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

DIRECT TESTIMONY OF RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES
(REDACTED VERSION)

August 9, 2006

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8343 Roswell Road, Sandy Springs, Georgia 30350.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am a utility rate and planning consultant holding the position of President and Principal with the firm of RFI Consulting, Inc. ("RFI"). I am appearing in this proceeding as a witness for the Industrial Customers of Northwest Utilities ("ICNU"). I previously submitted direct testimony in this proceeding regarding Portland General Electric Company's ("PGE" or the "Company") update to net variable power costs ("NVPC") for 2007, pursuant to the terms of Schedule 125, PGE's resource valuation mechanism ("RVM"). Exhibit ICNU/101 filed with my previous testimony describes my education and experience within the utility industry.

I. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. ICNU has asked me to examine PGE's net power cost study for the 2007 test year. I have identified certain problems in the PGE Monet study that overstate the Company's projected power costs and, consequently, PGE's overall revenue requirement.

In addition, I address PGE's proposal for an Annual Update tariff in Schedule 125 and an annual Power Cost Variance Mechanism ("PCVM") tariff in Schedule 126. In conjunction with addressing these specific proposed tariffs, I address PGE's discussion of automatic adjustment clauses and power cost adjustment ("PCA") mechanisms in general.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. PGE's variable power cost estimates for 2007 are overstated, and the Company's proposed PCA and annual update mechanisms do not comply with the Commission's recent statements regarding power cost recovery between rate cases. I recommend that the Commission adopt the following adjustments to PGE's power costs and reject PGE's proposed PCA for the following reasons.

1. The Commission should adopt an extrinsic value adjustment to capture the impacts of stochastic price variations to reflect the benefits of increased sales from gas-fired units when the spread between market gas and electric prices is positive and off-loading of gas plants when the spread is negative.

2. The Commission should discontinue its use of the four-year rolling average for computing outage rates. Use of the four-year average has a possible unintended consequence of making utilities less sensitive to plant reliability, as it provides additional revenues when reliability is bad and reduces revenues when reliability is good. As an alternative, I recommend use of stochastic outage modeling based on the distribution of actual plant availabilities for the North American Electric Reliability Council ("NERC") peer group generators.

3. PGE has underestimated the value of the Port Westward dispatch benefit annualization adjustment. Table 1, below, shows a more realistic estimate of the amount of this adjustment.

4. If the Commission does not adopt the extrinsic value adjustment discussed above, it should disallow the cost of the PPM Super Peak contract. This contract was justified on the basis of its extrinsic value. If the Commission does not accept extrinsic value modeling for rate case purposes, it should not consider its application in resource acquisition to be prudent.

5. The Commission should disallow costs of the PPM Cold Snap contract. This contract has never been utilized for generation, is not projected to be used in Monet for 2007, and it never was projected to be used in RVM

2005 or RVM 2006. Further, the contract produces no extrinsic value. Consequently, it does not represent a necessary expense.

6. The Commission should reject the PCA proposed by PGE in Schedule 126. Schedule 126 is merely the latest in a long line of power cost recovery mechanisms that PGE has proposed in recent years, and the Company's proposal does not comply with the Commission's guidance concerning PCAs in Order No. 05-1261 or the Commission's other decisions addressing recovery of power cost variances between rate cases.

7. There is no need for both Schedule 125 and 126. The two tariffs are intended to accomplish the same thing–shifting power cost variance risks from PGE to customers. The Annual Update in Schedule 125 would simply undermine any PCA deadband and sharing mechanism that the Commission might adopt. As a result, the Commission should reject the Annual Update tariff.

Adopting my proposed adjustments will reduce PGE's total power costs by the amount shown on Table 1.

Table 1 - Summary of Recommended Adjustments
$1,000

		=======Amount=======	
I. Monet Power Supply Cost Issues:		Without Port Westward	With Port Westward
1	Extrinsic Value - PGE Generators	-$11,398	-$11,398
2	Extrinsic Value - Super Peak	-$1,384	-$1,384
3	NERC Outage Rates	-$7,175	-$7,175
4	Port Westward Dispatch Benefit	-	-$1,922
5	Cold Snap Contract	-$1,752	-$1,752
Total Power Supply Cost Adjustments:		-$21,709	-$23,631
PGE Request		856,968	847,321
Total ICNU Recommended Power Supply Costs		**$835,259**	**$823,689**

II. NET VARIABLE POWER COST ISSUES

Q. WHAT ARE "NET VARIABLE POWER COSTS," AND WHY ARE THEY IMPORTANT TO THIS PROCEEDING?

A. Net variable power costs are the variable production costs related to fuel and purchased power expenses, net of power sales revenue. In the context of this case, net variable power costs are estimated using PGE's Monet production cost model. This model has been used since at least UE 115 and was used for all of the annual RVM filings since that case.

Q. WHAT INFORMATION, DOCUMENTS, AND DATA DID YOU REVIEW IN ORDER TO ANALYZE PGE'S POWER COSTS?

A. I read PGE's direct testimony and discovery responses and examined the modeling assumptions used in PGE's Monet power cost model in order to make recommendations regarding the proper level of net variable power costs for the 2007 test year.

<u>Stochastic Price Modeling</u>

Q. DOES MONET SIMULATE STOCHASTIC PRICE VARIATIONS?

A. No. Monet assumes that the prices for fuel inputs are fixed. Though prices may vary throughout the year, there is only a single point price forecast recognized in the model.

Q. IS THIS REALISTIC?

A. No. There is ample reason to believe that prices will deviate from the forecast as events unfold. However, it is impossible to determine exactly what market prices will materialize. As a result, one should view prices as a stochastic variable, with the current forecast being the midpoint of the probability distribution.

To deal with the problem of price variability, a variety of techniques are available. One approach would be to run Monet with multiple price forecasts, simulating system operation under differing scenarios. The problem with that approach is that it would require substantial modification to the model and would likely take far too long to perform all the runs. A better solution would be development of a pure stochastic modeling process within Monet. However, this would be an even more complex undertaking.

Q. ARE THERE ANY STEPS BEING TAKEN TO DEAL WITH THIS ISSUE?

A. Yes. For some months, Staff has advocated development of a form of stochastic modeling for both PacifiCorp and PGE. Various workshops and analyses have been conducted, but as yet, there has been no substantial progress in reformulating the power cost models. PGE ordered a consultant's report that analyzed the issue as part of the stipulation that the Company executed with Staff in Docket No. UE 165/UM 1187. See PA Consultants, "Portland General Electric, Hourly Power Cost Simulation," July 10, 2006. However, the report did not provide a solution to the problem of stochastic modeling within the context of Monet. Rather, it appears the report dealt more with the issue of the distribution of overall power costs and the standard deviation of power cost forecasts. Though potentially useful information, it does not provide a complete modeling solution.

Q. BASED ON YOUR EXPERIENCE, WHAT ARE THE MOST LIKELY RESULTS OF DEVELOPING MODELS THAT CAN SIMULATE STOCHASTIC PRICE VARIATIONS?

A. Stochastic models would provide more insight into both the expected value and the distribution of power cost forecasts. For purposes of this case, the most important question is whether the expected value of power costs is accurately estimated by Monet. Probably the most important result would be the ability to estimate the extrinsic value of marginal plants, which is not currently considered in Monet.

A stochastic model would also be useful for projection of revenues under differing power cost adjustment mechanisms to evaluate revenue neutrality. This would have important applications to the development of a revenue neutral PCA, as well as other applications.

Q. WHAT IS EXTRINSIC VALUE?

A. There are two sources of extrinsic value. First, there is the value of unused generation from gas-fired plants. Under a point price forecast, a power plant is either "in the money" or "out of the money." However, because of the dispersion in future price forecasts, it is probable that a plant will be in the money in actual operation in some situations, even though it might not be under a point forecast.

Conversely, there is value in off-loading gas fired units if market prices are less than forecast. In that case, lower cost purchased power would be available. The ability to dispatch a plant in response to price changes, the so-called "option value," is one of the most important benefits that distinguishes physical generating facilities from purchased power. It is important to try to capture this value in setting rates.

Q. CAN YOU PROVIDE AN EXAMPLE THAT ILLUSTRATES THESE BENEFITS?

A. Assume the Coyote plant has a variable operating cost of $50/MWh and that the market price forecast for power is just slightly below $50/MWh. In that case, Monet would not dispatch the unit, and Coyote would generate no energy. It would be "out of the money." In that mode, Coyote would provide virtually no benefit to ratepayers because the "spread" between power prices and the unit's generating cost is slightly negative.

Obviously, we recognize that any forecast is going to be imperfect. In all likelihood, gas and/or power prices will be different from expectations. In one scenario, the spread between Coyote's operating cost and market prices might be a positive $5/MWh, but equally likely might be a case where Coyote costs $5/MWh more than a market purchase.

The interesting thing is that with either outcome, there are opportunities to save money as compared to the mid-point forecast (which has a spread slightly below zero). In the former case (positive $5/MWh spread), the Company should operate the facility and make sales in the wholesale market. In the latter case, the Company would shut down the facility and make purchases. Either situation could provide savings compared to the point forecast ($50/MWh). The expected value of these benefits is called the "extrinsic value" or "option value" of the resource. By considering only the mid-point forecast, Monet ignores the extrinsic value of PGE's facilities, understating the benefits available and overstating power costs. Therefore, a primary benefit of the stochastic price analysis is that it would enable quantification of the savings or costs when prices turn out differently from the forecast.

Q. HAVE YOU DEVELOPED A METHODOLOGY TO COMPUTE THE EXTRINSIC VALUE OF RESOURCES?

A. Yes. Confidential Exhibit ICNU/104 provides an example calculation showing how the extrinsic value of a resource is developed. The methodology used historical spreads for Mid-Columbia market electric and gas prices based on Intercontinental Exchange day-ahead prices for the period June 2002 to June 2006. Spreads are computed for each resource using its specific heat rate. From this data, I developed monthly adjusted spread distributions taking the mean value of the spread from the gas and power prices used in Monet. I then computed the probability (and savings) from off-loading units as well as from making additional sales. Results from the analysis are shown on Table 1.

