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June 1, 2006

Via Electronic Mail and U.S. Mail

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

Re: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Application for Deferred Accounting of Excess Power Costs Due to Plant Outage
Docket No. UM 1234

Dear Filing Center:

Enclosed please find the original and six copies of the Testimony of Randall Falkenberg on behalf of the Industrial Customers of Northwest Utilities in the above-captioned Docket.

Please return one file-stamped copy of the document in the self-addressed, stamped envelope provided. Thank you for your assistance.

Sincerely,

/s/ Christian Griffen
Christian W. Griffen

Enclosures

cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Testimony of Randall Falkenberg on behalf of the Industrial Customers of Northwest Utilities upon the parties, on the official service list shown below for UM 1234, via U.S. Mail and electronic mail.

Dated at Portland, Oregon, this 1st day of June, 2006.

/s/ Christian Griffen
Christian W. Griffen

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1234

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

DIRECT TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

June 1, 2006

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Sandy Springs, Georgia 30350.

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

A. I am a utility rate and planning consultant holding the position of President and Principal with the firm of RFI Consulting, Inc. ("RFI"). I am appearing in this proceeding as a witness for the Industrial Customers of Northwest Utilities ("ICNU").

Q. PLEASE BRIEFLY DESCRIBE THE NATURE OF THE CONSULTING SERVICES PROVIDED BY RFI.

A. RFI provides consulting services in the electric utility industry. The firm provides expertise in electric restructuring, system planning, load forecasting, financial analysis, cost of service, revenue requirements, rate design, and fuel cost recovery issues.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. Exhibit ICNU/101 describes my education and experience within the utility industry. I have more than 25 years of experience in the industry. I have worked for utilities, both as an employee and as a consultant, and as a consultant to major corporations, state and federal governmental agencies, and public service commissions. I have been directly involved in a large number of rate cases and regulatory proceedings concerning the economics, rate treatment, and prudence of nuclear and non-nuclear generating plants.

During my employment with EBASCO Services in the late 1970s, I developed probabilistic production cost and reliability models used in studies for 20 utilities. I personally directed a number of marginal and avoided cost studies performed for compliance with the Public Utility Regulatory Policies Act of 1978 ("PURPA"). I also participated in a wide variety of consulting projects in the rate, planning, and forecasting areas.

In 1982, I accepted the position of Senior Consultant with Energy Management Associates ("EMA"). At EMA, I trained and consulted with planners and financial analysts at several utilities using the PROMOD III and PROSCREEN II planning models.

In 1984, I was a founder of J. Kennedy and Associates, Inc. ("Kennedy"). At that firm, I was responsible for consulting engagements in the areas of generation planning, reliability analysis, market price forecasting, stranded cost evaluation, and the rate treatment of new capacity additions. I presented expert testimony on these and other matters in more than 100 cases before the Federal Energy Regulatory Commission ("FERC") and state regulatory commissions and courts in Arkansas, California, Connecticut, Florida, Georgia, Kentucky, Louisiana, Maryland, Michigan, Minnesota, New Mexico, New York, North Carolina, Ohio, Oregon, Pennsylvania, Texas, Utah, West Virginia, and Wyoming. Included in Exhibit ICNU/101 is a list of my appearances.

In January 2000, I founded RFI Consulting, Inc. with a comparable practice to the one I directed at Kennedy.

Q. HAVE YOU PREVIOUSLY APPEARED IN ANY PROCEEDINGS BEFORE THE OREGON PUBLIC UTILITY COMMISSION?

A. Yes. I previously have filed testimony in six Portland General Electric ("PGE" or the "Company") cases: UE 137 and UE 139 in 2002, UE 149 in 2003, UE 161 in 2004, and UE 165/UM 1187 and UE 172 in 2005. In those cases, I addressed PGE's Resource Valuation Mechanism ("RVM"), and PGE's request for a Power Cost Adjustment Mechanism ("PCAM") and Hydro Generation Adjustment ("HGA"). I also filed testimony in several PacifiCorp proceedings in Oregon: UE 111, UE 116, UM 995, UE 134, UM 1050, and UE 170. In those cases, I addressed issues related to power cost modeling, PCAMs, power cost deferrals, prudence of new resources, and multi-state jurisdictional allocation.

