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October 6, 2006

Via Electronic and U.S. Mail

Public Utility Commission
Attn: Filing Center
550 Capitol St. NE #215
P.O. Box 2148
Salem OR 97308-2148

Re: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY
Request for a General Rate Revision
Docket Nos. UE 180/UE 181/UE 184

Dear Filing Center:

Enclosed please find an original and five copies of each of the following documents on behalf of the Industrial Customers of Northwest Utilities ("ICNU") in the above-referenced docket numbers:

- Surrebuttal Testimony and Exhibits of Randall J. Falkenberg;
- Surrebuttal Testimony of Michael P. Gorman; and
- Surrebuttal Testimony of Lincoln Wolverton.

Thank you for your assistance.

Sincerely yours,

/s/ Christian Griffen
Christian W. Griffen

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Surrebuttal Testimonies and Exhibits of Randall J. Falkenberg, Michael P. Gorman and Lincoln Wolverton on behalf of the Industrial Customers of Northwest Utilities upon the parties, on the official service list, by causing the same to be deposited in the U.S. Mail, postage-prepaid, and by electronic mail to those parties who waived paper service in this proceeding.

Dated at Portland, Oregon, this 6th day of October, 2006.

/s/ Christian Griffen
Christian W. Griffen

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/UE 181/UE 184

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180),	))))))))
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181),	)))))))))
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PARTIAL-REQUIREMENTS

SURREBUTTAL TESTIMONY OF LINCOLN WOLVERTON

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

October 6, 2006

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Lincoln Wolverton. My address is East Fork Economics, Post Office Box 620, La Center, WA 98629.

Q. ARE YOU THE SAME LINCOLN WOLVERTON WHO FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. I will comment on one issue: Portland General Electric Company's ("PGE" or the "Company") economic replacement power tariff for partial-requirements customers. The economic replacement power tariff is the only issue I am addressing because the Industrial Customers of Northwest Utilities ("ICNU") has entered into a settlement that resolves all issues related to rate spread and rate design and all other issues related to the partial-requirements tariffs.

I recommend that PGE be required to improve the economic replacement tariff by including three new pricing options that would replace the current Schedule 76R option. These options would be to: 1) substitute the daily-market pricing option under proposed Schedules 83/89 for the hourly market pricing provisions in 76R; 2) allow partial-requirements customers to use direct access service to purchase economic replacement power in the same manner as the buy-through arrangements in Schedule 576R are treated; and 3) allow Schedule 76R customers to purchase Schedule 87, Experimental Real Time Pricing Service economic replacement power, subject to the provisions of that experimental tariff, which impose limitations on size and the number of customers.

Q. PLEASE SUMMARIZE PGE'S REBUTTAL TESTIMONY.

A. PGE opposes ICNU's economic replacement power options because the Company claims that: 1) the proposals are not sufficiently detailed; 2) it is not clear how the options would interact among themselves; 3) it is not clear how they reflect market alternatives available to partial-requirements customers; 4) the proposals do not provide advanced price information to customers; 5) the proposals increase PGE's risks; and 6) some aspects may be difficult to implement.

I disagree with PGE's criticisms and recommend that ICNU's proposed pricing options be adopted. My proposals are similar to the existing market pricing options available to all of PGE's other industrial customers, would not unduly shift risk to PGE or its other customers, and are sufficiently developed.

Q. DO PGE AND ICNU AGREE THAT PGE SHOULD BE REQUIRED TO PROVIDE AN ECONOMIC REPLACEMENT POWER TARIFF?

A. Yes. There appears to be consensus that PGE should offer an economic replacement tariff for partial-requirements customers. PGE has proposed an economic replacement tariff and agrees that "the service should meet customer needs in [a] reasonable, administratively and operationally feasible manner." PGE/2200, Kuns-Cody/24. Thus, PGE agrees that this service should be offered and should focus on meeting the needs of partial-requirements customers. To meet the needs of customers, the economic replacement tariff should be workable and useful.

Q. WHY IS IT IMPORTANT THAT PGE BE REQUIRED TO EXPAND THE OPTIONS AVAILABLE UNDER SCHEDULE 76R?

A. Schedule 76R allows a partial-requirements customer to purchase power at market prices to displace onsite generation. This ensures that only the most efficient generation in the region will be used to meet load. The current Schedule 76R does not reflect the options available in the market, because it is limited to day-of, instead of day-ahead, pricing. Therefore the options should be expanded to encourage the efficient use of generation.

Q. WHAT IS PGE'S PRIMARY CRITICISM?

A. PGE asserts that ICNU's proposals are not fully developed, but PGE provides few specific criticisms regarding what aspects of the proposals need to be developed. Id. at Kuns-Cody/25. Most of their rebuttal testimony is based on vague claims of harm, confusion, and an alleged lack of detail. For the most part, PGE does not appear to be offering constructive criticism that would make my proposals more workable. Although I attempt to clarify how my proposals are developed, it is difficult to respond to PGE's complaints because they only identify a few specific areas that need additional clarification or development.

Q. DO YOU BELIEVE THAT ICNU'S ECONOMIC REPLACEMENT POWER OPTIONS ARE SUFFICIENTLY DEVELOPED?

A. Yes. ICNU's proposals allow partial-requirements customers to use existing PGE pricing options that are currently available to other industrial customers. Most of the details regarding these options are already specified in the pricing options that PGE is offering to those customers. Therefore, I do not believe that there are many new details that need to be developed.

Q. DOES PGE IDENTIFY ANY SPECIFIC AREAS THAT IT BELIEVES NEED TO BE FURTHER DEVELOPED?

A. Yes. PGE raises two specific details that it believes need to be worked out for ICNU's pricing options to work. Id. at Kuns-Cody/24.

First, PGE states that ICNU's pricing options need a settlement process. However, PGE did not propose a settlement process that it believes would be acceptable nor did PGE identify specific concerns regarding how the Company's existing settlement process could not work under these proposals. In any event, this issue is not a fatal flaw and can easily be addressed. Since ICNU's proposals rely upon the other existing PGE tariffs, I believe that the settlement process in those tariffs can be used. If PGE does not believe these processes are sufficient, then I believe the settlement process in PGE's proposed Schedule 76R is acceptable. The only change to Schedule 76R's settlement process that I propose would be that the settlement should be based on daily, and not hourly, imbalance prices.

Second, PGE complains that the specific advanced scheduling and pricing procedures are not fully developed. I agree that a specific proposal was not made, but I do not believe this is a significant issue that should warrant rejection of the proposals. Again, PGE made no specific proposal on scheduling that it believes is acceptable. It would be reasonable for the partial-requirements customer to provide notice on the day before they use the economic replacement power tariffs. I believe it is incumbent upon PGE not to object on this basis, but to instead propose reasonable notice provisions that it believes will work with these economic replacement power options.

Q. PGE ASSERTS THAT PRICE CERTAINTY IS AN IMPORTANT CONSIDERATION FOR PARTIAL-REQUIREMENTS CUSTOMERS. PGE/2200, KUNS-CODY/25. DO YOU AGREE?

A. Yes. Messrs. Kuns and Cody state that, "[w]hen Schedule 76 was originally developed with significant customer and Staff input, price certainty was an important consideration." Id. Price certainty is very important for customers, and the economic replacement tariff should provide customers with options to obtain price certainty when they decide to rely upon the market instead of their cogeneration resource to meet their load.

Although I agree with PGE that price certainty is important, I am confused as to why PGE would rely upon this basis to criticize the pricing options for economic replacement power. The current and proposed Schedule 76R does not provide significant price certainty. A partial-requirements customer can give PGE 90 minutes notice and obtain hourly pricing, plus a mark up and losses. While at certain times of the year the customer has a fairly good estimate of what the hourly prices will be, Schedule 76R itself provides no price certainty and is an hourly product that is very difficult to hedge in the market.

In contrast, all of ICNU's pricing proposals provide a partial-requirements customer with more price certainty. The proposal to use the real-time pricing service provides a customer with price certainty because they will know the price of power on the day before they use the electricity. The option to use an Electricity Service Supplier ("ESS") also provides a customer with the opportunity to better hedge their power or to enter into a transaction for a more guaranteed price. Finally, even though the proposed daily pricing option does not provide a customer with advance pricing knowledge, this type of product provides more price certainty than PGE's proposal because it would be easier to hedge than an hourly option. Therefore, I agree that price certainty is an important consideration, and I believe that ICNU's pricing options better meet this goal.

Q. PLEASE ADDRESS PGE'S SPECIFIC CONCERNS WITH YOUR PROPOSAL TO USE SCHEDULE 87, THE REAL-TIME PRICING SERVICE.

A. PGE argues that: 1) the real time pricing option is not designed to accommodate economic replacement power for a partial-requirements customer; 2) there is no day-ahead hourly market; and 3) the proposal would place risks on PGE when customers place their load on the utility. I disagree with PGE's criticisms. I also note that this is the most important option for a partial-requirements customer because it provides the most price certainty.

I do not believe PGE's assertion that this option was not designed to accommodate a partial-requirements customer to have any merit, as PGE provides no citation or support for this claim. In fact, I believe the opposite to be true. The real-time pricing tariff is supposed to be available only to customers who "must be able to demonstrate their ability to respond to market price signals." PGE Schedule 87 at 1. A partial-requirements customer with a cogeneration resource and more flexible load has a unique ability to respond to market price signals and is the most well-suited of PGE's customers to use this tariff.

This proposal should not expose PGE to any significant risks greater than it already faces if customers take service on Schedule 87. If a 1 MW or greater industrial customer elects to take service under Schedule 87, then PGE provides the customer with the option to take service priced at the Mid-C Day-Ahead Prices, plus wheeling and losses. PGE Schedule 87 at 1-2. The customer is provided the next day's market price by 4:00 p.m. the day before taking service. Id. at 5.

Assuming that there already are customers taking service under Schedule 87, the proposal would not place significantly more risk on PGE, because PGE is already at risk that these customers will modify their load based on the quoted day-ahead price.

Although I disagree that allowing a partial-requirements customer to have day ahead prices places PGE at greater risk, I acknowledge that Schedule 87 is an experimental tariff. For example, the tariff is limited to the first six customers that apply for service. In light of this, I am willing to agree to a cap of 50 MWs of load that a partial-requirements customer could purchase under the real-time pricing option.

Q. PGE ALSO ASSERTS THAT YOUR PROPOSED DAILY-INDEX OPTION SHOULD BE REJECTED BECAUSE IT PLACES TOO MUCH RISK ON PGE. PGE/2200, KUNS-CODY/25. DO YOU AGREE?

A. No, the proposal does not place significant new risks on PGE. The risk that PGE states it will be exposed to is that it must go into the market to obtain the power while the partial-requirements customer is paying at an indexed rate. PGE will be exposed to the risk that the market price it obtains may differ from the published market index.

PGE is already exposed to this risk through the current economic replacement power tariff. Under Schedule 76R, a partial-requirements customer places load on PGE with 90 minutes notice for one or more hours. The power is priced at an hourly market index, and PGE must serve the load with its existing resources or market purchases. Thus, PGE already faces the risk that the price it obtains may differ from the published index.

The primary effect of this proposal is to allow a customer to take this service in a daily block instead of hourly increments. PGE fails to recognize that its risks under the proposal may be diminished because the proposed notice requirements would provide PGE with longer notice rather than the 90 minutes notice in the current economic replacement power tariff. This would allow PGE more of an opportunity to mitigate the risk to which it currently is exposed.

PGE also overemphasizes the risk that it faces. If PGE chooses to serve a customer using economic replacement power with market purchases, then those market prices should typically be close to the market index. PGE's market purchase may even be one of the market transactions that are included in the index.

Finally, it is ironic that PGE states that the risk associated with the daily market option is too significant, but PGE will not agree to allow a partial-requirements customer to purchase economic replacement power from an ESS. PGE should not be allowed to simultaneously refuse to accept the "risk" associated with a daily price option and refuse to allow a partial-requirements customer to take the "risk" itself by contracting with an ESS. If PGE won't accept the risk associated with a daily market price option, then it should let the partial-requirements customer take the risk by contracting with an ESS.

Q. DOES PGE RAISE ANY LEGITIMATE CONCERNS WITH YOUR PROPOSAL TO ALLOW PARTIAL-REQUIREMENTS CUSTOMERS TO OBTAIN ECONOMIC REPLACEMENT POWER FROM AN ESS?

A. No. PGE simply objects based on the vague response that the proposal is not fully developed and that they "have not had an opportunity to fully consider all of the systems and operational ramifications of such a regime." Id. at Kuns-Cody/25. Apparently, PGE does not want to provide partial-requirements customers with this option, but it has not yet figured out any legitimate reasons to object to the proposal.

PGE also asserts that, if a partial-requirements customer wants to replace its own cogeneration resource with purchases from an ESS, then the customer should be required to purchase its baseline energy from an ESS too. Id. at Kuns-Cody/25. A partial-requirements customer can already take both baseline and replacement power from an ESS and I believe they should continue to have this option. However, there is no reason that a partial-requirements customer should be required to take baseline energy from an ESS in order to take economic replacement power from an ESS. Under the proposed settlement agreement, baseline energy cannot be changed without 6 to 13 months notice. In contrast, economic replacement power is for service in the next hour or day. These are fundamentally different services. I can think of no economic or regulatory grounds upon which a customer that is purchasing its baseline energy at cost-of-service rates should not be allowed to purchase power to replace their cogeneration resource in the market.

Q. DOES PGE'S NEW SPLIT LOAD SERVICE PROVIDE A USEFUL ANALOGY?

A. Yes. Under the recently approved Schedule 83R, a customer may purchase a block of power from an ESS, and the remainder of its power from PGE at a cost-of-service rate. As a result, PGE has already developed the systems necessary to allow simultaneous purchase from PGE and an ESS. These same options can be applied to Schedule 76R.

Q. DOES THIS CONCLUDE YOUR TESTIMONY

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/UE 181/UE 184

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180),	))))))))
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181),	)))))))))
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SURREBUTTAL TESTIMONY OF MICHAEL P. GORMAN

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

AND THE CITIZENS' UTILITY BOARD OF OREGON

October 6, 2006

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael Gorman, and my business address is 1215 Fern Ridge Parkway, Suite 208, St. Louis, MO 63141-2000.

Q. ARE YOU THE SAME MICHAEL GORMAN THAT HAS PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY IN THIS PROCEEDING?

A. I will respond to the rebuttal Joint Testimony of Portland General Electric Company's ("PGE" or the "Company") witnesses Patrick Hager and William Valach.

Q. PLEASE DESCRIBE THE CRITICISM OF YOUR PROPOSED CAPITAL STRUCTURE MADE BY MESSRS. HAGER AND VALACH.

A. The witnesses disagree that my proposed capital structure considered specific risks applicable to PGE, and they argue that it therefore did not produce a reasonable capital structure on which to base rates. Specifically, the witnesses argue that PGE has more risks than my proxy group, and thus, PGE requires a higher common equity ratio than the proxy group to offset its higher operating risk. The risk factors they identify in support of this argument are: 1) PGE has greater variable power costs as a percentage of total revenue; and 2) PGE needs to maintain an investment grade unsecured rating in order to maintain its access to wholesale energy markets, because of unresolved litigation, and because of SB 408-related issues. PGE/2000, Hager-Valach/65.

Q. DO THE WITNESSES RAISE VALID ARGUMENTS IN SUPPORT OF THEIR RECOMMENDATION TO THE COMMISSION TO REJECT YOUR CAPITAL STRUCTURE?

A. No. As set forth below, PGE does not have greater risk than my comparable group, and hence its capital structure should be reasonably comparable to that group. Further, my proposed capital structure and return on equity will support PGE's current credit rating, including its unsecured credit rating, and will support PGE's operations as well as its access to wholesale energy markets. For these reasons, the Commission should adopt my proposed capital structure and return on equity for PGE.

Q. THE WITNESSES CLAIM THAT PGE'S 50% NET VARIABLE POWER COST AS A PERCENTAGE OF TOTAL REVENUES CLEARLY DISTINGUISHES PGE'S RISKS FROM THAT OF YOUR COMPARABLE GROUP. IS THIS ARGUMENT PERSUASIVE?

A. No. This argument is completely without merit. The variability of the utility's cost structure, the ability to earn its authorized return on equity, and expected cash flows are all factors considered by credit rating agencies in assigning the credit risk of an underlying utility company. Hence, any variable cost risk, along with other credit risks, is encapsulated in PGE's bond ratings and business profile score. The same risks are captured in my proxy group's bond rating and business profile score.

Q. IS PGE'S CREDIT RATING COMPARABLE TO YOUR PROXY UTILITY GROUP?

A. Yes. As I showed on ICNU-CUB/304, PGE's bond rating and business profile score from Standard & Poor's ("S&P") is identical to my comparable group average, as is PGE's bond rating from Moody's. This bond rating comparison indicates that my group is comparable in total risk, i.e., the combination of business risk and financial risk. Hence, PGE should have a common equity ratio that is reasonably comparable to that of my proxy group. As such, my proposed adjustment to PGE's capital structure is reasonable and should be adopted.

Q. WILL YOUR PROPOSED CAPITAL STRUCTURE AND RETURN ON EQUITY HELP MAINTAIN PGE'S UNSECURED CREDIT RATING AND ACCESS TO WHOLESALE ENERGY MARKETS?

A. Yes. Indeed, the witnesses did not refute my calculations of the financial credit rating metrics at my proposed capital structure and return on equity in comparison to S&P's credit rating benchmarks. <u>See</u> ICNU-CUB/300, Gorman/30. That analysis shows that under my proposed capital structure and return on equity, PGE will maintain a credit metric consistent with a strong BBB to a weak A investment grade utility company. In other words, it supports PGE's current BBB+ bond rating from S&P and will help preserve PGE's credit strength and access to wholesale energy markets.

Q. HOW DO YOU RESPOND TO PGE'S CLAIM THAT ADOPTION OF ITS PROPOSED CAPITAL STRUCTURE IS NECESSARY IN ORDER TO PROTECT PGE FROM UNRESOLVED LITIGATION AND SB 408-RELATED ISSUES?

A. The witnesses did not expound on this assertion, so it is not possible to respond to this unsupported claim. Nevertheless, maintaining a strong investment grade credit rating will help PGE to respond to unexpected financial challenges, regulatory uncertainties, and access to wholesale energy markets. My recommendation accomplishes this objective, but at a much lower cost than the witnesses' recommendation.

Q. THE WITNESSES ASSERT THAT YOUR DCF RETURN RESULTS SUPPORT A RANGE FOR RETURN ON EQUITY FOR PGE OF 7.38% TO 12.58%, AND STATE THAT THIS RANGE PROVIDES A BETTER ASSESSMENT OF YOUR DCF RESULTS THAN YOUR AVERAGE DCF. HOW DO YOU RESPOND?