Q. YOUR ANALYSIS DOES NOT INCLUDE COAL OR HYDRO PLANTS. PLEASE EXPLAIN.

A. For plants with very large spreads, whether positive or negative, the expected value of savings will be zero. For example, a coal plant might have a spread of -$30/MWh, and the standard deviation of the spread is $5/MWh. It would take a very extreme event before the unit would be "out of the money."[1/] In such cases, the expected value of the difference between the spread in the probability distribution and the Monet spread is zero, resulting in no additional savings. Calculations provided in my workpapers show scenarios where the spreads are very large (both positive and negative) resulting in no extrinsic value. This confirms the reasonableness of the method employed and demonstrates that to capture the benefits of stochastic price modeling, it is not necessary to model all plants on the system. Only the "marginal" plants are likely to have spreads close enough to zero to make this kind of analysis necessary or useful.

Q. YOUR METHODOLOGY MIGHT BE CRITICIZED ON THE BASIS THAT IT ONLY TREATS GAS AND MARKET ELECTRIC PRICES AS STOCHASTIC VARIABLES, WHILE OTHER VARIABLES ARE DETERMINISTIC. PLEASE COMMENT.

A. One could consider including a host of stochastic variables: loads, outage rates, coal prices, and hydro generation in addition to gas and power prices. However,

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[1/] In this case, it would take a price movement six standard deviations from the mean—a highly unlikely event.

in at least some of these cases, it is unlikely the expected value of the power cost distribution would change, though the dispersion probably would. For example, coal prices are not known in advance. If one accepts the forecasted coal price as an unbiased mean, it is unlikely that uncertainty surrounding coal prices will be responsible for a systemic under or overstatement. Coal prices for individual plants are unlikely to have a systematic effect on market prices because coal is seldom at the margin. As a result, there is no reason to believe that inclusion of other variables in a stochastic analysis would change the expected value of power costs.

Certainly, it is likely that load and hydro conditions could affect market prices, though probably not as much as gas prices. However, loads will be unlikely to have a substantial impact on the market, unless all utilities in the market experience correlated load variations. There is some debate as to the impact of hydro variations on market prices as well. By using historical data over a four-year period, certainly some variations in load and hydro conditions have been captured in the price spreads used in my model. In the end, models improve when the capability and desire to improve them exists. By adopting a stochastic price adjustment, the Commission could well provide the impetus for the utilities to improve their models.

Q. WHAT IS YOUR RECOMMENDATION?

A. The Commission should adopt my proposed stochastic price modeling adjustment. While it would always be possible to improve any model, I believe this approach is reasonable, transparent, and verifiable.

Q. HAVE YOU APPLIED THIS MODELING METHOD TO ALL PGE RESOURCES?

A. No. I did not apply it to coal or hydro resources for the reasons discussed above. In the case of the PPM Super Peak contract, I relied upon an analysis performed by the Company when this contract was evaluated. My own analysis produced no extrinsic value. PGE provided this study in discovery along with the extrinsic value calculations performed by the Company. This analysis demonstrates that the Company's decision to sign the Super Peak contract was largely based on consideration of extrinsic value. Thus, I used the results derived by PGE for reasons I will discuss later.

For the other capacity tolling contract (PPM Cold Snap), I performed an extrinsic value analysis but found no extrinsic value. I discuss the treatment of this contract later.

Q. IT MIGHT BE ARGUED THAT IT IS NOT VALID TO APPLY STOCHASTIC MODELING TO ONLY A FEW PLANTS OR A LIMITED NUMBER OF VARIABLES, RATHER THAN BY DEVELOPING A COMPREHENSIVE MODEL. DO YOU AGREE?

A. No. Both PGE and PacifiCorp have made this comment in various discussions with parties. However, both companies have applied this modeling in precisely that manner when deciding to enter into contracts for long-term resources. PGE used extrinsic value modeling to justify the PPM Super Peak contract, while PacifiCorp used the approach to justify the West Valley lease and a number of other power contracts. See Re PacifiCorp, OPUC Docket No. UE 134, PPL/804, Klein/1 (Feb. 12, 2003). It would be inequitable for the Commission to allow resource selections to be made on the basis of extrinsic value modeling, but not to reflect the extrinsic value benefits in setting rates.

<u>Monet Outage Rates</u>

Q. EXPLAIN THE ROLE OUTAGE RATES PLAY IN MONET.

A. In Monet, thermal deration factors (also called outage rates) control the amount of generation available from thermal units. The more energy available from lower cost generation, the lower net power costs. If a generator has an average outage rate of 5%, Monet assumes a thermal deration factor of 95%. This means that only 95% of the unit's capacity is available to produce energy. The remaining capacity is assumed to be permanently on outage. The Company uses a compilation of outages over the most recent four-year historical period (2002 to 2005) to compute the outage rates for its thermal plants. The purpose of using the four-year average is to "normalize" or smooth out variations that might affect a single year. Staff/102, Galbraith/4.

Q. ARE THERMAL OUTAGE RATES AN IMPORTANT DRIVER IN OVERALL NET POWER COSTS?

A. Yes. Outage rates have a substantial impact on overall net power costs. The higher the outage rates, the higher the cost. This is particularly true for PGE's Boardman and Colstrip plants. These coal plants are the lowest cost resources on the system other than hydro.

Q. DID PGE INCLUDE THE OCTOBER 2005 BOARDMAN OUTAGE IN ITS CALCULATION OF THE FOUR-YEAR AVERAGE OUTAGE RATE?

A. Yes. The Company included the 70-day outage from October 23 to December 31, 2005, in its calculation of the Boardman outage rates. PGE/100, Tooman-Niman-Schue/12-13.

Q. DO YOU AGREE WITH THIS TREATMENT?

A. No. The Company has already requested a deferral of Boardman outage costs in UM 1234, but that case has not yet been decided. Further, UM 1234 has been bifurcated into two phases. If a deferral is allowed in Phase 1 of UM 1234, Phase 2 will deal with issues of prudence. At this point, PGE has not demonstrated that it acted prudently with respect to the cause of the Boardman outage, and the Company has not even completed a root cause analysis of the outage. In fact, based on PGE's responses to discovery requests in UM 1234, it appears that the Company has not normally performed root cause analyses on generator outages. Therefore, the cause of the outage is not even known at present. An extended outage should not be included in the forced outage rate absent a finding of prudence. Further, if the Boardman outage is recovered in a deferred account, it should not be included in this case. Finally, there may have been additional (possibly related) outages at the plant. It is apparent that the outage(s) at Boardman extended far beyond the February 5, 2006 date for which PGE requested a deferral. This all suggests a very complex set of circumstances surrounding the Boardman outage(s) and indicates a need for the Commission to thoroughly evaluate the underlying facts before reflecting the Boardman outage(s) in rates.

Q. DISCUSS THE COLSTRIP OUTAGE RATE USED IN MONET.

A. In Monet, the Company assumes Colstrip 3 and 4 will have an outage rate that represents a very poor level of performance for these units. The outage rates for Colstrip are 44% higher than comparable plants in NERC's peer group.

Q. DOES THE USE OF A FOUR-YEAR ROLLING AVERAGE OUTAGE RATE PROVIDE INCENTIVES FOR UTILITIES TO MAINTAIN OR IMPROVE PLANT RELIABILITY?

A. No. Use of the four-year average may have the unintended consequence of reducing incentives for maintaining or improving plant reliability. This is particularly true when applied in the context of an annual adjustment to power costs, based on a model like Monet. The reason is that when an outage occurs, it is factored into the four-year rolling average. Thus, utilities know that they will be “rewarded” for outages by an increase in rates. While it is true that, absent a PCA or deferral mechanism, utilities would typically bear the cost of replacement power, use of the four year average insulates utilities from most of the effects of outages. In times of increasing market prices, utilities actually may have a perverse incentive in that actual replacement power costs may be more than compensated for in the four years following the outage.

Q. DOES PGE HAVE A GOOD RECORD FOR GENERATOR RELIABILITY FOR ITS COAL UNITS?

A. No. Confidential Exhibit ICNU/105 compares PGE forced outage rates with NERC averages for peer group generators. The peer group is defined as units of similar size. This exhibit shows that for Colstrip, forced outage rates have substantially exceeded those of other large coal plants over the period 1998 to 2004.

While Boardman has had outage rates modestly better than the NERC averages in the past, is it quite improbable that will be the case for 2005 and 2006. Further, any four-year average outage rates, including the years 2005 and 2006, will likely exceed the NERC average by a substantial margin. Of course, it is not possible to completely attribute this substandard performance trend to the use of the four-year rolling average in Monet. Nonetheless, it does indicate that performance has been poor.

Q. HOW DO YOU RECOMMEND THE COMMISSION RESPOND TO THIS PROBLEM?

A. Falling short of the NERC national average figure does not, by itself, demonstrate imprudence. However, very substandard performance for an extended period of time clearly suggests the presence of a problem in the operation or management of resources. To rectify this problem, I recommend the Commission decouple plant outage rates from rate levels by imputing the NERC average outage rate for comparable plants in Monet.

It would also be desirable to implement a form of stochastic modeling for plant outage rates. To do so, I have relied on NERC statistics to create distribution margins for PGE plants. This analysis is shown in Confidential Exhibit ICNU/106.

Q. DESCRIBE THIS ANALYSIS.

A. NERC provides a distribution of outage rate statistics for all plant types and sizes. This distribution shows how many plants in each peer group obtained various outage rates for the five-year period 2000 to 2004.[2/] I used the Equivalent Availability Factor, as it represents the maximum amount of generation available from a resource and considers full and partial unplanned outages as well as all types of planned outages. Because there may be a trade-off between planned and

2/ NERC did not provide data for combined cycle plants for 2004 due to confidentiality issues. For combined cycle plants, I used 2000-2003 data instead. As these statistics do not vary much over time, this is a reasonable approach.

unplanned outages, this variable suffers from the fact that it weights both types of outages equally. A utility that cuts planned outages short as a cost-cutting move may increase overall costs by increasing unplanned outages. While I would prefer to use a different variable, the NERC data is not readily available for unplanned outage rate inputs appropriate for Monet.

From this data, I developed the aMW generation available for PGE resources, based on the data in the NERC distribution. This was then compared to the PGE aMW generation. From Monet data, I computed the total margin (market revenues less fuel cost) for each resource. This was applied to the aMW generation from the NERC distribution to compute the distribution and expected value of margins.

To provide a simple example, assume (hypothetically) that Boardman would produce a $100 million margin in Monet, based on an average generation of 300 MW in the model. If the NERC distribution showed a 5% chance of only 150 aMW generation from the historical distribution, then the model assigned a 5% chance of a $50 million margin. Each availability scenario was then examined, with the weighted average margin used to compare to the Monet assumption. The adjustment is computed as the difference between the Monet and NERC probability weighted margins. The amount is shown on Table 1.