Q. HAVE YOU APPEARED AS AN EXPERT IN OTHER PROCEEDINGS INVOLVING FUEL OR POWER COST ISSUES?

A. Yes. I have been involved in a number of PacifiCorp proceedings in California, Utah, and Wyoming, where I testified concerning power cost issues. In Texas, I have also been involved in a number of power cost related cases. Currently, I am appearing in Georgia regarding a fuel clause audit performed on behalf of the Georgia Public Service Commission staff. Finally, I have appeared in a number of other cases where fuel or purchased power costs were at issue. Exhibit ICNU/101 summarizes other cases in which I have appeared.

II. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. ICNU has asked me to address PGE's application for deferred accounting of costs related to the outage of the Company's Boardman plant between November 18, 2005, and February 5, 2006. Specifically, I address the issues identified by Judge Kirkpatrick in the March 2, 2006 prehearing conference report.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I have concluded that the Commission should deny PGE's application for deferral of costs due to the Boardman outage for the following reasons:

1. PGE's application fails to meet the requirements of ORS 757.259(2)(e). The deferral will increase, rather than minimize, the frequency of rate changes.

2. PGE's application also fails to satisfy the standards that the Commission identified in UM 1147, UM 1071, and UM 995 to determine whether the Commission should exercise its discretion to authorize deferred accounting. Specifically, the Boardman outage represents a stochastic risk that has not caused a sufficient financial impact on PGE to warrant deferred accounting.

3. PGE seeks to opportunistically use the deferral mechanism to increase its recovery of Boardman costs over the amount that might be recovered via ordinary ratemaking procedures.

If the Commission allows PGE to defer the Boardman outage costs, it should adopt a deferral mechanism similar to the one approved for PacifiCorp in UM 995. Based on my analysis, the proposed deferral amount would scarcely exceed the 250 basis point deadband adopted by the Commission in UM 995. In addition, the Commission should not approve any final deferral amount in this phase of the proceeding, as the issues of prudence and reasonableness of the deferral amount have been deferred to Phase 2 of this case.

III. DEFERRAL OF BOARDMAN OUTAGE

Q. WHAT ARE THE PRIMARY ISSUES IN PHASE 1 OF THIS PROCEEDING?

A. The prehearing conference report identified three issues to be addressed in Phase 1 of this docket:

1) Whether PGE's application meets deferral requirements;

2) What deferral mechanism should be used; and

3) What are the rate implications of the deferral?

The report also indicated that Phase 2 of this proceeding would address prudence and amortization issues.

Deferral Requirements

Q. HAS THE COMMISSION IDENTIFIED THE REQUIREMENTS THAT AN APPLICANT MUST SATISFY FOR APPROVAL OF AN APPLICATION FOR DEFERRED ACCOUNTING?

A. Yes. The Commission has provided guidance in recent years regarding the requirements for deferred accounting, especially as they relate to deferral of power costs, such as those at issue in this case. In Order No. 05-1070, the Commission identified two threshold requirements that any applicant for deferred accounting must satisfy. <u>Re Staff Request to Open an Investigation Related to Deferred Accounting</u>, OPUC Docket No. UM 1147, Order No. 05-1070 at 3 (Oct. 5, 2005). First, the application must satisfy one of the statutory bases for deferred accounting in ORS § 757.259. <u>Id.</u> Second, the application must warrant an exercise of the Commission's discretion to authorize deferred accounting. <u>Id.</u>

Q. UNDER WHAT STATUTORY AUTHORITY DOES PGE REQUEST DEFERRAL IN THIS CASE?

A. PGE relies upon ORS 757.259(2)(e) as the basis for its application. This subsection allows deferral of:

> Identifiable utility expenses or revenues, the recovery or refund of which the commission finds should be deferred in order to minimize the frequency of rate changes or the fluctuation of rate levels or to match appropriately the costs borne by and benefits received by ratepayers.

