGE/100, Niman-Peschka-Hager/12, Lines 11-13)

[15] As noted above, for test years beginning with 2014, this amount would be approximately $2.5 to $3.0 million, as the DSI system will become operative in July 2013, i.e. will only be operative during half of the 2013 test year, but would thereafter be operative year round, except when Boardman is off-line for maintenance,

Q. DO YOU AGREE WITH THIS REASONING?

A. No. Variable operations and maintenance (O&M) costs are also variable with the plant's production. However, variable O&M costs are included in base rates and only revisited during GRC proceedings.[16] Treatment of DSI-related chemical costs should be consistent with treatment of variable O&M costs. They both should be considered only in GRC proceedings.

More generally, the proposal to include DSI-related chemical costs in the 2013 NVPC forecast is contrary to the general principle that AUT proceedings in non-GRC years are strictly limited in scope.

[16] Although not collected through the AUT mechanism, variable O&M costs are included in MONET's dispatch logic.

IV. DAY AHEAD FORECAST ERROR COMPONENT OF WIND INTEGRATION COSTS

Q. PLEASE OUTLINE THIS SECTION OF YOUR TESTIMONY.

A. In this Section, I first summarize the Company's request to raise the day-ahead forecast error component of its wind integration costs from $0.50 to $3.36 per MWh of expected wind output. This unit increase of $2.86 per MWh translates into a $4.3 million increase in the 2013 test year NVPC forecast. Next, I discuss why this increase is not appropriate for a non-GRC test year. Finally, I recommend certain modifications to the Company's approach for use in the next GRC test year, or for the 2013 test year at issue in this Docket, if the Commission finds the Company's reasons for inclusion to be persuasive.

Q. WHAT ARE THE BASES FOR THE CURRENT AND PROPOSED UNIT FIGURES OF $0.50 AND $3.36 PER MWH?

A. The current $0.50 figure has been used in NVPC forecasts for the test years 2009 through 2012. Parties to Docket UE 198 agreed to this figure as part of a Stipulation that the Commission approved in Order No. 08-505.[17] Docket UE 198 ran concurrently with Docket UE 197, a GRC proceeding. Both were based on a 2009 test year.

The $3.36 figure comes from the PGE Wind Integration Study Phase II (Wind Integration Study or Study), dated September 30, 2011.[18] It is based on

[17] See Page 3 of the Order, as well as Page 3 of Appendix A to the Order.
[18] Table 9 on Page 47 of the Wind Integration Study lists a figure of $3.44 in 2014 dollars. The Company then adjusted that figure down by a 2.5 percent inflation factor. ($3.44 / 1.025 = $3.36)

the difference between mixed integer program modeling runs with and without day-ahead forecast error.

Q. IS THE COMPANY'S APPROACH TO CALCULATING WIND INTEGRATION COSTS GENERALLY REASONABLE?

A. Yes. A technical review committee worked with the Company as the Study progressed and endorsed the final product. To report progress and solicit input, PGE held a Stakeholder Briefing on February 23, 2011, and a Stakeholder Meeting on May 18, 2011. The Company also presented its conclusions to stakeholders in a Final Report on August 29, 2011. The structure of the Study allows for reasonably accurate separation of the various wind integration cost components, if covered by PGE's own resources. These components are summarized in Table 9 of the Study.[19] This separation allows for comparisons between Bonneville Power Administration (BPA) or other tariff costs and the costs of self-integration, on a component by component basis.[20] The Study is consistent with current "state of the art" practices in most respects. Staff does, however, question one aspect of the Study, namely the figures in Table 6 concerning bid/ask spreads for hour-ahead transactions.[21] I address the bid/ask spread issue later in this Section.

Q. IF THE COMPANY'S APPROACH TO ESTIMATING WIND INTEGRATION COSTS IS GENERALLY REASONABLE, THEN WHY SHOULDN'T THE

[19] See Page 47 of the Study.
[20] It is Staff's understanding that alternatives to self-supply are available for some, but not all, wind integration components.
[21] See Page 30 of the Study.

DAY-AHEAD FORECAST ERROR COMPONENT BE INCLUDED IN THE 2013 TEST YEAR NVPC CALCULATIONS?

A. As is the case with the chemical costs discussed in the previous two Sections, it is not appropriate to include a new method of estimating day-ahead forecast error costs in an AUT which is based on a non-GRC test year. The scope of a non-GRC test year AUT is strictly limited. If the Company wants to significantly change its calculation of costs other than those on the short list currently included on Tariff Schedule 125, it must also revisit all other costs in a GRC proceeding. It appears the Company has concluded that, for a 2013 test year-based GRC, the "negatives outweigh the positives." It would upset the Company-customer balance to allow the Company to then obtain some of the "positives" through the AUT.