Q. WHAT ARE THE ADVANTAGES OF THIS APPROACH?

A. <u>First</u>, use of industry-wide statistics provides an objective, verifiable means of estimating power costs without having to delve into the prudence and efficiency of PGE's management of its resources. Certainly, the Company should be able to match the national average level of performance. The NERC average represents a grade of "C" on the "bell shaped curve." It does not represent an unrealistic standard.

Second, use of this method effectively decouples PGE's revenues from its power plant reliability. The Company would then be able to reap the rewards of improved performance or suffer the consequences of poor performance.

Finally, by referencing the NERC data in establishing rates, the Commission could, were it so inclined, establish a priori guidelines for allowance of deferrals of specific outages when they had substantial impacts. In such cases, the Commission should consider that if ratepayers are expected to provide "outage insurance" to PGE, they should be compensated for the expected cost of assuming this risk.

Q. PLEASE EXPLAIN THAT LAST POINT.

A. Soon the Commission will have to decide in UM 1234 whether to grant a deferral in the case of the recent Boardman outage. Hopefully, in that proceeding, the Commission will take the opportunity to clarify its position regarding such issues. If the Commission were to decide to allow deferrals in cases of long outages, it would be very useful for the Commission to use the NERC data shown in Confidential Exhibit ICNU/106 to set standards for future deferrals.

For example, the Commission might decide it would allow a deferral if the annual outage rate for a particular plant placed it in a "one in 10" or a 10^{th} percentile circumstance (or worse). For Boardman, that would equate to an equivalent availability factor less of than 72.9%. In that case, the Commission should also eliminate the worst 10% of all outages from the determination of base rates, as it will implicitly be pre-approving a deferral in such circumstances. Naturally, nothing in this is to suggest that a utility should be allowed recovery of deferred costs unless prudence is demonstrated.

Q. WHAT WOULD BE THE IMPACT OF THE COMMISSION MAKING SUCH A DECISION VIS-À-VIS ALLOWING DEFERRALS?

A. In that case, the Commission should reduce the revenue requirement by $3.3 million compared to the NERC average result to reflect the removal of high cost, low probability events associated with these long outages. In effect, ratepayers would be responsible for bearing the costs of long outages. In return, such events should be removed from computing the expected net power costs. This would be comparable to providing ratepayers a "premium" for the "outage insurance" they would be providing to PGE.

Capacity Tolling Contracts

Q. WHAT IS A CAPACITY TOLLING CONTRACT?

A. These are contracts that function like a spark spread option contract. They allow PGE the right to obtain additional energy when the market price for energy exceeds the price of gas-fired energy with a specific heat rate.

Q. CAN YOU PROVIDE AN EXAMPLE THAT ILLUSTRATES HOW SUCH CONTRACTS OPERATE?

A. Yes. In this example, I am using only hypothetical numbers. In such a contract, pricing for energy is based on a gas index, heat rate, exercise price, and demand charge. Assume, for example, a heat rate of 10.0 MBTU/kWh; an exercise price of $1/MWh; the gas price index at $5.00; and a monthly demand charge of $1.00/kW.

In this example, the demand charge is irrelevant to the decision to obtain the energy allowed under the contract. The "strike price" in this example would be computed as follows:

(Gas Price Index) times (Heat Rate) plus Exercise Price; or

5.00*10+1 = $51/MWh.

Consequently, if power prices exceed $51/MWh, it makes sense to exercise the option because it would provide energy cheaper than the market. However, this does not mean that every time market prices exceed $51/MWh, the contract would be "in the money." For example, if gas prices were $6.00, the market price would have to exceed $61/MWh for the contract to be "in the money."

Q. DOES PGE INCLUDE ANY CAPACITY TOLLING CONTRACTS IN MONET?

A. Yes. PGE has two capacity tolling agreements (PPM Cold Snap and PPM Super Peak) included in its Monet study. The demand charges ($3.0 million in 2007) for these contracts are reflected in Monet; however, the contracts are never "in the money" based on PGE's 2007 gas and power price assumptions. Thus, these contracts are never dispatched in the model.

Q. IS THE SAME TRUE USING YOUR EXTRINSIC VALUE MODEL?

A. Yes. I found no extrinsic value associated with these contracts. These contracts have a spread so large, that it would be extremely unlikely they would ever be dispatched. However, PGE did perform its own extrinsic value analysis while evaluating the Super Peak contract and estimated substantial extrinsic values associated with this resource. As discussed above, I used the PGE figures in my extrinsic value adjustment for that contract.

Q. HAS THIS PROBLEM EXISTED SINCE THE INCEPTION OF THE SUPER PEAK CONTRACT?

A. Yes. In RVM 2005, the Company first included both capacity tolling contracts in the November 2004 update. At that time, Monet did not show either contract being dispatched. The same was true in RVM 2006. Further, actual data for 2005 shows the Super Peak contract dispatched only for 12 hours and the Cold Snap contract was never dispatched. As a result, absent consideration of extrinsic value, these contracts add nothing but a "dead weight" cost, with no offsetting benefits for ratepayers.

Q. IS THIS A REASONABLE TREATMENT OF THE DEMAND CHARGES?

A. No. This approach simply saddles ratepayers with additional costs, and allows shareholders to receive any benefits that might result if the contracts in question actually are dispatched at some time during 2007.

Q. ELABORATE ON THE CIRCUMSTANCES SURROUNDING THE INITIAL INCLUSION OF THESE CONTRACTS IN THE RVM PROCESS AND THEIR SUBSEQUENT RATE TREATMENT.

A. They were first included in the November 2004 update for RVM 2005. In that case, Staff opposed their inclusion in Monet and filed a request for a pre-hearing conference to address the issue. Exhibit ICNU/107 is a copy of the letter from Staff regarding this issue, along with PGE's response and the ALJ's decision. There was no resolution of the issue at that time. ICNU raised the issue of the capacity tolling contracts in the update to 2006 NVPC in UE 161 but that case was settled and the issue was not resolved. At this time, there is no Commission decision regarding these contracts.

Q. PLEASE ELABORATE ON THE POTENTIAL BENEFITS OF THESE CONTRACTS.

A. The benefit of these contracts stems from their ability to put a cap on power costs in the event of extreme changes in the relationship between gas and power prices. When power prices are high relative to gas prices, these contracts are "in the money." For this to happen, it would typically mean that capacity shortages are occurring in the wholesale market, driving up the spark spread between wholesale gas and power prices. Based on my extrinsic value analysis, this is a very unlikely scenario. However, in PGE's studies, the extrinsic value was a prime consideration and lead to the Company executing the Super Peak contract. In the end, these contracts amount to an insurance policy providing protection against very extreme price movements. Absent approval of Schedule 126 (PGE's PCA proposal), these benefits would inure to shareholders if they ever did materialize. This would merely amount to a "one-way street" where investors obtain the contract benefits, while ratepayers absorb the costs.

Q. WHAT IS YOUR PROPOSAL FOR DEALING WITH THIS ISSUE?

A. For the Super Peak contract, prudence rests upon the extrinsic value analysis performed by the Company. If the Commission rejects that type of analysis for rate case purposes then it should not accept the prudence of the Super Peak contract. I recommend that the Commission require the removal of the Super Peak contract from the 2007 test year if it decides against the extrinsic value adjustment. This will remove the excess costs from the study.

Q. HAVE SITUATIONS LIKE THIS ARISEN BEFORE?

A. Yes. In UE 147 and UE 170, PacifiCorp initially requested recovery of fixed costs associated with a hydro hedge contract. This contract was opposed by parties on the basis that the costs were included in the test year, but no benefits could be reflected in PacifiCorp's power cost model (GRID). In both cases, settlements were reached, so there is no clear precedent. However, in both cases, the Company proposed to implement a balancing account to pass through other payments and receipts from the hydro hedge. As the Company later withdrew those requests, it is reasonable to infer that it also dropped the request for recovery of the hydro hedge. The Commission adopted stipulations in both UE 147 and UE 170.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE COLD SNAP CONTRACT?

A. The Cold Snap contract has never been dispatched in Monet, and never been called upon to serve load. It provides no extrinsic value and amounts to nothing but a dead-weight cost. I recommend that the Commission remove this contract from Monet, as it represents an unnecessary expense.

<u>Port Westward Annualization</u>

Q. DO YOU AGREE WITH THE ANNUALIZATION OF THE PORT WESTWARD DISPATCH BENEFITS SHOWN IN PGE/201?

A. No. This is shown on page 1, column 4 of PGE/201. The Company computes an impact of $11.746 million. The Company computed this adjustment by taking the ratio of the 10 month dispatch benefit to the ten month load times the 12 month load. PGE/200, Tooman-Tinker/27.

This methodology is unrealistic. The dispatch benefit of the facility is not proportional to load. Rather, it depends on the dispatch cost of the unit and the forward curve. A quick review of the Monet hourly diagnostic report shows that in January and February 2007, Monet shows Coyote running at nearly a 100% capacity factor. This is because the spread between Coyote's cost and market prices is positive during nearly all hours.

Because Port Westward has a slightly better heat rate than Coyote, it is reasonable to assume the unit would run even more than Coyote. Therefore, I computed the annualization by assuming the facility runs all of the time in the first two months of the year. This should provide a conservative estimate of the dispatch benefit because it could include hours when the market price is below the dispatch cost, producing a "negative credit" for those hours. The amount of this adjustment is shown on Table 1. This adjustment would only apply after March 1, when Port Westward's costs are included in rates.

III. ANNUAL UPDATE AND POWER COST VARIANCE TARIFFS

Q. BRIEFLY DESCRIBE THE ANNUAL UPDATE TARIFF.

A. PGE proposes the Annual Update tariff (Schedule 125) to address power cost variability between general rate cases, and the tariff would provide a truncated version of the current RVM. PGE would make a filing each July to update the Monet power cost model to reflect a specific list of updated data items. These include loads, new contracts, planned and unplanned outage rates, and new forward curves. PGE/1302, Kuns-Cody/91.

This update would actually consist of a series of updated Monet studies that would be performed over the period July to November of each year. Id. at Kuns-Cody/92. In this respect, it would be comparable to the current RVM filing, except that it would be filed later, and the Company would not make changes to the model. Updates to the Transition Adjustment for direct access customers would be made under Schedules 128 and 129.

Q. PLEASE DESCRIBE THE ANNUAL POWER COST VARIANCE TARIFF, SCHEDULE 126.

A. This tariff would implement an ongoing PCA that would track the difference between the forecasted NVPC (those included in rates) and actual NVPC each year. PGE's proposed mechanism includes no deadband, a symmetric 90/10% sharing mechanism that would apply to all power cost variances, and an earnings test. PGE/400, Lesh-Niman/33. PGE refers to its proposed PCA as an "automatic adjustment clause" in testimony.[3/] I will use the terms PCA and automatic adjustment clause interchangeably in this testimony.

