UM-1187 / PGE EXHIBIT / 100
DAHLGREN - TINKER

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Hydro Generation Variance
UM-1187

PORTLAND GENERAL ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBITS OF

Randy J. Dahlgren
Jay J. Tinker

April 18, 2005

I. Introduction

Q. Please state your names and positions with PGE.

A. My name is Randy Dahlgren. I am Director of Regulatory Policy and Affairs. My qualifications appear in Section IV of this testimony.

My name is Jay Tinker. I am a project manager in the Rates and Regulatory Affairs Department. My qualifications appear in Section IV of this testimony.

Q. What is the purpose of your testimony?

A. In Section II of our testimony, we discuss recent PGE hydro deferral applications. In Section III of our testimony, we do the following:

- We describe lower than expected water flows and hydro production, both for 2005 and over the past several years.
- We describe the financial impacts of these poor hydro conditions on PGE.
- We discuss the System Dispatch Power Cost Adjustment Mechanism stipulated to by OPUC Staff and PGE for the 2005-2006 period.

II. Requirements of Order No. 04-108

Q. Please describe the Commission's Order No. 04-108.

A. Order No. 04-108 came in docket UM 1071, which concerned PGE's request to defer hydro replacement costs in 2003.

Q. What did the Commission find in this docket?

A. The Commission denied PGE's request to defer 2003 hydro replacement costs.

Q. What was the basis of the Commission's decision?

A. Briefly, the Commission found that hydro variability is a "stochastic risk," and as such, a showing of "substantial" financial impact is necessary to justify a deferral of excess costs. The Commission then found that the hydro conditions in 2003 did not produce a substantial financial impact.

Q. Do you agree with the representation that hydro variability is "stochastic"?

A. No. Even if we assume that the river flow data used to set rates are an accurate representation of our expected future, we don't have good information on the relationship between hydro conditions and market power prices. Without such a relationship, we can't say whether the deviations in the cost element we are actually trying to estimate (net variable power costs or NVPC) are stochastic. However, this is not an issue that the Commission needs to address in this docket. We believe that the current hydro conditions coupled with our hydro experience over the past several years makes the stochastic issue irrelevant. We explain our rationale in the following section.

III. Current Hydro Expectations

Q. Please describe PGE's current expectations of hydro availability in 2005.

A. As the Commission was informed at its April 5, 2005 Public Meeting, the Pacific Northwest is experiencing one of its worst water years on record. The Bonneville Power Administration has indicated that this is the sixth winter in a row of low precipitation and the "lowest cumulative runoff on record."[1] The Northwest River Forecast Center, as of April 8, 2005, currently forecasts the flow of the Columbia River at The Dalles to be 65% of average for the April through September 2005 period. Flows for the rivers serving our major hydro facilities and contracts are forecast, as of April 8, 2005, as follows:

Table 1

River Flows	% of Average
Columbia River at Grand Coulee	79% (April-Sept)
Deschutes at Benham Falls	73% (April-Sept)
Clackamas at Estacada	57% (April-Sept)

Overall, we expect that PGE's hydro generation from its facilities and long-term contracts to be about 88% of the average amount of generation used to establish rates for 2005. In other words, this is a shortfall of more than 568,000 MWhs.

Q. What is the estimated financial impact of this shortfall on PGE?

A. There are a numbers of ways to estimate this financial impact. Probably the most straightforward is to apply market prices to the "lost" kWhs. Doing so for 2005 yields an estimated increase in power costs of almost $30 million. This calculation uses actual prices through March, then the March 31, 2005 forward curve values for the remaining months.

Q. Please put this impact in perspective compared to PGE's earning power.

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[1] Joint press release of Bonneville Power Administration, Citizens Utility Board of Oregon, Clark Public Utilities, Northwest Energy Efficiency Alliance, Northwest Power and Conservation Council, PacifiCorp, Portland General Electric, Public Power Council, and Puget Sound Energy dated March 24, 2005.

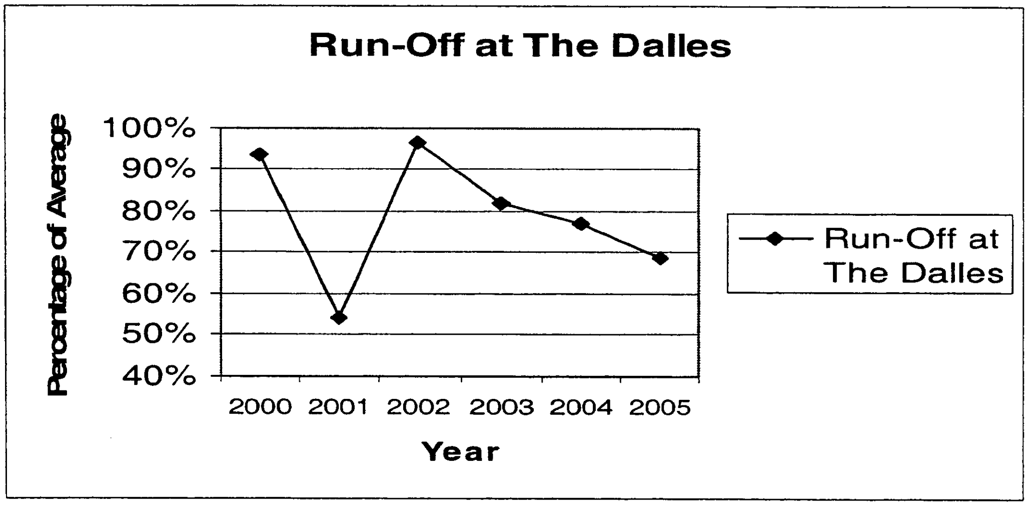
A. On a total company basis, $30 million represents 197 basis points (BP). Looking at generation investment, it is 558 BP. And focusing on hydro investment, it is 2830 BP. Since our allowed return on equity is 10.5% or 1050 BP, this means earnings decreases of about 19, 53, and 270 percent on total, generating plant, and hydro plant investment bases respectively.

Q. Putting aside for the moment PGE's arguments that hydro variability is not stochastic, is it reasonable for the Commission to allow recovery of PGE's 2005 hydro replacement power costs?

A. Yes, even if the Commission finds that the "substantial" financial impact standard is appropriate for hydro variability, recovery of 2005 replacement power costs should be allowed.

Q. Please explain.

A. While one can certainly argue that the current estimate of $30 million is substantial, its impact is heightened by hydro availability of the recent past. As we discussed above, PGE, and other Northwest utilities, have experienced lower than expected hydro availability over the past six years (including 2005). The following graph displays run-off at The Dalles (from January through July) as a percentage of the 1971-2000 average over the past six years.



The figure for 2005 is an April 8, 2005 estimate. Even during the relatively "good" year of 2002, run-off at The Dalles was only 97 percent of the 1971-2000 average. Run-off for the composite 2000-2001-2003-2004 period was only about 77 percent of the 1971-2000 average, and 2005 run-off is currently forecast to be only 69 percent of average.

The financial impact of these poor hydro years on PGE has been very substantial, approximately $21 million in each of 2003 and 2004, years in which PGE had no power cost adjustment mechanism (PCA) in place. As we stated above, the current estimate for 2005 is approximately $30 million, making a total of $72 million for the three-year period 2003-2005. We discuss years in which PGE had PCAs below.

Q. This deferral request is for 2005 only. Why are you including a discussion of prior years?

A. In Order No. 04-108, the Commission distinguished an Idaho Power deferred accounting request as related to a multiyear drought that Idaho Power had endured. This was a "deciding factor" in the decisions that allowed partial recovery of hydro replacement costs in UM 480 and UM 673.

Q. But didn't PGE have power cost adjustments during part of this time?

A. Yes, PGE had two different PCAs during 2001 and 2002. The first covered the period January 1, 2001 through September 30, 2001. The second was for the period October 1, 2001 through December 31, 2002. These PCAs had significant deadbands and then "sharing bands" that started at 50/50. Using the mechanisms contained in these adjustments (which addressed total power costs rather than just hydro replacement costs), PGE absorbed approximately $99 million in power cost variances over these two years, $54 million related to the first nine months, and $45 million related to the last 15 months.

Q. In its deferral application in this docket, PGE requested a particular methodology to calculate the deferral amount. Has the proposed methodology changed?

A. Yes, on April 11, 2005, PGE entered into a stipulation with OPUC Staff that describes the methodology that we agree should be used in this proceeding. PGE and Staff have filed joint testimony in this docket and in UE 165 (Staff-PGE Exhibit 100) that describes this stipulation. In addition, PGE and Staff separately filed rebuttal testimonies in UE 165 that provide support for the stipulation. A copy of PGE's rebuttal testimony is provided as PGE Exhibit 101.

Q. What is the estimated recovery of replacement power costs under the stipulated mechanism?

A. The mechanism, called the System Dispatch Power Cost Adjustment Mechanism (SD-PCAM), considers not only the value of deviations in PGE's hydro production from expected levels assumed in the RVM process, but also the value gained or lost from the redispatch of PGE's thermal plants, given electric and gas prices that also vary from levels assumed in the RVM process. The thermal redispatch effect is difficult to estimate, and we have not yet revised our power cost model (MONET) to fully reflect the stipulated mechanism. However, as we stated above, we currently estimate the 2005 value of lost hydro production to be about $30 million. If the SD-PCAM measures the overall 2005 power cost increase at $30 million, then $12 million of that amount would potentially be deferred for collection from customers. We say potentially because the mechanism also contains earnings test provisions, which in some circumstances would preclude deferral of some or all of that amount. In addition, the deferral in this docket will only capture replacement power costs up to the date the tariff in UE 165 becomes effective.

Q. What is the rate impact of the recovery of this amount?

A. We are not seeking a particular starting date or collection period at this time. If the estimated $12 million amount mentioned above were recovered over one year, it would result in an increase of approximately nine tenths of one percent. We are, however, considering whether it would be appropriate to collect this over several years and will make a recommendation after discussing the issue with the parties to this proceeding. In any case, the Commission will have the final determination of the collection timing (when it starts) and the collection period.

IV. Qualifications

Q. Mr. Dahlgren, please summarize your qualifications.

A. I received a BS degree from Oregon State University in Electrical Engineering. In addition, I have taken courses from other universities in the areas of engineering economics, systems analysis, and business administration. I also attended the 1980 Public Utilities Executives' Course at the University of Idaho.

I joined PGE in 1973 shortly after graduation and subsequently have been involved in the areas of load research, load and revenue forecasting, price analyses and design, and class cost-of-service analyses. I was appointed Rate Engineer in January 1977 and have held various management positions in the regulatory area since 1978. I entered my present position as Director of Regulatory Policy and Affairs in 2001.

Q. Mr. Tinker, please summarize your qualifications.

A. I received a Bachelor of Science degree in Finance and Economics from Portland State University in 1993 and a Master of Science degree in Economics from Portland State University in 1995. In 1999, I obtained the Chartered Financial Analyst (CFA) designation. I have worked in the Rates and Regulatory Affairs department since joining PGE in1996.

Q. Does this conclude your testimony?

A. Yes.

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List of Exhibits

PGE Exhibit	Description
101	PGE Rebuttal Testimony in UE 165 PGE Exhibit Nos. 800 - 1001

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE-165

PORTLAND GENERAL ELECTRIC COMPANY

REBUTTAL TESTIMONY AND EXHIBITS OF

Pamela G. Lesh
James F. Lobdell
Mike A. Niman
Jay J. Tinker
Doug Kuns

April 18, 2005

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Policy

PORTLAND GENERAL ELECTRIC COMPANY

Rebuttal Testimony and Exhibits of

Pamela G. Lesh

April 18, 2005

I. Introduction

Q. Please state your name and position with PGE?

A. My name is Pamela G. Lesh. I am PGE's Vice President for Regulatory Affairs and Strategic Planning.

Q. Have you sponsored previous testimony in this docket?

A. Yes. I sponsored PGE Exhibit 100, which also includes my qualifications.

Q. What is the purpose of your testimony?

A. My testimony is divided into three parts, which cover the following issues:

- In Section II, I rebut various statements made by ICNU on the appropriate conclusions to be drawn from the illustrative examples included in PGE Exhibits 300 and 301, and the appropriate use of limited empirical data.
- In Section III, I rebut various statements made by ICNU on appropriate risk sharing mechanisms and the history of such mechanisms for PGE.
- In Section IV, I rebut various assertions made by CUB on the appropriate parameters for a risk sharing mechanism.

II. PGE's Illustrative Example and General Conclusions

Q. Other parties contend that the examples in PGE Exhibits 300 and 301 are not based on empirical data, and hence irrelevant. For example, on Page 6 of ICNU/100 (Lines 23 and 24), Mr. Falkenberg states that "...the figures presented by the Company are nothing more than an unsupported example." Do you agree with this characterization?

A. No, for two reasons. First, the examples are relevant for the purpose that PGE provided them, to illustrate a point. Second, this argument is disingenuous because it is the very lack of reliable empirical data that renders problematic the use of ratemaking's standard forecasting techniques for net variable power costs in a system such as PGE's with significant hydro production.

Q. Please discuss your first response.

A. PGE made it clear that the examples were illustrative, rather than based on empirical data. They illustrate two points. First, the value of hydro production shortfalls in deficit hydro years will generally be higher than the value of surplus hydro production in surplus hydro years. This is because deficit hydro production tends to put upward pressure on electric prices, whereas surplus hydro production tends to put downward pressure on electric prices. Second, given an assumption that under average hydro conditions electric prices will be in the $40-45/MWh range, the examples show that deviations of power costs from expectations can now be very large, much larger than in the past, when electric prices were approximately $20/MWh. In other words, the increase in average market electric prices has greatly increased the financial consequences of hydro variation.

Q. Please discuss the lack of reliable empirical data.

A. I will discuss this in two pieces: hydro data and natural gas and electric market data.

We have approximately 60 years of data for flows on the river systems on which PGE has projects or which support contracts. Through complex modeling, PGE and staff of the Pacific Northwest Power Pool are able to transform the data on flows into approximations of the amount of hydro production under certain operating constraints that each flow would produce. Thus, in an empirical sense, this information and analysis tells us how much hydro-electric power the resources would have produced in those past years. However, that information and analysis actually give us no reliable data on what flows those river systems will experience next year, next decade or the next 70 years. We can assume that the flows might be the same. We can assume that they might show up in the same or a different pattern across the years. But those are assumptions, not facts.

