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June 1, 2006

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
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RE: **Docket No. UM 1234** - In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Application for Deferred Accounting of Excess Power Costs Due to Plant Outage.

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

/s/ Kay Barnes

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c: UM 1234 Service List - parties

PUBLIC UTILITY COMMISSION
OF OREGON

UM 1234

STAFF RESPONSE TESTIMONY OF

Carla Owings
Maury Galbraith

In the Matter of
PORTLAND GENERAL ELECTRIC COMPANY
Application for Deferred Accounting of Excess Power Costs Due to Plant Outage

June 1, 2006

CASE: UM 1234
WITNESS: Owings-Galbraith

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Response Testimony

June 1, 2006

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

A. My name is Carla Owings. The Public Utility Commission of Oregon employs me as a Senior Analyst in the Rates and Tariffs section of the Electric and Natural Gas Division.

My name is Maury Galbraith. The Public Utility Commission of Oregon employs me as a Senior Analyst in the Electric and Natural Gas Division. Our business address is 550 Capitol Street NE, Suite 215, Salem, Oregon 97301-2551. Our Witness Qualification Statements are provided in Exhibit Staff/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of our testimony is to provide evidence regarding the appropriateness of Portland General Electric's (PGE or Company) request to defer excess power costs associated with a forced outage at the Boardman Generating Facility (Boardman) that began on October 23, 2005.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. First, we summarize PGE's deferral request. Second, we analyze PGE's calculation of the excess power costs due to the Boardman outage. We then provide our own calculation of the excess costs. Fourth, we summarize the Commission's policy regarding approval of deferred accounting applications and analyze whether PGE's application satisfies the Commission's criteria for deferral. We conclude with Staff recommendations.

I. PGE'S BOARDMAN DEFERRAL APPLICATION

Q. WHAT IS PGE REQUESTING IN THIS DEFERRAL APPLICATION?

A. PGE is requesting authorization pursuant to ORS 757.259(2)(e) to defer, for later recovery in rates, approximately $45.4 million in excess net power costs incurred between November 18, 2005 and February 5, 2006, due to an October 23, 2005 forced outage at the Boardman plant. In its direct testimony the company indicates that:

- It incurred an additional $14 million in excess power costs between October 23, 2005 and November 18, 2005;
- A 105-day forced outage at Boardman was not modeled in rates, was not foreseeable as happening in the normal course of events, and was not reasonably predictable and quantifiable;
- The financial impact of the October 23, 2005 through February 5, 2006 outage is equivalent to 355 basis points of PGE's ROE;
- Granting its deferral request will minimize the frequency of rate changes; and
- Granting its deferral request will appropriately match the costs borne by and benefits received by ratepayers.

II. PGE'S CALCULATION OF EXCESS POWER COSTS

Q. PLEASE SUMMARIZE THE RESULTS OF PGE'S CALCULATIONS OF EXCESS POWER COSTS.

A. PGE estimates that the company incurred approximately $64.2 million in excess power costs during the October 23, 2005 through February 5, 2006 outage period and $50.1 million during the November 18, 2005 through February 5, 2006 deferral period.

Q. ARE PGE'S CALCULATIONS ACCURATE?

A. No. PGE's method of calculating excess power costs is flawed. In addition, the company made several minor errors in its calculations. The following table provides a comparison of the results of the PGE and Staff calculations of excess power costs.

Table 1. PGE and Staff Calculations of Excess Power Costs Due to the Boardman Outage.