Q. WHY DOES PGE PROPOSE THESE TARIFFS?

A. PGE maintains that substantial power cost variations occur each year, and that, without a PCA, neither customers nor the Company will have any assurance that prices will reflect the actual cost of service. PGE also argues that a comprehensive PCA is the best approach, because it is consistent with the

[3/] I assume that PGE intends this to imply that Schedule 126 would be an "automatic adjustment clause" under ORS § 757.210, which defines the term as a "provision of a rate schedule which provides for rate increases or decreases or both, without prior hearing, reflecting increases or decreases or both in costs incurred or revenues earned by a utility and that is subject to review by the commission at least once every two years." Authorizing a rate change without hearing precludes any meaningful review of tariff updates, which is a substantial drawback of PCA mechanisms.

Company's "resource portfolio" and there is substantial uncertainty related to many power cost elements. Finally, PGE suggests that parties including Staff, the Citizens' Utility Board ("CUB"), and ICNU support a comprehensive mechanism. PGE/400, Lesh-Niman/33-34. While I am not aware of the current position of Staff and CUB concerning a PCA, it is incorrect to suggest that ICNU supports a comprehensive PCA.

Q. ARE ANY OF THESE "NEW" ARGUMENTS?

A. No. The Commission has been presented with the same issues regarding power cost recovery in a number of recent cases, including UE 115, UE 137, UE 149, UE 165, and UM 1187. Further, PacifiCorp has also proposed its own PCA in other cases, including UE 173. There also have been cases related to requests for deferred accounts related to excess power costs (UM 995 and UM 1071) that dealt with similar issues.

In addition, ICNU, CUB, Staff, and PGE agreed as a part of a stipulation in PGE's 2004 RVM proceeding (UE 149) to engage in a process to address the need for and structure of a power cost recovery mechanism, and the parties met multiple times in 2003 and 2004 to discuss these issues. Furthermore, as PGE's testimony in this case indicates, the parties' discussions regarding an appropriate PCA continued earlier this year after the Commission rejected the SD-PCAM proposed in UE 165. In other words, PGE's concerns about power cost recovery have been under almost continuous discussion in either Commission proceedings or "off line" since PGE's last rate case, and PGE's arguments in all of these previous proceedings and discussions were generally similar to the arguments that the Company has made in this case.

Q. CONSIDERING THAT THE COMMISSION HAS TAKEN EVIDENCE IN ALL OF THESE CASES WHERE PCAS AND OTHER POWER COST RECOVERY ISSUES WERE CONSIDERED IN RECENT YEARS, HAS THERE EVER BEEN A FINAL RESOLUTION OF WHETHER AN ONGOING, COMPREHENSIVE PCA IS APPROPRIATE FOR PGE?

A. No. The Commission has not approved a PCA or a power cost deferral for PGE since the Company's last rate case (UE 115). Although the Commission authorized PGE to implement a PCA as part of its decision in UE 115, that was a temporary mechanism that was agreed to in a stipulation. In other proceedings since that time, PGE has either withdrawn its request for a PCA (UE 137) or the Commission rejected the proposal (UM 1071, UE 165/UM 1187). Nevertheless, due to the extensive litigation regarding power cost recovery issues, the Commission has provided some guidance as to what may be an appropriate PCA proposal. In Order No. 05-1261 (UE 165/UM 1187), for example, the Commission articulated certain standards for PCAs that should be applicable in this case. Re PGE, OPUC Docket No. UE 165/UM 1187, Order No. 05-1261 (Dec. 21, 2005). One of the fundamental problems with PGE's current proposed PCA is that it does not even resemble the structure outlined by Commission's guidelines for power cost recovery mechanisms.

Compliance with Order No. 05-1261

Q. DOES ICNU SUPPORT ADOPTION OF PGE'S PROPOSED SCHEDULES 125 AND 126?

A. No. There are many strong policy arguments against adopting these schedules that the Commission has already considered. In this case, however, Schedule 126 does not even come close to complying with the Commission's PCA standards articulated in Order No. 05-1261. Further, the PGE proposal is seriously flawed in other ways that I will discuss later.

Q. WHAT PCA STANDARDS DID THE COMMISSION ESTABLISH IN ORDER NO. 05-1261?

A. The Commission endorsed four basic principles: 1) limitation to unusual events; 2) revenue neutrality; 3) no adjustment if overall earnings are reasonable; and 4) long-term operation. Order No. 05-1261 at 8-10. PGE's proposal fails to comply with at least three of these standards.

Q. PGE DOES NOT PROPOSE TO USE A DEADBAND IN SCHEDULE 126. PLEASE COMMENT.

A. This aspect of the PGE proposal places it squarely at odds with the Commission's first standard from Order No. 05-1261. In that order, the Commission found that a hydro PCA should be "limited to unusual events." Order No. 05-1261 at 8. The Commission found that the "inclusion of a deadband around expected power cost is a reasonable way to identify whether an event is unusual." Id. at 9.

Without a deadband, Schedule 126 will allow recovery of virtually all power cost variances from all types of events, whether unusual or ordinary. Schedule 126 does not include any deadband and should be rejected out of hand.

Q. ORDER 05-1261 DEALT WITH A HYDRO-RELATED PCA. SHOULD A BROADER, ALL ENCOMPASSING PCA BE EXEMPT FROM THE REQUIREMENT TO EMPLOY A DEADBAND?

A. No. PGE's proposal would encompass not only hydro-related cost variances, but those related to gas prices, power prices, coal prices, contract prices and plant outages. In fact, nearly every kind of event (aside from load variation) that causes a power cost variance would be reflected in the PCA. It makes little sense to think that if the Commission required a deadband for a hydro PCA, it would not require one for a PCA that includes hydro and many other factors.

The Commission's decisions in the deferred accounting context reinforce the notion that utility shareholders must bear some amount of normal power cost variation between rate cases. In UM 995, the Commission approved a power cost deferral mechanism for PacifiCorp that included a 250 basis point deadband. Re PacifiCorp, OPUC Docket No. UM 995, Order No. 01-420 at 28-29 (Mar. 11, 2001). Furthermore, in UM 1071, the Commission denied PGE's request for a deferred account related to below-normal hydro conditions, finding that excess power costs that had an impact equivalent to 172 basis points of return on equity was insufficient to justify recovery of the excess costs. Re PGE, OPUC Docket No. UM 1071, Order No. 04-108 at 9 (Mar. 2, 2004). In commenting on the reason for the deadband in UM 995, the Commission stated that it "allowed no recovery of costs or refunds to customers within that deadband, reasoning that the band represented risks assumed, or rewards gained, in the course of the utility business." Id. at 9. Again, if PGE would not be allowed to recover normal power cost variations between rate cases through deferred accounting, then there is no basis to approve a PCA that would provide such a result. PGE's current proposal simply ignores the Commission's guidance on power cost recovery and, as a result, fails to meet the Commission's standards.

Q. ORDER NO. 05-1261 REQUIRES REVENUE NEUTRALITY. DOES SCHEDULE 126 MEET THIS REQUIREMENT?

A. No. PGE's proposal has no feature to address revenue neutrality. In the case of the SD-PCAM that the Commission rejected in Order No. 05-1261, the Commission appeared supportive of the notion of an asymmetric deadband as a means of providing for revenue neutrality:

> **Revenue Neutrality.** We agree with Staff that operation of a hydro-related PCA should not bias the overall expected level of power cost recovery; *i.e.*, the mechanism should be revenue neutral over time. CUB notes that this requires an asymmetric deadband on power costs because the cost of replacement power in poor hydro years outweighs the benefits of additional power in good hydro years.

Order No. 05-1261 at 10 (internal footnotes omitted). The Order did not identify any other approach to assure revenue neutrality, but did criticize PGE and Staff's proposed PCA on the basis that no evidence of revenue neutrality was provided. Id. at 12.

PGE's current proposed PCA includes no deadband at all, and the Company provides no evidence to demonstrate that the mechanism will be revenue neutral over time. As a result, PGE's evidence and the mechanism itself fail to meet the Commission's standard on this basis as well.

Q. DOES PGE CONTEND THAT ITS PROPOSAL MEETS THE COMMISSION'S REVENUE NEUTRALITY STANDARD?

A. No. Rather than attempting to address this standard, PGE contends it is impossible to determine if Schedule 126 would be revenue neutral. PGE/400, Lesh-Niman/45. As discussed above, the Commission has already indicated that an asymmetric deadband is one means of addressing this problem. Because the Annual Variance tariff fails to meet this standard, this provides one more reason it should be rejected by the Commission.

Q. IS THERE A WAY IN WHICH REVENUE NEUTRALITY COULD BE ESTABLISHED?

A. Yes. A comprehensive stochastic power cost model could be used to assist in evaluating the issue of revenue neutrality. PGE has not yet developed this capability, however.

Q. DOES PGE'S PROPOSED EARNINGS TEST COMPLY WITH THE COMMISSION'S STANDARD?

A. No. The Company acknowledges this at pages 49-50 of Exhibit PGE/400. In the end, the Company's proposal fails at least 3 of the Commission's four standards (limited to unusual events, revenue neutrality, and the earnings test). The fourth standard (long-term operation) is not really addressed by the Company, but if past history is any guide, it would not be at all surprising for the Company to abandon Schedule 126 when power costs stabilize or decline. In the end, there is no basis for the Commission to accept the PGE proposal.

Power Cost Variability and Risk

Q. IN PGE/400, THE COMPANY PRESENTS A GRAPH AT PAGE 34 THAT SHOWS POWER COST VARIANCES CAN BE MORE THAN $150 MILLION PER YEAR. PLEASE COMMENT.

A. The figure in PGE/400 is intended to illustrate that power cost variances can be substantial. However, it is equally important to realize that power cost variances tend to cancel out over time. Based on the data presented in PGE's graph, the cumulative variance from 1993 to 2005 is a negative $120 million, or approximately negative $9 million/year. These figures indicate that over time, positive and negative variances will generally cancel out, even though they may be large in some years.

It also is important to recognize that if a PCA is adopted in times of rising power costs but is not used in times when power costs are declining, then customers will pay for higher costs in "bad times" but never be "made whole" during good times. Unfortunately, PGE has tended to seek deferrals and other adjustment clauses in situations when power costs were increasing but has been less inclined to apply them in times when power costs were stable or declining.