We have far less data on electric and natural gas markets. Published indexes have been available for only approximately 10 years for electric markets and PGE has natural gas index data going back only to 1991. If one screens out the years the California market structure and attendant market behavior problems combined to create the western power market crisis, we really only have 2002 through 2004 that we can use as "empirical data." If we want to assume new generation and further assume prices for coal and natural gas, we can make a "fundamentals" forecast of what we might see in future years. But this will be far from "empirical data."

III. Risk Sharing

Q. How does ICNU propose to deal with the increased hydro risk?

A. On Page 32 (Lines 12-14) of ICNU/100 and in response to PGE Data Request No. 003, ICNU asserts that customers should not be required to assume unbounded hydro-related risks. Therefore, investors should bear these unbounded risks. These statements are made in the context of PGE not having been able to find counterparties willing to fully hedge its hydro risk. Lines 12-14 of Page 32 of ICNU/100 state specifically that "Apparently rational counterparties were unwilling to assume unbounded risks. Ratepayers should not be required to do so either."

Q. Do you agree with ICNU's position?

A. No.

Q. Why not?

A. PGE is not asking that customers assume a risk; we are asking that customers pay the cost of service for the electricity they consume. The difficulty is that, with hydro-electric power and some other types of resources, no one can know what this cost of service is in advance.

Addressing the difficulty is a matter of choices and consequences. One could choose not to have such resources. For some resources, it is a simple matter to know in advance exactly what the resource cost per unit consumed by a customer and, thus, to set an electric price for the future. Such resources might cost more at any given time and/or over time, however, than hydro resources. One could choose to make power available only when the resources produce it. For a utility, this choice is not an option. One could choose to have the resources, but pay the utility a premium for its willingness to set the price in advance of knowing the costs. Sometimes this premium will cost less than the change in the direct cost of the resource; sometimes it will be more. Or, one could choose to pay the actual cost of the resources at any given time and over time.

What our testimony regarding the willingness of third parties to accept a premium for setting the price for these resources in advance of knowing their production suggests is that, at least on a stand-alone basis and not as part of a larger system, this premium is quite high. Certainly a contributing factor is the general lack of reliable empirical data that I addressed above. ICNU appears to be supporting the choice and consequence of having utility investors provide the service for a premium, rather than having customers pay the actual cost of service as it is from time to time. This is a valid choice and our direct testimony describes both this choice and the reasons we rejected it. What is not a valid choice is for customers to neither pay the actual cost of service nor provide PGE a premium for setting a price without knowing the costs associated with these resources.

Q. Mr. Falkenberg states that "PGE's HGA proposal places ratepayers in the position of accepting an unbounded risk, with little real opportunity for a compensatory return in the future." (ICNU/100, Page 7, Lines 8-10) Please comment on this position.

A. I find confusing this testimony's use of the term "return" in connection with customers. The statement suggests that utility customers are investing in, rather than using, electricity service. Customers use the electricity that PGE is obligated to supply. The HGA and the System Dispatch Power Cost Adjustment Mechanism (SD-PCAM) stipulated to by OPUC Staff and PGE simply implement one of the choices outlined above for dealing with the difficulty of determining the cost of service for hydro resources; they track the changes in cost of service to customers over time, rather than paying the utility a premium to sell power at a price fixed before the costs of that power are knowable. These changes in cost of service are both up and down, because hydro production is both up and down.

Q. Mr. Falkenberg states that "In essence, Ms. Lesh is arguing that ratepayers have 'deep pockets' compared to investors, and can therefore absorb hydro risks without really noticing it. This should not be the basis upon which the Commission decides such issues. Rather, the Commission should assign hydro risks on the basis of conventional ratemaking practices. This would mean that investors (who have the discretion to invest or not) should bear appropriate risks, while ratepayers (who are captive customers) should not." (ICNU/100, Page 7, Lines 5-11) Please comment on this position.

A. Again, I find this statement confusing. It is also a misrepresentation of my testimony. The statement is confusing because it could literally be read to state that customers should not bear appropriate costs. It also appears to suggest that it would be an appropriate outcome that no one wanted to provide debt or equity investments to an existing utility. A utility that cannot attract equity capital cannot long continue to attract debt capital and, thus, cannot long continue to provide safe and adequate service to "captive customers."

Our direct case supports the premise that choosing to set rates from time to time to reflect actual hydro production rather than to pay utility investors a premium for setting a price before the cost of service can be known will provide customers better service at less cost. My comparison of the effects of cost changes on rates as opposed to net income simply illustrated in simpler terms why PGE debt and equity investors would require a premium to invest in a company whose net income is subject to such significant variations. In contrast to ICNU's belief that the Commission should address the difficulty hydro production poses for determining cost of service by using "conventional ratemaking practices," our suggestion is that the Commission determine the least cost means of assuring safe and adequate service in light of the conditions present today.

Q. What have conventional ratemaking practices been for addressing the difficulty of determining the cost of service from hydro resources?

A. As demonstrated in PGE Exhibit 302 and PGE's response to ICNU Data Request No. 001, the Commission has chosen to address this difficulty in a variety of ways. It is unclear why ICNU concludes that PGE "failed to accurately portray all of the facts and circumstances concerning these items" (ICNU/100, Page 26) and I certainly disagree with this conclusion. I also disagree with ICNU's conclusion that "the Commission has been reluctant to rely on cost recovery mechanisms as a permanent part of PGE's rate structure." (ICNU/100, Page 18) One of the approaches – the PCA in place from the late 1970s until mid-1987 – was "permanent" in the sense that it was an ongoing tariff in place until the Commission approved its withdrawal. That is what the HGA would be. At other times, the approaches were put in place for specific times. The System Dispatch Power Cost Adjustment Mechanism, stipulated to by OPUC Staff and PGE and supported in Staff-PGE Exhibit 100, is an example of the specific approach, as it applies only to the 2005-2006 period. In both cases – indefinite or finite – the Commission adopted an approach that it found best suited to the circumstances facing PGE. That is what is relevant about the past, as well as what we learned from the approaches chosen. The questions we need to concern ourselves with now, however, are not how we interpret past orders, but under what expected conditions we will be trying to determine cost of service and what ratemaking approach is least cost for customers. The condition that caused PGE to file the HGA approach are the recent and dramatic increase in the difference between the variable cost of hydro production and the value of the electricity produced or lost. That value is now determined in an essentially deregulated, competitive market, dominated at the margin by natural gas fired resources, meaning that volatility in those national markets also now affects electricity markets. This condition is what makes it impossible to find a third party willing to swap with PGE a set amount of power at a set price for the variable production of the hydro plants.

Q. Mr. Falkenberg states that "Without simulation results, the proposed HGA is a 'stealth' rate increase of unknown magnitude." (ICNU/100, Page 11, Lines 20-21) Is this a reasonable characterization of PGE's proposed HGA?

A. No. The statement does suggest that, perhaps, ICNU knows something about future hydro production that PGE does not. As I noted above, we have little to no reliable "empirical data" that would support a forecast of the results of this mechanism. We could do modeling and, after it was done, we would simply have modeling results with no idea of the probability of their accuracy. The HGA and the SD-PCAM are not "rate increases," unless customers are not now paying the cost of service. PGE believes, and our investors generally require, that customers pay the cost of service. A business cannot stay in business long selling its services at a loss. Instead, the HGA or the SD-PCAM implement one of the several choices for addressing the difficulties of determining cost of service in a system with a resource the costs of which can vary widely over time and are not predictable in advance.

Q. Aren't the costs of other inputs to electric service subject to change after the Commission has set a price for electricity service?

A. Yes. None of these changes – except perhaps the long-term loss of a large generating resource – is nearly as significant as changes in hydro can be year after year. And the loss of a large generating resource is unlikely to happen more than once in a number of years, if at all over the life of a resource. In addition, some of the other changes can move in opposite directions or have built-in hedges. For example, we set a price without knowing exactly what our load will be. But if we sell more than we expected, we generate additional revenue to cover the additional cost. If we sell less than expected, we at least partially offset the loss of retail revenue with additional wholesale revenue.

Q. ICNU states that "I am fearful that if ratepayers were due a very large credit, PGE might file to do away with the tariff using some variant of Ms. Lesh's 'deep pockets' argument." (ICNU/100, Page 32, Lines 7-9) Are there any grounds for this fear?

A. No. There are no grounds whatsoever for this fear. PGE would not make such a filing. It is insulting to the Commission to suggest that it would approve such a filing. ICNU provides no example of such an outcome in the past and I can think of none. And, of course, I have already explained that I made no "deep pockets" argument. This is the interpretation of the witness for ICNU.

IV. Parameters of Risk Sharing Mechanism

Q. CUB (CUB/100, Page 19) states that a cost adjustment mechanism "should not be triggered except in rare circumstances." Do you agree with this position?

A. No.

Q. Why not?

A. The suggested criterion assumes many decisions and circumstances, including that it is most valuable/least cost to customers to address difficulties in setting rates in advance based on unknown costs of service in this manner. To minimize the premium associated with providing this service, it would be the size of change in cost of service that is the most important criterion, not the frequency. Keying to frequency suggests that an acceptable outcome is many years when rates that are charged greatly exceed or greatly underrun cost of service.

Q. Staff recommends a dead band of 250 basis points in its interim proposal (Staff/100, Page 26), and CUB recommends a large dead band. Do you agree with these recommendations?

A. No.

Q. Why not?

A. There is no evidence that either "250 basis points" or a "large" dead band result in the most valuable or least cost electric service to customers. Perhaps both Staff and CUB are making, but not sharing, a number of assumptions that allow them to conclude that this approach to the difficulties of setting cost of service in advance for variable cost resources is least cost. Certainly we agree that it is difficult to determine the premium that investors require for the setting of a regulated price in advance of knowing the cost of service, in part or in total. But we disagree with any implication that this means one simply doesn't have to determine the required premium but can consider it "free" regardless of the approach chosen.

How other jurisdictions address this difficulty is relevant and some use no "dead band" at all. Some allow most of the cost of service change to affect rates; others allow less. For example, CUB Exhibit 111 notes that Idaho Power and Avista (within the State of Idaho) have dead bands of zero. This is inconsistent with CUB's statement that "In looking at those PCAs, however, it is immediately clear that they do not set a precedent for a mechanism as generous to a utility as what PGE is proposing." (CUB/100, Page 10, Lines 7-9)

In this docket, OPUC Staff and PGE have stipulated to the System Dispatch Power Cost Adjustment Mechanism (SD-PCAM). For purposes of settlement, OPUC Staff and PGE stipulate that the SD-PCAM applies only to the 2005-2006 period and includes a dead band of $15 million for higher than forecasted variations in power costs, and $7.5 million for lower than forecasted variations in power costs.

Q. On Lines 20-22 of Page 11 of CUB/100, CUB states that "PGE's current proposal stands out as the only one that has no sharing-band, placing 100% of the costs beyond the dead-band on customers." Do you agree with this statement?

A. No, because the design of the HGA is unique in the region and perhaps nationally. Most states, as we noted in PGE Exhibits 500 and 502, complement test period ratemaking with adjustment clauses that adjust rates later for most of the amount by which cost of service was unknown when the test period rates were set. In other words, power cost adjustment clauses are common. Mechanisms targeted to one variable – precipitation and consequent hydro production – over which the utility has no control are not common. The "no sharing-band" must be considered as part of the overall HGA design proposed by PGE in its direct testimony. In addition, PGE and the OPUC Staff have stipulated to a mechanism (SD-PCAM) that does provide for sharing beyond the dead band.

Q. Does this conclude your testimony?

A. Yes.

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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PGE's Hydro Resources

PORTLAND GENERAL ELECTRIC COMPANY

Rebuttal Testimony and Exhibits of

James F. Lobdell
Mike A. Niman
Jay J. Tinker

April 18, 2005

I. Introduction

Q. Please state your names and positions at PGE.

A. My name is James F. Lobdell. I am Vice President of Power Operations and Resource Planning. In this docket I sponsored PGE Exhibit 200, which includes my qualifications.

My name is Mike Niman. I am the Manager of the Financial Analysis Department. In this docket I co-sponsored PGE Exhibit 300, which includes my qualifications.

My name is Jay Tinker. I am a project manager in the Rates and Regulatory Affairs Department. In this docket I co-sponsored PGE Exhibit 300, which includes my qualifications.

Q. What is the purpose of your testimony?

A. Our testimony is divided into four parts:

- In Section II, we provide background for, and rebut various statements made by CUB and ICNU concerning the dispatch of PGE's gas-fired plants. We also discuss ICNU's assertions about the likely results of PGE's proposed Hydro Generation Adjustment (HGA) and the possibility of a hydro hedge mechanism.
- In Section III, we rebut various characterizations of PGE's capacity resources made by CUB.
- In Section IV, we rebut statements made by ICNU concerning the appropriate compensation for risks assumed by PGE's investors.
- In Section V, we provide PGE's rationale for entering into stipulations with the OPUC Staff in OPUC Dockets UE-165 and UM-1187 regarding the treatment of hydro variability.

II. Dispatch Issues

Q. Please summarize this section of your testimony.

A. In this section, we first explain the economic dispatch of PGE's gas-fired resources. We then discuss the lack of a clear relationship between electric and gas prices. Next, we show that there is no consistent relationship between changes in PGE's hydro production and changes in the output of PGE's gas-fired plants. We then use these conclusions to rebut assertions made by CUB and ICNU about the likely effects of thermal plant "redispatch" on PGE's proposed HGA mechanism. We correct the errors made in CUB/108 and Table 1 of CUB/100. Finally, we comment on the feasibility of the hydro hedge suggested by ICNU.