	Pre-Deferral Period	Deferral Period	Outage Period
PGE			
Replacement Energy (MWh)	238,930	732,922	971,851
Replacement Cost ($000)	16,856	59,043	75,898
Baseline Cost ($000)	2,795	8,895	11,690
Excess Cost ($000)	14,061	50,147	64,208
Maintenance Offset ($000)		4,764	4,764
Net Excess Cost ($000)		45,383	59,444
Staff			
Replacement Energy (MWh)	223,367	685,184	908,551
Replacement Cost ($000)	15,471	54,204	69,675
Baseline Cost ($000)	2,575	8,153	10,728
Excess Cost ($000)	12,896	46,050	58,947
Maintenance Offset ($000)		3,230	3,230
Net Excess Cost ($000)		42,820	55,717

Q. PLEASE SUMMARIZE THE FLAWS IN PGE'S METHOD OF CALCULATING EXCESS POWER COSTS.

A. First, PGE overstated the amount of replacement energy. Second, PGE inappropriately included line losses in its cost calculations. These flaws inflate replacement power costs and result in an inappropriate baseline from which to gauge excess costs. The baseline power costs should equal the amount of Boardman power costs included in PGE's 2005 and 2006 base rates.

Q. HOW DID PGE CALCULATE THE AMOUNT OF REPLACEMENT ENERGY?

A. PGE calculated replacement energy based on its 65 percent share of the rated capacity of the Boardman plant. PGE's share of the rated capacity of the Boardman plant was 382.9 MW in the 2005 RVM and 380.3 MW in the 2006 RVM.

Q. DOES THIS AMOUNT OF REPLACEMENT ENERGY REFLECT THE AMOUNT OF BOARDMAN GENERATION INCLUDED IN PGE'S RATES?

A. No. The amount of Boardman generation included in PGE's rates is based on PGE's share of the de-rated capacity of the plant. PGE's share of the de-rated capacity of the Boardman plant, based on a 6.5 percent forced outage rate, was 358.0 MW in the 2005 RVM and 355.5 MW in the 2006 RVM.

Q. HOW DID PGE CALCULATE REPLACEMENT POWER COSTS?

A. PGE's power operations group purchased replacement energy in the forward, day-ahead, and real-time electricity markets. (*See* PGE/200 Quennoz – Mayer/6-7.) PGE "stacked" the purchased energy to reach the level of replacement energy. Forward-market purchases and day-ahead market purchases comprised the first resource stack. Real-time purchases comprised the second resource stack. Resource stacking on a daily on- and off-peak basis continued up to the point of meeting the determined amount of Boardman replacement energy. At the end of the resource stacking process, any remaining replacement gap was filled with assumed purchases at Dow Jones Mid-Columbia Daily Firm Index prices. Replacement power costs were calculated on a daily on- and off-peak basis by multiplying the replacement quantity (in MWh) by the average replacement price (in $ per MWh) of each resource stack and adding costs across resource stacks.

Q. DID PGE INCLUDE A LINE LOSS ADDER IN ITS CALCULATIONS OF REPLACEMENT POWER COSTS?

A. Yes. PGE included a 1.9 percent adder for contractual losses on the BPA transmission system in its calculation of replacement costs and baseline costs.

Q. DOES PGE INCLUDE THIS LINE LOSS ADDER IN ITS MONET MODELING OF THE AMOUNT OF NET VARIABLE POWER COSTS TO INCLUDE IN RATES?

A. No. PGE includes the line losses in the load forecast used to estimate net variable power costs. Applying the 1.9 percent adder to replacement power costs and baseline costs is inconsistent with the modeling of line losses in general rate cases and RVM proceedings and causes double-counting.

Q. HOW DID PGE CALCULATE BASELINE POWER COSTS?

A. PGE calculated baseline power costs on a daily basis by multiplying Boardman generation, based on PGE's share of the rated capacity of the plant, by the incremental fuel and fuel transportation costs used in the 2005 and 2006 RVM forecasts. PGE then applied the 1.9 percent adder for line losses.

Q. PLEASE SUMMARIZE THE RESULTS OF PGE'S CALCULATIONS OF BASELINE POWER COSTS.

A. PGE puts baseline power costs at approximately $11.7 million during the October 23, 2005 through February 5, 2006 outage period and at $8.9 million during the November 18, 2005 through February 5, 2006 deferral period.

Q. DO PGE'S BASELINE AMOUNTS REFLECT THE AMOUNT OF BOARDMAN COST INCLUDED IN RATES?

A. No. The Boardman fuel and fuel transportation costs included in PGE's rates total approximately $10.7 million for the outage period and $8.2 million for the deferral period. The discrepancy between PGE's baseline costs and the Boardman costs included in PGE's rates is attributable to PGE's replacement energy and line loss assumptions.