Q. GIVEN PGE'S POWER COST SITUATION, IS SOME TYPE OF MECHANISM NEEDED TO ADDRESS THIS PROBLEM?

A. PGE has substantial power cost variability for several reasons: load forecast uncertainty,[4/] a resource deficit resulting in a need for the Company to contract for substantial amounts of energy on the wholesale market, a heavy reliance on gas-fired generation, and reliance on hydro generation.

4/ The Company acknowledges that load variations should be removed from its PCA. I will discuss this issue later in this testimony.

A PCA would only serve to insulate PGE from the financial impact of these problems and would not provide the Company any impetus to address them. From a policy perspective, this would amount to little more than endorsing PGE's failure to address its real problems.

Q. HOW CAN PGE ADDRESS ITS POWER COST VARIANCE WITHOUT A PCA?

A. The Company could address the causes of the problem. Dependence on the wholesale market could be reduced by either construction of new capacity, or acquisition of long-term contract resources. A PCA merely passes through the high costs of power purchases, and would remove most of the incentive for PGE to obtain longer-term resources.

While the Company is now completing the Port Westward facility, this will increase its reliance on natural gas. Port Westward may be considered "blessed" by the Commission's acknowledgement of PGE's IRP. While Port Westward was a "safe" resource choice for PGE because of the IRP process, it increases reliance on natural gas and the likelihood of power cost variances. Other choices, such as coal or wind power would have reduced PGE's susceptibility to gas price variations.

The lesson in this is that the Commission should be careful regarding the messages it sends the Company, as it is likely to follow them—perhaps to a fault. This will be very important for the Commission to consider when deliberating on the question of a PCA. Such mechanisms would provide substantial assurance concerning recovery of the cost of future power purchases. However, a PCA would not apply to base rate items such as construction of a new plant. As a result, we can expect that if Schedule 126 is approved, PGE would be inclined to follow the "regulatory incentive" and continue its reliance on purchased power. Schedule 126 would also insulate PGE from gas price increases and make it more likely the next major plant addition would be gas-fired. More capital intensive resources, such as coal generation, wind or other kinds of resources would not be as attractive on a relative basis.

Q. IS A PCA THE ONLY WAY TO ADDRESS POWER COST VARIABILITY DUE TO HYDRO?

A. No. Hydro hedges have been used by PacifiCorp in the past, and might be explored. PGE discarded the notion of the hydro hedge because counterparties were unwilling to accept what amounted to unlimited risks. Re PGE, OPUC Docket No. UE 165/UM 1187, PGE/900, Lobdell-Niman-Tinker/10 (Apr. 18, 2005). ICNU proposed a ratepayer backed "hydro hedge tariff" in UE 165/UM 1187 as an alternative in that case. However, the Company did not respond favorably to that option. Even after the Commission provided specific guidance in UE 165/UM 1187 directed toward improving its SD-PCAM proposal, the Company did not pursue the matter. In the end, the Company has had both market and regulatory tools potentially available to it to address hydro variations, but has not taken advantage of them. If Schedule 126 is approved, it will further reduce the incentive to minimize the impact of hydro variations because replacement costs will be largely be a "pass through" item.

Q. PLEASE SUMMARIZE THIS POINT.

A. Power cost variability is not likely to be reduced if Schedule 126 is adopted. In fact, just the opposite will likely occur, as the Company will be insulated from the risks of its decision processes. The Company will choose the path of most assured recovery, rather than the path that will minimize power cost risk, and perhaps overall costs.

Q. WOULD ADOPTION OF SCHEDULE 126 ACTUALLY REDUCE POWER COST RISKS?

A. No. Power cost risk would not vanish simply because PGE persuades the Commission to establish a PCA. Instead the risk would be transferred to ratepayers. However, ratepayers have no influence over the decisions that drive power cost variations and generally do not have access to risk management tools to mitigate such risks. PGE, on the other hand, can undertake prudent risk management strategies to manage its power cost risks. Even if PGE is not successful in its risk management, investors have the opportunity to develop a portfolio of investments to diversify their risks, thus eliminating exposure to the power cost risks of a single company such as PGE. As noted by Staff witness Mr. Maury Galbraith in UE 165, "It is much more efficient to have the financial market diversify NVPC risk, than to allocate the risk to customers and have them bear it." Re PGE, OPUC Docket No. UE 165, Staff/100, Galbraith/9 (Feb. 14, 2005).

Prudence and Risk Allocation

Q. DOES THE ADMINISTRATIVE DETERMINATION OF PRUDENCE AND OTHER REGULATORY PRACTICES ALLOCATE RISK TO UTILITIES (PGE/400, LESH-NIMAN/43)?

A. PGE provides no support for this statement, but it appears to stem from a deep mistrust (or misunderstanding) of the regulatory process. The Company apparently is suggesting that it bears a certain risk that regulators will use the prudence standard and other ratemaking practices in a punitive manner to arbitrarily invoke unwarranted disallowances. The attitude presupposes that all utility costs are reasonable and prudent, and that regulators will not be fair and objective. There is no basis for these assumptions.

Unfortunately, one of the most serious problems with the use of a PCA is that it serves to reallocate risk from utilities to consumers. Without a PCA (or without a meaningful deadband) the utility becomes indifferent to its costs, as they represent pass-through items. Customers then bear that risk of inefficient or imprudent decisions. Customers also bear the risk of gaming of accounting entries with a PCA.

Q. DO PCAS CREATE DISINCENTIVES FOR EFFICIENCY?

A. Yes. PCAs provide a utility with an incentive to purchase wholesale energy rather than increasing or even retaining investment in generation. By decreasing generation investment, return requirements decrease, thereby reducing the need for base rate increases. If there is a pass-through mechanism for fuel and purchased power, the utility may prefer to simply minimize investment and instead purchase high-cost fuel and energy in the market.

Such situations do not always arise from the decision to build new generating capacity or purchase power. In fact, many types of efficiency improvements requiring capital investment may be avoided when an automatic adjustment clause is present. The investments in question may not even involve generating capacity. Transmission upgrades might also be minimized, at the expense of higher purchased power costs, given the presence of a PCA.

A PCA also causes major differences between the revenue effects of different kinds of resources and the accounting treatment of different kinds of costs. Variable power supply expenses are passed through in the PCA, while investments are not. Without a PCA, the Company will have the incentive to minimize costs between rate cases, and would naturally select the lowest cost resources. With a PCA, the Company may have a financial incentive to select resources that are afforded full pass-through recovery, irrespective of their total cost to customers.

As just one example, consider a situation where PGE might have an unfavorable coal-supply contract or had a supplier default on a favorable contract. In both cases, the Company would likely incur legal expenses to undertake litigation with the supplier. However, legal expenses are not a pass-through while fuel and purchased power are when a PCA is used. In either case, the Company would have much less incentive to undertake the litigation necessary to obtain relief with a pass-through mechanism.[5/]

[5/] This is not purely hypothetical. I have been involved in cases where utilities requested to include legal fees in fuel cost recovery because, absent this recovery, they did not have the incentive to mount legal challenges to fuel supply contracts.

Q. CAN YOU PROVIDE MORE EXAMPLES OF HOW A PCA MIGHT DISCOURAGE PRUDENT OR EFFICIENT MANAGEMENT?

A. Yes. Currently many utilities are experiencing Powder River Basin coal delivery disruptions due to problems with the Union Pacific and Burlington Northern & Santa Fe railroads. In fact, at least 20 utilities have reported delivery problems. Obviously, an ample coal inventory is the best insurance against a supply disruption, but coal inventories are generally fixed costs included in base rates. With a PCA, however, fuel is largely a pass-through cost. Between rate cases, coal inventories are a "utility cost," but fuel and purchased power are "ratepayer costs" when a PCA is used. As a result, the utility could see an advantage in carrying a minimal coal inventory between rate cases, irrespective of the impact on total costs to customers of supply shortfalls.

Outage costs are another example. Outages can be reduced through a program of preventive maintenance and other "best practices." However, outage costs are largely a pass-through under a PCA, while the higher O&M expenses associated with reducing outages are not. Consequently, there is little incentive to incur the additional costs needed to minimize outages.

Finally, sensitivity to cost is simply not as great when costs are passed through to customers. The prices paid for purchased power become much less important to shareholders when the ratepayers are responsible for paying all or most of these costs between rate cases. The self-interest of shareholders is perhaps the greatest regulatory force of all. Regulatory lag *between* rate cases creates pressure on the part of management to minimize costs. This provides incentives to minimize outages and use the least cost power supply strategy.

Sharing Mechanism and Deadband

Q. IS PGE'S SHARING MECHANISM A SUBSTITUTE FOR A DEADBAND?

A. No. The Company proposes only a 90/10 sharing mechanism for all cost variances. It is interesting that in UE 165/UM 1187 the Company and Staff agreed to an 80/20 sharing for the SD-PCAM, which purportedly covered a narrower range of cost variations, and the Commission rejected that mechanism. However, a sharing mechanism (particularly a 90/10 sharing) does not exclude unusual events. Rather it simply assigns 90% of the cost impacts of events (whether unusual or not) to customers. This again is clearly inconsistent with Order No. 05-1261. I would ask if the Commission rejected the SD-PCAM with an asymmetric deadband and 80/20 sharing, why should it approve a mechanism which allows many additional costs with no deadband and only a 90/10 sharing?

Q. HOW DOES PGE VIEW THE ROLE OF A SHARING MECHANISM?

A. PGE contends that the role of a sharing mechanism and deadband are similar – to ease the regulatory burden of establishing prudence. PGE/400, Lesh-Niman/37. However, a sharing mechanism such as proposed by the Company should not be viewed as a substitute for a prudence determination. A deadband and sharing mechanism are tools to limit recovery to unusual events and to stimulate efficiency. Customers should not be asked to bear 90% of any imprudent cost simply as a means of simplifying the regulatory process for the benefit of PGE.

Q. HAS THE COMMISSION USED A 90/10 SHARING WITH A COMPREHENSIVE PCA IN PRIOR CASES?

A. No. To my knowledge, the only comprehensive mechanisms used in Oregon in the past were the 9 and 15 month PCAs approved in conjunction with the Stipulation in UE 115. In that case, there was a deadband of $28 million, and 50/50 sharing from $28 to $38 million. From $38 million to $100 million the sharing was 85/15. Beyond $100 million the sharing was reduced to 90/10 or 95/5 depending on the level of the variance. Re PGE, OPUC Docket No. UE 115, Order No. 01-777, Appendix D at 19 (Aug. 31, 2001). However, the UE 115 PCA was a stipulated mechanism, and the Commission's approval of that mechanism does not represent a precedent.