Q. What is the basis for the actual dispatch of PGE's gas-fired plants?

A. PGE's gas-fired resources run whenever it is economic to do so. Essentially, if the market value of the electricity generated would be greater than the variable costs of generation, then PGE runs the plant. If the market value of the electricity generated would be less than the variable costs, then PGE does not run the plant. Although line losses and variable O&M costs are also considered, the primary variable cost is that of fuel, leading us to dispatch our coal-fired generating plants as base load because they are almost always economic to run. We use our gas-fired plants on the "margin," running them when gas is comparatively cheap. The primary economic test is a comparison of the prices of electricity and natural gas at the time of potential production. Of course, operational constraints such as start-up requirements and minimum economic run-times affect our dispatch decisions. These constraints are taken into account in Monet through additional logic that we added in the 2005 RVM (Docket UE-161).

Q. Do the outputs of other PGE resources directly affect the dispatch of PGE's gas-fired plants?

A. No. The decision to run PGE's gas-fired plants depends only on a comparison of electricity prices and the opportunity cost of production (primarily natural gas) at the time of potential production. The output of other PGE resources can only indirectly impact this calculation. For example, a decrease (increase) in the output of PGE's hydro resources would generally be concurrent with decreases (increases) in overall regional hydro production. This would tend to increase (decrease) the market price of electricity, thereby making it more (less) likely that gas-fired resources would be economic to run, assuming gas prices remain constant.

Q. Is it always the case that decreases (increases) in hydro output will lead to increased (decreased) gas-fired generation?

A. No.

Q. Why not?

A. Gas-fired generation is based on a comparison of electricity <u>and</u> natural gas prices. Decreased hydro production might well put upward pressure on market electric prices. However, natural gas prices might also increase. If this increase in natural gas prices were greater than that of market electric prices, then PGE would dispatch its gas-fired resources less, and consequently have to make purchases in the wholesale market to replace lost hydro generation. In this case, it is more economic for PGE to purchase power on the wholesale market rather than continue to run the gas-fired plant.

Q. Is there a well-established relationship between the prices of electricity and natural gas?

A. No. Many factors influence natural gas prices. First, natural gas trades in a broader North American market. Natural gas from Canada is available not only to the Pacific Northwest and California markets, but to the Midwest as well. Second, natural gas is also used for purposes other than fueling gas-fired electric generation – heating homes, etc. Third, unlike electricity, natural gas can be stored. In addition, natural gas prices are affected by changes in crude oil prices.

Q. Please summarize the relationship between changes in PGE's hydro production and changes in PGE's gas-fired generation over the past few years.

A. In recent years, decreased (increased) hydro production has sometimes been associated with increased (decreased) gas-fired generation, but sometimes the opposite has been true. In other words, there is <u>no</u> systematic link between hydro output and the relationship between electric and natural gas prices.

Q. Is there a common summary measure for the relative prices of electricity and natural gas?

A. Yes. The market-clearing heat rate is a measure of these relative prices. Specifically, it is the heat rate of a plant that would just break even, given relative electric and gas prices. For example, if in some hour the prices of electricity and gas were $40 per MWh and $5 per MMBTU respectively, then the market-clearing heat rate would be 8,000 BTU per kWh. New combined-cycle combustion turbines have heat rates of approximately 7,000 BTU/kWh; simple-cycle units have heat rates in the 10-12,000 BTU/kWh range. A high market-clearing heat rate means that electric prices are high relative to gas prices, and it will be economic to run less efficient gas-fired plants. Likewise, lower electric prices relative to gas prices yield a lower market clearing heat rate and less gas generation from high heat rate plants.

Q. Have you prepared exhibits which demonstrate that there is no systematic relationship between PGE's hydro production and PGE's gas-fired generation?

A. Yes. PGE Exhibit 901 shows differences between actual and expected hydro and gas-fired generation (MWh) on a monthly basis for the 2002-04 period. Expected generation is based on Monet runs for UE-115 and PGE's 2003 and 2004 RVMs. The Exhibit shows no systematic relationship between changes from expectations in PGE's hydro and gas-fired production. For example, in 2002, during lower than expected hydro production months, gas-fired generation was greater than expected, and during higher than expected hydro production months, gas-fired generation was lower than expected. However, this inverse relationship did not continue. During 2003, hydro production was never higher than expected, and in almost all months lower than expected, but gas-fired production was significantly lower than expected in almost all months.

PGE Exhibit 902 shows percentage differences between PGE's expected and backcast hydro and gas-fired production on a monthly basis for the 2003-04 period. This Exhibit also shows percentage differences between expected and actual market-clearing heat rates. Expected levels of hydro and gas-fired production and market-clearing heat rates are consistent with PGE's 2003 and 2004 RVM filings. Monet backcasts for these same years provide a measure of actual hydro and gas-fired production. The backcasts change daily electric and monthly gas prices to actuals and allow gas-fired plants to re-dispatch, given the new relationships between electric and gas prices. PGE Exhibit 902 shows that changes from expectations in gas-fired generation are generally correlated with changes from expectations in market clearing heat rates. PGE Exhibit 902 also shows that there is no consistent relationship between changes from expectations in gas-fired generation and changes from expectations in hydro production. Across the entire 2003-2004 period, hydro production was never greater than expected, and in almost all months lower than expected. However, gas-fired production was in some months higher than expected, but in other months lower than expected. There simply is no consistent relationship between changes from expectations in hydro and gas-fired production.

Q. Please summarize the conclusions of these PGE Exhibits 901 and 902.

A. PGE Exhibit 902 shows a consistent relationship between market clearing heat rates and gas-fired dispatch. When market clearing heat rates increase (decrease) from expected levels, the dispatch of gas-fired plants increases (decreases) from expected levels. However, PGE Exhibits 901 and 902 show that there is no consistent relationship between changes in hydro production from expected levels and contemporaneous changes in gas-fired production from expected levels.

Q. Please comment on the graph presented on Page 5 of CUB 100, which shows an inverse relationship between PGE hydro production and gas-fired generation on an annual basis for the period 1995-2000.

A. CUB contends that this graph, reproduced and extended in PGE Exhibit 903, demonstrates an inverse relationship between hydro and gas-fired production, as annual changes move in opposite directions. Their conclusion is incorrect in two significant ways. First, over the period used by CUB, hydro production changes very little, i.e. 1995 and 2000 figures are approximately equal. However, gas-fired generation approximately doubles between 1995 and 2000. Second, CUB's graph inexplicably leaves off the last few years of data. PGE

Exhibit 903 extends CUB's graph through 2004, and invalidates CUB's contention that annual changes in hydro and gas-fired production are inversely related. For the period from 2002-04, the relationship is positive. In addition, PGE Exhibit 904 superimposes market clearing heat rates on PGE Exhibit 903 for 1997 through 2004, the period for which we have these data. This Exhibit reinforces the conclusion of PGE Exhibit 902, that there is a consistent relationship between market clearing heat rates and gas-fired generation, but not between hydro production and either market clearing heat rates or gas-fired generation. Again, the conclusion CUB draws from its graph on Page 5 of CUB/100 is invalidated by the data from the 2002-2004 period.

Q. CUB's analysis on Pages 6 and 7 of CUB/100 asserts that lower hydro production will be associated with higher gas-fired generation. Do you agree with this analysis?

A. No.

Q. Why not?

A. CUB's analysis is incomplete. CUB asserts that lower hydro production is associated with higher electric prices, and therefore higher gas-fired generation. This reasoning overlooks that gas-fired generation depends on the relative prices of electricity and gas, not simply on the price of electricity. For example, a small increase in the price of electricity, accompanied by a large increase in the price of natural gas, will decrease, rather than increase, the market clearing heat rate. Gas-fired plants will be less likely to run, not more likely to run.

Q. What are the financial implications?

A. CUB's analysis is incomplete because it assumes that gas prices do not change. However, gas prices have changed from forecasts. CUB's assumption of constant gas prices leads to erroneous financial conclusions.

A complete analysis recognizes that gas-fired generation depends on the relative prices of electricity and natural gas, which can be summarized in market-clearing heat rates. PGE Exhibits 902 and 904 show that there is no consistent relationship between hydro production and market-clearing heat rates, and therefore no consistent relationship between hydro production and gas-fired generation. Hence, there is no consistent relationship between hydro production and the margins from gas-fired generation. When hydro production deviates from forecasts, the associated changes in the margins from gas-fired generation might increase, but also might decrease. We simply have no way of knowing. Again, this is in substantial part due to natural gas prices being a function of many factors, not simply regional electricity load/resource balance.

Q. What does this imply about CUB's assertion that the mechanism PGE proposed would "require customers to pay more than 100% of the cost of replacing low hydro" (CUB/100, Page 1, Lines 6-7)?

A. This assertion is false.

Q. CUB objects to the statement made in PGE/700 (Page 8) that "Since the tariff mechanism requires a three-year amortization period of any balance in excess of $20 million, any resulting rate charges or credits are likely to be small in a given year." CUB states that "As partially presented in Table 1, PGE's HGA would have charged customers approximately $9.8 million in 2003, $25.8 million in 2004, and $45 million in

2005. On top of this, customers would owe an additional $135 million to the Company." Are CUB's calculations accurate?

A. No. CUB's calculations are based on CUB/108, which contains substantial errors, resulting in large overestimations of what PGE's HGA would have charged customers in various years. CUB submitted a corrected version of CUB/108. If we use CUB's corrected analysis, CUB's statement changes to "As partially presented in Table 1, PGE's HGA would have charged customers approximately $3.0 million in 2003, $8.9 million in 2004, and $15.3 million in 2005. On top of this, customers would owe an additional $45.8 million to the Company."

It is necessary to make an additional correction to CUB's analysis. As explained above, and in PGE's response to CUB Data Request No. 007 (PGE Exhibit 905), the Monet model backcast should also include changes in gas prices, as the dispatch and economic value of gas-fired plants depends on electric <u>and</u> gas prices, not simply on electric prices. Using the information provided in PGE's response to CUB Data Request No. 007 and CUB's corrected CUB/108, Table 1 of CUB/100 changes dramatically for 2003. "The Cost of Low Hydro" changes from approximately $10.0 million to $19.6 million. "PGE's HGA Charge" changes from $55.3 million to $19.9 million. Finally, what CUB designates as the "Overcharge Paid by Customers" changes from $45.3 million to $0.3 million.

Q. On Pages 7 and 8 of ICNU/100 (Page 7, Line 13 through Page 8, Line 8) Mr. Falkenberg asserts that the HGA would likely overstate the costs of low hydro production because of gas plant "optionality" and the possibility that purchases might be made at prices lower than Mid-C index. Do you agree with this?

A. No. As explained earlier in this section, we don't know what the impact of what Mr. Falkenberg calls gas plant "optionality" would be. Actual sales and purchases related to deviations in hydro generation would be at prices very close to the Mid-C indices. It is likely that sometimes the costs we incur would be lower than the index and sometimes they would be higher. The use of Mid-C prices makes implementation much more practical and transparent.

Q. Does the mechanism stipulated to by PGE and Staff provide a reasonable resolution to the issue of possible thermal plant optionality benefits?

A. Yes. By updating Monet for actual electric <u>and</u> gas prices, any additional dispatch benefits not included in the RVM Monet run will be captured if they could have been theoretically realized in the Monet model simulation with other factors such as forced outage rates held constant.

Q. ICNU suggests the possibility of a hydro hedge mechanism on Pages 29 and 30 of ICNU/100. Do you think this is a viable possibility for dealing with hydro risk?

A. No. As we explained in PGE Exhibit 200, Section VI, hydro hedges are not available from the marketplace at reasonable costs, and, as Mr. Falkenberg states, we do not have the analytic tools to create his synthetic hedge. However, we should be clear that, in our view, the cost of such a hedge is a legitimate cost of providing service to customers and thus would be appropriate to include in PGE's cost of service.

III. Capacity Resources

Q. On Pages 9 and 10 of CUB/100, CUB comments on PGE's IRP and Final Action Plan, and how customers receive benefits from relatively high heat rate resources. Do you agree with CUB's characterization of these resources and the benefits customers receive from them?

A. Not entirely. CUB's statement that "Customers pay the fixed costs and would never receive any value for the hedges and duct-firing" makes it seem that it is often economic to run capacity resources, resources that have high heat rates. CUB's comments can also be interpreted to imply that these resources will likely generate substantial margins. However, these conclusions are not true. Capacity resources have high heat rates and will be used infrequently. Their purpose is to handle extreme conditions of short duration. Given the infrequency of use, any "margins" will likely be very small.

Q. Please summarize the purpose of capacity resources.

A. Capacity resources are needed for reliability purposes. Under extreme conditions, it can be necessary to run these resources for short periods of time. High heat rates make them usually uneconomic to run under normal conditions. Their purpose is not to "make money," but to "keep the lights on." PGE's modeling will include the margins of capacity resources if the market clearing heat rates are high enough to provide an economic basis for their dispatch.

Q. Has PGE included capacity resources in its IRP process?

A. Yes. PGE's Final Action Plan related to its 2002 IRP included the acquisition of 400 MW of capacity resources.

Q. Did the Commission acknowledge this Final Action Plan?

A. Yes. In Order 04-375, the Commission acknowledged the Final Action Plan based on PGE's 2002 IRP.

Q. Has PGE acquired these capacity resources?

A. Yes, PGE has acquired these resources, primarily through an RFP process.

IV. Risk and Investors

Q. On Page 13 of ICNU/100, Mr. Falkenberg mentions various risks that investors face, but do not generally try to pass on to or share with customers. For example, "Financial and interest rate risks have always been assumed by investors, and these can certainly be extreme. In October 1987, for example, the stock market dropped by approximately 20% in one day." Are ICNU's examples relevant to this docket?

A. No, they generally are not. This docket is concerned with particular costs that are part of providing electricity to customers PGE is obligated to serve. Only if the possible events ICNU mentions lead to changes in the cost of providing service could they result in PGE absorbing costs, or filing new tariffs.

Q. Are hydro, stock prices, and interest rates the same type of risk for utility cost of service?

A. No. The risk that is relevant here is the risk that the utility faces from operations. Hydro risk directly impacts the utility's regulated earnings since it must replace the low cost generation with higher cost purchased power or increase the output from its other generating plants. In either case, the cost of replacement power will be higher than that from the hydro plants. On a regulated basis, the utility's earnings will be lower. Changes in the level of the stock market or in interest rates do not directly affect the utility's operations.