A. The witnesses' testimony is flawed and contradictory. First, in assessing PGE's risk in comparison to the proxy group, they rely on the average return on equity over the last five years, and the standard deviation of the returns. Hence, for assessment of risk, the witnesses believe that an average return on equity estimate is appropriate for assessing investment risk for the proxy group and for PGE. PGE/2000, Hager-Valach/67. Here, however, in assessing compensation for investment risk, the witnesses recommend rejecting the average methodology and instead relying on a range.

More importantly, however, the analysis supporting their own testimony is flawed for several reasons. First, the average DCF return gives equal weight to all the proxy group DCF observations. In contrast, the range developed by the witnesses only relies on the DCF results for two of the companies in my proxy group. As such, the witnesses have not given equal weight or consideration to the other DCF observations in my proxy group. Therefore, the witnesses' proposed DCF range is flawed and diminishes the significant value and accuracy created by relying on a large proxy group.

Second, the Commission cannot set rates based on a range; instead, a point estimate is needed to develop PGE's revenue requirement. The average DCF return result reflects the full breadth of all the companies included in my comparable group, and it allows the Commission to develop a point estimate that represents fair compensation for PGE in the development of its revenue requirement and retail rates.

For these reasons, I reject the witnesses' contention that my DCF return analysis supports anything other than the 9.5% return as I estimated in my direct testimony.

Q. WITNESSES HAGER AND VALACH ASSERT THAT THEY DID CONSIDER PGE'S INVESTMENT RISK IN RELATIONSHIP TO OTHER UTILITIES IN THE DETERMINATION OF AN APPROPRIATE RETURN FOR PGE. PLEASE RESPOND.

A. The witnesses claim they did this in their direct testimony, PGE Exhibit 1100, Sections III A and V. However, in those sections of their testimony, they did not compare PGE's risk factors to the same risk factors of the proxy group.

In their workpapers, at page 120, the witnesses did provide a comparison of bond rating, average debt leverage, historical average earnings, and earnings volatility over the last five years for PGE and the proxy risk utility groups. These risk factors, as illustrated by the witnesses' workpapers, show that PGE is reasonably comparable in terms of risk to the proxy risk utility group. Specifically, the witnesses show that PGE has a comparable S&P and Moody's bond rating, and the group's average debt ratio is reasonably comparable to the 50% debt ratio I recommend for PGE in this proceeding. These risk factors indicate that PGE's risk is comparable to that of the proxy group.

The witnesses also compare the average earned return on equity for PGE over the last five years with the average return on equity for the companies in their comparable risk utility group. This historical review of earnings volatility, while not insignificant, is not a complete review of the overall investment risk for PGE in relationship to the other companies. Further, the historical period contained periods that may not be characteristic of PGE's risk going forward. Specifically, the time period encapsulated the period when PGE was owned by Enron, the period of the Western power crisis that financially disrupted many Western U.S. utility companies, certain years in which below-normal hydro conditions occurred, and a period when most utilities were not employing risk management strategies to protect themselves from volatile wholesale commodity charges. These risks may be anomalies in comparison to PGE's forward-looking risk, or may be mitigated through risk management policies adopted by PGE and other utilities.

A comparison of the relevant risk factors for the witnesses' proxy group and my proxy group, as set forth in my direct testimony, shows that the DCF and CAPM return estimates are based on proxy groups that have risk characteristics reasonably comparable to that of PGE on a going forward basis. Hence, no adjustment to the estimated equity returns for the proxy groups need be made to fairly compensate PGE for its investment risk.

Q. THE WITNESSES DISAGREE WITH YOUR CONTENTION THAT THE DETERMINATION OF PGE'S COST OF CAPITAL TODAY SHOULD BE BASED ON OBSERVABLE AND VERIFIABLE MARKET DATA. THEY ASSERT THAT RATES ARE BEING SET FOR CALENDAR YEAR 2007 AND 2006 CAPITAL MARKET DATA IS NOT RELEVANT. PLEASE RESPOND.

A. The witnesses are relying on one source of forecasted interest rates for 2007 in order to draw inferences about what PGE's capital costs <u>might</u> be in calendar year 2007. PGE/2000, Hager-Valach/68. Importantly, the witnesses did not consider projected capital market cost in 2008 and 2009 or over any other period during which rates determined in this proceeding may be in effect.

Hence, the Company witnesses are using very limited forecasted data to reach conclusions about what future capital market costs might be.

Second, setting rates based on projections alone is not reasonable because the accuracy of the projections is highly uncertain. Hence, the Commission would be setting rates based on capital costs that are not known and measurable. Indeed, it is equally as likely that today's capital costs will remain in effect during the period rates determined in this proceeding are in effect. Therefore, using 2006 capital cost as an estimate of PGE's cost of capital in future periods is reasonable.

Q. IS THERE EVIDENCE THAT ECONOMISTS' PROJECTIONS OF FUTURE INTEREST RATES ARE HIGHLY UNCERTAIN AND MAY OVERSTATE FUTURE CAPITAL MARKET COSTS FOR PGE?

A. Yes. At pages 4 through 6 of my direct testimony, I showed that economists' projections of future interest rates have consistently overstated actual interest rates in the forecasted period. Therefore, forecasted interest rates are highly unreliable and produce uncertain cost estimates. Hence, setting utility rates based only on projected interest rates is unreasonable and most likely will overstate PGE's cost of capital during the period rates determined in this proceeding will be in effect. In any event, this analysis shows that future capital costs are not known and measurable.

Current interest rates are as reliable a proxy for PGE's future cost of capital as are a single economist's projections. More importantly, however, current interest rates represent PGE's actual cost of capital in the current year, and should not be disregarded in the development of a fair rate of return.

Q. THE WITNESSES CONTINUE TO DEFEND THEIR RISK POSITION MODEL, FOR VARIOUS REASONS. PLEASE SUMMARIZE THEIR TESTIMONY.

A. The witnesses contend that their risk position model is more reliable than a risk premium or CAPM model because the model results are statistically verifiable, and those available throughout the CAPM analysis or the DCF cost estimate are not. PGE/2000, Hager-Valach/69.

Q. HAVE THE WITNESSES JUSTIFIED THE RISK POSITIONING METHOD AS A RELIABLE TOOL TO ESTIMATE PGE'S COST OF EQUITY IN THIS PROCEEDING?

A. No. The witnesses demonstrate that use of long-term interest rates in this risk positioning model will reduce the return on equity estimate for PGE in the range of 40-45 basis points. PGE/2000, Hager-Valach/70. Hence, the witnesses' original model was flawed and unreliable because it relied on more volatile short-term interest rates.

Second, this model projects rates of return on a simplistic assessment that as interest rates drop, returns on equity increase. This result is largely driven by the time period used in the analysis. Since 1983 interest rates have generally trended downward. This general downward trend in capital market costs has largely created a distortion in market capital costs and regulatory commissions' authorized returns on equity, the primary data set used in the regression study. Importantly, the regression study does not fully capture a cycle in interest rate costs; that is, a cycle of downward trending interest rates and upward trending interest rates. Hence, the analysis is based on incomplete interest rate cycle data. A complete interest rate cycle would better explain the relationship of costs of common equity and interest rates.

Q. DOES A RISK POSITIONING MODEL ACTUALLY ESTIMATE THE RETURN ON EQUITY BASED ON DIFFERENCES IN INVESTMENT RISKS?

A. No. The analysis is a simple regression of authorized returns on equity since 1983, in comparison to contemporaneous interest rates. It does not capture current capital market costs, investment expectations, or changes to the relative levels of risk of equity securities in relationship to debt securities and, in particular, the current market's assessment of investment risk of regulated utility operations. Indeed, the model contains little analysis of the market's current assessment of investment risk at all, and is therefore unreliable and should be rejected.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/UE 181/UE 184

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180),	))))))))
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181),	))))))))
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision relating to the Port Westward plant (UE 184).	))))))))

POWER COSTS/ANNUAL UPDATE AND POWER COST VARIANCE TARIFFS

SURREBUTTAL TESTIMONY OF RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

October 6, 2006

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8343 Roswell Road, Sandy Springs, Georgia 30350. I am the same Randall J. Falkenberg who filed direct testimony in this docket.

I. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. I will respond to PGE's rebuttal testimony, specifically Exhibits PGE/1800 (Lesh) and PGE/1900 (Tinker-Schue-Drennan).

PGE/1800 Rebuttal

Q. PGE DEFINES A NOVEL NEW CONCEPT—"COST OF SERVICE RISK"—IN ITS REBUTTAL TESTIMONY. THE COMPANY ARGUES THAT PGE'S PROPOSED TRUE-UP MECHANISMS SHOULD BE ADOPTED BECAUSE THEY WILL REDUCE "COST OF SERVICE RISK." PLEASE COMMENT.

A. PGE defines "cost of service risk" as the risk that rates will not equal the actual cost of service of the utility providing service. PGE/1800, Lesh/9. The Company goes on to argue that a power cost adjustment mechanism ("PCAM") will reduce cost of service risk for both customers and the utility. Id. at Lesh/11. On the basis of this reasoning, there would be little room to oppose any sort of PCAM, because it reduces the chance that customer rates will not equal the actual costs of the utility. In fact, under PGE's logic, it appears that virtually any kind of a true-up mechanism should be required to reduce cost of service risk.

Unfortunately, PGE has defined the problem so that there is only one kind of solution—a true up. PGE's "cost of service risk" argument is merely a new way of saying rates should be based on actual historical costs, rather than projected normalized costs. PGE acknowledges this fact in Exhibit ICNU/109.

Interestingly, PGE identifies in its rate of return testimony a long list of risks that it allegedly faces, including higher than expected inflation, interest rate changes, unexpected changes in load, regulatory uncertainty, regulatory lag, and regulatory framework risks, but "cost of service risk" is not specifically mentioned. PGE/1100, Hager-Valach/18. The idea of "cost of service risk" appears to be simply an ad-hoc concept that PGE developed to further its argument in this set of circumstances.

Ironically, the cost of service risk concept that PGE complains about is the result of policy decisions to mitigate another risk that actually is included on the PGE/1100 list discussed above: regulatory lag. Allowing utilities to use a projected test year diminishes, if not eliminates, the regulatory lag associated with rates providing cost recovery only *after* costs were incurred. Rates *could* be based on actual costs through the use of historical test years and an annual rate case filing. The problem is that rates would always be a year or so behind, but actual costs would be recovered. PGE wants to have it both ways—it wants to use projected costs to establish rates, and then use a true-up mechanism to ensure that actual costs are recovered, with interest. This might be called a "projected plus actual" ratemaking paradigm, or "forward looking cost plus."

Q. ARE YOU SUGGESTING THAT "COST OF SERVICE RISK" IS NOT A VALID CONCEPT?

A. Yes. Cost of service risk is not a risk at all. Risk implies an unfavorable outcome spoiling an expected outcome. A risk is something to be avoided because it means something undesirable will happen.[1/] I do not worry about the risk that I might win the lottery, for example. Rather, I worry about the risk that I will throw a dollar away on a losing lottery ticket. Likewise, I do not think it is the risk that PGE's rates will exceed actual costs that concerns the Company, just as customers do not worry that PGE's rates are not high enough.

The risk that I have been addressing in my testimony is the risk to customers of additional rate increases that PGE likely would be granted if a PCAM were adopted. The risk to PGE is that its projected costs will be less than its actual costs, not that its rates are too high. So the concept of "cost of service risk" is meaningless because the customers' and investors' risks are equal in magnitude and opposite in sign. They cancel each other out and sum to zero. PGE's argument that cost of service risk can be reduced by a PCAM is illogical—zero risk cannot be reduced to less than zero risk.

Q. TURNING NOW TO SOME OF THE SPECIFICS IN PGE/1800, DID YOU TESTIFY ON PAGE 26 OF YOUR DIRECT TESTIMONY THAT THIS PROCEEDING IS A "COMPLIANCE FILING" FOR ORDER 05-1261?

A. No. It is unclear why PGE asserts that I did. PGE/1800, Lesh/3. I never stated that this proceeding was a compliance filing. I never suggested PGE was even required to file a PCAM proposal. I merely stated that the Commission has established its policies regarding the PCAM, and that PGE's proposal would not satisfy those requirements. I believe the Company has a problem with the Commission's policies more so than with my testimony.

[1/] Risk also implies an unfavorable outcome that is predictable, thus insurable in some sense.

Q. COMMENT ON THE PA CONSULTING MODEL STUDY REFERENCED ON PAGE 17.

A. According to PGE, the PA study shows that PGE's power cost distribution is skewed with a standard deviation of $55 million. PGE/1800, Lesh/17. The difference between the base case and expected value power cost is a positive $10 million. Id.at Lesh/18. PGE suggests that this means the Monet model likely understates costs by $10 million. Id.

While interesting from a modeling perspective, the PA study results hardly demonstrate that a PCAM is needed or that the Monet model is understating the expected value of power costs. I submit that if PGE was confident in the PA model, the Company could have used the model to design a revenue neutral PCA, and/or even could have used it to forecast power costs for this case. Instead, the Company admits that it does not consider the PA Consulting model to be a satisfactory ratemaking tool. ICNU/110, Falkenberg/1. In fact, even PA Consulting does not believe the model is a satisfactory ratemaking tool, nor has PA Consulting benchmarked the model to Monet. Id.; ICNU/111, Falkenberg/1. Further, PGE will not make the model available to parties in this case to review and run, as it does with Monet. ICNU/112, Falkenberg/1. It is PA Consulting's proprietary model, and apparently is intended to be accepted as a "black box." Fortunately, the Commission has not accepted such an approach with PacifiCorp's PD-Mac or GRID models, or PGE's Monet model.

The PA model result is so far below the Monet result that one cannot have confidence that both models are correct. Until PGE applies stochastic modeling to its rate setting process and allows parties to use the model as it does with Monet, the PA model and study are of little or no value.

Q. ON PAGE 36, PGE STATES THAT IT WILL WORK WITH PARTIES TO ADDRESS ISSUES RELATED TO INCLUDING CAPACITY ADDITIONS AND IMPROVEMENTS TO THE ANNUAL UPDATE TARIFF. PLEASE COMMENT.

A. PGE should make a proposal for the parties to review and the Commission to consider. In the absence of a proposal, we have nothing to evaluate, other than the fact that PGE does not agree with the underlying premise. In the absence of a suggestion from PGE, I propose that, if a PCAM is adopted, the actual costs be computed using all actual resources and any projections of power costs should do the same.

Q. ON PAGE 47, PGE ASSERTS THAT FROM 1979 TO 1987 THE COMPANY HAD A COMPREHENSIVE PCA MECHANISM, AND IT DISPUTES YOUR CONTENTION TO THE CONTRARY. IS PGE CORRECT?

A. No. PGE seems to admit that the 1979-1987 PCA did not include nuclear fuel. ICNU/113, Falkenberg/1. Furthermore, PGE ignores that in the order in which the OPUC initially approved the 1979-1987 PCA, which I have attached in Exhibit ICNU/114, the Commission limited the PCA to only oil and natural gas costs, plus purchased power cost in excess of those included in base rates. ICNU/114, Falkenberg/4. In addition, the Commission placed a strict limit on PCA increases of 0.4 cents per kWh. <u>Id.</u> Further, the 1979-1987 PCA allowed only 80% of eligible costs to be recovered. <u>Id.</u>

PGE also suggests that in a subsequent order the Commission allowed Boardman fuel costs to be included in the PCA. ICNU/113, Falkenberg/1. An excerpt of this order also is attached in Exhibit ICNU/114, and it reveals that the Commission did allow recovery of Boardman revenue requirements, but that appears to apply to base rates, not the PCA. ICNU/114, Falkenberg/13-14. The portion of the order discussing the PCA makes no mention of Boardman. Id. at Falkenberg/15-16. Finally, there is no indication that Colstrip costs were included in the PCA. This PCA did not allow recovery of all fuel and power costs; thus, there was no comprehensive PCA for the period 1979 to 1987.

Q. IS THERE ANYTHING NEW OR PERSUASIVE IN PGE'S DISCUSSION OF DEADBANDS?

A. No. At this point, there is little benefit in arguing about what the Commission's policy on deadbands is or whether it is a good or bad policy. While I agree with the Commission policies, as I understand them, the Commission knows what it has decided in the past and what it wants to do now. For that reason, I will not spend any additional time on this topic.

Q. PGE ALSO CRITICIZES YOUR COMMENT THAT COLORADO USES BOTH A DEADBAND AND SHARING MECHANISM. PLEASE COMMENT.

A. PGE contends there was no basis for that statement in my direct testimony, but in the Company's own exhibit, PGE/401, Lesh-Niman/33, NERA states that Colorado and Arizona have both a deadband and sharing mechanism. ICNU asked PGE about this statement in a data request, and the Company acknowledged that NERA did state that Colorado and Arizona both have deadbands but rationalized that NERA was talking about a different concept. ICNU/115, Falkenberg/1.

Q. ON PAGES 62-63, PGE DISCUSSES ISSUES CONCERNING THE REGULATORY REVIEW OF THE ANNUAL VARIANCE TARIFF. PLEASE COMMENT.

A. PGE states that the Company is willing to consider suggestions from other parties regarding the process. I will describe procedures used in other states that the Commission should consider if it decides to approve the Annual Variance Tariff.

In Texas, there is no annual true-up, but utilities are allowed to make changes to the projected fuel (and purchased power) every six months. There are "reconciliation cases" where both the revenues and costs recovered pursuant to a "fuel rule" are examined. These cases have substantial minimum filing requirements. The Texas rules specify a one-year period for a reconciliation case, but this can be extended by the hearing officer. Texas fuel cases usually take months to complete, feature dozens of rounds of discovery, and deal with issues of prudence, reasonableness, and necessity of costs. Costs not included as part of eligible fuel expense under the "fuel rule" are not allowed recovery, whether they were recovered as part of base rates or not. I have been involved in many Texas fuel cases, and this represents the procedure generally followed. While this may seem like a very complex process, it is necessary if a regulatory commission is going to take use of pass-through mechanisms seriously. All documents filed in all Texas cases (except confidential ones) are available on the PUCT web page, usually the day of filing. This substantially speeds up the review process. I have attached a copy of the current Texas fuel rule as Exhibit ICNU/116.

In Georgia, the commission has substantial minimum filing requirements ("MFRs") for fuel cases. I have attached a copy of the Georgia MFRs as Exhibit ICNU/117.

I propose that if the Commission allows PGE to implement an annual variance tariff, it first convene a rulemaking to establish eligible costs and minimum filing requirements. The Texas fuel rule and Georgia MFRs can be used as the "straw" proposal for establishing comparable requirements for Oregon. I propose that the Company be required to file its case on March 1 of each year, with a decision rendered by December 31. I propose PGE be required to turn around data requests in a 10 day period in such cases, and make all case documents available on a web page for immediate download. Confidential documents should be handled in the same manner, but through a secure web site.