PGE witness Pamela Lesh argues that granting this deferral will minimize the frequency of rate changes, because it would avoid an immediate interim rate increase:

> PGE's only other option under Oregon's regulatory framework would be a request for an interim rate increase based on the difference between the variable cost of operating Boardman and the cost of purchasing power on the market. Because this was a forced outage caused by a repairable problem, a temporary rate increase option would have caused – not minimized – the frequency of rate changes and the fluctuation of rate levels. Deferring these costs instead allows the Commission to design an amortization schedule that minimizes rate fluctuations for this temporary cost increase.

PGE/100, Lesh/3.

Q. DO YOU AGREE WITH MS. LESH'S CONCLUSIONS?

A. No. As described below, it is doubtful that PGE could justify interim rate relief. In addition, Ms. Lesh discounts the fact that PGE already has two other options readily available to it for purposes of addressing the Boardman outage – a general rate case and the RVM.

Q. ARE THESE PRACTICAL OPTIONS FOR THE COMPANY?

A. Certainly. The Company has now filed both a general rate case (Docket No. UE 180) and an RVM case (Docket No. UE 181). Further, PGE's filings in those cases demonstrate that the Company included the Boardman outage at issue in this Docket in its computation of forced outage rates. Thus, the Company already has raised the issue of the outage in UE 180/UE 181.

Unfortunately, it appears that the Company is taking an "opportunistic" approach in this case by requesting deferred accounting because this outage coincided with the particularly expensive period for natural gas and replacement power that occurred during the late fall and winter of 2005/2006. If part or all of the outage was included in future forced outage rates, the Company would lose the time value of money on the additional costs under traditional ratemaking, because these represent operating expenses that are not normally afforded carrying costs and would be reflected in rates for several years into the future. Of course, in a general rate case, PGE would have to demonstrate whether it was appropriate to include such an outage in the four year average. Prudence issues may preclude that, and there is also the question of whether it was an event that is likely to re-occur in the future. In any case, the traditional process would likely provide much lower recovery than the Company is requesting for deferral in this proceeding.

Q. IS IT "FAIR" THAT PGE MIGHT RECOVER LESS UNDER CONVENTIONAL RATEMAKING THAN USING DEFERRED ACCOUNTING?

A. Yes, for several reasons. First, conventional ratemaking treatments have never been intended to provide "perfect" or "exact" cost recovery of all unexpected expenses a utility encounters.

Second, the Commission has reflected outage costs via a four-year rolling average for many years. Inherent in this procedure is the assumption that outages result in higher operating expenses, and the associated costs are not afforded any direct carrying costs in the conventional return on rate base model. However, utilities *are* allowed to earn a return on working capital, which does compensate for the difference between the time revenues are collected and expenses occur. I submit that this does provide a sufficiently fair opportunity for the Company to earn a reasonable return on investment. To deviate from this approach raises the possibility of double recovery.

Finally, PGE has been allowed to use projected test years in setting rates for many years. Under a projected test year paradigm, forward looking costs are used and there is no true up to actual historical costs. Had PGE used historical test years, then true up to actual costs might be a more meaningful concept. However, normally in inflationary times, utilities benefit from the use of forward looking costs, as opposed to historical costs, even if that means that not all costs are perfectly recovered. PGE seeks to change the "regulatory bargain" by having the advantages of projected test years for most costs, but wishes to retain the right to reach back into historical costs when they exceed forward looking costs.

Ultimately, the Company seeks to break with the traditional method for treating outage costs in this case to seize an unfair advantage. In the end, this situation is illustrative of the one-sided nature of deferred accounting. In a situation where deferral appears advantageous to the Company, it can request a deferral. In cases where it is not, it can simply apply conventional ratemaking methods. This provides the best argument for the Commission to "stay the course" and only use deferred accounting "sparingly."