Q. Do investors "assume" the risk of extreme stock market fluctuations?

A. Yes, and they expect to be compensated for assuming such risks through a higher rate of return. The more volatile the return on an investment is, the higher the return an investor will demand to hold that investment. For example, the 20% decline in stock prices during one day in October 1987 caused a significant loss in investors' portfolios. Naturally, investors demanded a higher return after the stock market crash, all else equal.

Q. Does the large decline in the stock market affect a utility's cost of equity?

A. Yes. As we noted above, investors will demand a higher return on stocks than before the stock market crash. If investors do not believe the stock will achieve this return, they will sell the stock, causing the price to decline. The lower price, along with the same dividend, increases the return on the stock. This process will continue until the price of the stock is aligned with investors' required return.

Q. Do changes in interest rates affect the utility's cost of debt?

A. Yes, but only to the extent that the utility issues new long-term debt. Current long-term debt is unaffected.

Q. Is ICNU's "stock market" risk example relevant to this docket?

A. Not really. ICNU's stock market capitalization example is largely irrelevant. The estimated cost of PGE's equity capital is what affects PGE's costs, not the value of the overall stock market. Interest rate changes affect only the cost of new financing.

V. Rationale for UE-165 and UM-1187 Stipulations

Q. Please briefly describe the stipulated mechanism.

A. The mechanism, called the System Dispatch Power Cost Adjustment Mechanism, or SD-PCAM, consists of a comparison between the final RVM Monet run and an updated Monet run that replaces the assumed levels of hydro generation, market electric prices, and market gas prices with actual data. The resulting variance, referred to as the System Dispatch Cost Variance, or SDCV, is subject to 80/20 (Customers/PGE) sharing for variances beyond a dead band of $15 million (for excess costs) or $7.5 million (for negative excess costs). An earnings test then applies to any amount subject to collection or refund. Finally, the SD-PCAM is a two-year mechanism for calendar years 2005 and 2006. Staff-PGE Exhibit 100 provides additional details on the SD-PCAM mechanism.

Q. Are the calculations in the SD-PCAM different than those required by the HGA mechanism originally proposed by PGE in UE-165?

A. Yes. The HGA only tracked the actual variances in hydro generation and valued the excesses or shortfalls at market.

Q. Are the calculations in the SD-PCAM different than those required by an "all-in" power cost adjustment mechanism, such as that in UE 115?

A. Yes. The primary difference is that a traditional PCA tracks the actual <u>total</u> power cost a utility incurs and shares the variance with the assumed power costs used to set rates between the utility and customers. The SD-PCAM limits cost variances to costs resulting from varying hydro conditions as well as the value of changing thermal plant dispatch. By contrast, the scope of a traditional PCA is broad, sweeping all power cost items into the variance calculation.

Q. The mechanism for tracking cost variances using the Monet model is different than the HGA proposed by PGE and the interim PCA mechanism supported by the OPUC Staff in UE-165, which was based on an "all-in" PCA structure. Does PGE believe the stipulated mechanism to be a reasonable representation of the excess costs or benefits associated with variable hydro generation?

A. Yes. In calculating the SDCV, the stipulated mechanism focuses on the effect of hydro variability by holding most other variables constant at the levels assumed in the RVM proceeding. By updating Monet with actual gas and electric prices, any re-dispatch (relative to the dispatch assumed in the RVM) allows customers to benefit if market opportunities were present to limit the cost of deficient hydro generation. However, the SDCV calculation does not include changes in load or contracts entered into after the RVM proceeding, and, in particular, it maintains thermal plant performance (i.e., scheduled maintenance outages and forced outage rates) at the levels assumed in the RVM.

Q. Does the sharing represent a compromise between the OPUC Staff and PGE?

A. Yes. PGE's HGA proposal requested a dead band of $2.5 million with no sharing outside of the dead band, i.e. allocation of all variances outside the dead band to customers.[1] OPUC Staff filed testimony in support of a 250 basis point dead band (which translates into approximately a $35-$40 million dead band), with sharing – 90 % to customers and 10% to PGE – for variances outside the dead band.

Q. Why is $15 million a reasonable compromise on the size of the dead band?

A. PGE and Staff do not necessarily agree on an overall policy regarding the use or size of a dead band when a power cost adjustment mechanism tracks all variations in net variable power

[1] PGE's HGA did not, however, allow actual refunds or charges unless the cumulative balance reached $20 million, either positive or negative.

costs. However, PGE believes that it is reasonable to reduce the size of the dead band (relative to any dead band that may apply to a broad PCA) if the scope of a mechanism is reduced and does not include all power cost variances. In this case, since the stipulated mechanism is limited to only a subset of PGE's power costs and just as importantly, reflects items that are outside of the scope of influence of PGE (i.e., hydro, market electric and gas prices), PGE can support a $15 million dead band for purposes of this two-year stipulated mechanism.

To further put this in perspective, $15 million is equal to about 280 basis points of ROE on PGE's generation rate base in our last general rate case (UE-115) and about 1,400 basis points of ROE on our hydro rate base in UE-115. Since PGE's allowed ROE was 10.5%, or 1,050 basis points, the dead band is greater than the 'earnings power' of PGE's hydro assets in our last rate case.

Q. Is the sharing structure of the stipulated mechanism reasonable?

A. Yes. The asymmetrical dead band and 80/20 sharing provides a reasonable compromise between the views originally put forth by PGE and OPUC Staff. Further, an 80/20 sharing has significant history in Oregon regulation. The power cost adjustment mechanism that PGE had from 1979 through 1987 had 80/20 sharing. In addition, this level of sharing was used for purchased gas adjustment (PGA) mechanisms in Oregon when coupled with an earnings test (as the SD-PCAM provides).

Q. Why should the Commission approve the stipulations for both dockets UE-165 and UM-1187?

A. The Commission should approve the stipulations between the OPUC Staff and PGE for the following reasons:

1. The stipulations represent a reasonable resolution of the issues raised by all of the parties.

2. The stipulations represent significant compromises in the positions of both PGE and the OPUC Staff.
3. The stipulations recognize that today's operating conditions result in significant risks to PGE as a result of a variable (hydro generation) that is largely out of our control, but that conditions <u>may</u> result in some additional thermal dispatch value which helps to mitigate that risk.
4. The stipulated mechanism is temporary in nature, expiring at the end of 2006, thus allowing for the Commission to establish the appropriateness and structure of a long-term PCA mechanism in PGE's next general rate case.
5. The stipulated mechanism requires that PGE shareholders absorb a significant amount of the costs or benefits that result from varying hydro conditions.
6. The sharing structure recognizes the limited nature of the mechanism, one which is focused on the impact of hydro variability.
7. The use of an earnings test provides a reasonableness check on any recovery or refund amounts.
8. The funding of a study on the feasibility of expected value power costs may provide useful information to the Commission on this important topic.
9. Adoption of the stipulations would result in rates that are fair, just, and reasonable.

Q. Does the SD-PCAM address issues raised by CUB and ICNU?

A. Yes. For example, the SD-PCAM will capture additional margins, if economic, from PGE's thermal plants and dispatchable contracts such as PGE's capacity resources. The resulting margins will then be included in the SDCV.

Q. CUB indicates that an appropriate mechanism would update Monet for actual electric prices, but not actual gas prices (CUB/100, Page 6). In implementing the SD-PCAM, why is it important to update Monet with actual prices for both gas and electricity?

A. Gas-fired plants dispatch whenever it is economic to do so. The dispatch decision depends on the <u>relative</u> prices of gas and electricity, not just the price of electricity. Hence, the Monet measure of actual margins from gas-fired plants would be inaccurate if electricity prices were updated, but gas prices were not.

Q. Is the SD-PCAM consistent with ICNU's point that "Under traditional ratemaking, rates are set based on normalized results of operations, and rates are not trued-up to actual results." (ICNU/100, Page 16, Lines 12-13)?

A. Yes. The mechanism calculates the SDCV by means of an updated "normalized" look at power costs, using hydro production, and electric and gas price data not available at the time of an RVM filing, but leaving other parameters fixed.

Q. Did PGE provide principles for a power cost adjustment mechanism in its opening testimony?

A. Yes. In PGE Exhibit 100, we provided the following principles:

- Rate Stability/Predictability
- Transparency
- Incentives for Good Management

Q. Does the SD-PCAM, as stipulated by PGE and the OPUC Staff, meet these principles?

A. Yes, or at a minimum it has the potential to meet these criteria with future Commission decisions on amortization.

Q. How does the SD-PCAM meet the first principle, rate stability and predictability?

A. Unlike PGE's HGA mechanism, the SD-PCAM has no predetermined amortization period (e.g., the HGA amortization period was three years when the balance exceeded $20 million). Instead, the decision on an appropriate amortization period for any resulting collection or refund has been left for the Commission in a future proceeding. At the discretion of the Commission, any associated rate impacts can be managed by seeking opportunities to offset the existing balance with future customer credits or by selecting an appropriate amortization period. PGE intends to provide the Commission with guidance on amortization at the appropriate time with this goal in mind. With its discretion, the Commission can provide for rate stability and predictability.

Q. How does the SD-PCAM meet the second principle, transparency?

A. Like the HGA, the SD-PCAM will rely on objective, verifiable data to determine the SDCV. The Monet model will be used to ensure other elements of PGE's power costs are not included in the SDCV (e.g., load changed, plant availabilities, etc). The asymmetry of the mechanism addresses stated concerns from all of the parties regarding the nature of hydro risk, and the earnings test provides for a reasonableness check on the outcome.

Q. How does the SD-PCAM meet the final principle, incentives for good management?

A. The sharing provisions of the SD-PCAM ensure that adequate incentives are in place to manage cost changes as a result of variable hydro generation. Also, like the HGA, the SD-PCAM mitigates the financial distraction of water conditions over which PGE's management has little control.

Q. Does the stipulated mechanism meet the five principles that CUB sets out on Page 19 of CUB/100?

A. Yes. The asymmetrical dead band, which includes a $15 million increase in power costs, as measured by the SDCV, meets CUB Principles 1 and 2. The SDCV calculation does not include a lost revenue recovery mechanism, thereby meeting CUB Principle 3. The sharing provisions meet CUB Principle 4 through earnings test requirements. Finally, the earnings test requirements also meet CUB Principle 5.

Q. Does this conclude your testimony?

A. Yes

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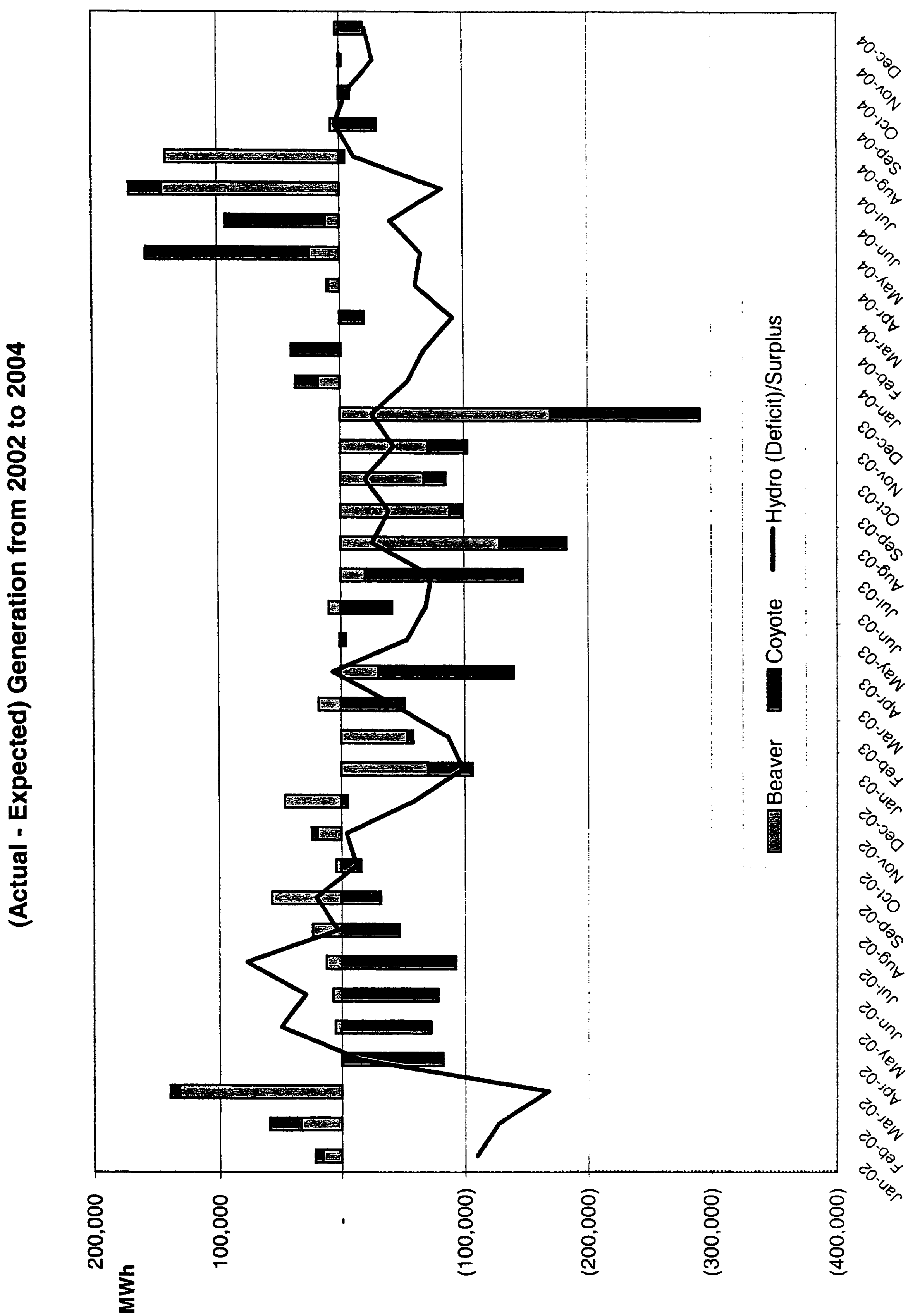
List of Exhibits