Q. SHOULD THE REPLACEMENT ENERGY AND BASELINE COSTS USED IN CALCULATING EXCESS POWER COSTS MATCH THE AMOUNTS INCLUDED IN PGE'S BASE RATES?

A. Yes. The amount of replacement energy used to calculate replacement power costs should reflect the amount of Boardman generation included in base rates. PGE's base energy rates include allowances for plant forced outages. PGE has already recovered normal replacement power costs associated with a forced outage rate of 6.5 percent at the Boardman plant during the October 23, 2005 through February 5, 2006 outage period. PGE's calculation of excess power costs fails to account for this pre-determined recovery and results in a double-counting of replacement power costs.

The baseline power costs should also reflect the amount of Boardman power costs already recovered in base rates. The baseline amounts should be netted against the total replacement power costs to calculate excess net power costs. This methodology ensures a full accounting of replacement power costs.

Q. PLEASE SUMMARIZE THE ERRORS PGE MADE IN ITS CALCULATIONS OF EXCESS POWER COSTS.

A. PGE erred in calculating the daily on- and off-peak average price or quantity of pre-scheduled power purchases on the following deferral period dates: November 11, 2005; November 13-14, 2005; November 20-21, 2005; and November 24-28, 2005. In most instances PGE assigned a two-day average price or average quantity of pre-scheduled purchases to each of the two days, when in fact the daily prices or quantities were different. (*See* PGE Response to Staff Data Request No. 40.) For example, PGE's power operations group purchased 4,800 MWh of off-peak energy for delivery on November 27-28. In its calculation of replacement power costs, PGE assigned 2,400 MWh to November 27th and 2,400 MWh to November 28th. However, PGE's transaction database indicates that the purchases provided 3,600 MWh on November 27th and 1,200 MWh on November 28th.

PGE also erred in its calculations for December 15, 2005. PGE included 1,200 MWh of off-peak energy from pre-scheduled power purchases that had been incorrectly coded (or "flagged") as Boardman replacement transactions. (*See* PGE Response to Staff Data Request No. 39.)

Q. PLEASE SUMMARIZE THE RESULT OF PGE'S CALCULATION OF AVOIDED MAINTENANCE SAVINGS.

A. Prior to a second forced outage that began February 6, 2006 and ended May 23, 2006, PGE was able to complete maintenance scheduled for a planned outage at Boardman. (*See* PGE/300, Drennan – Tinker – Hager/2-3.) PGE estimates that the company would have earned, but for the second forced outage, $4.8 million from wholesale sales during the April 29, 2006 through May 27, 2006 planned maintenance period.

Q. ARE PGE'S CALCULATIONS ACCURATE?

A. No. First, PGE used the rated capacity of the Boardman plant and the line loss adder in the earnings calculations. Second, PGE erred in its calculations for April 29, 2006. PGE included 800 MWh of forward market sales in its calculations even though its transaction database does not included any "flagged" forward market sales with April delivery. Finally, at the time of its direct testimony, the company used its February 3, 2006 forward electricity price curves to calculate the revenues from Boardman generation remaining to be sold in the day-ahead and real-time markets. Actual day-ahead index prices are now available and can be used to value the Boardman generation that could have been sold in the day-ahead market.

III. STAFF'S CALCULATION OF EXCESS POWER COSTS

Q. PLEASE EXPLAIN THE METHOD STAFF USED TO CALCULATE REPLACEMENT POWER COSTS.

A. PGE's power operations group purchased replacement energy in the forward, day-ahead, and real-time electricity markets. Staff "stacked" the purchased energy to achieve the appropriate level of replacement energy. Forward market purchases comprised the first resource stack. Day-ahead and real-time purchases comprised the second and third resource stacks. Resource stacking on a daily on- and off-peak basis continued up to the point of meeting the appropriate amount of Boardman replacement energy. For example, if forward market purchases covered the amount of Boardman replacement energy, then day-ahead and real-time purchases were not used in the replacement resource stack. At the end of the resource stacking process, any remaining replacement gap was filled with assumed purchases at Dow Jones Mid-Columbia Daily Firm Index prices. Replacement power costs were calculated on a daily on- and off-peak basis by multiplying the replacement quantity (in MWh) by the average replacement price (in $ per MWh) of each resource stack and adding costs across resource stacks.