Q. IS ALL OF THIS ADDITIONAL REGULATORY EFFORT REALLY NECESSARY IF THE COMMISSION ADOPTS PGE'S PCAM PROPOSAL?

A. Absolutely! The National Association of Regulatory Utility Commissioners ("NARUC") believes fuel and purchased power expense warrants "special attention" and cites many activities required in audits that the Commission may not currently be undertaking:

> **Fuel, Purchased Power, and/or Natural Gas Costs**
>
> For many electric utilities, the cost of fuel and purchased power can be the largest single expense and in some cases, well exceeds fifty percent of a utility's total operating expenses. Therefore, these costs warrant some special attention either in general rate proceedings or separate proceedings related to the review of costs included in fuel, purchased power, and natural gas cost recovery rate mechanisms.

> To begin, the auditor will want to become generally familiar with the utility's general operation . . . . [F]or an electric utility, is all of the power purchased in the open market, or does it own its own power plants, or is there a mix? Are purchase contracts long term or, as for many cooperatives, all requirement contracts?
>
> After reaching a basic understanding, the auditor will want to explore specific cost aspects of not only contracting for the fuel or purchased power, but also issues of transport of the fuel or power (i.e., wheeling costs, pipeline transport, train tariffs); inventory costs and arrangements (i.e., gas storage or coal inventory levels); and measurement (e.g., where is the power metered, who reads and maintains that meter – the buyer or seller; how often are scales calibrated, etc).
>
> From there, the auditor may wish to examine some of the actual contracts and billings from the utility's wholesale suppliers. Do these match the entries in the utility's ledgers and expense accounts? Is the fuel being provided within the heat content and moisture content specifications contained in the contract? One might want to look at reports on the testing of samples of the delivered fuel to verify that tests are being done to assure that the utility is receiving the quality of fuel for which it pays. In another area, one might want to see if any escalators in the contracts have been properly computed and documented. If the fuel or generation is purchased from an affiliate, determine if the purchase price is appropriate. Should it be priced at cost plus a return or at market price? Could it be purchased less expensively from a non-affiliated entity?

NARUC Rate Case and Audit Manual at 36-37 (2003).

Some of these items may not apply in the case of PGE, but it is clear that states that routinely use PCAMs have much higher regulatory standards for fuel and purchased power cost recovery than Oregon has needed up till now.

<u>PGE/1900 Rebuttal</u>

Q. ON PAGE 16 OF PGE/1900, PGE DISPUTES EXTRINSIC VALUE ADJUSTMENTS ON THE BASIS THAT IF THE MONET PROJECTIONS WERE SYSTEMATICALLY OVERSTATED, THE COMPANY WOULD HAVE EXPERIENCED ACTUAL NET POWER COSTS BELOW THE MONET FORECAST IN RECENT YEARS. DO YOU AGREE?

A. No. The Company contends that in 3 of the last 4 years, actual NVPC have exceeded forecast. The Company uses this argument to suggest than an extrinsic value adjustment is, therefore, inappropriate. However, the extrinsic value adjustments proposed by Staff and ICNU are quite small in relation to PGE's total net power costs and other variables that can cause power cost variations. My extrinsic value adjustment is on the order of 1% of total NPC. While still a substantial amount of money, this is not enough by itself to ensure that actual NVPC is always above forecast.

Q. DO SPECIFIC EVENTS HELP EXPLAIN WHY PGE'S ACTUAL POWER COSTS MAY HAVE EXCEEDED THE MONET FORECAST IN RECENT YEARS EVEN THOUGH NO EXTRINSIC VALUE ADJUSTMENT WAS IN PLACE?

A. Yes. In 2005, the Company experienced an outage at Boardman that led to higher actual power costs. Extrinsic value modeling would not capture that event, but the outage rate modeling I proposed does allow for recognition of extreme outage events in the development of the power cost forecast.

Further, during the 2001-2005 period, PGE experienced hydro generation levels that were below the forecast. In 2005, gas prices also exceeded forecast due to the hurricanes in the Gulf of Mexico. These kinds of occurrences caused the actual NVPC to exceed forecast, and were much more significant than the extrinsic value adjustments proposed by Staff and ICNU.

Q. ON PAGE 16, PGE CONTENDS THAT CUSTOMERS HAVE THE OPTION VALUE BY BEING ABLE TO TAKE POWER AS NEEDED. MS. LESH ALSO DISCUSSES "ON-DEMAND" SERVICE REQUIREMENTS OF CUSTOMERS. SHOULD THE CUSTOMERS' OPTION VALUE FOR "ON-DEMAND" SERVICE ALSO BE CONSIDERED IF ONE WERE TO DO AN EXTRINSIC VALUE CALCULATION?

A. No. PGE's rates more than compensate the Company for incremental power demands. PGE contends in its example on pages 25-26 that its average retail rate is approximately $78.5/MWh. Over the period from June 2002 to present, day-ahead market prices for power have exceeded $78.5/MWh only 5.5% of the time during heavy load hours ("HLH"), and 2.75% of the time during light load hours ("LLH"). As a result, the Company will nearly always collect more incremental revenue from customers for brief increases in demand than the cost of meeting those demands.

Q. DO YOU AGREE WITH PGE'S CHANGES TO YOUR EXTRINSIC VALUE CALCULATION?

A. In part. On page 21 of PGE/1900, the Company contends that my extrinsic value calculations should reflect hourly modeling, such as is performed in Monet rather than basing my analysis on standard products. PGE contends that I should have recognized that Monet models hourly prices, and the pre-existing distribution of spreads in Monet that I did not consider. However, the Company ignores some important points. First, I used day-ahead LLH and HLH standard product block prices to estimate spreads for extrinsic value analysis, not hourly spreads. Because actual hourly spreads will depart substantially from spreads for HLH and LLH blocks, there is no basis for assuming that the data I developed could be properly applied by the Company to an hourly analysis. PGE's hourly prices are merely shaped from the LLH and HLH block prices, so the Company is exaggerating the importance of this.

Second, even if PGE's arguments were correct, the Company ignores the fact that relatively little trading is done in the hourly market. In reality, most of PGE's short-term transactions are HLH or LLH block transactions, not hourly transactions. In fact, PGE's hourly spot purchases were a very small percentage of the combined spot and short-term firm purchase volume since 2001. Even assuming PGE's suggestion that hourly trading should be modeled was correct, it would only be applicable to a small fraction of PGE's transactions. PGE has not performed a true hourly analysis either, so there is no way to tell what an hourly study would show.

I do accept PGE's mathematical corrections, and that does reduce my extrinsic value adjustment. The Company also uses the outage rates for Port Westward and Coyote in its analysis that exceed the NERC peer group figures. For the same reasons as discussed in my direct testimony, I recommend use of the NERC figures. ICNU/103, Falkenberg/14-17.

Comparison of my revised results to those obtained by Staff and earlier PGE studies suggests my original assumptions are quite conservative. Based on this recalculation, my overall extrinsic value results are much less than Staff's, which were developed using an independent method. My results for the capacity tolling contract (PPM Superpeak) also produced a lower extrinsic value than the studies performed by the Company using its own analysis.

Q. WHY ARE YOUR RESULTS LESS THAN THOSE INDICATED BY THE PGE AND STAFF ANALYSES?

A. I believe a primary reason is that the Company and Staff studies relied upon a different (and earlier) time frame than spanned by my data. It is quite likely that use of data that included the western power crisis would have substantially increased my extrinsic value result. Further, I constrained the model results to set the mean spread equal to the Monet model spread. This is a very conservative assumption, because the Company is predicting different spreads than have been experienced historically. As gas and power prices moderate from recent highs, I expect that spreads will tend to reflect historical levels. Data from PGE's most recent update corroborates this view.

Q. HOW DO YOU ADDRESS THIS ISSUE?

A. I have computed a range of extrinsic value adjustments and updated the results using data from PGE's most recent Monet runs. Alternative 1 takes the revised ICNU results, but adjusts outage rates used by PGE and uses the updated Monet data. This produces an extrinsic value adjustment of $4.3 million. Alternative 2 adjusts the model so that the mean spread between gas and power is based on historical spreads, rather than the projected Monet spread. This produces an extrinsic value adjustment of $5.9 million. Considering that both estimates are below the Staff estimate, I believe the upper range figure is most reasonable.

Q. DO THE HYPOTHETICAL EXAMPLES PROVIDED BY PGE ON PAGES 25-26 PROVIDE A PERSUASIVE REASON FOR THE COMMISSION TO REJECT EXTRINSIC VALUE ADJUSTMENTS?

A. No. Hypothetical examples are generally meaningless if they rely upon "selective" data assumptions. PGE's example actually illustrates a logical fallacy, not a problem with extrinsic value analysis. This logical fallacy is known as improper generalization. An example of PGE's logic might be as follows – "John is a man. John doesn't like to watch football at four in the morning, but rather prefers to sleep. Therefore, men do not like to watch football at any time."

PGE asserts that extrinsic value analysis should not be applied by the Commission (except when the Company uses it for resource selection), because it produces results that are undesirable for the Company in one contrived example.

Q. EXPLAIN WHY YOU SAY PGE'S EXAMPLE IS CONTRIVED.

A. PGE's example assumes that, during a 48-hour cold spell, market prices for wholesale electricity and natural gas increase simultaneously. In fact, both gas prices and the market heat rate increase to extreme levels. In PGE's example, market gas prices increase from $9.8/mcf to $12.00/mcf, and the market heat rate increases from 7.5 mmbtu/MWh to 12.0 mmbtu/MWh.

Q. ARE THESE ASSUMPTIONS REALISTIC?

A. No. <u>First</u>, it is unrealistic to assume that natural gas prices (which are established in a national, if not world, market) would be substantially impacted by a cold front in the Pacific Northwest. A short spell of cold weather in Oregon is unlikely to increase market gas prices by more than 20%, as PGE assumes in its example. My analysis of Sumas and Henry Hub market data from 2002 to present shows the two markets have a correlation coefficient of 0.97. This means the two markets move largely in tandem. A cold front in the Northwest is very unlikely to drive up prices in the entire U.S. market.

<u>Second</u>, PGE ignores the fact that the market heat rate and natural gas prices do not move in tandem because they are driven by different factors. Market gas prices are influenced by demand over the entire country and are influenced by world oil prices, the national economy, and even hurricanes in the Gulf of Mexico, among other things. The market heat rate is driven by supply and demand for power in the western markets. These two items do not necessarily move in lock step as PGE's hypothetical assumes.

Based on the 990 observations of market price spreads used in my extrinsic value analysis over the period June 2002 to June 2006, PGE's hypothetical scenario ($12 gas and a market heat rate of 12.0) never occurred at the same time. Exhibit ICNU/118 is a graph showing a comparison of market heat rates and market gas prices over the period. It illustrates that while gas prices have exceeded $12 and heat rates have exceeded 12.0 mmbtu/MWh, these two events did not happen at the same time. Further, the chart shows that the two variables can even move in opposite directions. Overall, the correlation between gas prices and the market heat rate is only 0.18, implying that parallel movement of these variables (the very underpinning of PGE's example) seldom occurs. In reality, PGE's hypothetical is nothing more than "numerology" where contrived figures are combined to produce the desired results.

Q. CAN YOU PROVIDE A MORE REALISTIC COUNTER EXAMPLE?

A. Yes. In July 2003, market heat rates were around 12 mmbtu/MWh while gas prices were at $4.3/mmbtu. Based on this data, the added (extrinsic value) margin from a 500 MW sale for 48 hours from Beaver would amount to $258,000.[2/] Additional retail revenues would amount to $1,884,000, while the added cost to PGE of additional sales would be $980,400.[3/] This would produce an additional gain of $903,600 for PGE. Thus, the extrinsic value analysis would provide PGE with a much smaller "windfall" than would actually occur. While I admit that this situation is rare, unlike PGE's example, it is something that actually happened in the past 4 years.

[2/] Market revenue = 24000 MWh X 12 X 4.3 = $1,238,400. Cost = 24000 X 9.5 X 4.3 = $980,400, spread = $258,000.

Capacity Tolling Contracts

Q. PGE CONTENDS ON PAGE 36 OF PGE/1900 THAT YOU DO NOT BELIEVE THE COMPANY NEEDS PEAKING CAPACITY. IS THAT ACCURATE?

A. No. However, it is very difficult to establish a need for peaking resources that have only been used a few hours over a period of several years. Further, PGE's discussion of peaking capacity requirements and the capacity tolling contracts is quite misleading. The PPM Super Peak contract was justified on the basis of extrinsic value rather than the ratepayers' need for peaking capacity.

In my direct testimony, I was simply suggesting that PGE's estimate of the extrinsic value of the capacity should be reflected by the Commission in setting PGE's rates. Utility rates should only recognize *reasonable and necessary* costs. Capacity contracts that are seldom (or never) called upon do not result in *necessary* costs. Absent a PCA (which PGE did not have at the time it entered into these contracts) the only benefits these contracts might ever produce would inure to investors, not customers. For this reason, I stand by my adjustments for the capacity tolling contracts.

Q. PGE CONTENDS THAT ON THE BASIS OF EXHIBIT PGE/1910 THE COMPANY'S SUMMER RESOURCES ARE ALL NEEDED AND THAT IT NEEDS 450 MW OF ADDITIONAL CAPACITY IN THE WINTER. DOES THIS SEEM REASONABLE?

A. No. The Boardman outage experience belies this argument. In the winter of 2005/2006, the entire 380 MW capacity from Boardman was out of service, yet PGE never needed to rely upon the PPM or Cold Snap contracts.

3/ Retail revenue = 24,000 X 78.5 = $1,884,000. Cost = $980,400, spread = $903,600.

Outage Rate Adjustments

Q. PGE DISPUTES THE OUTAGE RATE ADJUSTMENTS PROPOSED BY ICNU AND STAFF. THEY CONTEND THAT THE COMPANY HAS EXHIBITED GOOD PERFORMANCE BASED ON COMPARISON OF PGE AND NERC EQUIVALENT AVAILABILITY FACTORS ("EAF"). DO YOU AGREE?

A. No, but first, it should be pointed out that I used the NERC EAF data in my proposed adjustments for Boardman and Colstrip. Therefore, I already used the metric proposed by the Company. Second, PGE's comparison presented on page 39 of PGE/1900 is misleading. The Company compares the 2001-2004 EAF for its plants to comparable NERC peer group figures. However, the Company is not requesting to use 2001-2004 outage rates in its Monet study. Rather, the Company proposes to use the 2002-2005 outage rates, which reflect much poorer performance by the Company.[4/] So the Company's comparison is simply off-base and irrelevant.

Q. DOES PGE'S TESTIMONY HIGHLIGHT ANY PROBLEMS WITH THE MANAGEMENT OF ITS CAPACITY RESOURCES?

A. Yes. On page 38, PGE concedes that it has higher unplanned outage rates than comparable plants in the NERC peer groups, but contends these are offset by lower planned maintenance outages. This is an unwise trade-off, however, because planned outages are coordinated to occur when replacement power is available at the lowest possible cost. Unplanned outages can (and, as shown in the case of the Boardman plant, do) occur at times when replacement power costs

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[4/] The 2001-2004 PGE figures are comparable to the NERC figures I propose. Thus, PGE would apparently agree with the use of NERC outage levels in 2004, but not in 2005.

are high. Skimping on planned maintenance at the expense of higher cost unplanned outages is false economy.

Q. HAS PGE ACCURATELY CHARACTERIZED ICNU'S POSITION VIS-A-VIS COLSTRIP OUTAGE RATES IN THE RECENT PACIFICORP CASES?

A. No. PGE quotes an ICNU data response and contends it reviewed ICNU's testimony in UE 179 (the recent PacifiCorp case). However, the Company did not acknowledge that I proposed a reduction to the Colstrip outage rate in UE 179. In that case, ICNU recommended a prudence disallowance applied to all outage rates, including those for Colstrip, based on an analysis of the outages that occurred at PacifiCorp plants and a review of PacifiCorp's root cause analyses. This adjustment amounted to a 7.7% reduction to Colstrip's forced outage rate in GRID.

Q. ON PAGES 44-45, PGE CHALLENGES THE OUTAGE RATES YOU USED FOR COYOTE, AND SUGGESTS THEY COULD NOT VERIFY THE NERC DATA YOU RELIED UPON. PLEASE COMMENT.

A. The NERC data I relied upon came directly from the NERC web page. Exhibit ICNU/119 presents the NERC data I relied upon. It is possible that NERC may have retroactively revised its figures after I obtained these documents from its web page. In the end, whether PGE's data is correct or not, it makes little difference, because the numbers differ by only a small amount.

Q. DO YOU DISPUTE THE CAPACITY CHANGES TO YOUR OUTAGE RATE ADJUSTMENT PROPOSED BY PGE ON PAGE 45?

A. No. I accept PGE's revision to my outage rate adjustment, which reduces the adjustment to $5.673 million.

PCAM Load Adjustment

Q. ON PAGE 12 OF PGE/1900, PGE CONTENDS THAT ICNU'S LOAD ADJUSTMENT MECHANISM FOR THE ANNUAL VARIANCE TARRIF DOES NOT ALIGN NVPC WITH NVPC-RELATED REVENUES. PLEASE COMMENT.

A. The Company contends that PGE/1903 illustrates this point. However, the Company has completely ignored the reason why a load adjustment was proposed in the first place. Once this fact is realized, it becomes apparent that the PGE proposal will not align revenues and costs.

Exhibit PGE/1903 shows that under a 5% increase or decrease in loads, there is no change in PCA revenues using ICNU's proposed method. This is proper because, as I pointed out in my direct testimony and above, PGE is already compensated for increases or decreases in load via base rates. Thus, the goal of a load adjustment is to remove loads from the equation when determining under or over recoveries of power costs. The purpose of the PCA is not to allow the Company to charge customers more because loads increased, but rather to insulate the Company from power cost increases unrelated to load changes. As discussed above, PGE's base rates compensate the Company for load changes.

Q. PAGE 3 OF EXHIBIT PGE/1903 SHOWS THAT UNDER THE ICNU PROPOSAL, A 5% INCREASE IN LOAD RESULTS IN PGE UNDERCOLLECTING ITS ACTUAL POWER COSTS BY $20,000. IS THIS ACCURATE?

A. Of course not! PGE's Exhibit/1903 is actually quite misleading because it ignores the base revenue component in its total revenue line. I have corrected that problem in Exhibit ICNU/120. When the change in base rate revenue is considered, PGE would still over collect revenues resulting from load increases under the ICNU proposal. However, the Company would over collect by a much smaller amount than in PGE's proposal. ICNU/120, Falkenberg/1-2. While there may be no way to perfectly align costs and revenues, the ICNU proposal is far superior to the PGE and Staff proposals.