PGE Exhibit	Description
901	Hydro and Gas-Fired Generation: Actual vs. Expected from 2002 to 2004
902	Market-Clearing Heat Rates, Hydro Output, and Gas-Fired Generation: Percentage Deviations from Expected during 2003 and 2004
903	PGE Hydro and Gas-Fired Generation from 1995 to 2004
904	PGE Hydro and Gas-Fired Generation, and Market-Clearing Heat Rates from 1995 to 2004
905	PGE Data Response to CUB Data Request No. 007


(Actual - Expected) Generation from 2002 to 2004
MWh
200,000
100,000
-
(100,000)
(200,000)
(300,000)
(400,000)
Jan-02
Feb-02
Mar-02
Apr-02
May-02
Jun-02
Jul-02
Aug-02
Sep-02
Oct-02
Nov-02
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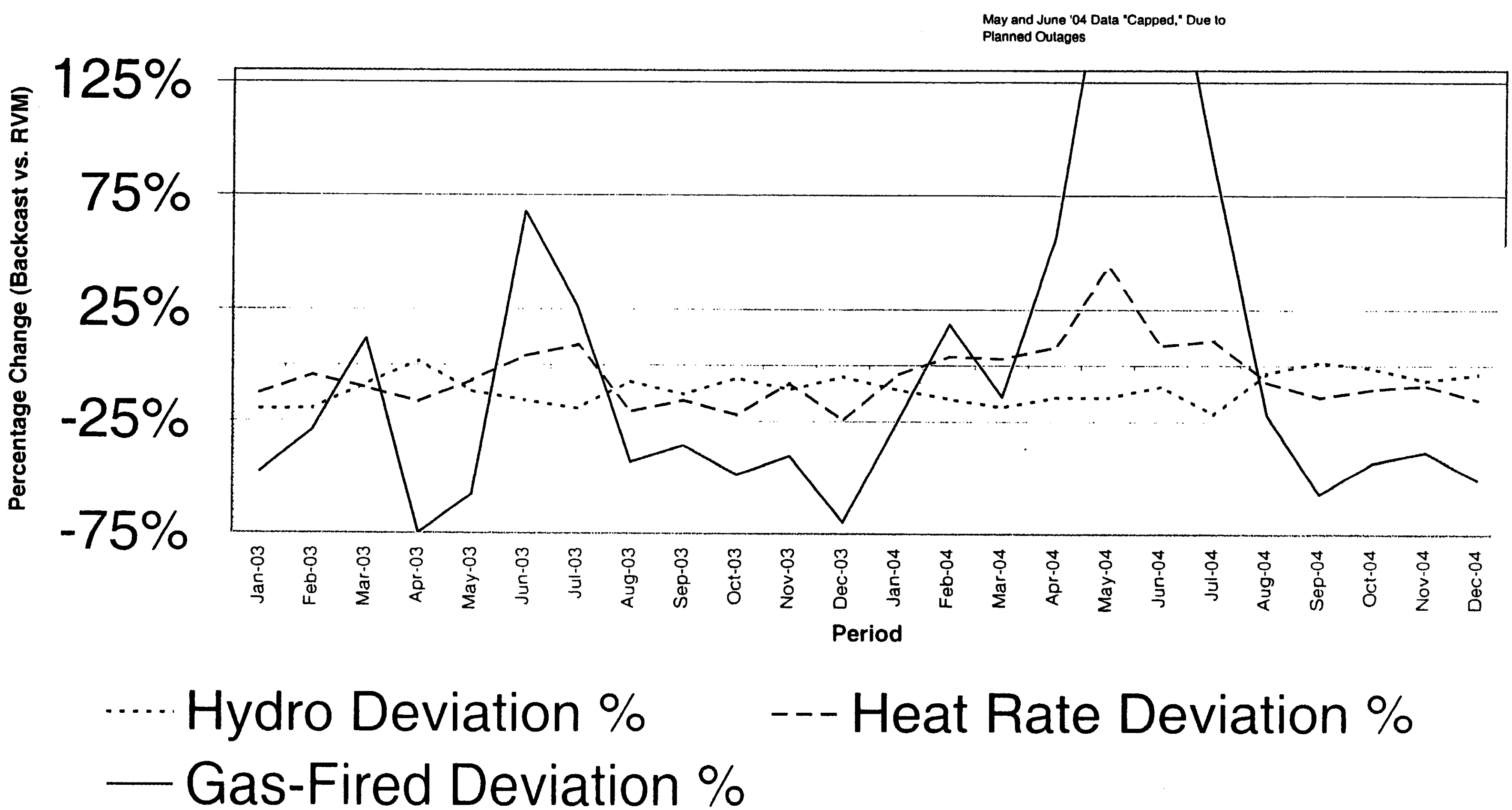
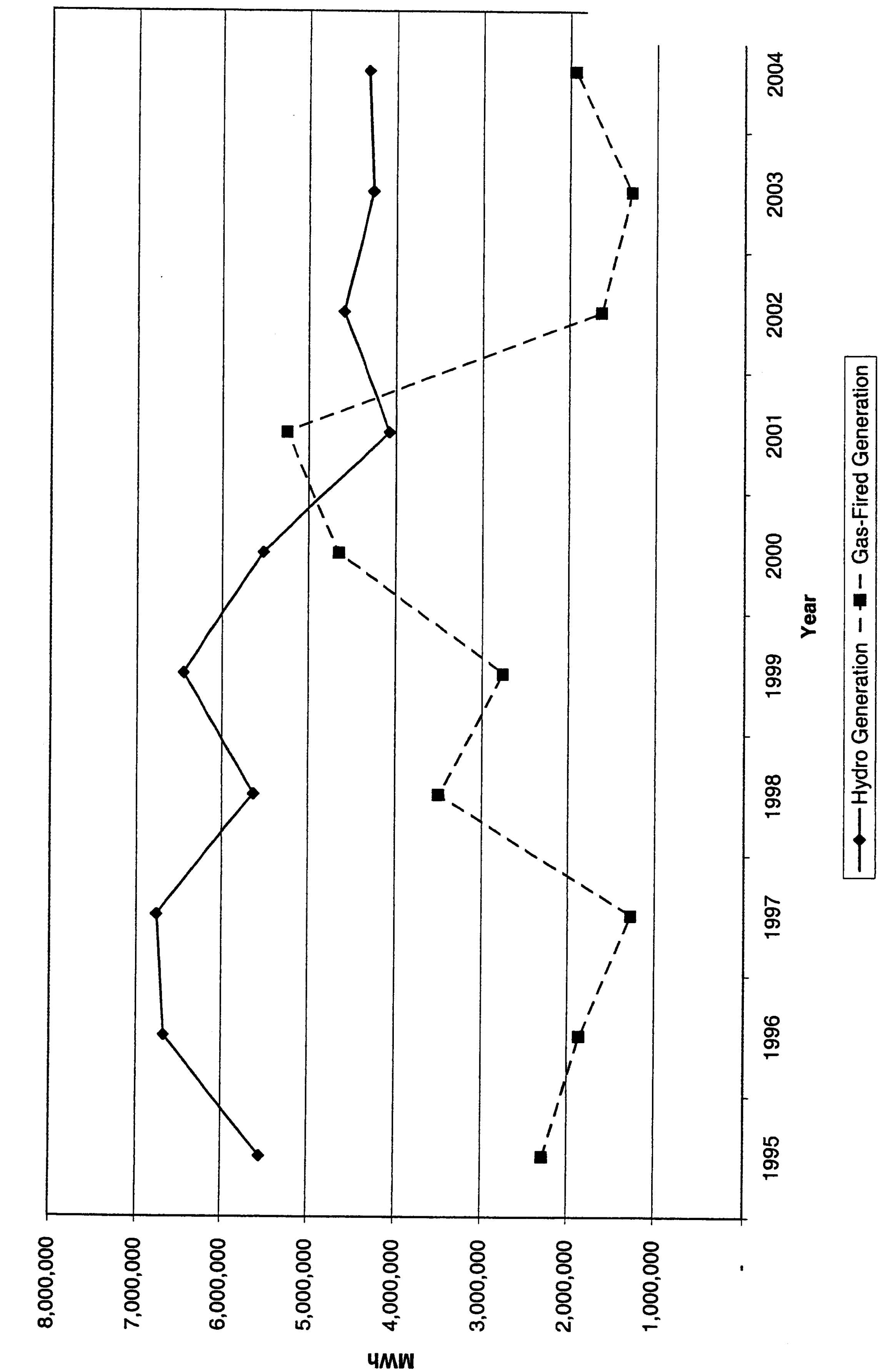
Mar-04
Apr-04
May-04
Jun-04
Jul-04
Aug-04
Sep-04
Oct-04
Nov-04
Dec-04
Beaver
Coyote
Hydro (Deficit)/Surplus

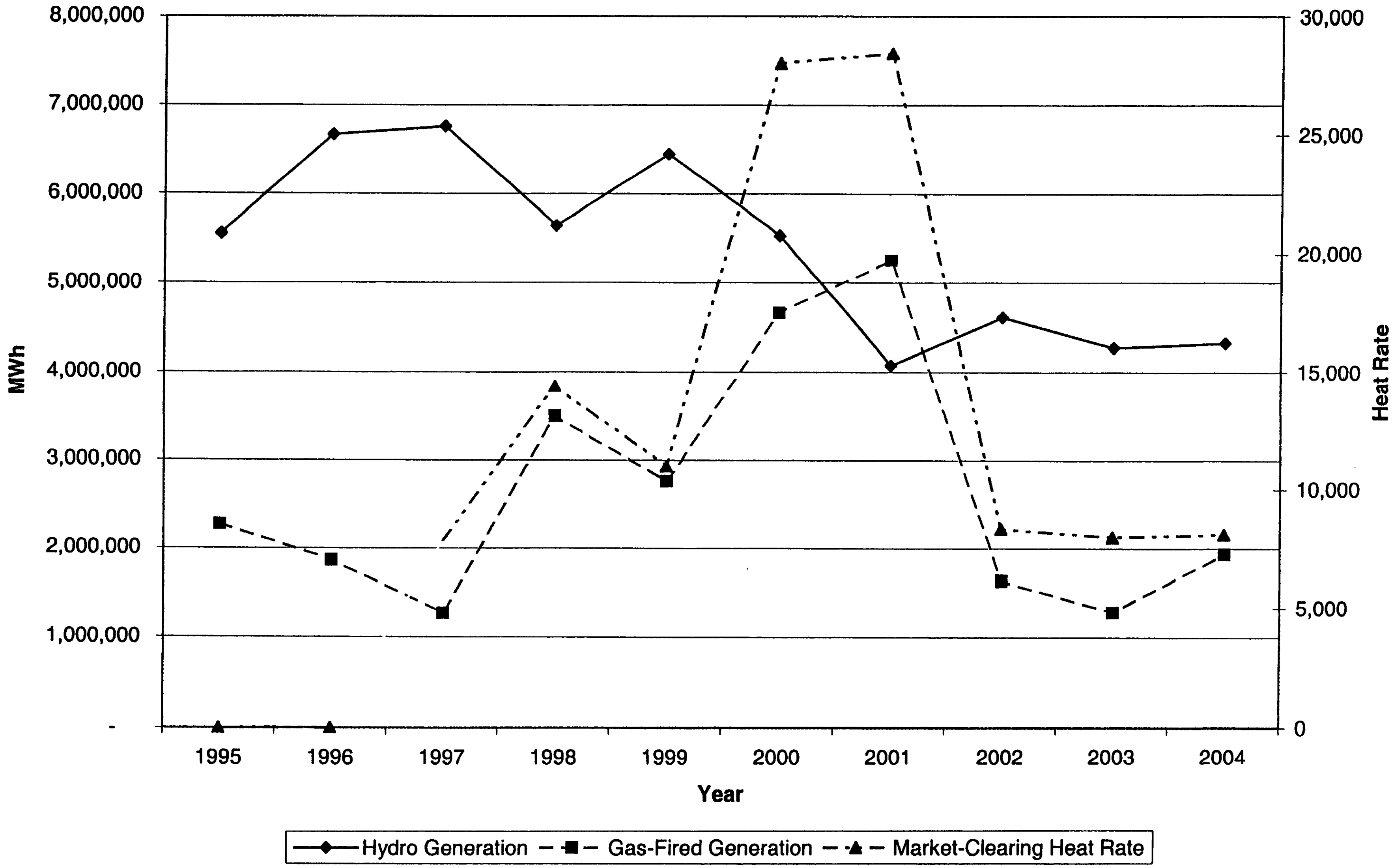
Hydro Output, Market-Clearing Heat Rates, and Gas-Fired Generation



PGE Hydro and Gas-Fired Generation: 1995-2004



PGE Hydro and Gas-Fired Generation, and Market-Clearing Heat Rates: 1995-2004



February 2, 2005

TO: Bob Jenks
CUB

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165
PGE Response to CUB Data Request
Dated January 5, 2005
Question 007

Request:

For the years 2001, 2002, and 2003, please provide the following in electronic format:

a. **A copy of the final Monet run used to set rates in the RVM**
b. **A copy of that final Monet run adjusted for actual hydro production for the year and for actual power prices (or monthly on- and off- peak Mid C prices). All other variables (load, gas prices, etc.) should be unadjusted.**

Response:

a. Attachment 007-A is a CD with five files, including the final Monet runs used to set rates in UE-115 and the 2003 RVM (UE 139).

b. The attached CD also provides three files in response to this portion of the request. The first file is the final UE 115 Monet run, adjusted for actual hydro and actual power prices. Actual power prices are monthly on- and off-peak Mid-C prices, adjusted up by a 1.9 percent line loss factor. This is to make the prices consistent with other Monet data, which is all calibrated to be at PGE's system. The second file is the final 2003 RVM (UE 139) Monet run, similarly adjusted for actual hydro and actual power prices.

The third file provides the final 2003 RVM (UE-139) Monet run, similarly adjusted for actual hydro and actual power prices. However, we have made two further adjustments to Monet. First, rather than use flat monthly on- and off-peak electric prices, we use hourly prices. The purpose of this first adjustment is to provide for the additional thermal plant response to higher super-peak prices. The second adjustment is to incorporate actual gas prices during 2003. The second adjustment is necessary for consistency. An analysis of power cost deviations that only changes assumed electric prices while holding gas prices constant is incomplete. We believe these, and possibly other adjustments are necessary if the goal was to net out the effects of thermal plant dispatch from the hydro variance that occurred in 2003.