Q. DOES MS. LESH ACKNOWLEDGE THAT THE GENERAL RATE CASE AND RVM OPTIONS ARE AVAILABLE TO THE COMPANY?

A. Yes. However, Ms. Lesh argues that these options were not as attractive because conventional recovery would spread the costs until 2011, while recovery via a deferral would occur "more closely in time" to the event. PGE/100, Lesh/6. In making this assertion, Ms. Lesh is implicitly assuming that the Commission should and would grant recovery of the outage costs through deferred accounting over a shorter time period than would occur under conventional rate treatment. There is no basis for this assumption. Furthermore, this assumption is a bit ironic, as Ms. Lesh also contends that one of the advantages of the deferral (as compared to an interim increase) is that "Deferring these costs instead allows the Commission to design an amortization schedule that minimizes rate fluctuations for this temporary cost increase." PGE/100, Lesh/3.

Q. MS. LESH STATES THAT A DEFERRED ACCOUNT WILL MINIMIZE THE FREQUENCY OF RATE CHANGES BECAUSE IT WILL AVOID AN INTERIM INCREASE. IS AN INTERIM INCREASE A REALISTIC OPTION FOR PGE?

A. That is very questionable. It is my understanding that the Commission has applied a very high standard to requests for interim rate relief in the past, requiring the utility to show severe financial stress or some other reason that jeopardizes its ability to serve the public at reasonable rates. See, e.g., Re PGE, OPUC Docket Nos. UE 47/UE 48, Order No. 87-1017 at 53 (Sept. 30, 1987). While Ms. Lesh contends that the Company earned a 6.3% ROE in 2005 and that earnings were down from $92 million in 2004 to $64 million in 2005, she does not allege that that PGE's ability to serve the public was jeopardized. PGE/100, Lesh/3. Regardless, however, even assuming that the claims about PGE's 2005 earnings are accurate and correct, this is not a sufficiently dire set of circumstances to justify an emergency or interim rate increase. This is particularly true when one considers that Ms. Lesh does not discuss any other factors that affected PGE's 2005 earnings and that the Company already had plans for filing both a general rate case and an RVM case when the deferral application was filed.

Attached as Exhibit ICNU/102 is an excerpt of PGE's Form 10-K for 2005, dated March 16, 2006, which indicates that PGE's $64 million in net income closely reflects the Company's earnings in 2003 and 2002, which were $60 million and $66 million respectively. ICNU/102, Falkenberg/6. PGE's net income in 2001 was $34 million, or $30 million below that which that the Company now claims justifies emergency rate relief. Id.

PGE's 10-K also states that 2005 earnings were the result of a number of factors, only one of which was the Boardman outage:

> PGE's net income in 2005 was $64 million compared to $92 million in 2004. The decrease was due primarily to reduced margins on energy sales, caused by replacement power costs for the extended, unplanned outage at the Boardman coal plant for repair of the plant's turbine rotor. In addition, results for 2005 were adversely affected by higher administrative and general expenses (including the settlement of certain asserted claims), a reserve for the refund to customers of previously collected local income taxes, and higher expenses related to preventive maintenance of the Company's distribution facilities.

Id. PGE's "[p]roduction, distribution, administrative and other expenses increased $21 (8%) million from 2004 due primarily to increased employee benefit expenses." Id. at Falkenberg/8. Furthermore, PGE specifically identifies the establishment of the $10 million reserve for the refund of Multnomah County Business Income Taxes as a factor impacting 2005 earnings. Id.

Elsewhere in the report, PGE states that other factors largely offset the increase in average variable power costs primarily due to the Boardman outage:

> An 11% increase in PGE's average variable power cost was largely offset by both a reduction in total system load and a $24 million decrease related to the amortization of costs deferred under power cost adjustment mechanisms in effect during 2001 and 2002, which were later recovered from customers (fully offset within Retail revenues). The increase in average variable power cost was caused primarily by approximately $41 million of incremental power costs incurred to replace coal-fired generation at Boardman, which was taken out of service in mid-October 2005 for removal and repair of the plant's turbine rotor. Lower hydro production in 2005 (due to low stream flows) also contributed to the year's higher average variable power cost. Such cost increases were partially offset by higher unrealized gains from derivative instruments.