Q. IS STAFF'S RESOURCE STACKING METHODOLOGY SIMILAR TO PGE'S METHODOLOGY?

A. Yes. However, Staff treated forward market purchases and day-ahead purchases as separate resource stacks, whereas PGE blended these types of purchases into a single resource stack. Staff used the de-rated capacity of the Boardman plant to set the amount of replacement energy and excluded PGE's line loss adder from the cost calculations.

Q. PLEASE EXPLAIN THE METHOD STAFF USED TO CALCULATE BASELINE POWER COSTS.

Staff calculated baseline power costs on a daily on- and off-peak basis by multiplying Boardman generation, based on PGE's share of the de-rated capacity of the plant, by the incremental fuel and fuel transportation costs used in the 2005 and 2006 RVM forecasts.

Q. DOES STAFF'S BASELINE CALCULATION REFLECT THE AMOUNT OF BOARDMAN COST INCLUDED IN PGE'S BASE RATES?

A. Yes.

Q. CAN YOU RECONCILE THE DIFFERENCE BETWEEN PGE'S CALCULATION OF EXCESS POWER COSTS AND STAFF'S CALCULATION OF EXCESS POWER COSTS?

A. Yes. The following table provides a reconciliation of the PGE and Staff calculations of excess power costs.

Table 2. Reconciliation of PGE and Staff Calculations of Excess Power Costs Due to Boardman Outage ($000).

	Pre-Deferral Period	**Deferral Period**	**Outage Period**
PGE Excess Cost	**14,061**	**50,147**	**64,208**
Correct Calculation Errors	6	-24	-18
Remove Line Losses	-262	-934	-1,197
Use De-rated Capacity	-909	-3,139	-4,046
Staff Excess Cost	**12,896**	**46,050**	**58,947**

Q. HAS STAFF UPDATED PGE'S CALCULATION OF SAVINGS DURING THE AVOIDED MAINTENANCE PERIOD?

A. Yes. Staff puts the avoided maintenance savings at $3.2 million. Staff used the de-rated capacity of the Boardman plant, excluded PGE's line loss adder, and corrected PGE's calculation error. Staff also used Dow Jones Mid-Columbia Firm Index prices to value Boardman generation not sold in the forward market.

Q. WHAT AMOUNT OF EXCESS POWER COSTS SHOULD THE COMMISSION APPLY TO ANY CUSTOMER-SHAREHOLDER SHARING MECHANIM?

A. As long as all of the costs were prudently incurred, the Commission should apply $42.8 million of net excess power costs to any deferral mechanism. This number is derived by subtracting the $3.2 million in maintenance period savings from the $46 million in deferral period excess power costs. The question of whether the costs were prudently incurred should be examined at the time the Company seeks to amortize the costs into rates.

IV. COMMISSION POLICY REGARDING DEFERRAL APPLICATIONS

Q. CAN YOU DESCRIBE COMMISSION POLICY REGARDING AUTHORIZATION OF DEFERRED ACCOUNTING?

A. Yes. Oregon Revised Statue 757.259 sets out a two-stage decision process. One stage, delineated in subsections (a) to (e) of the statue, requires that the Commission determine whether a deferral request is authorized by law. The other stage entails an exercise of Commission discretion. The legal determination is necessary, but not in and of itself sufficient, for the Commission to authorize deferred accounting. (*See* Order 04-108 at 8.)

Q. HAS THE COMMISSION IDENTIFIED CONSIDERATIONS THAT INFLUENCE WHETHER IT WILL EXERCISE ITS DISCRETION TO GRANT A DEFERRAL REQUEST?