Q. IF THE COMMISSION ALLOWS INCLUSION OF THE NEW DAY-AHEAD FORECAST ERROR COMPONENT IN THE 2013 NVPC FORECAST, DO YOU RECOMMEND CHANGES TO THE COMPANY'S CALCULATIONS?

A. Yes. The hour-ahead bid/ask spread percentages in Table 6 of the Wind Integration Study should be modified.[22]

Q. PLEASE EXPLAIN.

A. The $3.36 per MWh request is based on the difference between two mixed-integer programming model runs, one with day-ahead forecast errors, one without. Both runs depend in part on the hour-ahead bid/ask percentage figures in Table 6 of the Study. The run with day-ahead forecast errors is likely

[22] See Page 30 of the Study.

to rely more on hour-ahead sales and purchases to compensate for these errors. Although PGE vetted most of the Study with stakeholders and the technical review committee, the figures in Table 6 were not based on analysis of relevant historical data. Instead, the Study states “In the Hour-Ahead stage of the model, a sliding bid/ask spread is used as a function of the desired transaction block size based on the operational experience of PGE’s Real Time Power Operations.”[23]

Q. DID STAFF CONDUCT DISCOVERY ON THIS ISSUE?

A. Yes. Staff asked for data to support the figures in Table 6. The Company was responsive, both formally and informally. This led to the Company’s Confidential First Supplemental Response to OPUC Data Request No. 006 (Response), which provided a basis for modifying Table 6. Confidential Exhibit Staff/102 includes the Company’s Response and my translation of that Response into modified Table 6 figures.[24]

Q. IF THE COMMISSION ALLOWS INCLUSION OF THE NEW DAY-AHEAD FORECAST ERROR COMPONENT IN THE 2013 TEST YEAR NVPC FORECAST, DO YOU THEN RECOMMEND THAT THE COMMISSION ALSO REQUIRE THE COMPANY TO USE THE MODIFIED TABLE 6 FIGURES CONTAINED IN CONFIDENTIAL EXHIBIT STAFF 102?

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[23] See Page 29 of the Study.

[24] My modified Table 6 calculations take into consideration two key factors. The Company provided data which was all for transaction of standard 100 MW, 200 MW, and so on sizes. However, the mixed integer programming model does not constrain hour-ahead transactions to “even 100 MW” sizes. Also, the Company’s “No Negative Percentage” figures should not be used. They might be useful if a few negative data points dominated the analysis. However, that is not the case.

A. Yes. The Company might present one or more new alternatives to Table 6 in its Reply Testimony. However, other parties would not have a chance to respond. Therefore, in the event that the Commission allows inclusion of the new day-ahead forecast error component in the 2013 test year NVPC forecast, the figures in Confidential Exhibit Staff 102 should be used.

Q. SHOULD THE WIND INTEGRATION MODEL RUNS ALSO ASSUME CURRENT GAS AND ELECTRIC FORWARD CURVES?

A. Yes. Current curves differ somewhat from those used in preparing the Wind Integration Study. Up-to-date curves would allow for a more accurate cost forecast.

Q. IS THERE AN ADDITIONAL COMPLICATION INHERENT IN ALLOWING INCLUSION OF THE NEW DAY-AHEAD FORECAST ERROR COMPONENT OF WIND INTEGRATION COSTS IN THE 2013 TEST YEAR NVPC FORECAST?

A. Yes. PGE uses a complex mixed-integer programming model to calculate wind integration costs. A new run takes approximately six weeks to complete. Therefore, the Company could not complete a model run to calculate the day-ahead forecast error cost if it began after the Order in this case is issued in late October 2012.

The Company should run the wind integration cost model using Confidential Exhibit Staff 102 figures for Table 6 and August gas and electric forward curves. Then it will have a figure for possible use in its November MONET runs after the Commission issues its Order.

Q. COULD THIS APPROACH LEAD TO CONTROVERSY?

A. Yes. If the result of the Company's day-ahead forecast error calculation were substantially different than expected, there would be little opportunity for other parties to respond. Given the current disagreement concerning this calculation, the possibility of further disagreement is not simply theoretical. This is another reason for not allowing inclusion of the new day-ahead forecast error component in the 2013 test year NVPC forecast.