Q. IS THERE ANOTHER WAY TO ADDRESS THIS PROBLEM OF MATCHING COSTS AND REVENUES WHEN LOAD CHANGES OCCUR?

A. Yes. Avista uses such a method in Washington. Under the Avista method, there is a production factor applied to credit costs deferred under its Energy Recovery Mechanism ("ERM") with the change in base rate revenues resulting from load changes. PacifiCorp proposed a similar approach in its last Washington rate case. I recommend the Commission consider such a methodology (assuming it decides to reverse its PCAM policies and implement PGE's annual variance tariff). The design of this rate component would need to be developed in a subsequent case where the PCA rules and minimum filing requirements are also determined, as this issue has not been fully developed in the current record.

<u>Port Westward Dispatch Benefit</u>

Q. ARE ICNU AND PGE IN AGREEMENT ON THIS ISSUE?

A. I believe so. PGE agrees that if the Commission does not adopt the Annual Update and Annual Variance Tariffs, the Company should perform a new Monet run including the facility for all twelve months. PGE/1900, Tinker-Schue-Drennan/51. I agree. I used an outboard adjustment to estimate the dispatch benefits of Port Westward for all twelve months as a placeholder, and continue to do so. However, I would prefer a new Monet run be performed to address this issue.

<u>Summary of Adjustments</u>

Q. DO YOU HAVE AN UPDATE TO TABLE 1 FROM YOUR DIRECT TESTIMONY, SHOWING YOUR RECOMMENDED ADJUSTMENTS?

A. Yes. Below is an updated Table 1.

Table 1 – Summary of Recommended Adjustments
$1000

	======Amount======	
I. Monet Power Supply Cost Issues:	**Without Port Westward**	**With Port Westward**
1 Extrinsic Value - PGE Generators	**-$2,849**	**-$5,936**
2 Extrinsic Value - Super Peak	**-$1,384**	**-$1,384**
3 NERC Outage Rates	**-$5,673**	**-$5,673**
4 Port Westward Dispatch Benefit	**-**	**-$1,922**
5 Cold Snap Contract	**-$1,752**	**-$1,752**
Total Power Supply Cost Adjustments:	**-$11,658**	**-$16,667**
PGE Request	**856,968**	**847,321**
Total ICNU Recommended Power Supply Costs	**$845,310**	**$830,653**

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/UE 181/UE 184

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180),	)
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181),	)
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision relating to the Port Westward plant (UE 184).	)

ICNU/109

PGE Response to ICNU Data Request No. 192

October 6, 2006

September 22, 2006

TO: S. Bradley Van Cleve
ICNU

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to ICNU Data Request 16.192
Dated September 14, 2006
Question No. 192

Request:

PGE/1800, Lesh/11, lines 20-22. Does Ms. Lesh imply that use of 100% historical actual costs would eliminate cost-of-service risk completely? Doesn't this just mean that Ms. Lesh has defined risk in such a way as to imply the only risk free approach to ratemaking is to use pass-through mechanisms that true up all costs of the Company to actual historical costs?

Response:

By definition, a commission that used only actual costs in ratemaking would eliminate cost of service risk. Although instances of a commission reaching such a conclusion have occurred in the past, it is unlikely that a commission would conclude that using only actual costs best meets the statutory and constitutional requirements and commission goals for regulated utility service. As explained in PGE Exhibits 400, 401 and 1800, it is common for commissions to conclude that using actual purchased gas costs and net variable power costs (either 100% or subject to some amount of sharing) does meet statutory and constitutional requirements and further regulatory goals. Inclusion of actual non-fuel/power operations and maintenance costs is rare, although it does occur on selective items, such as energy efficiency program costs as mentioned in PGE's response to ICNU Data Request No. 188.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/UE 181/UE 184

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180),	))))))))
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181),	)))))))))
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision relating to the Port Westward plant (UE 184).	)))))))))

ICNU/110

PGE Response to ICNU Data Request No. 193

October 6, 2006

September 22, 2006

TO: S. Bradley Van Cleve
ICNU

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to ICNU Data Request 16.193
Dated September 14, 2006
Question No. 193

Request:

PGE/1800, Lesh/17, line 18. Does PGE find the PA Consulting model satisfactory enough at this time that it would be willing to use the mean $650 million NVPC estimate for purposes of establishing rates in this case rather than the Monet model results that exceed $800 million? Explain why the PA Consulting model was not used for this case.

Response:

No. The authors of the study do not believe the model is satisfactory for rate setting, see PGE Exhibit 1800, Lesh/17 lines 12-14:

> PA found that "an important factor limiting the precision of any probabilistic cost simulation is the availability of data describing the distributions and dependencies of its uncertain inputs."

Further, the "PA cost simulation model produced a "descriptive model" PGE Exhibit 1800, Lesh/17 line 16. See also PGE Exhibt 1900, Tinker-Schue-Drennan/pages 13-15 for a general discussion of the PA Consulting model. One conclusion of the report:

> The distribution of uncertainty data is critical to estimating expected value. If one intends to use the model to produce a "once and for all" number, what the authors call a "prescriptive" use, then one must invest considerable effort in estimating the underlying values. (PGE Exhibt 1900, Tinker-Schue-Drennan/14 lines 3-6)

Finally, PA Consulting used forecasts for gas and electric prices which are substantially different than those relevant to the 2007 test year.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/UE 181/UE 184

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180),	))))))))
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181),	)))))))))
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision relating to the Port Westward plant (UE 184).	))))))))))

ICNU/111

PGE Response to ICNU Data Request No. 194

October 6, 2006

September 22, 2006

TO: S. Bradley Van Cleve
ICNU

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to ICNU Data Request 16.194
Dated September 14, 2006
Question No. 194

Request:

Did PGE Benchmark the PA Consulting model against any Monet studies? If so, please provide the relevant benchmarking studies.

Response:

PGE did not benchmark the PA Consulting model against any Monet studies.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/UE 181/UE 184

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Request for a General Rate Revision (UE 180),	)
	)
In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181),	)
	)
In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Request for a General Rate Revision relating to the Port Westward plant (UE 184).	)

ICNU/112

PGE Response to ICNU Data Request No. 170

October 6, 2006

September 22, 2006

TO: S. Bradley Van Cleve
ICNU

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to ICNU Data Request 16.170
Dated September 14, 2006
Question No. 170

Request:

PGE/1900, Tinker-Schue-Drennan/14. PA Consulting Report. Provide all supporting workpapers, including all spreadsheets and underlying documentation. Provide spreadsheets with all cells and formulae intact in full working order. To the extent that computer models where used to prepare the report, provide those models and all input data as well, along with instructions on how to use the models.

Response:

PGE objects to this request because it is overly broad and unduly burdensome. Without waiving its objection, PGE responds as follows:

PA Consulting's (PA) report was their work product. The model used in preparing the analytical results described in that report is the property of PA and was never directly examined or run by PGE. PGE asked PA to explore the concept and issues surrounding hourly power cost modeling, and PGE's acquisition of and development of the ability to apply PA's model were objectives beyond the scope of the work.

PGE possesses spreadsheets and documentation for PA's work only to the extent that PGE provided some specific data sets to PA for use in statistical analysis and inputs to PA's simulation model. Some data, for example, gas and electric market price series, were offered to PA as points of reference, but not used by PA because of commercial propriety concerns. For such data, PA Consulting ultimately used its own sources, for which it had appropriate access, after checking that the data were substantively identical to the series possessed by PGE. In response to this question, PGE is providing all relevant files that we provided to PA.

Confidential Attachment 170-A is a CD which contains all confidential files PGE provided to PA. This attachment is confidential and subject to Protective Order No. 06-111 and is provided under separate cover. Attachment 170-B is a CD which contains all non-confidential files provided to PA.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/UE 181/UE 184

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180),	)
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181),	)
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision relating to the Port Westward plant (UE 184).	)

ICNU/113

PGE Response to ICNU Data Request No. 197

October 6, 2006

September 22, 2006

TO: S. Bradley Van Cleve
ICNU

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to ICNU Data Request 16.197
Dated September 14, 2006
Question No. 197

Request:

PGE/1800, Lesh/47, lines 20-21. Is Ms. Lesh aware that the 1979-1989 PCA did not include costs for all types of fuels used by PGE? If so, does that not imply it was not a comprehensive PCA?

Response:

It is our understanding that all fuels were covered by the PCA. Order No. 79-830 initiating the PCA indicated that it included hydro, fuel costs, net purchased power, oil, natural gas, and thermal plant efficiency. Nuclear fuel was not cited; generally nuclear fuel costs would not fluctuate throughout the year. After Boardman came online, Order No. 80-021 addressed the plant and stated that "PGE will be authorized to adjust its revenues by the annual effect of inclusion of its share of the Boardman Generating facility…. The revenue requirement related to this adjustment will include changes in power costs…." Further, see Schedule 100, Power Cost Adjustment, issued March 12, 1981. It states that, "the total power cost will be determined as the sum of the fuel expenses of all Company-owned or leased generating facilities…."

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/UE 181/UE 184

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180),	)
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181),	)
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision relating to the Port Westward plant (UE 184).	)

ICNU/114

Order No. 79-830 and

Excerpts of Order No. 80-021

October 6, 2006

ORDER NO. 79-830

ENTERED November 15, 1979

BEFORE THE PUBLIC UTILITY COMMISSIONER

OF OREGON

UF 3518

In the Matter of Revised Tariff Schedules applicable to electric service in the State of Oregon, filed by PORTLAND GENERAL ELECTRIC COMPANY (on the Commissioner's own motion).	)	ORDER (POWER COST ADJUSTMENT)

On June 1, 1979, Portland General Electric Company (PGE) filed revised tariff schedules with the Public Utility Commissioner of Oregon. PGE originally requested a general rate increase of 21.1 percent (since revised to 19.75 percent). The total requested increase would have increased the company's annual revenues by approximately $78 million during test year 1980 (since revised to $68 million). As part of its filing, PGE requested a power cost adjustment. Pursuant to ORS 756.528, the Commissioner gave notice on October 8, 1979, that the power cost adjustment issue would be segregated and a hearing on this issue was to be held prior to the other issues in the case. Hearings on the power cost adjustment were held October 29 through November 1, 1979.

Portland General Electric Company's Proposal

PGE proposes a power cost adjustment tariff which would vary rates depending on hydro availability, fuel costs, thermal plant efficiency, and cost of purchased power. Briefly, the tariff would establish an expected power cost per kilowatt hour (kWh) called the "base rate." Eighty percent of the estimated increase or decrease in power costs from the base rate would be reflected in rates to be collected for the period. The maximum change from existing tariffs in any single period would be 0.4 cents per kWh. The adjustment rate would be revised every three months. Any under- or over-collection of power costs for a quarter would be placed in a power cost adjustment account.

Power costs are determined as the sum of the operating and maintenance expenses of all company-owned or leased generating facilities, the net cost of purchased power, and the cost of transmission (wheeling) supplied by other systems to PGE, less revenues from sales for resale.

The power cost adjustment is imposed by increasing or decreasing the energy charge to each customer on a cents-per-kWh basis.

PGE proposed several alternatives to its proposal to meet various objections of the parties.

Position of Commissioner's Staff (Staff)

Staff opposes a power cost adjustment generally, and specifically opposes PGE's proposal because:

1. Eighty percent of all power costs is recovered. PGE's proposal does not distinguish between power cost variations within or beyond management's control.

2. It is cumbersome to administer.

3. Refunds and surcharges are not in phase with changes in the actual costs of power. Consequently, the consumer does not receive an accurate economic signal for the price of the commodity which he or she consumes.

4. There is no provision for variations in revenue that might occur with variations in power costs.

If a power cost adjustment is deemed desirable, Staff suggests several modifications to PGE's power cost adjustment. The modifications (1) limit recovery to only 50 percent of the power cost variance, (2) include only costs for fuel, net purchased power, and transmission less the revenues from sales for resale, (3) exclude extraordinary thermal plant shutdowns, and (4) provide for a temperature adjustment.

Positions of Other Parties

The Oregon Committee for Equitable Utility Rates (OCEUR) supports the power cost adjustment concept. OCEUR urges that the rates for each customer class be adjusted on an equal percentage of existing revenues basis. If a power cost adjustment goes into effect before rates are adjusted in the general rate order, the power cost adjustment would collect permanent increases above rates set in Commissioner's Order No. 79-055 in addition to power cost variations about the mean. OCEUR does not object to recovery of variations on a cents-per-kWh basis once the base rates are adjusted to reflect realistic expected power costs.

Ratepayers Union opposes any power cost adjustment.

Staff Exhibit 8A

A suggested alternate power cost adjustment, Staff Exhibit 8A, would allow PGE to collect additional revenues when it experiences increases in the net cost of purchased power, in related wheeling expense, and in the cost of fuel burned at the company's Beaver, Harborton, Summit, and Bethel facilities less prorated sales for resale. This tariff, however, holds the company to the estimated production costs and kWh amounts adopted in the Commissioner's latest general rate order for the company. Recovery would be limited to 50 percent of the cost increase.

Exhibit 8A provides that average power costs shall be based on forecasts. If forecasted power costs fall below base power costs, the tariff would not allow a reduction in rates below existing tariffs. Because rates are set based on forecasted power costs, over- and under-collections are possible. When they occur, this tariff provides that the over- and under-collection amounts be put into a power cost adjustment account. The tariff allows no adjustment to exceed 0.4 cents per kWh. Balances in the adjustment account are to be amortized in succeeding quarters.

Need For And Determination To Adopt Power Cost Adjustment

A power cost adjustment is necessary for PGE at this time. PGE is facing increased costs of oil and natural gas for its Beaver, Harborton, Summit, and Bethel facilities and of purchased power which are not reflected in existing rates. The company should be compensated for these cost increases.

Like Staff Exhibit 8A, the adopted tariff identifies as eligible costs those power cost increases over the costs adopted in the last general rate order for the following:

1. Natural gas and oil (FERC Account 547)[1]

2. Net purchased power plus related transmission costs (FERC Accounts 555 and 565)[1]

3. Less prorated sales for resale (FERC Account 447)[1]

Like Staff Exhibit 8A, the adopted tariff imposes the rate adjustment on a cents-per-kWh basis for the period in which the costs are expected to be incurred. Also, no increase greater than 0.4 cents per kWh will be allowed. The adopted tariff specifies that only 80 percent of eligible costs may be recovered by the company.

Like Staff Exhibit 8A, amounts over- or under-collected from previous quarters will be placed in a power cost adustment account. Accumulated revenues balances in the adjustment account are to be amortized in subsequent quarters subject to the over-all maximum rate of 0.4 cents per kWh.

Like Staff Exhibit 8A, the company is directed to procure its power from the lowest cost available resource regardless of the other provisions of the tariff. The monthly bill sent to each customer shall separately state the dollar amount collected under the power cost adjustment tariff from that customer.

Unlike Staff Exhibit 8A, the adopted tariff specifies slightly different quarterly filing requirements, defines additional terms, and becomes operative for "service rendered on and after" rather than for "meter readings on and after" its effective date.

Most of the concerns raised by the parties about power cost adjustment tariffs are addresssed by the adopted tariff:

1. Price increases for fuel used at the Beaver, Harborton, Summit, and Bethel facilities and for purchased power in excess of that adopted in the last general rate order are covered. Increases for additional generation or purchased

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[1] The FERC accounts identified include certain costs beyond eligible costs as defined by the terms of this order. Subaccounts may be established by the company to isolate the eligible costs beyond those approved in the latest general rate order.

power beyond amounts specified in the last general rate order are excluded. Only costs beyond the company's control are included.

2. Since only a portion of the eligible costs are allowed recovery, the company is given an incentive to obtain its needed power at the lowest possible cost.

3. Corrections are to be made for over- or under-collections.

4. Customer billings are altered to show the exact dollar effect of the power cost adjustment tariff.

5. The rate changes are in phase with the cost changes. Matching the charges to the costs gives the ratepayer the best price signal.

6. Only the company's immediate needs are covered.

7. The 0.4 cents per kWh maximum charge acts to reduce sharp changes in the adjustment rate.

8. Implementing the adjustment on a cents-per-kWh basis will give a clear energy conservation signal to customers.

The exact tariff language adopted is shown in the Appendix to this order.

IT IS THEREFORE ORDERED that:

1. Schedule 100, Original Sheet No. 100-1, filed by Portland General Electric Company on June 1, 1979, is permanently suspended.

2. Portland General Electric Company may file a power cost adjustment rate schedule, using the language of the Appendix, to be effective for service rendered on and after the date the schedule is approved by the Commissioner. For the purposes of this order, the period between the effective date of the tariff and the end of 1979 shall be deemed a quarter.

3. Portland General Electric Company shall submit to the Commissioner, 30 days prior to the beginning of each calendar quarter, the following information:

ORDER NO. 79-830

a. A letter of transmittal which summarizes the proposed changes under the schedule.

b. A revised rate schedule page which reflects the new quarterly adjustment rate.

c. Working papers supporting the calculation of the revised adjustment rate.

4. If the adopted power cost adjustment tariff be modified or terminated for any reasons, the remaining balance in the power cost adjustment account shall be amortized to rates over a period to be determined by further order of the Commissioner.

Made, entered and effective November 15, 1979.

JOHN J. LOBDELL
Public Utility Commissioner

ah

ORDER NO. 79-830

APPENDIX

Schedule 100

POWER COST ADJUSTMENT

In addition to the rates set forth in the other schedules of this tariff, each Customer's bill will be adjusted to compensate for certain power costs (as specified herein) as they differ from those included in the base rate schedules. The adjustment rate to be applied to each kilowatt hour sold will include 80 percent of the difference between Average Power Costs and Base Power Costs, as specified herein. This adjustment will be subject to revision every calendar quarter.

APPLICABLE

To all bills for electric service calculated under applicable tariffs.

POWER COSTS

The power costs used in this schedule are defined as follows:

(1) Base Power Rates:

Base Power Rates are defined as the quarterly power costs per kilowatt hour used to develop existing rate schedules. Power costs included are as follows:

(a) The net cost of purchased power (FERC Account 555) plus the related expense of transmission of power by others (wheeling) (FERC Account 565); and

(b) The cost of fuel burned at the Company's Beaver, Harborton, Summit, and Bethel facilities (FERC Account 547) based upon monthly average inventory cost.

(c) Less prorated revenues from sales for resale. Total revenues from sales for resale (FERC Account 447) are to be multiplied by the proportion of the total kilowatt hours of purchased power and energy generated at the Beaver, Harborton, Summit, and Bethel facilities to the total kilowatt-hours of system generation and purchases.