Id. at Falkenberg/7. PGE had a hydro deficit of 316,000 MWh in 2005, an amount equal to roughly half of the energy lost during the November 18, 2005, through February 5, 2006 deferral period. ICNU/103, Falkenberg/2. Because hydro energy costs even less than Boardman, this deficit was quite significant in reducing PGE's earnings in 2005. I estimate the impact to be 149 basis points of ROE, while the Boardman outage amounted to 210 basis points, based on the PGE figures. Thus, a major cause of the 6.3% ROE was a hydro deficit for which the Company is not now requesting a deferral.[1/]

Q. MS. LESH ALSO CONTENDS THAT A DEFERRAL MECHANISM WILL APPROPRIATELY MATCH COSTS WITH BENEFITS OF THE EVENT. DO YOU AGREE?

A. No. Ms. Lesh testifies as follows:

> As explained above, the power that PGE bought to replace Boardman's output was actually used to provide service to customers. Absent this deferral, customers will have used power at a cost significantly less than PGE incurred to provide it.

PGE/100, Lesh/4. While Ms. Lesh is correct in her statement, she does not recognize that use of a deferral will also result in rates being elevated at a later time to recover the outage costs.

Q. SETTING ASIDE THE STATUTORY REQUIREMENTS, HAS THE COMMISSION ESTABLISHED POLICIES REGARDING DEFERRALS THAT HAVE A BEARING ON THIS CASE?

A. Yes. The Commission has addressed deferrals in several recent cases, including UM 1147, UM 1071, UE 165/UM 1187, and UM 995.

Q. DISCUSS THE IMPLICATIONS OF ORDER NO. 05-1070 IN UM 1147.

A. A key element of the Commission's decision in that case was that deferrals should be used sparingly:

[1/] In UE 165/UM 1187, the Commission denied recovery of the hydro deficit costs under the methodology contained in the PGE/Staff stipulation. However, the Commission did allow PGE to reformulate its request and possibly recover those costs. PGE did not avail itself of that option.

> As the parties point out, there are a number of regulatory mechanisms that provide avenues for recovery of excess utility costs or revenues. While deferred accounting appears to have been one of the more frequently used mechanisms due to its versatility and expediency, we agree with the customer groups that deferrals should be used sparingly.

Order No. 05-1070 at 10.

The Commission also indicated it would consider whether other regulatory tools were available in deciding to grant deferral applications:

> In exercising our discretion under ORS 757.259(2), we will consider whether there are other, more appropriate regulatory tools to address recovery of the identified costs or revenues. These include the many mechanisms identified by the parties, as well as a general rate proceeding.

Id.

Finally, the Commission identified the criteria that it considers when deciding whether to exercise its discretion to authorize deferred accounting:

> As we explained in Order No. 04-108, in exercising this discretion, we consider two interrelated factors: the type of event that caused the deferral; and the magnitude of the event's effect. These two considerations interact with each other so that neither is dispositive without the other. With regard to the type of event causing the deferral, we drew a distinction between risks that can be predicted to occur as part of the normal course of events, classified as stochastic risks, and risks that are not susceptible to prediction and quantification, classified as scenario risks. We concluded that risks that are reasonably predictable and quantifiable are generally not appropriate for deferral unless the second consideration, the magnitude of the financial impact of the event on the utility, is substantial enough to warrant deferral.

Id. at 3.

Q. THE COMMISSION DISCUSSED STOCHASTIC RISKS AND SCENARIO RISKS. IS THE BOARDMAN OUTAGE AN EXAMPLE OF A STOCHASTIC RISK OR A SCENARIO RISK?

A. The Boardman outage is clearly an example of a stochastic risk. As described above, the Commission considers "risks that can be predicted to occur as part of the normal course of events, classified as stochastic risks, and risks that are not susceptible to prediction and quantification, classified as scenario risks." Id.