In Docket No. UM 995 (PacifiCorp excess power costs), the Commission adopted a 250 basis point deadband and 50/50 sharing from 250 to 400 basis points for the deferred account approved in that case. Order No. 01-420 at 6-9. Above 400 basis points the sharing was 75/25. Id. at 29. While UM 995 was not a PCA case, it did deal with a comprehensive power cost deferral mechanism, and it probably best represents the type of sharing the Commission would consider appropriate for a comprehensive PCA.

Q. PGE INDICATES THAT IT SELECTED THE 90/10 SHARING USED IN ARIZONA AND IDAHO, AND PROPOSED FOR AVISTA IN WASHINGTON. ON PAGES 37-39 OF PGE/400 THE COMPANY DISCUSSES A NUMBER OF SHARING MECHANISMS. PLEASE COMMENT.

A. It appears that in Arizona and Idaho, a 90/10 sharing is used as the Company suggests. However, a number of the examples the Company cites used 50/50 sharing (the Colorado example, which also included a deadband), 80/20 or even

67/33 (the Purchased Gas adjustment examples.) Further, in one of the PCAs referenced (Avista), PGE cites a 90/10 sharing.

In Washington, Avista recently agreed to and the Washington Utilities and Transportation Commission approved a new sharing and deadband mechanism. Re Avista, WUTC Docket No. UE-060181, Order No. 3 at ¶ 1 (June 16, 2006). The new mechanism will have a $4 million deadband, 50/50 sharing from $4 to $10 million and 90/10 sharing above $10 million. Id. Further, Puget Sound Energy in Washington also has a PCA with a $20 million deadband and sharing mechanism, and has sharing bands starting at 50/50. Consequently, the evidence provided by the Company regarding practices in other states is not particularly persuasive as regards PGE's recommended sharing bands.

Q. IS IT POSSIBLE TO MAKE INFERENCES ABOUT THE SIZE OF DEADBANDS OR SHARING BANDS FROM ONE STATE TO THE NEXT?

A. No. The size and the nature of the utility have a substantial bearing on the size of the deadband. Avista's $4 million deadband in Washington is not comparable to a $4 million deadband for PGE in Oregon, for example. Avista has net power costs of less than $125 million, while PGE's requested power costs in this case are approximately $857 million. As a result, a $4 million deadband for Avista is comparable to approximately $27 million for PGE. The 50/50 sharing band used for Avista in Washington would be comparable to nearly $70 million for PGE.

Q. ON PAGE 40 OF PGE/400, THE COMPANY ASSERTS THAT OREGON HAS NEVER USED A DEADBAND IN AN AUTOMATIC ADJUSTMENT CLAUSE, OTHER THAN THE STIPULATED PCA FROM UE 115. PLEASE COMMENT.

A. It is also true that other than the UE 115 PCA, the Commission has never approved of a comprehensive PCA for PGE. That PCA did contain a deadband, but because it was the result of a stipulation, it is not indicative of Commission precedent. It would be safe to say that PGE's proposal to implement a comprehensive PCA without any deadband is unprecedented, and most certainly contrary to the standards established in Order No. 05-1261, as discussed above.

Q. COMMENT ON THE ARGUMENT THAT DEADBANDS DO NOT WORK WELL WITH THE OUTAGE RATE METHODOLOGY.

A. This argument is found on page 43 of PGE/400. The Company is suggesting that use of a deadband interferes with application of the rolling average methodology because it absorbs some of the costs that would otherwise be allocated to either the Company or customers. The Company has also raised the concern that the impact of the recent Boardman outage within the context of the 48-month rolling average methodology will be problematic because the unit's reliability will likely be better than the rolling average, thus creating downward pressures on actual net power costs.

These issues illustrate a defect with the use of the 48-month rolling average methodology, which I will address in my power cost testimony. Suffice it to say at this point, that it provides more of a reason to decouple normalized power costs from the operational history of generators, rather than to adopt a PCA.

Q. DOES A DEADBAND IMPLY THAT A UTILITY'S EARNINGS MUST BE PUT AT RISK FOR COSTS OVER WHICH IT HAS NO CONTROL?

A. No. PGE makes this argument in PGE/400 on page 43, and the Company's assertion misses the entire point of utility regulation. Regulation is not intended to provide a guarantee of earnings. It merely provides an opportunity to obtain allowed earnings. PGE would prefer a scheme where it establishes base rates using forward looking costs, (substantially reducing the risk of regulatory lag), then the Company would reach back to historical costs to provide even greater assurance that rates will produce the allowed earnings levels. I fear this is a slippery slope that leads to a complete "cost plus" paradigm. Unless PGE is allowed an "all cost" PCA, it will always be able complain of costs that are "beyond its control." Use of a PCA will entrench the mentality that costs are beyond control, and result in the Company doing less about controlling costs in the long run.

<u>Prudence Review and Procedural Issues</u>

Q. DOES THE OPPORTUNITY TO CONDUCT AN AUDIT AND PRUDENCE REVIEW AFTER THE PCA DEFERRALS ARE RECORDED PROVIDE AN EFFICIENT TOOL FOR PROTECTING RATEPAYERS?

A. No. A prudence review is a necessary component of authorizing a utility to include any costs in rates. However, an after-the-fact audit and prudence review of power costs recorded under Schedule 126 is unlikely to effectively ensure that customers do not pay for costs that are imprudent or otherwise inappropriate for recovery, particularly considering the procedural schedules envisioned by the Company. A retrospective review of the costs that PGE incurred in response to the various factors that may affect the Company's power costs is a complex and administratively burdensome task. In a recent Washington case, a WUTC Staff witness, James Russell, testified that an after-the-fact review of deferred costs "shifts the burden of proof from the utility to the Commission and its Staff to find the excessive or imprudent dollars in multi-year deferrals versus the utility having to justify a normal level of expenses in a rate case." Re PSE, WUTC Docket Nos. UE-040641, 040640, Exh. No. 421 at 22:7-11 (Russell Direct) (Sept. 23, 2004). Given the complexity associated with such a review, it is simply not as efficient or effective a means of protecting ratepayer interests.

Q. PGE PROPOSES TO ALLOW A PRUDENCE REVIEW TO BE CONDUCTED DURING ITS ANNUAL VARIANCE PROCEEDING. DOES THIS RESOLVE THE ISSUE?

A. Hardly. PGE proposes to conduct its Annual Variance proceeding in a six month period, starting on July 1. Working "backwards" to develop a schedule, one can see what an unreasonable proposal this is. Below is what a typical schedule might look like for this annual review process:

December 21 – Commission Decision
November 21 – ALJ's proposed decision
October 21 – Briefs Filed
October 1 - Hearing
September 15 - PGE Rebuttal
August 21 – Staff and Intervenor Testimony
August 7 – Settlement Meeting
July 1 – Filing date

In other words, with PGE's proposed filing dates, parties would likely have about 7 weeks to analyze the case, prepare discovery and prepare testimony. Because of Oregon's tradition of scheduling settlement meetings before filing of testimony (rather than after which is the norm in most states) the most significant analysis would need to be completed about five weeks after the filing. Given that it would probably consume at least 3 weeks for initial discovery to be prepared and answered, this schedule would really allow about two weeks for the "prudence review" and perhaps two rounds of discovery, at most. While this proposal would obviously be appealing to PGE (which as discussed above views regulation as punitive and arbitrary), it does not bode well for consumers.

Q. WOULD PGE'S ANNUAL VARIANCE PROCEEDING PROTECT RATEPAYERS AGAINST GAMING OF ACCOUNTING ENTRIES TO MAXIMIZE ITS REVENUES?

A. No. PGE'S proposal does not provide for specific rules or minimum filing requirements to govern the process of reviewing accounting entries under the Annual Variance Tariff or the amounts deferred.

Q. COULD YOU CHARACTERIZE THESE ADDITIONAL PROBLEMS INHERENT IN THE PGE PROPOSAL AS ADDITIONAL RISK FACTORS FOR CUSTOMERS?

A. Yes. While PGE characterizes the Annual Variance tariff as reducing risk for the Company, in reality, it increases the overall level of risk borne by customers. Not only would customers face risk of power cost variations, but they would also face risks "induced" by the presence of Schedule 126 related to inefficient management and the gaming of accounting entries. While I do not assume that regulators will be unfair or biased, good decisions cannot be made without good information. The process envisioned by PGE would make it very difficult, if not impossible for the requisite amount of "good information" to be developed.

<u>National Economic Research Associates ("NERA") Study</u>

Q. DOES THE NERA STUDY PROVIDE COMPELLING SUPPORT FOR ADOPTION OF THE ANNUAL VARIANCE TARIFF?

A. No. It would be very difficult to actually verify NERA's findings. However, PGE has already identified situations where it believes the NERA report is in error.[6/] Based on my review, the NERA report presents inaccurate data regarding practices in Georgia and Texas.[7/]

NERA reports Georgia has only a three-month time lag for recovery of fuel costs. PGE/401, Lesh-Niman/21. In reality, Georgia has no definite time limit for fuel cost recovery and currently is amortizing deferral balances over a period of four years.

Texas is considered "not relevant" by NERA, presumably because the state is shown as transitioning to restructuring. PGE/401, Lesh-Niman/23, 18. Actually, regulatory practice in Texas is highly relevant to this case. While some utilities in Texas have deregulated electric rates (without a traditional PCA), others still have traditional rate regulation. Consequently, Texas should have been shown as a "utility by utility" state. Utilities that still have regulated rates use a "traditional PCA" along with a highly detailed "fuel rule" and very detailed minimum filing requirements. In Texas, fuel "reconciliation proceedings" are quite lengthy and complex. They often feature twenty or more rounds of discovery, and no definite procedural schedule is required. Oregon should

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6/ For example, PGE identified NERA's description of the Cheyenne Light, Fuel and Power mechanism and the use of a deadband in Kansas. PGE/400, Lesh-Niman/42.

7/ I have recently participated in a Fuel Cost Recovery audit for Georgia Power and Savannah Electric, and am currently conducting a power supply cost investigation for the Georgia PSC staff.

consider whether it wants to engage in this level of regulatory activity before adopting Schedule 126. However, the Texas model is quite valid if the Commission intends to provide a legitimate opportunity for parties to determine the prudence, necessity and reasonableness of costs included in the Annual Variance tariff.