The algebraic sum of Items (a), (b), and (c) is divided by the total kilowatt hours of purchased power and energy generated at the Beaver, Harborton, Summit, and Bethel facilities used to develop existing rates.

The Base Power Rates from the last general rate order are:

0.7714¢	November and December only
0.4911¢	January through March
0.4658¢	April through June
0.6907¢	July through September
0.7916¢	October through December

(2) Projected Average Power Rates:

Projected Average Power Rates are defined as the average quarterly cost per kilowatt hour for the composite of the projected values of the items listed above as (a), (b), and (c) and calculated, using projected kilowatt hours purchased and generated at the Beaver, Harborton, Summit, and Bethel facilities, as in Base Power Rates. Projected Average Power Rates will be calculated for each period specified under Base Power Rates.

(3) Actual Average Power Rates:

Actual Average Power Rates are defined as the average quarterly cost per kilowatt hour for the composite of the actual values (as available) of the items listed above as (a), (b), and (c) and calculated, using actual (as available) kilowatt hours purchased and generated at the Beaver Harborton, Summit, and Bethel facilities, as in Base Power Rates. Actual Average Power Rates will be calculated for each period specified under Base Power Rates.

(4) Base Power Costs:

Base Power Costs are defined as the product of:

(a) Base Power Rates; and

(b) The net kilowatt hours of purchased power and of energy generated at the Beaver, Harborton, Summit, and Bethel facilities used to develop existing rate schedules.

(5) Projected (or Actual) Average Power Costs:

Projected (or Actual) Average Power Costs are defined as the product of:

(a) Projected (or Actual) Average Power Rates; and

(b) The net kilowatt hours of purchased power and of energy generated at the Beaver, Harborton, Summit, and Bethel facilities used to develop existing rate schedules.

When the calculation of Projected (or Actual) Average Power Costs results in a figure less than Base Power Costs, the figure for Base Power Costs will be substituted for Projected (or Actual) Average Power Costs for purposes under this schedule.

The Company shall at all times procure energy from the most economic resource available, regardless of the other provisions of this tariff.

POWER COST ADJUSTMENT ACCOUNT

The Company will maintain a Power Cost Adjustment Account to record over- and under-collections. The account will contain the cumulative difference between previously authorized power cost revenues and 80 percent of the "power cost variances" for the prior periods. "Power cost variance" is defined as the difference between the Actual Average Power Costs and Base Power Costs, as defined herein.

ADJUSTMENT RATE

The Adjustment Rate, to become effective for service rendered on and after each quarterly revision and continuing thereafter until the next Adjustment Rate becomes effective, shall be the algebraic sum of the following two components carried to the nearest 0.01 cents per kilowatt hour.

(1) An amount per kilowatt hour equal to the balance of the Power Cost Adjustment Account divided by the projected energy sales for the following calendar quarter.

(2) Eighty percent of the difference between the Projected Average Power Costs and the Base Power Costs divided by the projected energy sales for the following calendar quarter.

The Adjustment Rate shall not exceed 0.40 cents per kilowatt hour. No charge shall be made when the Adjustment Rate is less than 0.05 cents per kilowatt hour. Any amounts not collected owing to these limitations shall be treated under the terms of the above section entitled Power Cost Adjustment Account.

If this tariff be modified or terminated for any reason, the remaining balance in the Power Cost Adjustment Account shall be amortized to rates over a period to be determined by the Commissioner.

Each Customer's billing shall state the dollar amount of the adjustment occasioned by this tariff.

TIME AND MANNER OF FILING

Thirty days prior to the first day of each calendar quarter, the Company shall submit to the Commissioner the following information:

(1) A letter of transmittal which summarizes the proposed changes under the schedule.

(2) A revised rate schedule page which reflects the new quarterly adjustment rate.

(3) Working papers supporting the calculation of the revised adjustment rate.

ORDER NO. 79-830

POWER COST ADJUSTMENT

ADJUSTMENT RATE

The Adjustment Rate, applicable to all service rendered from ____________________ through December 31, 1979, shall be:

0.40¢ per kWh.

All references to "quarter" or "quarterly" shall be applied to the period ______________________ to December 31, 1979.

ah

ORDER NO. 80-021

ENTERED January 14, 1980

BEFORE THE PUBLIC UTILITY COMMISSIONER

OF OREGON

UF 3518

In the Matter of Revised Tariff Schedules applicable to electric service in the State of Oregon, filed by PORTLAND GENERAL ELECTRIC COMPANY (on the Commissioner's own motion).	)	ORDER

The Trojan Recreation Area and corporate aircraft adjustment issues were summarily determined at the second prehearing conference in accordance with Order No. 79-055, entered January 26, 1979. PGE does not contest the staff's treatment of the Boardman Plant's fixed charges provided the Commissioner adopts staff's proposal that new tariffs can go into effect after staff's review, but without hearing, when Boardman goes into service in August, 1980.

The adjustments proposed by staff for Land Held for Future Use and Preliminary Survey and Investigation Expenditures were accepted by PGE for the purposes of this case.

Staff and PGE agreed to a semi-automatic ratemaking treatment for three additional occurrences expected in 1980. The first occurrence is the rate change occurring because of the BPA rate increase (affecting rates on July 1, 1980), the second occurrence is the commercial operation of the Boardman Coal-Fired Generation Plant (expected to affect rates on August 1, 1980), and the third occurrence is the change in expenses arising from PGE's property tax litigation (date unknown).

Increases in company rates are expected when the Boardman and BPA adjustments are recognized. A change in rates is expected when the property tax litigation is settled. All changes are expected to occur during 1980; their impacts are not exactly known at this time.

By agreeing to the concept of altering the rates when these changes occur, the Commissioner observes the requirement of Ballot Measure 9 (ORS 757.355), insures the best possible accuracy in making the alteration, and avoids the unnecessary expense of duplicate hearings on the issues.

B. <u>BPA Rate Increase</u>

Beginning January 1, 1980, PGE is to accumulate the incremental expenses it incurs because of the BPA rate increase in a deferral account for a period of six months. On July 1, 1980, (1) the increased expenses and (2) an amount designed to amortize the six months' accumulated expenses over a one-year period will be included in the company's rates.

C. <u>Boardman Coal Plant Increase</u>

PGE will be authorized to adjust its revenues by the annual effect of inclusion of its share of the Boardman Generating facility in its power supply base. It will be required to file, not less than 45 days prior to the in-service date for Boardman, revised tariff schedules reflecting the normalized, annual impact of the Boardman facility on 1980 operations. The revenue requirement related to this adjustment will include changes in power costs and sales for resale, as well as fixed costs. Because of changes in power costs that are unknown at this time, the amount of the change cannot be calculated. PGE is to adjust 1980 test year information as adopted in this order for power cost, sales for resale, and fixed costs.

D. Property Tax Expense Change

PGE has appealed its January 1, 1979, property tax assessment set by the Oregon Department of Revenue. The assessment is one of the factors used in determining property taxes owed by PGE for the fiscal year beginning July 1, 1979, and ending June 30, 1980. As a result of the appeal, the Department of Revenue has agreed to reduce the assessed value by about $48,000,000, leaving approximately $300,000,000 at issue. At an estimated tax rate of 1.6%, the valuation in dispute represents about $4,800,000 of property taxes annually.

The staff proposed and the company accepted a plan to hold both the ratepayer and the company harmless from the effect of the final assessment determination from the date this order issues. Staff proposes to reduce 1980 property taxes by $2,500,000--an amount equal to the total estimated effect of the $48,000,000 assessment reduction already agreed to by the Department of Revenue plus one-half of the estimated effect of the $300,000,000 still contested. Once the appeals process is completed and the final valuation determined, the company would calculate the difference between the property tax expense approved herein and the final valuation. That difference would either be refunded to or collected from ratepayers over a period to be later determined by the Commissioner.

Staff's proposal is accepted. Property tax expense for 1980 will be reduced by $2,500,000.

V. COST OF CAPITAL: ALLOWED RETURN PERCENTAGE ON RATE BASE

A. Capital Structure

PGE and staff reached tacit agreement as to the appropriate capital structure. No other party contested the average capital structure agreed upon by PGE and staff for the test year. The adopted structure is shown in Table IV, subsection F.

B. Cost of Long-Term Debt

The average cost of long-term debt during the test period is 9.14 percent, and the average long-term debt balance equals $912,423,000.

6. Revision of General Rules and Regulations

Examining PGE's proposed changes to its tariff rules and regulations revealed certain problems:

a. Policies concerning the same subject occurred in different rules.

b. Policy changes established by the proposed rules were not discussed by the sponsoring witness.

c. Minimal or no cost information was submitted to support certain proposed changes.

d. Beyond the estimated revenue effect, minimal or no customer impact information was provided.

e. Some proposed rules seemed designed to stimulate consumption.

The Commissioner is more than willing to entertain rule changes from the company. However, he expects to see other than brief descriptions, oblique reasoning, and casual justification. In its next general rate filing, PGE should file new general rules and regulations which are easily understandable, internally consistant, economically rational, and do not conflict with its espoused conservation goals. Proposed changes should be clearly identified and justified.

F. Officer and Director Service Discounts

For policy reasons stated earlier, the discounts provided officers and directors will be reduced by the estimated total amount of $5,000.

VIII. POWER COST ADJUSTMENT

On November 15, 1979, Order No. 79-830 was entered putting into effect a permanent power cost adjustment (PCA). On December 4, 1979, PGE filed a motion for reconsideration seeking an amended order to conform the Base Power Rates appearing in the Order and the tariff to the Order and tariff language. The Order and tariff language allows only wheeling expense related to purchased power. The Base Power Rates, as filed, included wheeling expense related to PGE's own generation. Order No. 79-830 should be amended to show the following corrected Base Power Rates:

0.7460¢ November and December only
0.4842¢ January through March
0.4598¢ April through June
0.6815¢ July through September
0.7846¢ October through December

Earlier PGE applied for and received approval to correct the base power rates in Schedule 100. Commissioner's LSN Order No. 812, entered December 18, 1979, and effective January 1, 1980, approved the correction.

Order No. 79-830 and Schedule 100 currently provide for a PCA refund only if the company overestimates the amount of collections necessary to cover eligible costs for each quarter. Because this order revises power costs and Base Power Rates to more realistic levels, good reason exists to revise both the order and the tariff.

As the existing order and tariff allow limited surcharge and collections for 80 percent of eligible increased purchased power expense, increased purchased power wheeling expense, and increased fuel expense for the company's Beaver, Harborton, Summit, and Bethel facilities less prorated sales for resale, the amended order and tariff will allow a limited subcharge (negative surcharge) and refund (or reduction) of 80 percent of the same eligible costs when they decrease below the levels set by general rate orders.

The paragraph on page 100-3 of Schedule 100 (Order No. 79-830, Appendix, p. 3) beginning "When the calculation..." will be deleted. On page 100-4 of the same schedule, (Order No. 79-830, Appendix, p. 4), the first unnumbered paragraph shall be superseded by the following:

> The Adjustment Rate (whether positive or negative) shall not exceed 0.40 cents per kilowatt hour. No charge or reduction shall be made when the Adjustment Rate is less absolutely than 0.05 cents per kilowatt hour. Any amounts not collected or refunded owing to these limitations shall be treated under the terms of the above section entitled Power Cost Adjustment Account.

IX. CONCLUSION

From the foregoing, the Commissioner concludes that Portland General Electric Company has established a need for additional revenues. The company should be allowed to increase its rates in the amounts and manner set forth herein to recover those revenues. Rates developed in accordance with the findings and criteria expressed herein are fair, just, and reasonable.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/UE 181/UE 184

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180),	)
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181),	)
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision relating to the Port Westward plant (UE 184).	)

ICNU/115

PGE Response to ICNU Data Request No. 199

October 6, 2006

September 22, 2006

TO: S. Bradley Van Cleve
ICNU

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE 180
PGE Response to ICNU Data Request 16.199
Dated September 14, 2006
Question No. 199

Request:

PGE/1800, Lesh/52, lines 21-23. Does PGE dispute the statements found on PGE/401, page 33, where NERA states Arizona and Colorado have both a dead band and sharing mechanism? Is PGE satisfied that this provides the reference supporting ICNU's testimony?

Response:

PGE understands the statements appearing on page 33 of the NERA report as stating exactly what they state: under the author's interpretation of "dead-band," Arizona, and Colorado have one. It is clear from the text, however, that the author is not using "dead-band" in the same sense that the parties in UE 180 use this term. In other words, the authors of the NERA report use the term to cover a range of constraints, including amounts of NVPC change above which the change may not go through the PCA (Arizona) and the cumulative sharing tiers of Colorado. The author does not use the term only for the meaning the parties in UE 180 give it: a certain amount of NVPC change that the utility must absorb the PCA captures further changes. To PGE's knowledge, only Washington uses that type of "dead-band." While a list of defined terms could perhaps have helped clarify the NERA report, the text is clear on the content of the Arizona and Colorado mechanisms and allow any reader to reach their own conclusion about how those Commissions have decided to address NVPC cost of service risk for the respective utilities. Page 34, which is a detailed list of the few utilities without 100% coverage, is particularly clear on the content of the PCA's used in those states. Accordingly, we do not agree with the assumptions made in ICNU Exhibit 103 at p. 44. PGE did not identify "errors" in the NERA study. As we explained in PGE Exhibit 400 at p. 42, we would not classify the two states as having dead-bands, in the sense of the narrow meaning of dead-band used in Oregon. ICNU has identified no instances in which the <u>content</u> NERA described for the various states' approaches is in error. PGE is not satisfied that the reference supports ICNU's testimony regarding the NERA report.

The lines referred to (PGE/1800, Lesh/52, lines 21-23) discuss only Colorado. PGE Exhibit 1807 demonstrates that Public Service Company of Colorado (PSCO) has a power cost adjustment mechanism which contains no dead band wherein an initial cost amount is allocated entirely to PSCO. The first $15 million above or below a base power cost level is shared 50/50; the second $15 million is shared 25/75; anything above $30 million is allocated entirely to customers. That is, the maximum excess cost or savings that the Company will absorb in any one year is $11.25 million. This information is also contained in PGE/401 pages 33-34 and page 45.

As for Arizona Public Service, the PCA limits the amount of recoverable fuel and purchased power costs to $776.2 million, with a sharing mechanism where 90% of any costs or savings relative to the base level are allocated to customers. See PGE/401 pages 33-34 and page 40. This is not a dead band in the sense discussed in this case, i.e., PGE first absorbs a specific amount of excess power costs.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/UE 181/UE 184

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Request for a General Rate Revision (UE 180),	)
	)
In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181),	)
	)
In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Request for a General Rate Revision relating to the Port Westward plant (UE 184).	)

ICNU/116

Substantive Rules Applicable to Electric Service Providers

of the Public Utility Commission of Texas

October 6, 2006

§25.236. Recovery of Fuel Costs.

(a) **Eligible fuel expenses.** Eligible fuel expenses include expenses properly recorded in the Federal Energy Regulatory Commission Uniform System of Accounts, numbers 501, 503, 518, 536, 547, 555, and 565, as modified in this subsection, as of April 1, 1997, and the items specified in paragraph (7) of this subsection. Any later amendments to the System of Accounts are not incorporated into this subsection. Subject to the commission finding special circumstances under paragraph (6) of this subsection, eligible fuel expenses are limited to:

(1) For any account, the electric utility may not recover, as part of eligible fuel expense, costs incurred after fuel is delivered to the generating plant site, for example, but not limited to, operation and maintenance expenses at generating plants, costs of maintaining and storing inventories of fuel at the generating plant site, unloading and fuel handling costs at the generating plant, and expenses associated with the disposal of fuel combustion residuals. Further, the electric utility may not recover maintenance expenses and taxes on rail cars owned or leased by the electric utility, regardless of whether the expenses and taxes are incurred or charged before or after the fuel is delivered to the generating plant site. The electric utility may not recover an equity return or profit for an affiliate of the electric utility, regardless of whether the affiliate incurs or charges the equity return or profit before or after the fuel is delivered to the generating plant site. In addition, all affiliate payments must satisfy the Public Utility Regulatory Act (PURA) §36.058.

(2) For Accounts 501 and 547, the only eligible fuel expenses are the delivered cost of fuel to the generating plant site excluding fuel brokerage fees. For Account 501, revenues associated with the disposal of fuel combustion residuals will also be excluded.

(3) For Accounts 518 and 536, the only eligible fuel expenses are the expenses properly recorded in the Account excluding brokerage fees. For Account 503, the only eligible fuel expenses are the expenses properly recorded in the Account, excluding brokerage fees, return, non-fuel operation and maintenance expenses, depreciation costs and taxes.

(4) For Account 555, the electric utility may not recover demand or capacity costs.

(5) For Account 565, an electric utility may not recover transmission expenses paid to affiliated companies for the purpose of equalizing or balancing the financial responsibility of differing levels of investment and operating costs associated with transmission assets. A non-ERCOT electric utility may not recover expenses for wheeling transactions. An ERCOT electric utility may recover only the expenses properly recorded in Account 565 for ISO fees related to planned and unplanned transmission service and for payments to parties related to unplanned transmission service, such as losses and re-dispatch fees.

(6) Upon demonstration that such treatment is justified by special circumstances, an electric utility may recover as eligible fuel expenses fuel or fuel related expenses otherwise excluded in paragraphs (1) - (5) of this subsection. In determining whether special circumstances exist, the commission shall consider, in addition to other factors developed in the record of the reconciliation proceeding, whether the fuel expense or transaction giving rise to the ineligible fuel expense resulted in, or is reasonably expected to result in, increased reliability of supply or lower fuel expenses than would otherwise be the case, and that such benefits received or expected to be received by ratepayers exceed the costs that ratepayers otherwise would have paid or otherwise would reasonably expect to pay.

(7) Eligible fuel expenses shall not be offset by revenues by affiliated companies for the purpose of equalizing or balancing the financial responsibility of differing levels of investment and operation costs associated with transmission assets. In addition to the expenses designated in paragraphs (1) - (6) of this subsection, unless otherwise specified by the commission, eligible fuel expenses shall be offset by:

(A) revenues from steam sales included in Accounts 504 and 456 to the extent expenses incurred to produce that steam are included in Account 503; and

(B) revenues from wheeling transactions except for non-ERCOT electric utilities; and

(C) revenues from off-system sales in their entirety, except as permitted in paragraph (8) of this subsection.

(D) For electric utilities in ERCOT, revenues from third parties for unplanned transmission service, such as ISO fees, losses, and re-dispatch fees.

(8) **Shared margins from off-system sales.** An electric utility may retain 10% of the margins from an off-system energy sales transaction if the following criteria are met:

(A) the electric utility participates in a transmission region governed by an independent system operator or a functionally equivalent independent organization;

(B) a generally-applicable tariff for firm and non-firm transmission service is offered in the transmission region in which the electric utility operates; and

(C) the transaction is not found to be to the detriment of its retail customers.