Generator outages are clearly predictable, and are completely expected risks. Indeed, as noted above, the Company already builds into rates an allowance for generator outages. While PGE argues that an event of this duration is "extremely rare," in fact, PGE's own analysis demonstrates that such events have occurred and do occur with predictable frequency.[2/] PGE/300, Drennan-Tinker-Hager/4; see, e.g., PGE/302, Drennan-Tinker-Hager/1. While only a small percentage of outages may have been of as long a duration as the Boardman outage, PGE has many generators. The odds of at least one unit having an extended forced outage are certainly substantial enough that the Company could and should have taken steps to protect itself against the risk.

Furthermore, the North American Electric Reliability Council ("NERC") data that PGE cites demonstrates that all outages lasting more than a couple of days are rare, but that does not mean that all such outages warrant deferred accounting. PGE states that only 0.24% of outages reflected in NERC data covering the last twenty years lasted as long as the Boardman outage, but this data also demonstrates that almost 90% of the 21,415 outages that PGE focused on lasted 5 days or less. PGE/302, Drennan-Tinker-Hager/1. Indeed, PGE states that the twenty-six days that Boardman was out of service prior to the Company filing its deferred accounting application "is probably more representative of a 'normal' event," but outages longer than twenty-six days comprise only approximately 1.5% of the total outages considered by PGE. PGE/100, Lesh/5. Under these circumstances, the NERC data provides no basis for PGE's distinction between an allegedly "normal" outage and one that is "extremely rare."

Finally, it was just a few years ago that PacifiCorp experienced an even more severe outage event at the Hunter plant. Consequently, this type of event was certainly predictable as a part of the normal course of events and the Company could and should have taken steps to quantify the risk, and either reflect it in rates or protect itself against such risks by forward purchases.[3/]

Q. PGE CONTENDS THAT THE BOARDMAN OUTAGE HAD AN IMPACT EQUAL TO 355 BASIS POINTS ON ITS ROE. DO YOU AGREE THAT THIS NUMBER REPRESENTS THE ACTUAL IMPACT ON PGE?

A. No. In computing this figure, PGE has included costs for the days prior to its deferral request in this case. These costs amount to more than $14 million. Those days should be ignored, because the deferred accounting statute expressly prohibits recovery of costs incurred prior to the date of the application. It would be inappropriate to consider costs that the Commission cannot lawfully authorize PGE to recover for purposes of determining whether the total costs at issue are "substantial" enough to justify the Commission exercising its discretion to

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[2/] Certainly much more frequently that the death of a young adult. This fact does not stop young adults from acquiring life insurance.

authorize deferred accounting. Once these unrecoverable costs are adjusted out, the ROE impact of the outage for which PGE is requesting deferral in this case is only 271 basis points, or an estimated $45.5 million.

PGE's requested deferral amount must be further adjusted because the Company's calculation also assumed the entire 383 MW of Boardman capacity was lost due to the outage. In contrast, the Monet model used for 2005 and 2006 assumed only 358 MW of capacity was available. Consequently, base rates already contained an allowance for replacing 25 MW of Boardman. Correcting this problem reduces the deferral amount to $42.6 million or 254 basis points.

In UM 1071, the Commission denied deferral of hydro deficit costs amounting to $31.6 million on the basis that the amount was not substantial enough to warrant a deferral. The Commission identified the 250 basis point deadband in the deferral mechanism authorized in UM 995 as a potential measuring stick for "substantial" financial impact:

> In UM 995, for instance, we established a deadband around PacifiCorp's baseline of 250 basis points of return on equity. We allowed no recovery of costs or refunds to customers within that deadband, reasoning that the band represented risks assumed, or rewards gained, in the course of the utility business. In the Idaho Power cases, discussed below, we allowed partial recovery for a financial impact that represented approximately 700 basis points of Idaho Power's return on equity.
>
> * * *
>
> In the present application, PGE claims that it has incurred $31.6 million in excess NVPC, only some of which is attributable to hydro replacement costs. PGE asserts that this excess NVPC amounts to 172 basis points of return on equity. This is well short

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[3/] PGE indicated in its response to ICNU Data Request No. 2.5, which is attached as Exhibit ICNU/104, that it does not normally reserve additional energy for forced outages beyond WECC requirements.