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Attachment 007-A

Final Rate Setting Monet Runs for UE-115 and UE-139 (on CD)
Backcast Monet Run for UE-115 and UE-139 (on CD)

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Hydro Generation Adjustment Tariff

PORTLAND GENERAL ELECTRIC COMPANY

Rebuttal Testimony and Exhibits of

Doug Kuns

April 18, 2005

I. Introduction

Q. Please state your name and position at PGE.

A. My name is Doug Kuns. I am the Manager of Pricing and Tariffs at PGE. In this docket, I sponsored PGE Exhibit 700, which includes my qualifications.

Q. What is the purpose of your testimony?

A. My testimony is divided into two parts, which cover the following issues:

- In Section II, I rebut various claims made by CUB and ICNU concerning PGE's proposed Hydro Generation Adjustment (HGA) and PGE's ongoing RVM process.
- In Section III, I address CUB's concerns about the relationship between PGE's proposed HGA and demand response programs, and explain PGE's views on the appropriate roles for these two approaches.

II. Characteristics of the HGA and RVM

Q. CUB asserts that the HGA proposed by PGE in its direct testimony "is focused on the costs associated with two elements: hydro variability and wholesale electric prices (CUB/100, Page 2, Lines 15-16)." Is this true?

A. Not really. The proposed HGA focuses on the costs and benefits associated with hydro variability, as valued at Mid-C index electric prices. It does not include other impacts on power costs related to wholesale electric prices. However, the System Dispatch Power Cost Adjustment Mechanism, stipulated to by OPUC Staff and PGE, includes the effects of market electric and gas price variability on the value of thermal plant dispatch.

Q. On Page 15 of ICNU/100 (Lines 12-15), Mr. Falkenberg states that "Under the proposed HGA, the concept of rate finality is violated. Customers may not know the full cost of their consumption for several years afterwards. PGE itself admitted that this is a problem with tracking mechanisms in its testimony in UE-113." Please comment on this discussion.

A. ICNU misrepresents the concept of rate finality and PGE's testimony. The Commission must balance many considerations in setting rates, including the time period over which costs are recovered and the implications of the costs of debt and equity capital. It is not true that customers would not know the full cost of their consumption for several years. The HGA, or any deferral mechanism, might change future rates, but customers will know the rates in effect at the time they use electricity. Neither the HGA, nor any other mechanism to capture excess power costs, has the ability to go back and charge customers a different rate for their historical consumption. This is rate finality.

Q. ICNU asserts that "PGE's rates are already too complex," and that "The HGA is a step in the wrong direction." (ICNU/100, Page 27, Lines 8-10) We presume that ICNU would make the same assertion regarding the mechanism stipulated to by PGE and Staff. Please comment on this assertion.

A. There are three significant problems with ICNU's statement. First, some of PGE's tariff "complexities" facilitate power supply options for customers that ICNU represents. Second, it is unclear whether ICNU disagrees with "extra" tariff schedules that implement credits to customers. Finally, the Commission must balance many objectives, only one of which is making rates "less complex." A desire for fewer tariff sheets is not sufficient to preclude appropriate sharing of costs between customers and PGE, the subject of this docket.

Q. Mr. Falkenberg states that "Up to this point, the total NPC collected in rates has increased substantially due to the RVM. Thus, customers have already absorbed much of the risk of increased power costs." (ICNU/100, Page 15, Lines 6-8) Is this statement true?

A. No. The RVM has resulted in substantial benefits to customers. Without the RVM process, PGE's rates would be unchanged from those authorized by the Commission in UE-115. PGE Exhibit 1001 demonstrates that PGE's current energy rates for Schedule 83 Cost-of-Service customers are between 15 and 18 percent lower than comparable rates set in UE-115.

III. Relationship Between HGA and Demand Response Programs

Q. Please comment on CUB's testimony concerning demand response programs.

A. On Pages 24 and 25 of CUB/100, CUB tries to tie together low hydro events that PGE's proposed HGA might handle and market electric price spikes that demand response programs might handle. For example, beginning on Line 22 of Page 24, CUB states that "The PUC should consider guidelines for when demand response programs are triggered during serious low hydro event." Demand response programs, which involve changes in customer energy usage, can sometimes be effective means to deal with price spikes of short duration. However, demand response programs do not effectively deal with the financial consequences of sustained low hydro production over the course of a year. If hydro generation were 100 MWa lower than average over the course of a year, and PGE had to replace it with market purchases costing $50 per MWh, the cost of making up for the low hydro generation would be more than $43 million. A demand response program would not be able to address this financial result, as it would operate only during a relatively few hours during the year.

PGE continues to consider demand response programs, and believes that they can have a place in an overall capacity resource strategy. However, they are not designed to handle the consequences of low hydro conditions.

Q. Does this conclude your testimony?

A. Yes.

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List of Exhibits

PGE Exhibit	Description
1001	RVM-Related Tariff Schedule 83 Changes

Portland General Electric
Schedule 83
Percentage Change from UE-115 Energy Rates

Docket

UE-115 **Schedule 83 Energy Prices 2002**

	Secondary	Primary	Subtrans.
Flat	40.72	38.69	n/a
On-peak	44.19	42.55	41.86
Off-peak	34.10	32.79	32.19
Sch 125a	(1.34)	(1.34)	(1.34)
Sch 125b	12.89	12.89	12.89
Sch 125c	0.45	0.45	0.45
Net Flat Rate	52.72	50.69	n/a
Net On-peak	56.19	54.55	53.86
Net Off-peak	46.10	44.79	44.19

UE-139 **Schedule 83 Energy Prices 2003**

	Secondary	Primary	Subtrans.	Pct. Change from UE-115 Secondary	Pct. Change from UE-115 Primary	Pct. Change from UE-115 Subtrans.
Flat	40.44	38.46	n/a			
On-peak	43.74	42.30	41.44			
Off-peak	33.89	32.76	32.06			
Sch 125a	(0.30)	(0.30)	(0.30)			
Sch 125b	0.24	0.24	0.24			
Net Flat Rate	40.38	38.40	n/a	-23.4%	-24.2%	n/a
Net On-peak	43.68	42.24	41.38	-22.3%	-22.6%	-23.2%
Net Off-peak	33.83	32.70	32.00	-26.6%	-27.0%	-27.6%

UE-149 **Schedule 83 Energy Prices 2004**

	Secondary	Primary	Subtrans.	Pct. Change from UE-115 Secondary	Pct. Change from UE-115 Primary	Pct. Change from UE-115 Subtrans.
Flat	42.39	40.83	n/a			
On-peak	45.07	43.26	42.54			
Off-peak	37.43	35.93	35.34			
Sch 125a	(0.77)	(0.77)	(0.77)			
Sch 125b	(0.10)	(0.10)	(0.10)			
Net Flat Rate	41.52	39.96	n/a	-21.2%	-21.2%	n/a
Net On-peak	44.20	42.39	41.67	-21.3%	-22.3%	-22.6%
Net Off-peak	36.56	35.06	34.47	-20.7%	-21.7%	-22.0%

UE-161 **Schedule 83 Energy Prices 2005**

	Secondary	Primary	Subtrans.	Pct. Change from UE-115 Secondary	Pct. Change from UE-115 Primary	Pct. Change from UE-115 Subtrans.
Flat	56.76	54.79	n/a			
On-peak	59.81	57.64	56.54			
Off-peak	51.69	49.75	48.71			
Sch 125a	(9.93)	(9.93)	(9.93)			
Sch 125b	(2.52)	(2.52)	(2.52)			
Net Flat Rate	44.31	42.34	n/a	-16.0%	-16.5%	n/a
Net On-peak	47.36	45.19	44.09	-15.7%	-17.2%	-18.1%
Net Off-peak	39.24	37.30	36.26	-14.9%	-16.7%	-17.9%

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Hydro Tariff and Hydro Generation Variance

UE-165 / UM-1187

PORTLAND GENERAL ELECTRIC COMPANY
OREGON PUBLIC UTILITIES COMMISSION

JOINT DIRECT TESTIMONY AND EXHIBITS OF

Jay J. Tinker
Maury Galbraith

April 18, 2005

I. Introduction

Q. Please state your name and position with PGE.

A. My name is Maury Galbraith. I am employed by the Oregon Public Utility Commission (OPUC) as a senior economist. I am the case manager for the OPUC Staff in both docket UE-165 and UM-1187. I previously submitted testimony in this docket as Staff Exhibit 100. My qualifications were previously provided in Staff Exhibit 101.

My name is Jay Tinker. I am a project manager with PGE. I previously submitted testimony in this docket as PGE Exhibit 300. PGE Exhibit 300 also provided my qualifications.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to describe the stipulations entered into by PGE and the OPUC Staff in dockets UE-165 and UM-1187. PGE and the OPUC Staff intend to submit separate testimony explaining their rationale for supporting the stipulations.

II. OPUC Staff-PGE Stipulation in UE-165 and UM-1187

Q. Please describe in general terms the stipulations entered into by the OPUC Staff and PGE.

A. The OPUC Staff and PGE have entered into two stipulations, included as Exhibits 101 and 102, that provide for a sharing of increases and decreases in PGE's cost of service associated primarily with the difference between the average hydro generation assumed in setting PGE's base rates in RVM proceedings and the hydro generation that actually occurs. The UM-1187 stipulation incorporates the UE-165 stipulation, which establishes the System Dispatch Power Cost Adjustment Mechanism (SD-PCAM). The SD-PCAM utilizes PGE's power cost model, Monet, to determine the System Dispatch Cost Variance (SDCV). The stipulations provide for an interim mechanism only, covering the period from January 1, 2005 through December 31, 2006. The structure of a long-term PCA for PGE will be determined in PGE's next general rate case, which PGE expects to file in December, based on a 2007 test year.

Q. Please describe in more detail the specific mechanism agreed to by the OPUC Staff and PGE for tracking power cost variances in 2005 and 2006.

A. The SD-PCAM will track the annual difference between the Base Power Costs established in PGE's RVM proceedings and Updated Power Costs. Updated Power Costs will be determined by taking the Base Power Cost Monet run and updating it using actual data for hydro generation and market energy prices, while holding all other assumptions constant. More specifically, PGE will update the final RVM Monet runs with the following actual data:

1. Actual hourly hydro generation.
2. Actual market electricity prices using the hourly shape of the Dow Jones Mid-Columbia Hourly Index prices to shape Dow Jones Mid Columbia Daily Index on and off-peak prices to hourly prices.

3. Actual gas prices using daily index prices.

Only part of the annual SDCV will result in a change to rates, subject to an earnings test. We describe the sharing that limits the effect of the new forecast on rates and the earnings test below.

Q. Please describe how you will incorporate actual hourly hydro generation in the Monet update.

A. PGE will input actual hourly generation figures for each PGE hydro plant (66.67% shares in the case of Pelton and Round Butte), the Portland Hydro Project, and PGE's shares of the output of four Mid-Columbia hydro facilities into Monet. These actual generation figures will come from PGE's Power Scheduling and Accounting System (PSAS). In addition to the actual hourly generation figures, PGE will also update the monthly actual hydro generation for these plants. These monthly actual generation figures will then flow through the model to affect three other power cost components -- the Wells Settlement Agreement, PGE's Mid-C indexed purchase from the Confederated Tribes of the Warm Springs, and the Priest Rapids Renewal Contract Reasonable Portion Auction Payment. PGE will also make an adjustment to reflect Daylight Savings Time, something Monet does not model directly.

Q. Please explain how you will calculate actual electric prices for the Monet update.

A. PGE will start with actual day-ahead on and off-peak prices from the Dow Jones Mid-Columbia Daily Electricity Price Index and the actual shape of hourly prices from the Dow Jones Mid-Columbia Hourly Electricity Price Index. PGE will apply the hourly index shape to the daily forward on and off-peak index prices to obtain hourly prices that are consistent with the daily on and off-peak prices, but which follow the observed hourly shape. We will fill any gaps in the hourly data with available data from similar periods. Finally, we will multiply the

Mid-Columbia based prices by a (line-loss) factor of 1.019 to convert them to PGE prices.

Relying primarily on the daily day-ahead price index maintains consistency with the actual day-ahead natural gas prices to be input into Monet. Consistency is important to obtaining a realistic dispatch of PGE's resources. Shaping the daily on- and off-peak prices based on the actual hourly observed prices, however, allows the model to include "super-peak" hours in its economic dispatch logic.

Q. Please explain how you will calculate actual gas prices for the Monet update.

A. First, PGE will enhance Monet so that it can accept daily gas prices, as it currently runs based on monthly gas prices. Then, PGE will input actual day-ahead natural gas index prices for Sumas, AECO, and Malin from the Platts "GasDat" Database. The Monet dispatch of PGE's gas plants will be based on these daily forward gas prices, along with the shaped day-ahead electricity prices described above. For simplicity, and because the dollar values are small, we will continue to use monthly gas prices to determine gas transportation variable losses and the Glendale Sales contract price. We will calculate the monthly gas prices as the averages of the relevant actual daily index prices.

Q. Will the physical and financial natural gas transactions included in Base Power Costs be updated using actual natural gas prices?

A. Yes. PGE will update the natural gas financial swaps included in Base Power Costs to actual, settled values. PGE will also update the weighted average costs of gas (WACOGs) for any physical natural gas purchases included in Base Power Costs based on actual, settled values. Settlement of these transactions are based on monthly index prices and the spot foreign exchange rate at the time of settlement.

Q. What inputs to Monet will not be updated in performing the calculations for Updated

Power Costs?

A. The most significant inputs that will not be updated are:

1. Generating plant availability factors
2. Loads
3. Advanced power and fuel purchases

Not updating these inputs preserves the original RVM assumptions. For example, the update will not reflect PGE's generating plants operating better or worse than expected. Nor will it reflect changes in load, which would also have caused changes in PGE's revenue. This eliminates what has been a controversial issue with power cost adjustment mechanisms.

Q. Do PGE and Staff believe the SD-PCAM will provide a realistic representation of the changes to PGE's cost of service that can result from variation in hydro generation?