(b) **Reconciliation of fuel expenses.** Electric utilities shall file petitions for reconciliation on a periodic basis so that any petition for reconciliation shall contain a maximum of three years and a minimum of one year of reconcilable data and will be filed no later than six months after the end of the period to be reconciled. However, notwithstanding the previous sentence, a reconciliation shall be requested in any general rate proceeding under the PURA, Chapter 36, Subchapters C and E and may be performed in any general rate proceeding under the PURA, Chapter 36, Subchapter D. Upon motion and showing of good cause, a fuel reconciliation proceeding may be severed from or consolidated with other proceedings.

(c) **Petitions to reconcile fuel expenses.** In addition to the commission prescribed reconciliation application, a fuel reconciliation petition filed by an electric utility must be accompanied by a summary and supporting testimony that includes the following information:

(1) a summary of significant, atypical events that occurred during the reconciliation period that affected the economic dispatch of the electric utility's generating units, including but not limited to transmission line constraints, fuel use or deliverability constraints, unit operational constraints, and system reliability constraints;

(2) a general description of typical constraints that limit the economic dispatch of the electric utility's generating units, including but not limited to transmission line constraints, fuel use or deliverability constraints, unit operational constraints, and system reliability constraints;

(3) the reasonableness and necessity of the electric utility's eligible fuel expenses and its mix of fuel used during the reconciliation period;

(4) a summary table that lists all the fuel cost elements which are covered in the electric utility's fuel cost recovery request, the dollars associated with each item, and where to find the item in the prefiled testimony;

(5) tables and graphs which show generation (MWh), capacity factor, fuel cost (cents per kWh and cents per MMBtu), variable cost and heat rate by plant and fuel type, on a monthly basis; and

(6) a summary and narrative of the next-day and intra-day surveys of the electricity markets and a comparison of those surveys to the electric utility's marginal generating costs.

(d) **Fuel reconciliation proceedings.** Burden of proof and scope of proceeding are as follows:

(1) In a proceeding to reconcile fuel factor revenues and expenses, an electric utility has the burden of showing that:

(A) its eligible fuel expenses during the reconciliation period were reasonable and necessary expenses incurred to provide reliable electric service to retail customers;

(B) if its eligible fuel expenses for the reconciliation period included an item or class of items supplied by an affiliate of the electric utility, the prices charged by the supplying affiliate to the electric utility were reasonable and necessary and no higher than the prices charged by the supplying affiliate to its other affiliates or divisions or to unaffiliated persons or corporations for the same item or class of items; and

(C) it has properly accounted for the amount of fuel-related revenues collected pursuant to the fuel factor during the reconciliation period.

(2) The scope of a fuel reconciliation proceeding includes any issue related to determining the reasonableness of the electric utility's fuel expenses during the reconciliation period and whether the electric utility has over- or under-recovered its reasonable fuel expenses.

(e) **Refunds.** All fuel refunds and surcharges shall be made using the following methods.

(1) Interest shall be calculated on the cumulative monthly ending under- or over-recovery balance at the rate established annually by the commission for overbilling and underbilling in §25.28 (c) and (d) of this title (relating to Bill Payment and Adjustments). Interest shall be calculated based on principles set out in subparagraphs (A) - (E) of this paragraph.

(A) Interest shall be compounded annually by using an effective monthly interest factor.

(B) The effective monthly interest factor shall be determined by using the algebraic calculation $x = (1 + i)^{(1/12)} - 1$; where i = commission-approved annual interest rate, and x = effective monthly interest factor.

(C) Interest shall accrue monthly. The monthly interest amount shall be calculated by applying the effective monthly interest factor to the previous month's ending cumulative under/over recovery fuel and interest balance.

(D) The monthly interest amount shall be added to the cumulative principal and interest under/over recovery balance.

(E) Interest shall be calculated through the end of the month of the refund or surcharge.

(2) Rate class as used in this subparagraph shall mean all customers taking service under the same tariffed rate schedule, or a group of seasonal agricultural customers as identified by the electric utility.

(3) Interclass allocations of refunds and surcharges, including associated interest, shall be developed on a month-by-month basis and shall be based on the historical kilowatt-hour usage of each rate class for each month during the period in which the cumulative under- or over-recovery occurred, adjusted for line losses using the same commission-approved loss factors that were used in the electric utility's applicable fixed or interim fuel factor.

(4) Intraclass allocations of refunds and surcharges shall depend on the voltage level at which the customer receives service from the electric utility. Retail customers who receive service at transmission voltage levels, all wholesale customers, and any groups of seasonal agricultural customers as identified by the electric utility shall be given refunds or assessed surcharges based on their individual actual historical usage recorded during each month of the period in which the cumulative under- or over-recovery occurred, adjusted for line losses if necessary. All other customers shall be given refunds or assessed surcharges based on the historical kilowatt-hour usage of their rate class.

(5) Unless otherwise ordered by the commission, all refunds shall be made through a one-time bill credit and all surcharges shall be made on a monthly basis over a period not to exceed 12 months through a bill charge. However, refunds may be made by check to municipally-owned electric utility systems if so requested. Retail customers who receive service at transmission voltage levels, all wholesale customers, and any groups of seasonal agricultural customers as identified by the electric utility shall be given a one-time credit or assessed a surcharge made on a monthly basis over a period not to exceed 12 months through a bill charge. All other customers shall be given a credit or assessed a surcharge based on a factor which will be applied to their kilowatt-hour usage over the refund or surcharge period. This factor will be determined by dividing the amount of refund or surcharge allocated to each rate class by forecasted kilowatt-hour usage for the class during the period in which the refund or surcharge will be made.

(6) A petition to surcharge or refund a fuel under- or over-recovery balance not associated with a proceeding under subsection (d) of this section shall be processed in accordance with the filing schedules in §25.237(d) of this title (relating to Fuel factors) and the deadlines in §25.237(e) of this title.

(f) **Procedural schedule.** Upon the filing of a petition to reconcile fuel expenses in a separate proceeding, the presiding officer shall set a procedural schedule that will enable the commission to issue a final order in the proceeding within one year after a materially complete petition was filed. However, if the deadlines result in a number of electric utilities filing cases within 45 days of each other, the presiding officers shall schedule the cases in a manner to allow the commission to accommodate the workload of the cases irrespective of whether such procedural schedule enables the commission to issue a final order in each of the cases within one year after a materially complete petition is filed.

(g) **Final fuel reconciliation.** Notwithstanding the provisions of subsections (b) and (f) of this section, each electric utility's affiliated power generation company, except El Paso Electric Company's, shall file after January 1, 2002, a final fuel reconciliation according to the schedule in paragraphs (1) — (9) of this subsection. For the final fuel reconciliation, the presiding officer shall set a procedural schedule that will enable the commission to issue a final order in the proceeding within six months of the filing date, except for Reliant Energy, Central Power and Light and TXU Electric proceedings, which will be completed in eight months.

(1) West Texas Utilities — June 1, 2002;
(2) Reliant Energy — July 1, 2002;
(3) Southwestern Public Service — August 1, 2002;
(4) TXU Electric — October 1, 2002;
(5) Central Power & Light — December 1, 2002;
(6) Lower Colorado River Authority — February 1, 2003;
(7) Entergy Gulf States, Inc. — March 1, 2003;
(8) Texas-New Mexico Power Company — April 1, 2003; and
(9) Southwestern Electric Power Company — May 1, 2003.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/UE 181/UE 184

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180),	))))))))
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181),	)))))))))
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision relating to the Port Westward plant (UE 184).	)))))))))

ICNU/117

Current Georgia Fuel Case Minimum Filing Requirements

October 6, 2006

Exhibit ICNU/117
Current Georgia Fuel Case Minimum Filing Requirements.

(Docket No. 20932)
PROPOSED MINIMUM FILING REQUIREMENTS for FUEL FILINGS

The following package of proposed fuel filing minimum filing requirements (“MFRs”) is organized in three parts:

I. General instructions for preparing and filing the MFRs.

II. MFRs referring to actual / historical data and the calculation of the over- / under-recovered balance. Such MFRs are labeled as “MFRH” to represent the historical period.

III. MFRs referring to the test year and / or future periods and the calculation of the proposed fuel factor. Such MFRs are labeled as “MFRP” to represent the projected period.

GENERAL INSTRUCTIONS

The following instructions are applicable to all schedules required in the process of a fuel filing with the Georgia Public Service Commission ("Commission"):

1. The listed information should be provided as testimony, exhibits, attachments, or schedules in the initial filing. Each schedule shall be sponsored by a witness providing testimony in the case. Schedules shall be referenced by schedule number and name as indicated in each instruction. Schedules which are not applicable at the present time shall be so designated.

2. Where required schedules are filed as exhibits in witness pre-filed testimony, reference to those schedules may be made in the MFRs.

3. All schedules will be filed in both hard copy and electronic format. The information in electronic format shall be in Microsoft Word, Microsoft Excel with formulas left intact, or any other appropriate software, and may be filed on a compact disk or other appropriate file storage media. If available, Adobe files should be provided in searchable text format. Units of measure (e.g., dollars, millions of dollars, MWh, tons) should be clearly identified.

4. Confidentiality: The Utility may allege that some information requested within the fuel filing package requirements is proprietary and confidential, and may be filed as "Trade Secret." In such case, the Utility will comply with the Commission's rules governing Trade Secret filings.

5. The term "historical period" is meant to designate the shorter of twelve months or the time period since the last FCR proceeding. Actual data shall be provided on an ongoing basis up to the hearing.

6. To the extent that the Utility already prepares reports with information listed below, those reports may be acceptable if the requested information is clearly identifiable from the report.

7. References to Utility actions include those which are taken by any affiliates acting on the Utility's behalf.

8. Where a coal description is required, it should be provided in terms of source (freight district), typical Btu/lb, and typical percent sulfur.

9. Fuel oil should include a description by type number and sulfur content.

10. Should the Utility propose treatment different from that used in prior fuel proceedings, the Utility will identify such different treatment and explain the reasons such treatment is proposed.

HISTORICAL PERIOD FUEL DATA AND INFORMATION

Schedule MFRH-1: Filing Workpapers

The Utility shall provide the complete set of workpapers, related to the historical period that was used in the Utility's preparation of its prefiled testimony and exhibits. Such workpapers shall include both numerical data and chart data. All sources used to generate any of the data incorporated in the attached worksheets should be provided as workpapers. All tabular data should include the measurement units for which data are provided.

Schedule MFRH-2: Overall Description and Variance Report

The Utility shall provide a narrative description of the specific reasons for seeking a change in the FCR rate and statistical schedules comparing the historical period fuel and purchased power expense by component (e.g. steam, nuclear, hydro, and other generation, purchased power, sales for resale, carrying costs, and other FCR costs) to the corresponding information used in the prior FCR rate case. The narrative description will include a report of all components of fuel costs that are included in the FCR filing showing the amounts for each by month and account. The statistical schedules should be provided on a Georgia Retail basis.

Schedule MFRH-3: Fossil Fuel Inventories

Schedule MFRH-3.1: Inventory Targets

This schedule shall present the Utility's monthly fossil fuel inventory targets effective during the historical period. The Utility shall identify the time period over which each target existed.

Schedule MFRH-3.2: Fossil Fuel Inventories

This schedule shall present a detailed analysis of fossil fuel inventories for the historical period. The analysis shall categorize historic inventories by tons, barrels, or cubic feet / Btu equivalent, and dollars. This schedule shall include:

1. Identification by number (or other designation) of each separate inventory, including inventories located at individual plants;
2. Type of fuel in each inventory; and
3. Units which are supplied from each inventory.

For each separate inventory, for each month for this historical period, the Utility will provide:

1. Beginning-of-month inventory level, in tons, barrels, cubic feet / BTU equivalent and dollars;
2. Additions for each month, in tons, barrels, cubic feet / BTU equivalent and dollars;
3. Fuel removed from inventory for generation for month, in tons, barrels, cubic feet / BTU equivalent and dollars;
4. End-of-month inventory level, in tons, barrels, cubic feet / BTU equivalent and dollars; and
5. Adjustments to inventory level, in tons, barrels, cubic feet / BTU equivalent and dollars and reason for adjustment.

The Utility will also provide a listing of each physical inventory survey of each coal stockpile, including the following information:

1. Date of survey and name of party performing survey;
2. Identification of plant and particular stockpile surveyed; and
3. Results of survey (tons and dollars if applicable) and comparison to book or accounting values for tons.

<u>Schedule MFRH-3. 3: Inventory Values</u>

This schedule shall present a description of the accounting treatment of how the Utility determines the unit cost of fossil fuel burned from its inventory. The Utility shall include the method of determining the cost of fossil fuel burned from inventory (FIFO, LIFO, average, or other) for each stockpile at each plant. **[**

Schedule MFRH-4: Unit Outages

Schedule MFRH-4.1: Nuclear Unit Outage

For each nuclear unit, list the outages as reported in GADS database in column form, for unit unplanned, forced, and scheduled outages and power reductions that occurred during the historical period:

1. Unit name;
2. Date started;
3. Date ended;
4. Duration of outage or power reduction in hours;
5. Type of outage or power reduction;
6. If power reduction, indicate the amount of power reduction (MWs) and maximum power level permitted (MW);
7. Reason code for outage or power reduction and remarks; and
8. Incremental cost of forced outages and derates exceeding 50,000 MWH's.

Schedule MFRH-4.2: Fossil Unit Outage

For each fossil unit list the outages in column form for unit unplanned and forced outages that occurred during the historical period:

1. Unit name;
2. Date started;
3. Date ended;
4. Duration of outage or power reduction in hours;
5. Type of outage or power reduction;
6. If power reduction, indicate the amount of power reduction (MWs) and maximum power level permitted (MW);
7. Reason code for outage or power reduction and remarks; and
8. Incremental cost of forced outages and derates exceeding 50,000 MWHs.

Schedule MFRH-4.3: Fossil and Nuclear Unit Equivalent Availability

To the extent not covered in MFRH-4.1 and 4.2, the Utility will report actual equivalent availability for the historical period. Such report will include a listing of all unplanned outages, and, if reported in the NERC GADS data base, deratings greater than 75%, and deratings of more than 90% and continuing for at least one month. Listing should be sorted by type of event (maintenance outage, forced outage, derating), plant, unit, and date and should include a brief description of cause, e.g., boiler tube leak.

Schedule MFRH-4.4: Transmission Outage and Congestion

List in column form any transmission outages and/or congestion that led to the need for replacement power during the historical period. Include:

1. Identity of transmission facility;
2. Date started;
3. Date ended;
4. Duration of outage or congestion in hours;
5. Reason for outage or congestion; and
6. Incremental cost of the outage or congestion.

Schedule MFRH-5: Generating Plant and Unit Data

For each unit operated by the Utility and which is located at a plant at least partly included in retail rate base, the Utility shall provide an identification of generating resources, including:

1. Name of plant, location by city or county and unit designation;
2. Year the unit was first placed in operation;
3. Maximum net dependable capacity for each unit (MW);
4. Generator nameplate rating (MW or MVA (specify));
5. Percent of total net dependable capacity included in retail rate base;
6. For any units with capacity not included in rate base, the name of each Utility or other entity which receives unit energy and net dependable MW or percent of total net MW assigned to that Utility or entity;

7. Primary types of fuel used by each generating unit and types of fuel used for startup/ignition. For coal units, the following information will be provided:
   A. Type of coal used, if applicable: design coal, current coal used, and other types of coal which can be burned in the unit;
   B. If coals are blended, the maximum percentages of each coal which may be used and the types of coal which may be blended together;
   C. Description of specific design and permitting constraints on coal blending;
8. Copy of the annual Environmental Compliance Strategy Review;
9. Railroads with track physically available to deliver coal to plant; and
10. Pipelines physically able to deliver natural gas and/or fuel oil to plant.

<u>Schedule MFRH-6: Fuel and Purchased Power Procurement Practices</u>

This schedule shall include the current fuel procurement procedures and a narrative of purchased power procurement practices of the Utility during the historical period. Provide a copy of the most current Intercompany Interchange Contract ("IIC") and note any changes from the previously filed IIC.

<u>Schedule MFRH-7: Fuel and Fuel-Related Contracts</u>

This schedule shall include summaries as described in more detail below of all fuel and fuel-related contracts existing between the Utility and its suppliers, or between any affiliate of the Utility that supplies fuel or fuel-related services to the Utility and its suppliers. Provide those summaries of contracts that were in effect during any portion of the historical period.

<u>Schedule MFRH-7.1: Coal Supply Contracts</u>

For each coal supply contract, the Utility will provide:

1. Name and number by which the Utility identifies the contract;
2. Supply start date;
3. Supply termination date;
4. Description of contract year, if other than January 1 through December 31;

5. Minimum and maximum tons of coal to be supplied for each contract year ending in the historical period and for remainder of contract term;
6. Number of tons actually received each contract year ending in the historical period and projected number of tons which will be provided each contract year through end of test year;
7. Name of mine and coal district from which coal is to be supplied;
8. Coal quality: percent sulfur and heating value;
9. Name of rail transporters between mine (or port) and plants and freight district in which coal loading facility is located;
10. Actual cost per ton FOB mine (or port) for each contract month ending in the historical period;
11. Method of determining cost of coal under the contract, e.g., fixed price, market review (provide years in which reviews are effective), base price plus escalation. List by date of the value of any index used to compute price of coal, e.g., Producer Price Index;
12. Location of scale used to determine tons of coal shipped and party responsible for cost of weighing; and
13. Location of coal sampling equipment and party responsible for obtaining coal analysis.

The Utility will also provide a list of any filed litigation between the Utility and any contract coal supplier beginning or pending during the historical period.

<u>Schedule MFRH-7.2: Spot Coal Purchase Information</u>

For each spot coal purchase order or other agreement, other than coal contracts, the Utility will provide a schedule with the following information:

1. Name and number by which the Utility identifies the purchase order or other agreement;
2. Supply start and end dates;

3. Number of tons actually received under purchase order or other agreement for the historical period to date, number of tons projected for the remaining historical period, and number of tons projected for the test year;
4. Name of mine and coal district from which coal is to be supplied;
5. Coal quality: percent sulfur and heating value;
6. Name of rail transporters between mine (or port) and plants and freight district in which coal loading facility is located; and
7. Cost per ton FOB mine (or port).

<u>Schedule MFRH-7.3: Natural Gas Contracts</u>

For natural gas contracts that occur during the historical period, the Utility may provide one or more "generic" contracts which represent the terms of the individual base load (one year or longer) and spot market (less than one year) contracts, in lieu of copies of all of the natural gas contracts. In addition, the following items should be included in a summary schedule:

1. Contract description;
2. Supplier;
3. Negotiation date or date signed;
4. Term of deal;
5. Specific service provided under the contract;
6. Pricing terms;
7. Purchase volume obligation;
8. Receipt point(s); and
9. Transportation provision, if applicable.