> of the 250 basis points of return on equity within which we allowed no recovery in UM 995.

Re PGE, OPUC Docket No. UM 1071, Order No. 04-108 at 9 (Mar. 2, 2004) (internal footnotes omitted). Once PGE's claims about the financial impact are corrected as described above, the deferred amount scarcely exceeds the 250 basis point threshold that the Commission used in UM 995 and reaffirmed in UM 1071.

Deferral Mechanism

Q. IF THE COMMISSION DECIDES TO GRANT SOME FORM OF COST DEFERRAL, WHAT TYPE OF MECHANISM SHOULD BE USED?

A. If the Commission approves a deferral, I recommend the Commission use the deadband and sharing mechanism adopted in UM 995. Because UM 995 probably best represents the type of events that occurred during the Boardman outage, it provides a reasonable model to follow, with regards to the issue of sharing and deadbands.

Q. IN UM 995, THE COMMISSION USED A METHODOLOGY THAT COMPARED THE AMOUNT OF POWER COSTS INCLUDED IN BASE RATES TO THE (MUCH HIGHER) ACTUAL NET POWER COSTS. ARE YOU ADVOCATING THAT SPECIFIC APPROACH?

A. No. In UM 995 there were three substantial events taking place – a significant generator outage (Hunter), a severe hydro shortage, and the Western power crisis. Because all of these events caused power costs to increase, the Commission accepted an approach that compared actual power costs to those allowed in rates. While the present situation may have some of the same elements, the Boardman outage has the largest impact, and the Boardman outage is the only element for which the Company has requested a deferral. As a result, it makes much more sense to focus on a methodology like PGE's, where the specific costs of the outage are identified. Were the comparison of actual to normalized power costs used, it would invariably include costs from other sources. However, application of deadbands and a sharing mechanism comparable to that used in UM 995 would still be appropriate.

Q. DESCRIBE THE UM 995 DEADBAND AND SHARING MECHANISM.

A. In UM 995, the Commission used a 250 ROE basis point deadband. For cost variations between 250 and 400 basis points, the Commission used a sharing mechanism that assigned 50 percent of costs to customers and 50 percent to the Company. For cost variations greater than 400 basis points, the Commission assigned 75 percent of the costs to customers and 25 percent to the Company.[4/] A similar approach should be applied here. PGE has proposed no deadband or sharing mechanism, and this is clearly inconsistent with the Commission's decision in UM 995.

Q. ARE THERE OTHER PROBLEMS WITH THE PGE METHODOLOGY?

A. Yes. As discussed above, the Company has computed lost generation for Boardman based on the full rated capacity (383 MW) for its share of the unit. A proper method should compute lost generation based on the level of capacity assumed in setting the rates (358 MW for RVM 2005 and RVM 2006). This adjustment substantially reduces the level of the deferral, as discussed earlier.

4/ Re PacifiCorp, OPUC Docket Nos. UM 995/UE 121/UC 578, Order No. 01-420 at 5, 29 (May 11, 2001).

Q. ARE THERE ANY OTHER ADJUSTMENTS YOU WOULD RECOMMEND IN THE DEFERRAL COMPUTATION?

A. Not at this time. The Company proposes to use the cost of power it claims to have purchased to replace Boardman's output in computing the deferral. However, the reasonableness and prudence of these costs and the PGE methodology should be reserved for Phase 2 of this case, assuming that is necessary. Further, parties should be allowed to provide alternative calculations of the replacement power costs stemming from the PGE analysis. For example, there is a legitimate question of whether PGE gas units might have made up some of the shortfall, in cases when gas was cheaper than purchased power. Finally, the prudence of the outage itself, as well as the time lost during repair, should be addressed in Phase 2. As a result, I recommend the Commission not adopt any specific figures in this proceeding, but rather defer that until Phase 2, assuming the right to defer is granted. In Phase 2, the cost of replacement power and prudence would be examined in more detail. In this phase, I have not done such an analysis.