A. Yes. In Order 04-108, the Commission identified the type of event leading to the deferral request and the magnitude of the event's financial impact as two interrelated considerations that influence its decision to grant a deferral request. The Commission indicated that neither consideration is dispositive without the other. (*See* Order 04-108 at 8.)

Q. WHAT TYPE OF EVENT IS APPROPRIATE FOR DEFERRED ACCOUNTING?

A. The Commission has indicated that deferred accounting is more appropriate for extraordinary events that are not susceptible to prediction and quantification. (*See* Order 04-108 at 8.) This type of event occurs at an unknown frequency and can be characterized as a scenario or paradigm risk. On the other hand, events that occur during the normal course of business, at a frequency that is quantifiable, are less appropriate for deferred accounting. This type of event is often characterized as a stochastic risk.

Q. DOES THE COMMISSION CONSIDER WHETHER THE EVENT WAS MODELED IN RATES?

A. Yes. In Order 05-1070, the Commission stated:

> The Commission will look to whether the event was modeled in rates, and, if so, whether extenuating circumstances were involved that were not foreseeable during the rate case, or whether the event fell within a foreseen range of risk when rates were last set. If the event was not modeled, we will consider whether it was foreseeable as happening in the normal course of events, or not likely to have been capable of forecast. The Commission will examine whether or not the "risks are reasonably predictable and quantifiable. (*See* Order 05-1070 at 7.)

Q. WHAT MAGNITUDE OF FINANCIAL IMPACT IS APPROPRIATE FOR DEFERRED ACCOUNTING?

A. For an event characterized as a stochastic risk to warrant deferred accounting, the financial impact on the utility must be substantial. (*See* Order 04-108 at 9.) The financial threshold for deferred accounting is lower for an event characterized as a scenario risk. For an event characterized as a scenario risk to qualify, the financial impact on the utility need only be material.

Q. DOES THIS TWO-STAGE DECISION PROCESS PROVIDE FLEXIBILITY FOR THE COMMISSION TO EXERCISE ITS DISCRETION?

A. Yes. The Commission has indicated that it will not evaluate deferral applications in a rigid manner. (*See* Order 05-1070 at 7.) However, the following matrix is illustrative of Commission policy regarding authorization of deferred accounting.

Table 3. Under What Circumstances Does the Commission Consider a Deferral?

Financial Effect **Type of Event**

	Stochastic Risk (1)(2)	Scenario Risk (3)(4)	Commission Approved (5)(6)
Substantial	Deferral Considered (7)	Deferral Considered	Deferral Considered
Material	Deferral Not Considered	Deferral Considered	Deferral Considered
Immaterial	Deferral Not Considered	Deferral Not Considered	Deferral Considered

(1) Stochastic risk is defined as a risk that can be predicted as part of the normal course of events; it is quantifiable and can be represented by a known statistical distribution (Order 04-108).

(2) Examples of stochastic risk are hydro variability, normal plant outages, employee compensation, and weather.

(3) Scenario risk is defined as a risk that is not susceptible to prediction and quantification; it is often represented by abrupt changes in business factors or practices (Order 04-108).

(4) Examples of scenario risk are catastrophic plant outages (Trojan), environmental costs, and material unexpected changes to costs.

(5) These events are either mandated, pursuant to Commission approval, or emerging from a rate case settlement.

(6) Examples of these events are DSM costs, a PGA, and intervenor funding.

(7) Event should be extraordinary.

V. STAFF ANALYSIS OF PGE's DEFERRAL APPLICATION

Q. DOES STAFF CATEGORIZE A FORCED OUTAGE AS A STOCHASTIC OR SCENARIO RISK?

A. Staff considers generating plant forced outages to be a stochastic risk. Outages occur during the normal course of business and at a frequency and magnitude that are quantifiable.

Q. IS THE POSSIBILITY OF A FORCED OUTAGE AT THE BOARDMAN PLANT MODELED IN PGE'S RATES?

A. Yes. For example, in both the 2005 and 2006 RVM proceedings PGE modeled a forced outage rate of 6.5% at the Boardman plant. This is equivalent to one 24-day forced outage per year.