Q. HOW SHOULD THE COMPANY INCORPORATE ITS WIND INTEGRATION STUDY INTO NVPC FORECASTING?

A. First, the Company should wait until the next GRC test year, for reasons discussed in detail above. Then, in a more complete, "five rounds of testimony" proceeding, the Company should present the following in its opening testimony:

1) An analysis of how wind integration can be done with the lowest expected costs for customers. This should include an analysis of whether it is cost-effective to continue to purchase some components of wind integration from BPA, or whether one or more of the components currently purchased from BPA should be provided by PGE's system.

2) For the new day-ahead forecast error component, if the Company still intends to self-provide, it should include a calculation either based on Confidential Exhibit Staff 102, or an alternative analysis, with an explanation of why the alternative analysis results in hour-ahead bid/ask spread figures which are more accurate than Staff's.

3) A date for calculation of the day-ahead forecast error and any other self-provided components. This should balance two factors: i) later gas and electric forward curves for the test year are likely to produce more accurate estimates of test year wind integration costs; and ii) other parties need to have an opportunity to respond to the Company's calculations.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS CONCERNING WIND INTEGRATION COSTS.

A. The discussion in this Section leads to the following conclusions:

1) A new estimate for the day-ahead forecasting error component of wind integration costs should not be included in the 2013 test year NVPC forecast because 2013 is not a GRC test year.

2) Table 6 of the Wind Integration Study should be modified to be consistent with actual historical data, such as that provided in Confidential Exhibit Staff 102.[25]

3) Concurrent with its next GRC, the Company should present in its opening testimony an analysis of the least cost way to cover wind integration costs.

4) The opening testimony mentioned in 3) should also include a schedule to complete wind integration cost calculations in a timely manner.

5) If the Commission finds the Company's reasons for including the day-ahead forecast error component in the 2013 test year NVPC forecast to be persuasive, the calculations should be based on Confidential Exhibit

[25] As noted above, Confidential Exhibit Staff 102 is based on extensive data provided by the Company in both its Response and First Supplemental Response to Staff Data Request No. 006.

Staff 102 and forward curves as late as is practicable for inclusion in the final November MONET runs.

V. SUMMARY

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. Based on Sections I through IV, I conclude the following:

1) $1.5 million in chemical costs for the Boardman mercury control system should not be included in the 2013 test year NVPC forecast. Instead, the Company should continue to include these costs in the deferral mechanism approved in Order Nos. 10-478 and 11-153.

2) $1.6 million in Boardman DSI-related chemical costs should not be included in the 2013 NVPC forecast. The Company can request inclusion of these costs beginning in its next GRC test year.

3) $4.3 million for the new day-ahead forecast error component of wind integration costs should not be included in the 2013 NVPC forecast. The Company can request inclusion of these revised costs beginning in its next GRC test year, consistent with the methodology adjustments discussed in Section IV.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UE 250
WITNESS: Stephen Schue

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

July 6, 2012

WITNESS QUALIFICATION STATEMENT

NAME:	STEPHEN SCHUE
EMPLOYER:	PUBLIC UTILITY COMMISSION OF OREGON
TITLE:	SENIOR ECONOMIST, ELECTRIC AND NATURAL GAS DIVISION
ADDRESS:	550 CAPITOL ST. NE, SALEM, OR 97308-2148
EDUCATION:	Bachelor of Science, Economics, University of Oregon Master of Arts, Economics, University of Minnesota Master of Business Administration, University of Leuven (Belgium)
EXPERIENCE:	I have been employed at the Oregon Public Utility Commission (Commission) since August of 2011. My current responsibilities include research, analysis and technical support for electric cost recovery proceedings, with an emphasis on variable power costs. I was previously employed at Portland General Electric Company (PGE) for 18 years. At PGE, I performed analysis and sponsored testimony related to net variable power costs, resource planning, and purchases (both transmission and power) from the Bonneville Power Administration. I was the project manager for PGE's 2000 Integrated Resource Plan. During 1986 and 1987, I worked at the Commission, specializing in economic evaluation of utility conservation programs.

CASE: UE 250
WITNESS: Stephen Schue

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

July 6, 2012

STAFF EXHIBIT 102

IS CONFIDENTIAL AND SUBJECT TO

PROTECTIVE ORDER NO: 12-120. YOU MUST HAVE SIGNED

APPENDIX B OF THE PROTECTIVE ORDER IN

DOCKET UE 250 TO RECEIVE THE

CONFIDENTIAL VERSION

OF THIS EXHIBIT.

UE 250
SERVICE LIST (PARTIES)

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CERTIFICATE OF SERVICE

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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 6th day of July, 2012 at Salem, Oregon

Kay Barnes

Kay Barnes
Public Utility Commission
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