<u>Schedule MFRH-8: Transportation</u>

The Utility will provide a copy of the coal transportation strategy effective for any part of the historical period or for the test year. The Utility will also provide a list of any filed litigation between the Utility and any coal transporter beginning or pending during the historical period.

Schedule MFRH-8.1: Rail

The Utility will provide a listing of coal rail transportation contracts with the following information:

1. Name and number of transportation contract;
2. Effective date and term of contract;
3. Contract year, if different from calendar year;
4. Maximum and minimum tonnage which can be transported under the contract on an annual basis;
5. Actual tons transported under the contract for each contract year ending in the historical period;
6. Points of origin under the contract;
7. Points of delivery under the contract;
8. Table of rates applicable to the Utility's coal transportation for each contract year, i.e., rate for specific origins and delivery points with information for different railcar equipment, if applicable. For future months through end of test year, if rate is not specifically set out in contract, provide the rates used by the Utility in projecting fuel costs;
9. Description of method of pricing under contract, e.g., fixed by year, base plus escalation;
10. List of any indices or other factors upon which escalation or other rate change is based, e.g., RCAF-A or price of diesel fuel; and
11. Cost per ton for weighing coal, if applicable.

Schedule MFRH-8.2: Other

The Utility shall provide a listing of any other coal transportation contracts or agreements, e.g., any for trucking or transshipment at docks, including service provided, terms of agreement, any coal tonnage and costs per contract year, actual or projected through end of test year.

Schedule MFRH-8.3: Railcar Leases and Maintenance

The Utility shall provide a list of number of railcars owned by the Utility, including type of car and tons of coal which can be loaded into each car, and whether these cars are included in rate base. It shall also provide a list of railcar leases which includes the following:

1. Name and identification of lease;
2. Beginning date and term of lease;
3. Number of railcars provided under lease;
4. Type of car provided, including aluminum or steel; and
5. Annual costs for the lease.

The Utility shall specify the total number of rail cars available for coal transportation, number of cars in a typical unit train, number of spare cars, and number of unit trains assigned to each originating or delivering railroad. It shall provide a listing of lease and maintenance costs used by the Utility for evaluation of costs of delivered coal from different mining districts and freight districts and for delivery to the Utility's various coal-fired plants. The Utility shall provide a listing of actual lease costs and actual maintenance costs since the beginning of the historical period and a description of how and when these costs are included in the Utility fuel costs.

Schedule MFRH-9: General Coal Cost Breakdown

To the extent that accounting records are kept in this format, this schedule shall present the breakdown of the purchased fuel costs for the Utility's coal-fired stations into the following categories per ton, on a monthly basis during the historical period:

1. FOB mine price;
2. Rail transportation;
3. Railcar maintenance;
4. Railcar ownership/lease expenses;
5. Railcar depreciation;
6. Other transportation costs (specify);
7. Ad valorem, state and use taxes; and

8. Any other costs or credits which can be separately identified.

The Utility will provide any joint ownership reconciliations for coal deliveries.

Schedule MFRH-10: Natural Gas Hedging

This schedule shall include an explanation of the Utility's fuel hedging practices and hedging results during the historical period. The following items should be included with the hedging results:

1. Administrative cost of the hedging program;
2. Hedging gains and/or losses; and
3. Copies of correspondence related to hedging strategy and recommendations.

Schedule MFRH-11: Nuclear Fuel Expense

This schedule shall present monthly nuclear fuel expenses for each of the Utility's nuclear plants during the historical period.

Schedule MFRH-12: Gas & Oil Cost Breakdown

To the extent that accounting records are kept in this format, this schedule shall present the breakdown of the purchased fuel costs for the Utility's gas and oil fired stations into the following categories per mmBtu, on a monthly basis during the historical period:

1. Delivered price;
2. Fixed pipeline (transportation) costs;
3. Other transportation costs (specify);
4. Ad valorem taxes; and
5. Details of any gain or loss on sales to other parties.

Schedule MFRH-13: Purchased Power / Off-System Sales

Schedule MFRH-13.1: Power Pool Purchases and Sales Data

This schedule shall provide, for the historical period, copies of the monthly IIC billing ("Pool Bill") for the Utility. It will include the Associated Pool Purchases for each month of the historical period.

Schedule MFRH-13.2: Summary of Contract Purchased Power Data

This schedule shall provide, for the historical period, documents summarizing the Utility's purchased power agreements for procuring generation. The summary will include:

1. Term of the contract;
2. Counter party on the contract;
3. Capacity of the contract;
4. Generation asset tied to the contract;
5. Capacity pricing of the contract;
6. Energy pricing of the contract;
7. Amount of generation obtained under the contract by dollars and MWH; and fuel accounting treatment of the purchase.

Schedule MFRH-13.3: Energy Strips

This schedule shall provide documents summarizing the purchase of any energy strips during the historical period.

Schedule MFRH-13.4: Summary of Off-System Sales and Sales for Resale

This schedule shall provide documents summarizing the Utility's wholesale contracts for off-system sales. The summary shall include:

1. Term of the contract;
2. Counter party on the contract;
3. Capacity of the contract;
4. Generation assets used for supplying the contract;
5. Firmness of the sale;
6. Capacity pricing of the contract;
7. Energy pricing of the contract;
8. Amount of generation sold under the contract by dollars and MWH; and
9. Fuel accounting treatment of the sale.

Schedule MFRH-13.5: Historical Retail Energy Sales Data

Provide the following energy retail sales information:

1. Monthly kWh sales by customer class for the three most recent historic calendar years, including the historic period of the fuel filing;
2. Actual Sales – Provide actual sales data in MWHs by month for the historical period; and
3. A reconciliation for any differences between its historic per book sales MWH for GPSC jurisdictional customers and the MWHs assumed in previous filing budget.

Schedule MFRH-14: Fuel Cost Over- / Under-Recovery

This schedule shall begin with the deferred fuel balance as approved in the Utility's last fuel case. The schedule shall present the adjusted monthly booked over- / under-recovery of fuel costs since the date of the Utility's last fuel proceeding through the last month of the historical period requested. This schedule shall include monthly amounts as reported to the Commission on the monthly fuel cost recovery reports.

Schedule MFRH-15: Carrying Cost Calculation

This schedule shall include the calculation and presentation of the carrying cost of the over-/ under-recovered fuel balance.

Schedule MFRH-16: Emission Costs

This schedule shall include an analysis of emission costs recovered through FCR during the historical period and shall include:

1. Explanation of how costs of emissions flow through to fuel costs on an accounting basis;
2. Tabulation of total number of SO_2 emissions allowances allocated to the Utility in the historical period;
3. Number of SO_2 allowances retained for auction by EPA and resulting revenue returned to the Utility during the historical period;

4. Tabulation of SO_2 emission allowance activity with following information for the historical period:
    a. Number and vintage of allowances banked by the Utility;
    b. Number of SO_2 allowances surrendered to EPA on both a total Company and Georgia Retail basis;
    c. Number and vintage of allowances sold, name of buyer, and revenue received per allowance;
    d. Number, vintage, and seller for any allowances which the Utility bought / will buy; and
    e. Cost of each allowance bought for use with rate base generation.
5. Tabulation of all NOx allowance activity, i.e., allocation, purchase, use, trade or sales, for this historical period;
6. Table of average actual market price by month of the historical period of SO_2 emission allowances and source of information; and
7. Table of average actual market price by month of the historical period of NO2 emission allowances and source of information.

TEST YEAR / PROJECTED FUEL DATA AND INFORMATION

Schedule MFRP-1: Filing Workpapers

The Utility shall provide the complete set of workpapers, related to the projected test period that was used in the Utility's preparation of its prefiled testimony and exhibits. Such workpapers shall include both numerical data and chart data and will include a list of all inputs and assumptions used to derive the expected fuel clause results, by month, for all months of estimated or projected data relied upon or used in the Utility's FCR filing. Such workpapers shall include the detailed energy budget, along with all assumptions and documentation used in the preparation of such budget.

Schedule MFRP-2: Fossil Fuel Inventories

Schedule MFRP-2.1: Inventory Targets

This schedule shall present the Utility's fossil fuel inventory targets effective for the test period.

Schedule MFRP-2.2: Fuel Inventories

This schedule shall present an analysis of fossil fuel inventories projected for the test period by type and by location whether at the Utility's generating plant sites or otherwise. The Utility shall categorize such projected inventories by tons, barrels, or cubic feet / Btu equivalent, and dollars and include all assumptions which support estimated values.

Schedule MFRP-2.3: Inventory Values

This schedule shall present a complete description of the accounting treatment of how the Utility determines the unit cost of fossil fuel burned from its inventory for the test period. The Utility shall include the method of determining the cost of fossil fuel burned from inventory (FIFO, LIFO, average, or other.)

Schedule MFRP-3: Nuclear Unit Outage Planning

This schedule shall present the projected start date (month and year) and the projected length of outage (days) for each refueling scheduled from the beginning of the test period through 12 months after the end of the test period.

Schedule MFRP-4: Fossil Unit Outage Planning

This schedule shall present the projected start date (month and year), the projected length of outage (hours), and the reason for the outage/major work planned for each outage scheduled from the beginning of the test period through 12 months after the end of the test period.

Schedule MFRP-5: Fossil and Nuclear Unit Equivalent Availability

To the extent not covered in MFRP-3 and 4, Utility shall report and specify equivalent availability or forced outage rate (or other), depending on input data for modeling program.

Schedule MFRP-6: Fuel Expense Information

The following schedules shall be presented, as specified, for fuel expenditures and operating statistics for the test year.

Schedule MFRP-6.1: Fuel by Classification

This schedule shall provide, as appropriate, projected fuel expense by classification consistent with FERC Uniform System of Accounts for each month through the test year.

Schedule MFRP-6.2: Fuel to be Burned

This schedule shall present projected fuel expense by each of the Utility's generating stations for each month through the test year. The information shall be disclosed for each individual fuel type and shall include units burned, cost of fuel burned, and price per unit burned.

Schedule MFRP-6.3: Fossil Fuel Purchases

This schedule shall present projected fossil fuel purchases by each of the Utility's generating stations for each month of the test year. The information shall be disclosed for each individual fuel type and by supplier and shall include units purchased, cost of fuel purchased, and price per unit purchased. With regard to coal, it shall include projected cost of coal per ton FOB mine according to supplier, projected transportation cost per ton according to supplier; the number of tons delivered per month according to supplier and heating value and percent sulfur estimated for those coal tons, and any other per ton or per MMBtu costs (or credits) known or projected for purchases from each supplier, e.g., states taxes, lease and maintenance costs, synfuels discount.

Schedule MFRP-6.4: Gas and Oil Forecast

The Utility shall include its forecast for the test year of gas and oil prices detailed by month.

Schedule MFRP-7: Fuel and Fuel-Related Contracts

This schedule shall include summaries described below of all fuel and fuel-related contracts that have changed since the historical period and that will be in effect during the test year between the Utility and its suppliers. The Utility shall also include summaries of new agreements that will be effective during the test period:

Schedule MFRP-7.1: Coal Supply Contracts

For each coal supply contract in effect for the test year, the Utility will provide:

1. Name and number by which the Utility identifies the contract;
2. Supply start date;
3. Supply termination date;
4. Description of contract year, if other than January 1 through December 31;

5. Minimum and maximum tons of coal to be supplied for remainder of contract term;
6. Projected number of tons which will be provided each contract year through end of test year;
7. Name of mine and coal district from which coal is to be supplied;
8. Coal quality: percent sulfur and heating value;
9. Name of rail transporters between mine (or port) and plants and freight district in which coal loading facility is located;
10. Projected cost per ton FOB mine (or port) through the end of the test year;
11. Method of determining cost of coal under the contract, e.g., fixed price, market review (provide years in which reviews are effective), base price plus escalation. List by date of the value of any index used to compute price of coal;
12. Location of scale used to determine tons of coal shipped and party responsible for cost of weighing; and
13. Location of coal sampling equipment and party responsible for obtaining coal analysis.

Schedule MFRP-7.2: Coal Not Under Contract

The Utility will list by month of coal requirements, through the end of the test year, which are not yet under contract, purchase order or other agreement, including the following information:

1. Projected tons of coal needed by type and originating / delivering railroad;
2. Coal quality: percent sulfur and heating value; and
3. Projected price per ton FOB mine (or port).

The Utility will provide the internet bid list of potential fuel and transportation service providers including the most recent bids solicited from competitive suppliers.

Schedule MFRP-7.3 Natural Gas Contracts

For natural gas contracts that occur during future periods, the Utility may provide one or more "generic" contracts which represent the terms of the individual base load (one year or longer) and spot market (less than one year) contracts, in lieu of copies of all of the natural gas contracts. In addition, the following items should be included in a summary schedule:

1. Contract description;
2. Supplier;
3. Negotiation date or date signed;
4. Term of deal;
5. Specific service provided under the contract;
6. Pricing terms;
7. Purchase volume obligation;
8. Receipt point(s); and
9. Transportation provision, if applicable.

Schedule MFRP-8: Natural Gas Hedging Narrative

This schedule shall include an explanation of the fuel hedging practices anticipated for the projected fuel data and a "snapshot" view of current open hedge positions.

Schedule MFRP-9: Fuel and Purchased Power Assumptions Narrative

This schedule shall provide an explanation setting out the major methods, assumptions, and sources of information used by the Utility to project fuel and purchased power costs for the test year.

Schedule MFRP-10: Purchased Power / Off-System Sales

Schedule MFRP-10.1: Projected Power Pool Purchases and Sales Data

This schedule shall provide, for the test year, monthly projected Pool purchases and sales by dollar and MWH. This information shall also include the estimated MWh sales for each forecast month by supplier. The Utility shall also identify the monthly assumed marginal replacement fuel costs ("MRFC") for each Utility-owned generating stations by month for the forecast period. All assumptions and support for the development of the MRFCs shall be included within the filing.

Schedule MFRP-10.2: Summary of Contract Purchased Power Data

This schedule shall provide documents summarizing, for the projected period, the Utility's purchased power agreements for procuring generation that will be in effect for the time period. The summary will include:

1. Term of the contract;
2. Counter party on the contract;
3. Capacity of the contract;
4. Generation asset tied to the contract;
5. Capacity pricing of the contract;
6. Energy pricing of the contract;
7. Forecast of expected procurement from the resource by dollars and MWH.
8. MW demand by month for forecast period.

The Utility shall identify all assumptions used in the development of estimated purchase power MWHs and associated fuel costs. Such assumptions shall be contained in a separate list along with a narrative that summarizes how the assumptions were determined.

Schedule MFRP-10.3: Energy Strips

This schedule shall provide documents summarizing the proposed purchase of any energy strips during the test period.

Schedule MFRP-10.4: Summary of Off-System Sales and Sales for Resale

This schedule shall provide documents summarizing, for the projected period, the Utility's wholesale contracts for off-system sales. The summary will include:

1. Term of the contract;
2. Counter party on the contract;

3. Capacity of the contract;
4. Generation assets used for supplying the contract;
5. Firmness of the sale;
6. Capacity pricing of the contract;
7. Energy pricing of the contract;
8. Forecast of expected sales by dollars and MWH;
9. The portion of estimated fuel revenue associated with off-system sales, including MWH, by month for the forecast period; and
10. Identify all assumptions used in the development of estimated off-system sale MWHs and associated fuel revenues. Such assumptions shall be contained in a separate list along with a narrative that summarizes how the assumptions were determined.

<u>Schedule MFRP-11: Budget By Generating Plant</u>

This schedule shall provide the budget input assumptions for each of the Utility's generating plants and shall include the following:

1. Summary of dependable capability;
2. MWH generated;
3. Average annual heat rate;
4. Capacity factor;
5. Scheduled outage rate;
6. Forced outage rate;
7. Number of start-ups; and
8. Maintenance schedules.

For plants that are not 100% included in rate base, provide unit net capacity factor data on both a total unit and Georgia Retail, as well as gross and net generation data on both a total unit basis and gross and net generation from the Utility's rate base portion of the capacity. (For hydro, report only hydro system net generation.) For future months, report results from modeling program used to project future fuel costs.

Schedule MFRP-12: Fuel Price Workshop Presentations

This schedule shall include copies of the most recent Fuel Price Workshop presentations.

Schedule MFRP-13: Emission Cost Assumptions Narrative

This schedule shall provide an explanation setting out the major methods, assumptions, and sources of information used by the Utility to project emission costs for the test year and shall include where available:

1. Tabulation of total number of SO_2 emissions allowances allocated to the Utility for the test year;
3. Number of SO_2 allowances retained for auction by EPA and resulting revenue returned to the Utility for the test year;
4. Tabulation of SO_2 emission allowance activity with following information anticipated through the end of the test year:
   a. Number and vintage of allowances banked by the Utility;
   b. Number of SO_2 allowances surrendered to EPA each year on both a total Company and Georgia Retail basis;
   c. Number and vintage of allowances sold, name of buyer, and revenue received per allowance;
   d. Number, vintage, and seller for any allowances which the Utility bought / will buy; and
   e. Cost of each allowance bought for use with rate base generation;
5. Tabulation of all NOx allowance activity, i.e., allocation, purchase, use, trade or sales, anticipated through the end of the test year;
6. Table of average actual market price by month of the historical period of SO_2 emission allowances and source of information. Include projected market price for each month through end of test year;
7. Table of average actual market price by month of the historical period of NO2 emission allowances and source of information. Include projected market price for each month through end of test year;
8. Unit SO_2 emissions, in tons. Provide data on both a total unit basis; and

9. Unit NOx emissions, in tons. Provide data on both a total unit.

Schedule MFRP-14: Carrying Cost Assumptions Narrative

This schedule shall provide a detailed explanation setting out the major methods, assumptions, and sources of information used by the Utility to determine carrying costs for the test year.

Schedule MFRP-15: Fossil Fuel Mix

This schedule shall present, by month, the projected mix of contract and spot fossil fuel purchased for each of the Utility's generating plants in the test year. Contract fuels are defined as those provided under agreements with a term of generally more than one year, while spot fuels are defined as those provided under agreements with a term of generally one year or less.

Scheduled MFRP-16: Forecasted Energy Sales Data

Provide the following energy sales information:

1. Monthly kWh sales by customer class for the three most recent historic calendar years, including the historic period for the fuel filing;
2. Monthly kWh sales by customer class, by delivery voltage, by month for the proposed test year plus three additional forecasted years. All assumptions used in developing the projected sales data shall be identified and testimony shall be provided that supports all assumptions incorporated in the sales forecast;
3. Actual Sales – Provide actual sales data in MWHs by month for the historical period; and
4. A reconciliation for any differences between its historic per book sales MWH for GPSC jurisdictional customers and the MWHs used in developing its over/under recovered fuel cost balance.