Q. IS THE 105-DAY BOARDMAN OUTAGE UNDER CONSIDERATION IN THIS DOCKET AN EXTRAORDINARY EVENT?

A. Yes. First, PGE's analysis of data from the North American Electric Reliability Council's (NERC) Generating Availability Data System (GADs) indicates that outages exceeding 105 days account for approximately 0.25 percent of all outages. (*See* PGE/300, Drennan – Tinker – Hager/4-5.) Second, assuming that the 329 generating units included in the 20-year data extract represent roughly 6,000 unit-years of operation, an outage with duration greater than 104 days occurs roughly once every 100 years (i.e., 6,000 unit-years of operation divided by 52 outages that lasted 105 days or longer implies one such outage roughly every 100 years).

Q. DOES THE LOW RELATIVE FREQUENCY OF THESE EXTENDED OUTAGES PRECLUDE THEIR QUANTIFICATION AND INCLUSION IN BASE RATES?

A. No.

Q. DOES THE EXTRAORDINARY NATURE OF THE BOARDMAN OUTAGE JUSTIFY DEFERRED ACCOUNTING?

A. Yes. But, this consideration is not dispositive on its own. The Commission has indicated that for an event characterized as a stochastic risk to qualify for deferred accounting the financial impact on the utility must be substantial.

Q. WHAT IS THE MAGNITUDE OF THE FINANCIAL IMPACT OF THE BOARDMAN OUTAGE?

A. Staff estimates that the excess power costs associated with the deferral period reduce return of equity (ROE) by 255 basis points. The outage period impact is a 332 basis point reduction in ROE. Staff calculated these financial impacts using the same methodology shown at PGE/301, Drennan – Tinker – Hager/1.

Q. SHOULD THE COMMISSION ASSIGN MORE WEIGHT TO THE OUTAGE PERIOD IMPACT OR THE DEFERRAL PERIOD IMPACT?

A. The Commission should assign more weight to the deferral period impact because consideration of prior periods can lead to infinite regress. For example, Staff has estimated that the Boardman outage resulted in $12.9 million in excess power costs during the pre-deferral outage period (October 23, 2005 – November 17, 2005.) But why stop there? Did actual Boardman operations exceed the normalized level included in rates during the first part of 2005? What about 2004, and earlier?

Q. DOES THE MAGNITUDE OF THE FINANCIAL IMPACT OF THE BOARDMAN OUTAGE JUSTIFY DEFERRED ACCOUNTING?

A. Yes. The Boardman outage was an extraordinary event, and the financial impact on the utility is substantial. In this case, deferred accounting is justified.

Q. PGE ESTIMATES ITS CALENDAR YEAR 2005 RETURN ON EQUITY WILL BE 6.29 PERCENT. (*SEE* PGE/100, LESH/3 AND PGE/303, DRENNAN – TINKER – HAGER/1.) DOES STAFF CONCUR WITH PGE'S ESTIMATED ROE FOR 2005?

A. No. PGE based its calculation on Net Income reported in its 10k financial statement for the period ending December 31, 2005. (*See* PGE/303, Drennan – Tinker – Hager/1.) The reported Net Income of $64 million is adjusted for Allowance of Funds Used During Construction (AFUDC) and interest. These adjustments are not compatible with the Net Operating Income (or Utility Operating Income) typically used in the calculation of ROE for regulatory purposes. The estimated ROE also does not reflect standard regulatory adjustments that will be contained in PGE's Results of Operations Report for 2005. If the Commission wishes to consider PGE's calendar year 2005 return on equity in this proceeding then it should use verified results from PGE's Results of Operations Report for 2005, which is expected to be filed in June of 2006.

V. STAFF RECOMMENDATIONS

Q. DOES STAFF RECOMMEND A SHARING MECHANISM FOR ALLOCATING THE DEFERRAL PERIOD EXCESS POWER COSTS TO SHAREHOLDERS AND CUSTOMERS?