Based on this limited analysis, the NERA report does not appear to be very accurate or illuminating. In the end, the OPUC should be consistent with its own history of regulatory practices and prior decisions, and not follow the lead of other states.

Price Finality

Q. ARE THERE OTHER PROBLEMS WITH THE PCA CONCEPT?

A. A PCA would violate the principle of price finality because customers would not know the actual price of consumption until long after the fact. In Docket No. UE 113, Ms. Lesh testified that PGE disliked true-up mechanisms because, it reduced incentives for management and the concept of rate finality is violated:

> Philosophically, we dislike the idea of a true-up. Even with use of variance sharing, the true-up weakens the utility's incentives to manage its business and it seriously detracts from the value customers receive in knowing that the price they pay for electricity used today is the actual price. Few people would be willing to buy an airline ticket if, several weeks after the flight, the airline could send another bill - or a refund check for that matter - based on the final count of seats taken in the plane or some such set of actual inputs. People generally like price certainty. *Until our customers have a choice of products, we would prefer not to require all to choose an electricity product that does not include price finality as a feature.*

Re PGE, OPUC Docket No. UE 113, PGE/100, Pollock-Lesh/13 (Aug. 16, 2000) (emphasis added). This testimony also shows how inconsistent PGE has been regarding true up mechanisms in the past.

Schedule 126 Load Adjustment

Q. DISCUSS THE SCHEDULE 126 LOAD ADJUSTMENT.

A. The Company proposes to make an adjustment to reduce the power cost variance for the effects of changes in loads. PGE contends that this approach will reward customers appropriately for reducing loads during power shortages PGE/400, Lesh-Niman/36. However, the Company proposes to compute the load adjustment by pricing out the difference between actual and forecasted loads at the forecast average unit cost of power.

Q. IS THIS A REASONABLE APPROACH?

A. No. It effectively assumes that additional kWhs can be purchased or sold at the forecasted average unit variable cost of power. This is a composite of the cost per kWh or hydro, coal, gas and purchased power. In proposing this mechanism, the Company really assumes that if sales exceed forecast, it can buy some of the additional power needed at zero cost (the cost of hydro) and some at a very low cost (the cost of coal). Likewise, the Company assumes that when sales are below forecast, it will simply generate less from its coal and hydro plants (or sell those resources at cost) to dispose of the surplus.

This results in use of a measure of incremental cost that is substantially below the market prices of power. As a result, the Company greatly mutes the impact of load changes on power cost variances overstating the impact of other causes.

Q. ARE YOU SUGGESTING THAT LOAD SHOULD NOT BE EXCLUDED FROM SCHEDULE 126?

A. No. If Schedule 126 is adopted, which I do not recommend, it should price load variations out based on the forecast forward curve prices used in Monet.

<u>Schedule 125 Issues</u>

Q. DOES PGE NEED BOTH SCHEDULE 125 AND 126?

A. No. There is certainly no necessity for having both Schedule 125 and 126. Schedule 125 provides a means of updating power cost estimates, while Schedule 126 would true up those estimates. Both tariffs are directed to the same end, that of reducing or eliminating power cost variances, but there is no reason both are required.

Schedule 125 would update nearly all important cost drivers, including fuel prices, loads, purchased power expenses, and potentially capacity resources. Current forward curves would be applied as late as November of each year. Given this, most of the power supply costs of PGE would be "pass through" items. This eliminates much of the concern that long-term cost changes between general rate cases would result in large and growing power cost variances.

Q. WHAT COST ELEMENTS ARE MOST LIKELY TO CAUSE POWER COST VARIANCES IF SCHEDULE 125 IS APPROVED?

A. In prior cases, PGE identified load variations and hydro as two of the most significant cost elements responsible for power cost variances. PGE agrees that it is not appropriate to include load variation in the Annual Variance tariff, and the

Commission has already accepted the view that hydro variations are a "stochastic" event. This suggests that a true up for such cost variances is only appropriate in unusual circumstances. This undermines a substantial basis for adoption of Schedule 126.

Q. IS SCHEDULE 125 NEEDED IF SCHEDULE 126 IS ADOPTED?

A. No. By having both, in theory the Company will greatly reduce the impact of power cost variances on PGE. This would potentially undermine the efficiency promoting benefits of any deadband and sharing mechanism the Commission might adopt. If Schedule 126 is adopted, the Company will always be able to true up its costs to the level approved in the last rate case. There is no need to update that level each year.

Q. DOES PGE PROPOSE TO REFLECT CAPACITY UPGRADES OR EFFICIENCY IMPROVEMENTS IN SCHEDULE 125?

A. No. PGE/400, Lesh-Niman/29. While PGE makes a vague suggestion it will discuss options, it does not propose to reflect these items in rates. This is not a reasonable approach, assuming Schedule 125 is adopted. Base rates generally contain allowances for capital improvements and maintenance spending on power plants. Once completed, expenditures for such projects are finished, but new projects generally take their place. Further, as load grows margins increase, providing the Company additional funds for plant improvements and even new capacity resources. Simply because a Company has not had a rate case in a few years, does not mean customers are not paying continuously for plant improvements. If Schedule 125 is to have value for reducing power cost variances, it should reflect the best estimate of system costs.

Q. SHOULD THE COMMISSION ADOPT SCHEDULE 125 OR RETAIN THE RVM?

A. No. Irrespective of the decision regarding Schedule 126, the need for Schedule 125 is questionable. PGE proposes that Schedule 125 replace the RVM process; however, there is no need to link the transition adjustment to an annual update of power costs for all customers. The most significant power cost drivers are load and hydro variations. Because load adds revenue as well as cost, it should not be reflected in a power cost update outside of a full rate case. Hydro is a stochastic variable and expected hydro levels do not change so quickly over time that they could not be addressed in a general rate case setting.

ICNU recommends terminating the RVM without adopting Schedule 125 to replace it. The original RVM was adopted as part of a settlement of power cost issues in UE 115. Without unanimous support from the parties that signed the stipulation in UE 115, the Commission should not renew the RVM. Since approval of the RVM, there has been substantial controversy in the RVM cases, and it has added to the regulatory burden of the parties. In some cases, there were disputes about the proper scope of the RVM or problems arose because the Company entered into controversial contracts very late in the year. In these situations, the Company sought the benefits of a full blown rate case to implement modeling changes or include new contracts, but the time for review of the associated costs was severely limited. While the RVM arguably helps to address power cost variances, like a PCA, it shifts the risk of those variances between rate cases from the Company to customers. Customers are not able to manage power cost risk with the same degree of effectiveness as the Company. The Company has hedging tools available to it to address such risks, while ratepayers do not. As a result, it makes more sense to delegate dealing with these issues to PGE's management rather than to ratepayers. In the end, many of the arguments against a PCA apply to the RVM as well. The Commission should put an end to this experiment and allow PGE to update power costs only when it files a general rate case.

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/104

CALCULATION OF EXTRINSIC VALUE

CONFIDENTIAL

SUBJECT TO GENERAL PROTECTIVE ORDER

August 9, 2006

ICNU/104

<u>CONFIDENTIAL</u>

SUBJECT TO GENERAL PROTECTIVE ORDER

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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In the Matter of

PORTLAND GENERAL ELECTRIC COMPANY

Request for a General Rate Revision relating to the Port Westward plant (UE 184).

ICNU/105

COMPARISON OF PGE AND NERC FORCED OUTAGE RATES

CONFIDENTIAL

SUBJECT TO GENERAL PROTECTIVE ORDER

August 9, 2006

ICNU/105

CONFIDENTIAL

SUBJECT TO GENERAL PROTECTIVE ORDER

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/106

COMPUTATION OF STOCHASTIC REVENUE FOR BOARDMAN

CONFIDENTIAL

SUBJECT TO GENERAL PROTECTIVE ORDER

August 9, 2006

ICNU/106

<u>CONFIDENTIAL</u>

SUBJECT TO GENERAL PROTECTIVE ORDER

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/107

LETTERS REGARDING PGE NOVEMBER 2004 RVM UPDATE

August 9, 2006

HARDY MYERS
Attorney General

PETER SHEPHERD
Deputy Attorney General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

November 5, 2004

TRACI KIRKPATRICK
ADMINISTRATIVE LAW JUDGE
OREGON PUBLIC UTILITY COMMISSION
550 CAPITOL STREET, N.E., SUITE 215
P.O. BOX 2148
SALEM, OR 97308-2148

RE: RATEMAKING TREATMENT OF CAPACITY TOLLING AGREEMENTS IN PORTLAND GENERAL ELECTRIC'S 2005 RESOURCE VALUATION MECHANISM (DOCKET UE 161)

Dear Judge Kirkpatrick:

On November 3, 2004, Portland General Electric (PGE) filed a draft MONET run in Docket UE 161. Staff has reviewed the updates made in the November 3rd draft MONET run and has identified the ratemaking treatment of capacity tolling agreements as an issue to bring to your attention. Because of Staff's concerns we request a pre-hearing conference be scheduled next week to further discuss this issue.

As PGE indicated in its cover letter accompanying the November 3rd draft MONET run, the company recently signed two new capacity contracts pursuant to its 2002 Integrated Resource Plan and the associated Request for Proposals. Both of these capacity contracts have delivery periods in 2005 and future years. As a result, PGE has modeled the dispatch of these contracts in the November 3rd draft MONET run.

The cost for each of these contracts is comprised of a capacity charge and an energy charge. PGE pays the capacity charge on a monthly basis whether or not it actually schedules any delivery of energy. For calendar year 2005, PGE estimates that the capacity payments for these two contracts will total $2.174 million. PGE pays the energy charge on a monthly basis for each megawatt-hour (MWh) of delivered energy. Based on its MONET modeling of the dispatch of these contracts, PGE estimates for ratemaking purposes, that it will not dispatch (i.e., not actually use) these contracts in 2005. Therefore, for calendar year 2005 the energy payments for these two contracts are estimated to be zero dollars. Consequently, the total cost of these two contracts that PGE has included in the 2005 RVM is $2.174 million.

The benefit of these contracts is comprised of the company's ability to reduce net variable power costs when market prices of electricity and natural gas make the dispatch of these contracts profitable. Both of these capacity tolling agreements have terms and conditions that suggest that economic dispatch will only occur during periods where the spread between market electricity prices and natural gas prices is extreme. The company, however, models net variable power costs in the MONET model on an expected price basis. Under normal, or expected, price conditions the likelihood that these capacity contracts will be economic to dispatch is low – hence in MONET energy payments modeled to be zero dollars in 2005. The uncertainty surrounding the dispatch of these capacity contracts complicates their treatment in PGE's rates.