A. Yes. The SD-PCAM addresses concerns raised by the Staff, CUB, and ICNU that PGE's original HGA mechanism did not take into account how hydro conditions could affect the use of PGE's thermal plants, particularly PGE's natural gas-fired generation. Under some circumstances, hydro replacement costs may be reduced by PGE dispatching its natural gas-fired resources. This occurs if spark spreads (i.e., the spread between market gas prices and market electric prices) widen, regardless of the factors driving the spark spreads. The SD-PCAM captures the variation in margins associated with thermal plant operation if spark spreads actually change (either increase or decrease) relative to the assumptions used PGE's final RVM filings.

Q. Does the SD-PCAM provide for a sharing of the SDCV between the company and customers?

A. Yes. When the annual SDCV is positive (i.e., the Updated Power Costs are greater than Base Power Costs), a dead band of $15 million will apply. Thus, PGE shareholders will absorb the first $15 million of additional cost as a result of poor hydro conditions. When the annual SDCV is negative (i.e., the Updated Power Costs are less than Base Power Costs), a dead band of $7.5 million will apply. Thus, PGE shareholders will retain the first $7.5 million of cost of service reductions attributable to better-than-average hydro production. In addition, deferral will be limited to 80% of the SDCV outside the dead band.

Q. Is the recovery or refund of deferred amounts subject to any other limitations?

A. Yes. An earnings test will apply for each year (2005 and 2006) to determine the reasonableness of any refund or recovery amounts. The features of the earnings test include:

1. Recovery of any deferred amounts will be limited to those that result in PGE earning no greater than a 10.5% ROE on a regulated basis. All deferral amounts which result in PGE earning an ROE that exceeds 10.5% on a regulated basis will be written off.
2. Refund of any deferred amounts will be limited to those that result in PGE earning no less than a 10.5% ROE on a regulated basis. All deferral amounts which result in PGE earning an ROE that is less than 10.5% on a regulated basis will be written off.
3. For the purposes of the earnings test, actual power costs will be used rather than normalized power costs.
4. All other elements of the earnings test will leverage from Commission decisions in PGE's last general rate case (UE-115), which are generally provided in PGE's annual Results of Operations Report filed with the OPUC.

Q. What is the purpose of limiting SDCV recovery or refund amounts through the earnings test?

A. The purpose of an earnings test is to provide a reasonableness check for the recovery or refund of SDCV amounts. For example, if recovery under the mechanism would result in PGE earnings a 10.75% ROE on regulated basis, PGE will reduce the adjustment to rates to bring PGE's ROE to 10.5%. Similarly, if refund under the mechanism would result in PGE earning a 10.0% ROE on a regulated basis, PGE will reduce the refund to bring PGE's ROE to 10.5%.

Q. Does the earnings test guarantee PGE a 10.5% ROE?

A. No. For example, PGE might be in a situation in which its ROE would be five percent without the SD-PCAM, and the mechanism provides enough cost recovery so that its ROE increases by three percent. Then PGE's ROE, even with the SD-PCAM, would still be only eight percent. On the other hand, PGE's situation in a particular year might be such that its ROE would be 15 percent without the SD-PCAM, and the mechanism provides a sharing with customers that translates into two percent ROE. Then PGE's ROE, even adjusted for sharing with customers, would still be 13 percent. The earnings test provides comfort that the incremental impact of the mechanism will not push PGE's ROE (up or down) to an unreasonable level.

Q. Are there any other features of the stipulation?

A. Yes. A key feature of the stipulation is PGE's agreement to fund (without recovery from customers) $100,000 for consulting services to study the feasibility of developing expected value (or stochastic) power costs. As indicated in our respective testimonies, PGE and Staff disagree on the appropriateness and feasibility of developing expected value power costs. The funding of a study will provide both parties information on the issues involved in developing expected value power costs. While neither party will be bound by the recommendations or results of the study, valuable information may result to facilitate Commission decisions on the appropriateness of expected value power costs in future proceedings.

Q. Will adoption of the stipulations in UE-165 and UM-1187 result in rates that are fair, just, and reasonable?

A. Yes. PGE and the OPUC Staff will submit separate testimony explaining their rationales for supporting the stipulations.

Q. Does this conclude your testimony?

A. Yes.

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List of Exhibits

PGE Exhibit	Description
101	UM-1187 Stipulation
102	UE-165 Stipulation

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

Douglas C. Tingey
Assistant General Counsel

April 11, 2005

Via Electronic Filing and U.S. Mail

Oregon Public Utility Commission
Attention: Filing Center
PO Box 2148
Salem OR 97308-2148

Re: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Application for Deferral of Costs and Benefits Due to Hydro Generation Variance
OPUC Docket No. UM 1187

Attention Filing Center:

Enclosed for filing in the above-captioned docket is a Stipulation between Portland General Electric and Oregon Public Utility Commission Staff. This document is being filed by electronic mail with the Filing Center.

An extra copy of this cover letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided.

Thank you in advance for your assistance.

Sincerely,

DCT:am

cc: UM 1187 Service List

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1187

In the Matter of the Application of Portland General Electric Company for an Order Approving the Deferral of Costs and Benefits Due to Hydro Generation Variation	**STIPULATION**

This Stipulation ("Stipulation") is between Portland General Electric Company ("PGE") and Staff of the Public Utility Commission of Oregon ("Staff).

On December 30, 2004, PGE filed its Application in this docket seeking deferral for later ratemaking treatment of the costs and benefits due to variation in PGE's owned and contract hydro generation resources. PGE sought deferral of those costs and benefits beginning January 1, 2005. The Application stated that PGE would determine the variance consistent with the method contained in its proposed Hydro Generation Adjustment tariff in Docket UE 165. An amended application was filed on January 21, 2005, to clarify that this deferral application was filed because of the existing drought conditions in the Pacific Northwest and that, therefore, PGE was requesting that the Public Utility Commission of Oregon ("Commission") approve this Application irrespective of the ultimate outcome in UE 165.

The Hydro Generation Adjustment tariff proposed in Docket UE 165 was an ongoing mechanism designed to capture the costs and benefits of the variation in hydro generation. After two rounds of testimony in UE 165, numerous data requests and responses, and settlement conferences over many months, Staff and PGE have agreed upon terms of a temporary cost variance mechanism to be applied to calendar years 2005 and 2006. As a result, Staff and PGE have entered into a Stipulation in docket UE 165, and this Stipulation, setting forth the terms of that agree-upon temporary mechanism, and seeking Commission orders implementing that temporary mechanism.[1] Specifically, Staff and PGE agree to and request that the Commission adopt orders in this docket implementing the following:

STIPULATION

1. Attached as Exhibit "A" is a copy of the Stipulation between PGE and Staff in UE 165. The UE 165 Stipulation is incorporated herein. Staff and PGE request an order in this docket allowing the deferral and amortization of power cost variances under the terms set forth in paragraphs 1 through 7 of the UE 165 Stipulation. Staff and PGE's intent and request is that the terms set forth in the UE 165 Stipulation govern the calculation and amortization of cost variances for all of calendar years 2005 and 2006. In this docket, Staff and PGE request a Commission order allowing such calculation and amortization from and after January 1, 2005, to the effective date of the implementation of the requested temporary cost variance tariff in UE 165. Staff and PGE agree that the deferral and amortization of power cost variances as set forth in paragraphs 1 through 8 of the UE 165 Stipulation is an automatic adjustment clause under ORS 757.210. The Parties agree to support the deferral and amortization of power cost variances as described in the UE 165 Stipulation and neither Party will propose or support an earnings test applicable to the System Dispatch Cost Variance Account (SDCV Account) different from the earnings test set forth in paragraphs 4 through 6 of the UE 165 Stipulation.

2. The characteristics and terms of an ongoing power cost adjustment mechanism for calendar year 2007 and thereafter will be addressed in PGE's next general rate case. This Stipulation will not be used in whole or part as precedent in that proceeding. This Stipulation provides for a temporary mechanism only.

[1] It is anticipated that the terms and conditions of an ongoing PCA beginning in 2007 will be addressed in PGE's next general rate case.

3. Staff and PGE agree that this Stipulation is in the public interest and will produce rates that are fair, just and reasonable.

4. Staff and PGE shall file this Stipulation with the Commission. Staff and PGE agree to support this Stipulation before the Commission and before any court in which this Stipulation may be considered. If the Commission rejects all or any material part of this Stipulation or the Stipulation in UE 165, or adds any material condition to any final order which is not contemplated by this Stipulation, each party reserves the right to withdraw from this Stipulation upon written notice to the Commission and the other party within five (5) business days of service of the final order rejecting this Stipulation or the UE 165 Stipulation, or adding such material condition.

5. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

6. The parties to any dispute concerning this Stipulation agree to confer and make a good-faith effort to resolve such dispute prior to bringing an action or complaint to the Commission or any court with respect to such dispute.

7. Staff and PGE agree that this Stipulation represents a compromise in their positions. As such, conduct, statements, and documents disclosed in the negotiation of this Stipulation shall not be admissible as evidence in this or any other proceeding. Staff and PGE agree that a Commission order adopting this stipulation will not be cited as precedent in other proceedings for the matters resolved in this stipulation.

8. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR § 860-14-0085. Staff and PGE agree to cooperate in drafting and submitting the explanatory brief or written testimony required by OAR § 860-14-0085(4).

9. By entering into this Stipulation, no party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

DATED THIS 11th day of April, 2005.

PORTLAND GENERAL ELECTRIC COMPANY	STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON
______________________	______________________

8. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR § 860-14-0085. Staff and PGE agree to cooperate in drafting and submitting the explanatory brief or written testimony required by OAR § 860-14-0085(4).

9. By entering into this Stipulation, no party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

DATED THIS_day of March, 2005.

PORTLAND GENERAL ELECTRIC COMPANY	STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON
_______________________	_______________________

PGE

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

Douglas C. Tingey
Assistant General Counsel

April 11, 2005

*Via **Electronic Filing and U.S. Mail***

Oregon Public Utility Commission
Attention: Filing Center
PO Box 2148
Salem OR 97308-2148

Re: In the Matter of PORTLAND GENERAL ELECTRIC
Application for a Hydro Generation Power Cost Adjustment Mechanism
OPUC Docket No. UE 165

Attention: Filing Center

Enclosed for filing in the above-captioned docket is a Stipulation between Portland General Electric and Oregon Public Utility Commission Staff. This document is being filed by electronic mail with the Filing Center.

An extra copy of this cover letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided.

Thank you in advance for your assistance. If you have any questions, please do not hesitate to call.

Sincerely,

DougT77

DCT:am

cc: UE 165 Service List

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 165

In the Matter of PORTLAND GENERAL ELECTRIC Application for a Hydro Generation Power Cost Adjustment Mechanism.	))))))	**STIPULATION**

This Stipulation ("Stipulation") is between Portland General Electric Company ("PGE") and Staff of the Public Utility Commission of Oregon ("Staff). Capitalized terms used in this Stipulation have the meanings ascribed to them in this Stipulation.

On May 18, 2004, PGE filed an Application for a Hydro Generation Power Cost Adjustment Mechanism, requesting approval of tariff schedule 128. Tariff schedule 128 is an automatic adjustment clause under ORS 757.210. PGE sought this tariff to track the costs and value associated with hydro generation assets and contracts.

PGE filed its Direct Testimony in this docket on November 17, 2004. The filing consisted of seven pieces of testimony by eight different witnesses supporting the need for the proposed tariff mechanism. In addition, on December 30, 2004, PGE filed an Application for Deferral of Costs and Benefits Due to Hydro Generation Variance, seeking to defer the costs and benefits caused by hydro generation variance beginning January 1, 2005. That deferral was assigned docket number UM 1187.

Numerous data requests have been propounded and responded to by PGE, Staff and other parties in this docket.[1] On February 14, 2005, Staff and other parties filed Rebuttal Testimony in

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1 The Citizens' Utility Board ("CUB") and the Industrial Customers of Northwest Utilities ("ICNU") have also been active participants in this docket. CUB and ICNU have not, however, joined in this Stipulation.

this docket. In that testimony Staff proposed that a temporary mechanism be implemented for calendar years 2005 and 2006, with the anticipation that an ongoing mechanism would be adopted as part of a general rate case and effective beginning in 2007.

PGE, Staff and all intervenors in this docket held settlement conferences in this docket on December 8, 2004, March 3, 2005, and March 14, 2005. As a result of those settlement discussions, PGE and Staff are entering into this Stipulation requesting implementation of a temporary automatic adjustment tariff applicable to calendar years 2005 and 2006.[2] Specifically, Staff and PGE agree to and request that the Commission adopt orders in this docket implementing the following:

STIPULATION

1. For purposes of this Stipulation, Base Power Costs for each year are defined as the costs included in PGE's final RVM MONET run filed in mid-November of the previous year, as updated for cost of service loads and corresponding costs to reflect customer elections made in November.

2. For purposes of this Stipulation, Updated Power Costs for each year will be determined by taking the Base Power Cost MONET run and updating it for the following factors:

a) Actual hourly hydro generation;

b) Actual market electricity prices using daily on-peak and off-peak prices from the Dow Jones Mid-Columbia Daily Electricity Firm Price Index and the hourly price shape from the Dow Jones Mid-Columbia Hourly Electricity Price Index.

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[2] As set forth below, Staff and PGE agree to support and request an order in docket UM 1187, the hydro deferral filed by PGE, implementing the terms of the adjustment mechanism agreed to in this docket beginning January 1, 2005.

c) Actual market natural gas prices using the Platts GasDat daily index prices for Sumas, AECO, and Malin.

3. The System Dispatch Cost Variance ("SDCV") is the difference between the Updated Power Costs and Base Power Costs. The SDCV will be deferred into a new account, the SDCV Account, subject to the following provisions:

a) If the SDCV is negative (i.e., Updated Power Costs are less than Base Power Costs), then deferral of the SDCV will be subject to a deadband of $7.5 million.

b) If the SDCV is positive (i.e., Updated Power Costs are higher than Base Power Costs), then deferral of the SDCV will be subject to a deadband of $15 million.

c) Eighty percent of SDCV amounts outside these deadbands will be deferred into the SDCV Account.