A. Yes. Staff recommends that the Commission adopt the three-tier sharing mechanism that was the basis for the Commission-approved deferral mechanism in PacifiCorp Docket UM 995. (*See* Order 01-420 at 5.) The three sharing tiers should be structured in the following manner:

1. Shareholders absorb 100 percent of the excess power costs in a deadband equivalent to 250 basis points of ROE;
2. Shareholders absorb 50 percent of the excess power costs in a sharing band between 250 and 400 basis points of ROE; and
3. Shareholders absorb 10 percent of the excess power costs beyond 400 basis points of ROE.

Staff believes this mechanism fairly allocates the risk of extraordinary power cost increases between rate cases to PGE and its customers.

Q. PLEASE CONVERT BASIS POINTS OF ROE TO DOLLARS.

A. For PGE, at the end of 2004, 100 basis points of ROE were equivalent to $16.8 million. (*See* PGE/301, Drennan – Tinker – Hager/1.) Restating the three sharing tiers in terms of this amount results in the following structure:

1. Shareholders absorb the deadband amount of $41.9 million in excess power costs;
2. Shareholders absorb 50 percent of any excess power costs above the deadband but less than $67.1 million; and

3. Shareholders absorb 10 percent of any excess power costs above $67.1 million.

Q. WHAT IS THE RESULT OF APPLYING THIS DEFERRAL MECHANISM TO PGE'S EXCESS POWER COSTS FROM THE BOARDMAN OUTAGE?

A. Application of the Staff deferral mechanism would result in PGE absorbing $42.4 million (99 percent) of the deferral period excess power costs due to the Boardman outage. The following table shows the application of Staff's recommended deferral mechanism.

Table 4. Application of Staff Deferral Mechanism to Excess Power Costs Due to Boardman Outage ($000).

	Tier Amount	PGE Share	Customer Share
Deadband	41,915	41,915	0
Tier 2 Sharing	905	452	453
Tier 3 Sharing	0	0	0
Total	42,820	42,367	453

Q. WHAT JUSTIFIES PGE'S SHAREHOLDERS ABSORBING THE DEADBAND AMOUNT OF $41.9 MILLION?

A. Between rate cases, PGE's shareholders typically bear the risk of generating plant outages and increased power costs. Staff recommends a 250 basis point deadband to capture the normal business risk that the company is generally exposed to between rate cases. Staff believes that 250 basis points of ROE represents normal variability that would not trigger a rate filing by the company or a show cause request by other parties.

Q. WHY DID STAFF APPLY THE ANNUAL DEADBAND AMOUNT TO THE 80-DAY BOARDMAN DEFERRAL PERIOD?

A. The Commission may authorize deferral applications under ORS 757.259(4) for a period not to exceed 12 months. As PGE indicated in its direct testimony, the company had the option to request a deferral to track the difference between actual net variable power costs and the normalized net variable power costs included in rates for up to 12 months. In general, the ability of an applicant to select the deferral period should not affect the determination of the amount of risk and reward that it typically bears between rate cases. In addition, the application of an annual deadband is consistent with the amortization decision under OAR 860-027-0300(9), which uses a review of the utility's financial results for an entire 12-month period, regardless of the length of the deferral.

Q. PGE INDICATES IN ITS DIRECT TESTIMONY THAT IF THE COMMISSION ADOPTS ITS RECOMMENDATION AND ALLOWS FULL COST RECOVERY, THEN THE COMPANY WILL ADJUST ITS FORECAST OF BOARDMAN AVAILABILITY WHEN SETTING RATES ON A GOING-FORWARD BASIS. (SEE PGE/100, LESH/6-7.) IS PGE'S PROPOSAL REASONABLE?

A. No. If PGE continues to forecast Boardman's availability based on a four-year rolling average, then regardless of whether the Commission adopts PGE's recommendation, Staff' recommendation, or an intervenor's recommendation, the calculation of the four-year average should reflect Boardman as 100 percent available during the deferral period. Anything short of this would simply circumvent the Commission's final decision in this docket. It would be reasonable, however, to include the pre-deferral outage period in the calculation of the four-year average.