Schedule MFRP-17: Calculation of Fuel Cost Recovery Factor

This schedule shall include the calculation of the fuel cost recovery factor and will include the increase/decrease for the average residential consumer, and for the average low-income senior citizen, which would result under the Utility's FCR filing; and the average residential monthly kWh usage and the average low-income senior citizen monthly kWh usage.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/UE 181/UE 184

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180),	))))))))
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181),	)))))))))
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision relating to the Port Westward plant (UE 184).	)))))))))

ICNU/118

Market Heat Rate vs. Market Gas Price

October 6, 2006

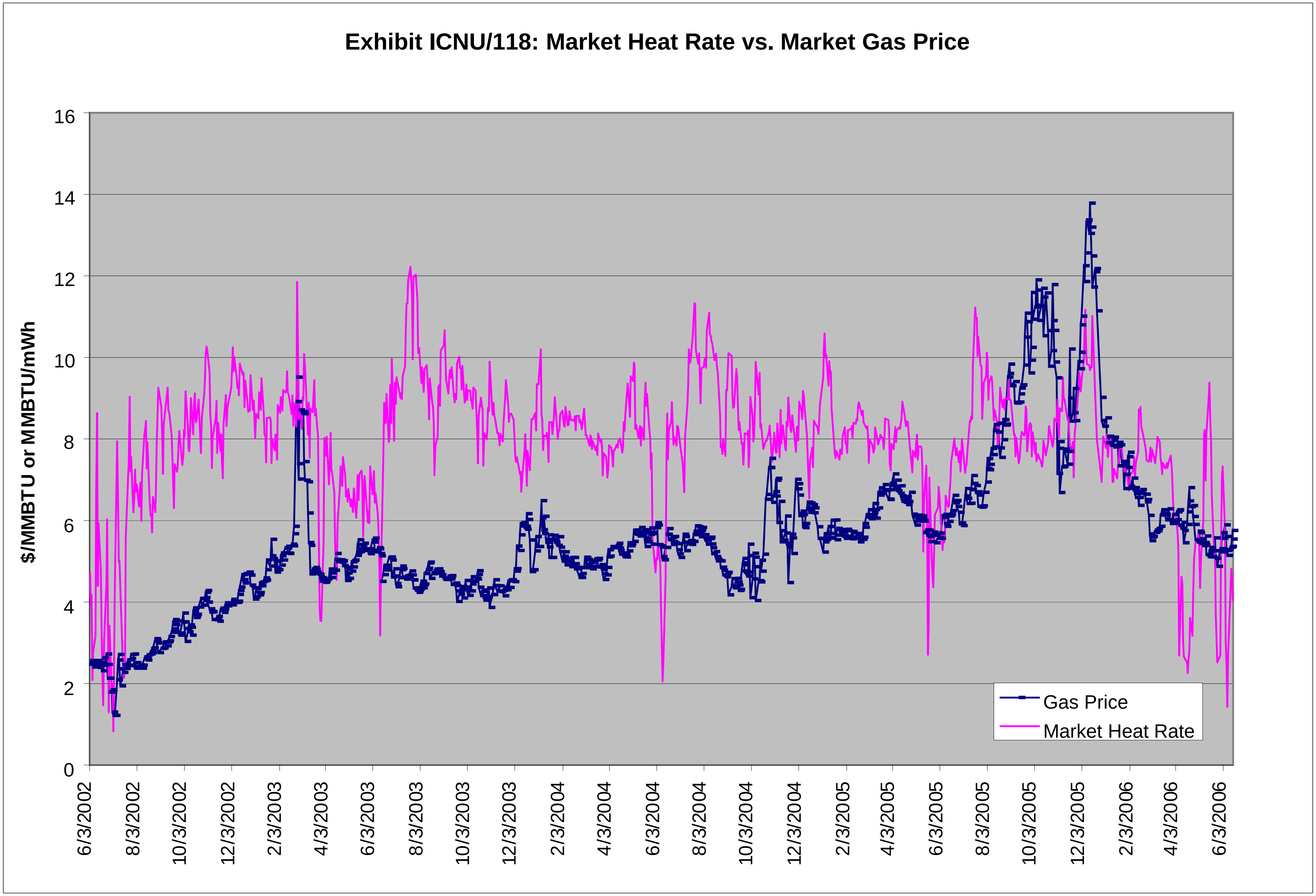
Exhibit ICNU/118: Market Heat Rate vs. Market Gas Price
$/MMBTU or MMBTU/mWh
0
2
4
6
8
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12
14
16
6/3/2002
8/3/2002
10/3/2002
12/3/2002
2/3/2003
4/3/2003
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4/3/2005
6/3/2005
8/3/2005
10/3/2005
12/3/2005
2/3/2006
4/3/2006
6/3/2006
Gas Price
Market Heat Rate

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/UE 181/UE 184

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180),	))))))))
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181),	)))))))))
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision relating to the Port Westward plant (UE 184).	)))))))))

ICNU/119

NERC Data on Outage Rates

October 6, 2006

2002 Only Generating Unit Statistical Brochure -- All Units Reporting

OTE: This brochure contains data on all units, whether they reported event records or not. For a review of statistics containing only those units that reported events, see the brochure "1998-2002 Generating Unit Statistics -- Units with Events".
The differences between statistics with or with events will appear in equations needing derating information such as EAF, EFOR, and other equations. The equations are more accurate if events are reported.)

Unit Type	MW Trb/Gen Nameplate	# of Units	Unit-Years	ART	SR	NCF	NOF	SF	AF	EAF	FOR	EFOR	EFORd	SOF	FOF	WSF	WAF	WEAF	WFOR
Coal	All Sizes	803	799.83	398.97	97.18	71.46	85.98	83.12	87.02	84.28	4.97	6.98	6.74	8.63	4.34	85.23	86.61	83.99	5.08
Primary	1-99	123	121.25	351.78	98.81	52.40	71.50	73.29	86.75	84.13	5.53	7.84	7.09	8.96	4.29	74.30	86.92	84.35	5.02
	100-199	224	223.17	343.19	98.29	65.06	77.97	83.45	88.43	85.38	4.37	6.31	6.05	7.76	3.81	84.01	88.38	85.37	4.32
	200-299	104	104.00	499.13	98.63	70.20	81.43	86.21	87.72	85.39	4.54	5.87	5.79	8.17	4.10	86.11	87.67	85.33	4.50
	300-399	78	77.67	452.94	93.48	69.08	81.78	84.47	85.82	83.17	5.40	7.41	7.33	9.36	4.82	84.84	86.07	83.47	5.20
JET	All Sizes	299	293.92	4.51	97.58	4.12	83.76	4.92	93.16	91.88	30.58	35.93	9.56	4.67	2.17	5.28	92.27	90.42	27.47
ENGINE**	1-19	44	43.67	3.40	94.81	0.76	75.93	1.01	95.75	95.74	66.02	66.07	10.75	2.30	1.96	0.94	95.68	95.67	67.01
	20 Plus	255	250.25	4.56	97.71	4.33	77.30	5.61	92.71	91.21	28.24	33.98	9.72	5.09	2.21	5.61	92.01	90.03	26.34
GAS	All Sizes	752	735.83	7.09	96.58	4.24	98.95	4.28	93.96	93.88	28.82	29.22	6.45	4.31	1.73	6.02	93.30	93.19	20.78
TURBINE**	1-19	173	172.67	7.14	92.90	1.49	69.27	2.15	94.51	94.48	46.91	46.91	7.38	3.59	1.90	1.98	94.77	94.74	47.96
	20-49	180	179.17	9.34	94.38	2.78	100.81	2.76	96.33	96.21	31.64	33.20	7.60	2.39	1.28	3.31	96.13	95.97	25.81
	50 Plus	399	384.00	6.73	97.54	4.72	79.36	5.95	92.60	92.52	23.92	24.13	6.15	5.53	1.87	6.77	92.76	92.66	19.32
COMB. CYCLE	All Sizes	87	83.00	48.77	96.60	48.50	84.90	57.13	89.74	86.49	3.38	6.96	5.15	8.27	2.00	65.79	90.32	87.51	2.37
HYDRO	All Sizes	971	969.00	45.60	99.32	41.18	75.13	54.81	87.09	87.02	6.78	6.87	6.20	9.19	3.99	56.97	86.03	85.99	6.48
	1-29	421	421.00	79.77	99.44	37.33	67.98	54.91	87.48	87.42	6.89	6.97	6.14	8.48	4.06	52.96	89.10	89.04	4.53
	30 Plus	550	548.00	34.39	99.28	41.57	75.95	54.73	86.79	86.71	6.70	6.78	6.28	9.73	3.93	57.29	85.79	85.75	6.62
PUMPED STORAGE	All Sizes	87	87.00	5.15	99.44	12.85	58.08	22.12	90.56	90.49	5.94	5.99	3.60	8.05	1.40	24.66	91.21	91.03	4.79
MULTI-BOILER/ MULTI-TURBINE	All Sizes	41	40.33	389.66	96.42	54.63	84.53	64.63	91.14	88.00	2.78	5.93	4.80	7.02	1.85	73.70	90.33	88.00	1.52
GEOTHERMAL	All Sizes	1	1.00	537.31	100.00	91.59	93.32	98.14	98.24	92.16	0.59	5.20	5.19	1.18	0.58	98.14	98.24	92.16	0.59
DIESEL**	All Sizes	75	73.58	7.78	99.73	7.28	145.54	5.00	95.43	95.43	20.87	20.87	4.72	3.26	1.32	8.37	95.48	95.48	10.43

Statistics for groups of 1 to 2 units are included in the all sizes category but are not shown separately.
Caution: EFOR and WEFOR values may be low since deratings during reserve shutdown periods may not have been reported for a large number of these units.

2001 Only Generating Unit Statistical Brochure

Unit Type	MW Trb/Gen Nameplate	# of Units	Unit-Years	ART	SR	NCF	NOF	SF	AF	EAF	FOR	EFOR	EFORd	SOF	FOF
JET	All Sizes	284	271.83	4.34	96.83	2.89	68.87	4.20	92.55	91.00	34.68	45.33	10.39	5.23	2.23
ENGINE**	1-19	45	44.00	3.27	94.98	0.71	67.91	1.05	91.69	91.69	80.99	81.01	18.08	3.86	4.45
	20 Plus	239	227.83	4.40	96.93	3.07	63.82	4.81	92.71	90.87	27.24	39.70	9.07	5.49	1.80
GAS	All Sizes	657	645.00	9.41	94.89	4.37	86.58	5.04	91.81	91.75	34.69	34.86	9.46	5.52	2.68
TURBINE**	1-19	154	152.00	7.79	83.97	1.28	63.29	2.03	92.29	92.29	62.74	62.74	13.80	4.29	3.42
	20-49	166	163.33	8.44	95.54	1.74	70.73	2.45	95.03	94.98	34.98	35.10	7.78	3.66	1.32
	50 Plus	337	329.67	9.84	96.68	5.07	65.71	7.72	89.99	89.89	28.08	28.30	9.15	7.00	3.01
COMB. CYCLE	All Sizes	64	62.08	60.09	97.68	51.62	82.34	62.69	88.24	83.80	2.65	6.10	4.78	10.06	1.71
HYDRO	All Sizes	720	720.00	54.77	99.57	34.95	72.95	47.91	90.04	90.04	5.36	5.36	4.57	7.24	2.71
	1-29	240	240.00	100.20	99.30	33.50	66.14	50.65	91.02	91.01	5.30	5.30	4.98	6.15	2.84
	30 Plus	480	480.00	43.93	99.63	35.04	75.30	46.53	89.55	89.55	5.39	5.40	4.36	7.79	2.65
PUMPED STORAGE	All Sizes	64	64.00	4.61	99.53	16.58	70.39	23.55	89.43	89.43	15.57	15.57	10.32	6.23	4.34
MULTI-BOILER/ MULTI-TURBINE	All Sizes	43	41.75	347.59	99.30	55.49	82.23	67.48	92.47	89.05	2.15	4.75	3.94	6.05	1.49
GEOTHERMAL	All Sizes	1	1.00	569.00	100.00	75.89	83.45	90.94	90.95	80.40	0.40	6.88	6.88	8.69	0.37
DIESEL**	All Sizes	56	56.00	8.82	99.58	11.03	153.21	7.20	90.33	90.08	45.18	46.07	15.79	3.74	5.93

*Statistics for groups of 1 to 2 units are included in the all sizes category but are not shown separately.
**Caution: EFOR and WEFOR values may be low since deratings during reserve shutdown periods may not have been reported for a large number of these units.

Date-06/03/02

NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL
GENERATING AVAILABILITY DATA SYSTEM

COMBINED CYCLE All Sizes 1996-2000 Data

1996-2000
ANNUAL UNIT PERFORMANCE STATISTICS

	AGE	NCF	SF	NOF	AF	EAF	FOR	EFOR	EFORd	SOF	FOF	SR	ART	-
1996	12.96	41.26	55.11	74.86	92.13	87.82	2.48	5.27	3.77	6.47	1.40	98.29	59.62	-
1997	13.53	41.20	54.69	75.34	91.71	87.98	1.90	4.66	3.27	7.23	1.06	98.82	54.58	-
1998	14.67	44.33	58.20	76.16	91.66	87.27	3.98	7.21	5.36	5.92	2.41	98.39	63.05	-
1999	15.12	49.12	62.36	78.77	88.47	83.67	4.33	8.00	6.36	8.71	2.82	97.86	63.30	-
2000	13.52	57.68	74.32	77.62	91.33	85.58	2.51	7.36	6.26	6.76	1.91	97.73	93.76	-
1996-00		46.51	60.55	76.82	91.03	86.47	3.09	6.59	4.99	7.04	1.93	98.24	65.09	-

		1996	1997	1998	1999	2000	1996-00
Unit-Years	:	53	56	55	57	47	269
Maximum Capacity (MW)	GROSS:	193	195	198	195	202	196
	NET:	187	188	185	182	195	187
Dependable Capacity (MW)	GROSS:	190	191	194	191	200	193
	NET:	184	185	181	179	193	184
Actual Generation (MWh)	GROSS:	707,379	708,793	778,540	842,819	1,026,203	806,621
	NET:	677,691	678,619	718,183	783,055	988,083	762,673
Attempted Unit Starts	:	82.61	88.83	82.17	88.19	71.25	83.03
Actual Unit Starts	:	81.20	87.78	80.85	86.30	69.63	81.57
Service Hours	:	4,840.77	4,791.25	5,097.47	5,462.39	6,528.23	5,309.21
Reserve Shutdown Hours	:	3,251.89	3,243.83	2,930.41	2,287.32	1,494.49	2,673.10
Number of Occurrences	:	64.94	67.90	72.00	71.11	72.90	69.71
Pumping Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
Synchronous Condensing Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL AVAILABLE HOURS	:	8,092.54	8,035.07	8,027.73	7,749.61	8,022.92	7,982.27
Forced Outage Hours	:	123.35	92.71	211.48	247.44	168.14	169.18
Number of Occurrences	:	6.14	5.75	7.38	9.84	9.72	7.72
Planned Outages:							
Planned Outage Hours	:	406.38	487.09	320.99	582.09	456.54	451.77
Number of Occurrences	:	1.28	1.10	1.23	1.79	1.07	1.30
Planned Outage Ext. Hours	:	13.46	17.81	5.05	4.30	5.30	9.28
Number of Occurrences	:	0.06	0.07	0.07	0.02	0.04	0.05
Maintenance Outages:							
Maintenance Outage Hours	:	148.59	128.62	192.84	176.37	131.61	156.44

Number of Occurrences	:	2.22	1.92	2.79	3.02	3.22	2.62
Maintenance Outage Ext. Hours	:	0.00	0.00	0.00	0.00	0.00	0.00
Number of Occurrences	:	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL UNAVAILABLE HOURS	:	691.74	726.34	730.43	1,010.39	761.70	786.75
TOTAL PERIOD HOURS	:	8,784.23	8,761.42	8,758.15	8,760.00	8,784.51	8,768.99
Equiv. Forced Hours	:	139.71	135.72	172.26	211.10	326.22	193.23
Equiv. Scheduled Hours	:	207.99	149.86	150.17	151.29	141.25	160.25
Equiv. Forced Hours During RS	:	31.50	21.18	13.89	20.16	18.03	20.96
Equiv. Seasonal Derated Hours	:	207.99	149.86	150.17	151.29	141.25	160.25
TOTAL EQUIVALENT DERATED HOURS	:	347.69	285.59	322.43	362.39	467.47	353.47

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/UE 181/UE 184

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180),	))))))))
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181),	)))))))))
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision relating to the Port Westward plant (UE 184).	)))))))))

ICNU/120

ICNU Revision to PGE/1903

October 6, 2006

PCA Examples
Variance Tariff

Assumptions:

Total NVPC (000)	$800,000	
Load (000 MWh)	20,000	Structure:
Forecast Avg NVPC ($/MWh)	40.00	(Actual Avg NVPC - Forecast Avg NVPC) * Actual Load
Avg. Retail Rate	78.5	

Cost Change	Load Change	Load Delta	NVPC Delta	Total Load	Total NVPC	Actual Avg NVPC	Delta Avg NVPC	PCA Revenue	Delta Revenue*	Total Rev Change	Net Change
	Average NVPC =			40.00							
	Market Power =			60.00							
0%	5%	1000	$60,000	21,000	$860,000	40.95	0.95	20,000	$ 78,500	$ 98,500	$38,500
0%	-5%	-1000	-$60,000	19,000	$740,000	38.95	-1.05	-20,000	$ (78,500)	$ (98,500)	($38,500)

* Total Retail Rate

PCA Examples
ICNU Proposal

Assumptions:

Total NVPC (000)	$800,000
Load (000 MWh)	20,000
Forecast Avg NVPC ($/MWh)	40.00
Avg. Retail Rate	78.5

Structure:

Actual NVPC - Base NVPC - (Actual Loads - Base Loads)* Mrkt

Cost Change	Load Change	Load Delta	NVPC Delta	Total Load	Total NVPC	Actual Avg NVPC	Delta Avg NVPC	PCA Revenue	Delta Revenue*	Total Rev Change	Net Change
	Average NVPC =			40.00							
	Market Power =			60.00							
0%	5%	1000	$60,000	21,000	$860,000	40.95	0.95	0	$ 78,500	$ 78,500	$ 18,500
0%	-5%	-1000	-$60,000	19,000	$740,000	38.95	-1.05	0	$ (78,500)	$ (78,500)	$(18,500)

* Total Revenue

This analysis assumes that the actual market prices experienced in adjusting load equals that used in adjustment calculation