Staff believes that the ratemaking treatment implied in PGE's November 3rd draft MONET run creates a significant mismatch between ratepayer costs and benefits. For 2005, PGE is asking its customers to pay $2.174 million in costs. In exchange, because rates are set on an expected price basis, the only benefit that customers could possibly receive is if an extreme price event occurs and the company or an intervening party anticipates the event and files an application for a power cost deferral. Absent that unlikely situation, the benefits of these capacity tolling agreements fall entirely to PGE's shareholders, despite the $2.174 million included in customers' rates.

Permanent remedies to this mismatch of ratepayer costs and benefits include: (1) Abandoning expected price modeling in MONET and implementing expected net variable power cost modeling, or (2) Establishing a permanent power cost adjustment mechanism that appropriately matches costs and benefits on a long-run basis. The first alternative involves an enhancement to MONET. Implementing this alternative in the 2006 RVM would require the consent of PGE, Staff, the Citizens' Utility Board, and the Industrial Customer's of Northwest Utilities (see Order 03-535 adopting stipulations in Docket UE 149) and significant analytical work. The second alternative is being considered in Docket UE 165.

To remedy this mismatch in the 2005 RVM, Staff recommends that the Commission remove the $2.174 million in capacity payments from PGE's net variable power costs. Under this approach, shareholders would bear all of the costs and receive all of the benefits of these contracts during 2005. This has the effect of matching the 2005 costs and benefits. It also reflects the fact PGE has traditionally borne the risk of extreme price events between rate cases. Staff is willing to consider other remedies that PGE or intervenors may propose.

As you know, PGE files its final MONET run on November 10, 2004. We request a pre-hearing conference next week to further discuss this issue.

Sincerely,

David B. Hatton
Assistant Attorney General
Regulated Utility & Business Section

DBH:nal/GENK7978.DOC

cc: UE 161 Service List

PGE

Portland General Electric Company
Legal Department
121 SW Salmon Street • Portland, Oregon 97204
(503) 464-8926 • facsimile (503) 464-2200

Douglas C. Tingey
Assistant General Counsel

November 9, 2004

Traci Kirkpatrick
Administrative Law Judge
Oregon Public Utility Commission
P.O. Box 2148
Salem OR 97308-2148

Re: Docket No. UE 161 – Portland General Electric's 2005 Resource Valuation Mechanism

Dear Judge Kirkpatrick:

On November 5, 2004, counsel for Oregon Public Utility Commission Staff ("Staff") sent you a letter attempting to raise an issue regarding the ratemaking treatment of two capacity tolling agreements. That letter argued Staff's position on the issue, and this letter is sent to respond to that argument. In sum, as set forth below, Staff's letter is ill-timed and founded on a misunderstanding of capacity agreements and their Commission-approved ratemaking. Portland General Electric Company ("PGE") requests that Staff's request be summarily denied.

Capacity contracts have been included in every RVM proceeding. The Resource Valuation Mechanism ("RVM") was created and adopted by the Commission as part of a PGE general rate case, Docket No. UE 115, in 2001. At that time, as part of the implementation of Senate Bill 1149, the Oregon Public Utility Commission ("Commission") adopted the RVM proceeding to annually value and reset net variable power costs and determine the amount of any credit or charge for those customers opting for direct access. In creating the RVM process, PGE's costs were divided into two groups – net variable power costs that were included in the RVM update process, and fixed costs not included in the RVM process. PGE's power costs included two capacity contracts, one entered into in 1992 with Washington Water Power, and one entered into in 1995 with EWEB. Both of those capacity contracts were included in the RVM net variable power costs for ratemaking. Those capacity contracts were also included in RVM net variable power costs in the 2003 RVM proceeding (UE 139) and the 2004 RVM proceeding (UE 149). They are also included in net variable power costs in this 2005 RVM proceeding, and Staff has stipulated that the costs were proper and should be included in rates. Contrary to Staff's assertion, there is no issue as to the ratemaking treatment of capacity agreements in RVM proceedings.

The capacity contracts were entered into as part of the IRP process. In LC 33, the recently concluded PGE least cost planning docket, PGE's Integrated Resource Plan ("IRP") was subjected to intense scrutiny and numerous revisions over a two-plus year period. The need for capacity was included in that discussion starting with the August 2002 IRP filing. On July 20, 2004, the Commission issued an Order acknowledging PGE's Integrated Resource Final Action Plan. Ten action items were specifically acknowledged, including the following:

> 5. Acquire up to 50 MWa of baseload energy tolling in place of fixed price PPAs if required, *and 400 MW of tolling capability for peak purposes.* (Emphasis added.)

As part of the least cost planning procedure, PGE had issued a Request for Proposals ("RFP") seeking capacity tolling agreements. Staff was involved in and familiar with the results of that RFP. Consistent with the Commission's acknowledgment in LC 33, PGE entered into the two capacity tolling agreements that Staff questions here.

The two contracts are for a total of 400 MW, as called for by the acknowledged IRP. PGE has done exactly what its Commission-acknowledged least cost plan directed. The Commission itself said, in the LC 33 order that: "In ratemaking proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions that are consistent with acknowledged least-cost plans."

PGE acted timely and consistently with the Commission acknowledged Least Cost Plan, acquired these capacity resources in the manner directed by that plan, and included them in RVM net variable power costs like other capacity contracts. Notwithstanding this, Staff has asked the Commission to deny cost recovery for these contracts. Such a result would not be proper, fair, just or reasonable, or promote confidence in the regulatory process.

<u>Capacity contracts are for reliability.</u> Staff misconstrues or misunderstands the function and purpose of capacity agreements. PGE and other utilities enter into capacity agreements so they can reliably provide power to customers. Capacity contracts provide the right for the utility to receive, when needed, energy up to a specified amount. In those hours or days when there may not be sufficient resources in the region to meet all demands, having the ability to draw on capacity contracts helps to keep the lights on for PGE customers, even if there are blackouts elsewhere in the region due to insufficient energy. That is the reason PGE enters into capacity contracts.

Staff's theory that capacity contracts are for shareholder benefit is incorrect. They are for customer benefit in the form of reliable electric service. PGE customers expect, and deserve, reliable service, including during those times when energy resources may be short in the region. Capacity contracts are one necessary component of providing reliable service to customers. The costs of those capacity contracts are properly included in net variable power costs in the RVM, as they have been since the creation of the RVM process.

<u>Staff's proposed remedy is inconsistent with its Stipulation in UE 149.</u> In UE 149, PGE's 2004 RVM proceeding, all parties entered into a Stipulation settling all issues in the docket. That Stipulation was adopted and approved by the Commission in Order No. 03-535, issued August 29, 2003. In that Stipulation the parties agreed that, other than specifically identified enhancements, no party "will propose in the 2005 or 2006 RVM proceeding any enhancements to the Monet model used in the Final RVM Filing, unless the Monet model is modified through a general rate case or by the unanimous agreement of the Parties." In its letter Staff posits that one remedy to its perceived problem would be implementing expected net variable power cost modeling, an enhancement to Monet. Staff recognizes that implementing that change in this docket or in the 2006 RVM proceeding would require the consent of PGE, Staff, the Citizens' Utility Board, and the Industrial Customers of Northwest Utilities. Yet, Staff is attempting to indirectly and partially do what it has agreed not to do directly. Staff's real issue seems to be that they do not like the way capacity contracts are modeled by Monet. Staff's request is a backdoor attempt to undo the Stipulation in UE 149 and that request is inappropriate.

Conclusion. Staff has attempted, in the eleventh hour of this docket, to raise an issue that is well settled – the ratemaking treatment of capacity contracts. Capacity contracts have been included in net variable power costs since the RVM process was created. Staff's request is based on an erroneous view of the nature and purpose of capacity contracts. Staff's request is also inconsistent with its Stipulation in UE 149. These capacity contracts were entered into in conjunction with PGE's Least Cost Plan as acknowledged by the Commission. They are properly included in net variable power costs in this RVM.

The final RVM filing in this docket will be made very soon. From that filing customer rates will be set for next year, and the size of the credit for customers choosing direct access will be determined and posted on PGE's website on November 15, 2004. That process should not be stalled, or made uncertain, because of this last minute filing by Staff. Staff's request should be summarily denied. If, however, the Commission determines that further proceedings are necessary, PGE requests that a hearing be set, with the Commissioners present, the week of November 22, 2004, so that an order can be issued as soon thereafter as possible.

Sincerely,

DCT:am

cc: UE 161 Service List

ISSUED: November 16, 2004

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 161

In the Matter of	)	
	)	
PORTLAND GENERAL ELECTRIC COMPANY	)	PREHEARING CONFERENCE MEMORANDUM
	)	
Adjustments to Schedule 125 (2005 RVM Filing).	)	

On November 5, 2004, Public Utility Commission of Oregon (Commission) Staff (Staff) requested a prehearing conference to discuss concerns about the ratemaking treatment of capacity tolling agreements raised upon review of Portland General Electric's (PGE) draft MONET run November 3, 2004. As PGE was scheduled to file a final MONET run on November 10, 2004, Staff requested that a prehearing conference be held as soon as possible. PGE filed a letter on November 9, 2004, opposing Staff's request for an investigation of capacity tolling agreement ratemaking.

On November 10, 2004, a prehearing conference was held in Salem, Oregon. Appearances were entered as follows: David B. Hatton, attorney, appeared on behalf of Commission Staff; Doug Tingey, attorney, appeared on behalf of Portland General Electric Company (PGE); Matthew Perkins, attorney, appeared by telephone on behalf of the Industrial Customers of Northwest Utilities (ICNU); Brad Van Cleve, attorney, also appeared by telephone on behalf of ICNU; and Bob Jenks, attorney, appeared by telephone on behalf of Citizens' Utility Board of Oregon (CUB).

After preliminary matters were addressed, conference participants went off the record to discuss how to proceed. Back on the record, Mr. Hatton represented that the conference participants agreed that no further action by the Commission was necessary in this docket and that the final MONET run would be filed as scheduled. Instead, parties agreed to work informally outside of a contested case proceeding to draft language regarding the modeling of capacity tolling agreements, with the intent to present such language in PGE's next general rate case filing. Should efforts be unsuccessful, however, Staff indicated it would consider filing a deferred accounting request with the Commission, prior to the end of this year, to address the capacity tolling agreements at issue for 2005.

Dated this 16th day of November, 2004, at Salem, Oregon.

Traci A. G. Kirkpatrick
Administrative Law Judge