Q. DID PGE INCLUDE THE OCTOBER 23, 2005 OUTAGE IN THE FOUR-YEAR AVERAGE USED TO SET BOARDMAN'S FORCED OUTAGE RATE IN DOCKET UE 180?

A. Yes. The 70 days of outage from October 23, 2005 through December 31, 2005 are included in PGE's calculation of the four-year average availability of Boardman. (*See* UE 180, PGE/400, Lesh – Niman/20 and UE 181, PGE/100, Tooman – Niman – Schue/12-13.)

Q. IS THE PRIMARY PURPOSE OF INCLUDING FORCED OUTAGE RATES IN THE MODELING OF NORMALIZED NET POWER COSTS TO PROVIDE AN OPPORTUNITY FOR THE UTILITY TO RECOVER THE COST OF PAST FORCED OUTAGES ON A GOING-FORWARD BASIS?

A. No. The primary goal is to accurately forecast future plant availability.

Q. IS STAFF WILLING TO CONSIDER ALTERNATIVE METHODS OF FORECASTING FUTURE PLANT AVAILABILITY THAT WOULD MORE ACCURATELY, AND MORE PERMANENTLY, REFLECT THE POSSIBILITY OF EXTENDED FORCED OUTAGES IN RATES?

A. Yes. In previous dockets, Staff has proposed the use of Monte Carlo simulation to model plant forced outages in the determination of normalized net variable power costs for ratemaking purposes. Staff is also willing to consider a forced outage adder to account for outages that are more extreme than those reflected in a normal four-year rolling average.

Q. DOES STAFF INTEND TO FILE TESTIMONY ON THIS ISSUE IN DOCKET UE 180/ UE 181?

A. Yes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

CASE: UM 1234
WITNESS: Owings-Galbraith

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualification Statement

June 1, 2006

WITNESS QUALIFICATION STATEMENT

NAME:	Carla M. Owings
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst/Revenue Requirement/Rates and Regulation
ADDRESS:	550 Capitol Street NE Suite 215, Salem, Oregon 97301-2115.
EDUCATION:	Professional Accounting Degree Trend College of Business 1983
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since April of 2001. I am the Senior Utility Analyst for revenue requirement for the Rates and Regulation Division of the Utility Program. Current responsibilities include leading research and providing technical support on a wide range of policy issues for electric, telecommunications, and gas utilities. From September 1994 to April 2001, I worked for the Oregon Department of Revenue as a Senior Industrial/Utility Appraiser. I was responsible for the valuation of large industrial properties as well as utility companies throughout the State of Oregon.
OTHER EXPERIENCE:	I received my certification from the National Association of State Boards of Accountancy in the Principles of Public Utilities Operations and Management in March of 1997. I have attended the Institute of Public Utilities sponsored by the National Association of Regulatory Utility Commissioners at Michigan State University in August of 2002 and the College of Business Administration and Economics at New Mexico State University's Center for Public Utilities in May of 2004. In 2005, I attended the National Association of Regulatory Utility Commissioners Advanced Course at Michigan State University. I worked for seven years for the Oregon State Department of Revenue as a Senior Utility and Industrial Appraiser.

WITNESS QUALIFICATION STATEMENT

NAME: Maury Galbraith

EMPLOYER: Public Utility Commission of Oregon

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EDUCATION: Graduate Student in Environmental Studies Program (1995 – 1997)
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Master of Arts in Economics (1992)
Washington State University
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Bachelor of Science in Economics (1989)
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Eugene, Oregon

EXPERIENCE: The Public Utility Commission of Oregon has employed me since April 2000. My primary responsibility is to provide expert analysis of issues related to power supply in the regulation of electric utility rates.

From April 1998 through March 2000 I was a Research Specialist with the State of Washington Office of the Administrator for the Courts in Olympia, Washington.

From April 1993 through August 1995 I was a Safety Economist with the Pacific Institute for Research and Evaluation in Bethesda, Maryland.

CERTIFICATE OF SERVICE

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I certify that I have this day served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-13-0070, to the following parties or attorneys of parties.

Dated at Salem, Oregon, this 1st of June, 2006.

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