4. A positive SDCV Account balance may be charged to customers subject to the following provisions. The amount to be charged to customers will be called the SDCV Recovery Amount. An earnings test will be applied to determine the SDCV Recovery Amount:

a) The SDCV Recovery Amount will be limited to amounts that result in PGE earning no greater than the return on equity ("ROE") authorized in its last general rate case, 10.5%, on a regulated basis.

b) All amounts which result in PGE earning an ROE in excess of 10.5% on a regulated basis will not be recovered and may not be carried over to future periods.

5. A negative SDCV Account balance may be refunded to customers subject to the following provisions. The amount to be refunded to customers will be called the SDCV Refund Amount. An earnings test will be applied to determine the SDCV Refund Amount:

a) The SDCV Refund Amount will be limited to amounts that result in PGE earning no less than the return on equity ("ROE") authorized in its last general rate case, 10.5%, on a regulated basis.

b) All amounts which result in PGE earning an ROE less than 10.5% on a regulated basis will not be refunded and may not be carried over to future periods.

6. The earnings test shall be subject to the following provisions:

a) Actual power cost- rather than normalized power costs will be used.

b) All other elements of the earnings test will be determined in a manner consistent with the Commission's decisions in PGE's last general rate case, in a form generally provided in PGE's annual Results of Operations Report filed with the OPUC. Adjustments will be limited to Type 1 adjustments only.

7. Amortization of any SDCV Recovery Amount or SDCV Refund Amount will be determined by the Commission for each year. If approved by the Commission, amortization of the SDCV Recovery Amount may begin, subject to refund, prior to the Commission's final determination of SDCV Recovery Amount.

8. The deferral and amortization of power cost variances described in this Stipulation constitutes an automatic adjustment clause under the terms of ORS 757.210.

9. Interest will accrue on any SDCV Account balance at the interest rate authorized by the Commission for deferred accounts, which is currently PGE's authorized overall cost of capital. In addition, catch-up interest will apply to the SDCV Account balance by multiplying the balance by one-half and then multiplying by PGE's authorized interest rate.

10. Staff and PGE request implementation of a tariff consistent with the terms of this Stipulation beginning on the first day of the month following Commission approval. Staff and

PGE also agree to request and support deferral, beginning January 1, 2005, and amortization of power cost variances consistent with this Stipulation in Docket No. UM 1187. For the purpose of calculating the variance deferred between January 1, 2005, and the effective date of a tariff consistent with the terms of this Stipulation, the same method described above for calculating the SDCV Account balance and the SDCV Recovery Amount and SDCV Refund Amount shall apply.

11. The characteristics and terms of an ongoing power cost adjustment mechanism for calendar year 2007 and thereafter will be addressed in PGE's next general rate case. This Stipulation will not be used in whole or part as precedent in that proceeding. This Stipulation provides for a temporary mechanism only.

12. PGE agrees to obtain appropriate consultation services for the purpose of evaluating the statistical distribution of net power costs, at a cost of up to $100,000. The analysis will consider the volatility of hydro generation, electricity prices, natural gas prices, system load, forced outages, and any correlations between these variables. Staff and PGE will work together to formulate a work statement to guide the work of the consultant. PGE will schedule quarterly public workshops to provide progress reports and receive input from interested parties. Staff and PGE reserve the ability to accept or reject the opinion or work product of the consultant for use in ratemaking, including in PGE's next general rate case. The consultant will report results by December 31, 2005, unless Staff and PGE agree to a different date. PGE will not seek recovery of the cost of these consultation services from customers.

13. Staff and PGE agree that this Stipulation is in the public interest and will produce rates that are fair, just and reasonable.

14. Staff and PGE shall file this Stipulation with the Commission. Staff and PGE agree to support this Stipulation before the Commission and before any court in which this Stipulation may be considered. If the Commission rejects all or any material part of this Stipulation or the Stipulation in UM-1187, or adds any material condition to any final order which is not contemplated by this Stipulation, each party reserves the right to withdraw from this Stipulation upon written notice to the Commission and the other party within five (5) business days of service of the final order rejecting this Stipulation or the UM-1187 Stipulation, or adding such material condition.

15. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

16. The parties to any dispute concerning this Stipulation agree to confer and make a good-faith effort to resolve such dispute prior to bringing an action or complaint to the Commission or any court with respect to such dispute.

17. Staff and PGE agree that this Stipulation represents a compromise in their positions. As such, conduct, statements, and documents disclosed in the negotiation of this Stipulation shall not be admissible as evidence in this or any other proceeding. Staff and PGE agree that a Commission order adopting this stipulation will not be cited as precedent in other proceedings for the matters resolved in this stipulation.

18. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR § 860-14-0085. Staff and PGE agree to cooperate in drafting and submitting the explanatory brief or written testimony required by OAR § 860-14-0085(4).

19. By entering into this Stipulation, no party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

20. Appendix A to this Stipulation is a Term Sheet which provides further description of the terms of the Stipulation.

DATED THIS // th day of April, 2005.

PORTLAND GENERAL ELECTRIC COMPANY	STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON
______________________	______________________

19. By entering into this Stipulation, no party shall be deemed to have approved, admitted or consented to tlae facts, principles, methods or theories employed by any other party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

20. Appendix A to this Stipulation is a Term Sheet which provides further description of the terms of the Stipulation.

DATED THIS____day of April, 2005.

PORTLAND GENERAL ELECTRIC COMPANY	STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON
______________________	______________________

UE-165/UM-1187 Settlement Term Sheet

- Base Power Costs are defined as the costs included in PGE's final RVM Monet run filed in mid-November, with updated cost of service loads to reflect customer elections in November.

- Updated Power Costs start with the Base Power Cost Monet run and update for the following factors:

  1. Actual hourly hydro generation.
  2. Actual electric prices using Dow Jones Mid Columbia Hourly Index prices to shape Dow Jones Mid Columbia Daily Index on and off-peak prices to hourly prices.
  3. Actual gas prices using daily index prices. Monet must be modified to accept daily gas prices.
  4. The procedure for updating Monet is more fully described in Attachment 1.

- The total variance is defined as the difference between the Updated Power Costs and Base Power Costs. The following sharing applies:

  1. A dead band of $15 million for higher power costs, $7.5 million for lower power costs
  2. All variances beyond $15 million (higher power costs) or $7.5 million (lower power costs) are shared 80 / 20 (Customers/PGE).

- An earnings test will be applied to determine a reasonable level of amortization. The following parameters apply to the earnings test:

  1. Recovery of any deferred amounts will be limited to those that result in PGE earning no greater than a 10.5% ROE on a regulated basis. All deferral amounts which result in PGE earning an ROE that exceeds 10.5% on a regulated basis will be written off.
  2. Refund of any deferred amounts will be limited to those that result in PGE earning no less than a 10.5% ROE on a regulated basis. All deferral amounts which result in PGE earning an ROE that is less than 10.5% on a regulated basis will be written off.
  3. For the purposes of the earnings test, actual power costs will be used rather than normalized power costs.
  4. All other elements of the earnings test will leverage from Commission decisions in PGE's last general rate case (UE-115) and which are generally provided in PGE's annual Results of Operations Report filed with the OPUC. Adjustments will be limited to Type 1 adjustments only.
  5.

- Amortization of any deferred amounts, after application of the earnings test, will be decided later by the Commission. There will be two separate amortization dockets (one for any 2005 deferral, another for any 2006 deferral). At PGE's request, the parties agree to consider amortization of deferred amounts (subject to refund) prior to the Commission's final determination of deferral amounts.

- Parties agree to support this stipulation in the UE-165 docket for purposes of implementation beginning the calendar month after Commission approval of the stipulation. In addition, parties agree to support this stipulation in the UM-1187 docket for purposes of implementation beginning 1/1/2005.

- The characteristics of an on-going PCA for 2007 and beyond will be addressed in PGE's next general rate case. This agreement will not be used as a precedent in that proceeding.

- PGE agrees to provide $100,000 (not recoverable from customers) for the purpose of evaluating the statistical distribution of net power costs. The analysis will consider the volatility of hydro generation, electricity prices, natural gas prices, system load, forced outages, and any correlations between these variables. The parties to the stipulation will work together to formulate a work statement to guide the work of the consultant. PGE will schedule quarterly public workshops to provide progress reports and receive input from interested parties. All parties are free to accept or reject the opinion or work products of the consultant for use in rate making, including PGE's next general rate case. Unless otherwise agreed to by the parties, the consultant will report results by 12/31/2005.

- Interest will accrue on any deferred amounts at the interest rate authorized by the Commission for deferred accounts, which is currently PGE's authorized overall cost of capital. In addition, catch-up interest will apply to the deferred amount by taking the deferral amount, multiplying by ½(i.e., assuming the deferred amount accrues equally through the year) and multiplying by PGE's authorized interest rate.

g:\ratecase\opuc\dockets\ue-165_hydrotariff\settlement\term sheet.doc

Attachment 1 of Term Sheet
Monet Update Methodology

Updated Power Costs begin with the "Base Power Cost Monet run" and updates for actual hydro generation, electric prices and gas prices. The following outlines the specific procedures.

Actual Hydro Generation

Procedure
Take actual hydro hourly generation for each PGE hydro plant (PGE 66.67% shares of Pelton and Round Butte), Portland Hydro Project, and total Mid-C generation according to our Power Scheduling and Accounting System (PSAS). Because of the Mid-C hourly dispatch logic implemented in the 2005 RVM and continuing in the 2006 RVM, it will be necessary to override this logic to input the hourly Mid-C generation to Monet. One way to do this without modifying the Monet Visual Basic source code is to create a new PGE resource called "Mid-C Actual Generation", which would appear as a new line item in the Hydro Resource section of the Monet Energy report. Then, for each PGE hydro plant, the Portland Hydro Project and the Mid-C as a total, hourly generation will be placed into the hourly factor cells of the WSCCHydroConditionl Sheet. The monthly factors will be adjusted to cancel with the product of the plant capacity and the annual factor. Then, there are three consequential contract effects of updating the hydro energy in Monet and the treatment of Daylight Savings Time.

1. Wells Settlement Agreement: This is a hydro-related contract whose energy and price is modeled as a function of the Wells plant generation. The modeling assumes that if there is more generation from Wells, PGE will receive more energy under the Wells Settlement Agreement. Further, the modeling bases the Wells Settlement Agreement pricing on the Wells plant energy. To capture both of these consequential effects of updating the hydro energy, we would need to obtain and model the monthly Wells plant generation on the PC_Input sheet and modify the Wells Settlement Agreement formulas on the PC_Input sheet accordingly.

2. Tribes Mid-C Index Purchase: This is an index-priced purchase from the Confederated Tribes of Warm Springs based on their share of Round Butte, Pelton and Regulating Project's generation after accounting for any fixed-priced sales of energy to PGE. Even though this is an index-priced purchase, it is indexed at the Mid-C, while in Monet the energy is incrementally valued at the PGE price, which is greater than the Mid-C price by 1.9% transmission losses, or roughly 1 $/MWh at a market price of 50 $/MWh. To capture this consequential effect of updating the hydro energy, we would update the monthly Round Butte and Pelton (and possibly the Regulating Project) plant generation on the PC_Input sheet, which would then flow through the modeling of the Tribes Mid-C Index Purchase.

3. Priest Rapids Renewal Contract Reasonable Portion Auction Payment: This is one component of the series of contracts that constitute the Priest Rapids Renewal. As modeled in the 2005 RVM, updating either the Priest Rapids hydro energy or the market electric price affects the Reasonable Portion Auction Payment.

4. Daylight Savings Time: Monet does not model Daylight Savings Time. We will adjust market electric prices and hydro generation as necessary to develop Updated Power Costs.

Actual Gas Prices

Procedure
Take daily index prices for Sumas, AECO and Malin from the Platts Database "GasDat" per Table 1. Enhance Monet to accept daily gas prices and input these to Monet. The other uses of the monthly gas prices in Monet excluding the fueling of Beaver and Coyote Springs, such as the gas transportation variable loss costs and Glendale Sales contract prices, would continue to use the monthly modeling on the PC_Input sheet. The monthly gas prices on the PC_Input Sheet would be calculated as the average of the daily index gas prices for that month. The gas financials (e.g. swaps) would be updated to the actual, settled values of the RVM swaps, which are settled based on monthly (not daily) gas index prices and the spot Canadian/US foreign currency exchange (F/X) rate at settlement. The RVM gas physical transactions, if any, would have their weighted average costs of gas (WACOGs) updated based on the actual, settled values of those transactions, which are again based on monthly index prices and the spot F/X rate at settlement. We will update the value of any RVM Canadian Dollar hedges to reflect the actual settled value of such hedges.

Table 1
Gas Price Index

Monet	Platts GasDat
Sumas	Gas Daily "Sumas", $US
AECO	Gas Daily "Nova(Aeco-C,NIT)", $US
Malin	Gas Daily "Malin", $US

Actual Electric Prices

Procedure
Take daily on/off-peak and hourly index prices for the Mid-C from Dow Jones. Apply the hourly index shape to the daily on/off-peak index to obtain an hourly electric price whose price level is based on the daily index but whose hourly shape is based on the hourly index. This is done to preserve the hourly volatility present in the hourly index prices while maintaining the simultaneous day-ahead views of the electric and gas market prices. Any gaps in the hourly data would be filled in based on shapes from similar periods where data are available. At some point in the process before inputting the prices to Monet, multiply the Mid-C prices by the factor 1.019 to convert them to PGE prices, consistent with the RVM model.

Dispatchable Contracts

Procedure
PGE will also appropriately model any dispatchable contracts based on the terms (e.g., capacity, heat rate, natural gas price index, exercise fee, etc.) and constraints (e.g., minimum take in hours, maximum take for delivery period, etc.) of the contracts, using the actual gas and electric prices used in the Updated Monet run. Current dispatchable contracts include:

- Superpeak Capacity Agreement
- ColdSnap Capacity Agreement
- On-Peak Tolling Agreement

CERTIFICATE OF SERVICE

I certify that I have caused to be served the foregoing **Stipulation Between Portland General Electric Company and Oregon Public Utility Commission Staff in Docket UE 165** by mailing a copy by First Class U.S. Mail, postage prepaid and properly addressed, and by electronic mail, to the following persons on the official service list maintained by the Commission:

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Dated this 11th day of April, 2005.

DOUGLAS C. TINGEY