Q. SHOULD THE COMMISSION CONSIDER OR ALLOW DEFERRAL OF COSTS THAT OCCURRED PRIOR TO THE DATE THAT PGE'S REQUEST FOR DEFERRAL WAS MADE?

A. No. PGE never made any request to defer those costs, and it would constitute retroactive ratemaking to grant their recovery. Further, the Commission should not consider those costs in establishing the deadband and sharing mechanism. The Commission should recall that in UM 995 (and elsewhere) PacifiCorp claimed substantial additional excess power costs occurred prior to its request for deferral as well. Despite all of that, the Commission applied its deadband and sharing mechanism only to the costs during the requested deferral period.

Ratemaking Implications

Q. ASSUMING PGE'S APPLICATION IS GRANTED, WHAT ARE THE RATEMAKING IMPLICATIONS OF THIS DEFERRAL?

A. If the Commission grants the request for deferral, the Company will only have the right to request amortization of the deferral after the prudence and reasonableness of its costs are established in Phase 2 of this case. Once the Company applies for amortization, the Commission will still have to consider all other applicable ratemaking standards, and the limitations of ORS 757.259(6) and (7) before establishing a rate adjustment. Further, the Commission should give large customers the option to prepay their share of the deferred amount similar to the prepayment option provided in ORS 757.259(11).

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

ICNU/101

Randall Falkenberg Qualifications

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

EDUCATIONAL BACKGROUND

I received my Bachelor of Science degree with Honors in Physics and a minor in mathematics from Indiana University. I received a Master of Science degree in Physics from the University of Minnesota. My thesis research was in nuclear theory. At Minnesota I also did graduate work in engineering economics and econometrics. I have completed advanced study in power system reliability analysis.

PROFESSIONAL EXPERIENCE

After graduating from the University of Minnesota in 1977, I was employed by Minnesota Power as a Rate Engineer. I designed and coordinated the Company's first load research program. I also performed load studies used in cost-of-service studies and assisted in rate design activities.

In 1978, I accepted the position of Research Analyst in the Marketing and Rates department of Puget Sound Power and Light Company. In that position, I prepared the two-year sales and revenue forecasts used in the Company's budgeting activities and developed methods to perform both near- and long-term load forecasting studies.

In 1979, I accepted the position of Consultant in the Utility Rate Department of Ebasco Service Inc. In 1980, I was promoted to Senior Consultant in the Energy Management Services Department. At Ebasco I performed and assisted in numerous studies in the areas of cost of service, load research, and utility planning. In particular, I was involved in studies concerning analysis of excess capacity, evaluation of the planning activities of a major utility on behalf of its public service commission, development of a methodology for computing avoided costs and cogeneration rates, long-term electricity price forecasts, and cost allocation studies.

At Ebasco, I specialized in the development of computer models used to simulate utility production costs, system reliability, and load patterns. I was the principal author of production costing software used by eighteen utility clients and public service commissions for evaluation of marginal costs, avoided costs and production costing analysis. I assisted over a dozen utilities in the performance of marginal and avoided cost studies related to the PURPA of 1978. In this capacity, I worked with utility planners and rate specialists in quantifying the rate and cost impact of generation expansion alternatives. This activity included estimating carrying costs, O&M expenses, and capital cost estimates for future generation.

In 1982 I accepted the position of Senior Consultant with Energy Management Associates, Inc. and was promoted to Lead Consultant in June 1983. At EMA I trained and consulted with planners and financial

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

analysts at several utilities in applications of the PROMOD and PROSCREEN planning models. I assisted planners in applications of these models to the preparation of studies evaluating the revenue requirements and financial impact of generation expansion alternatives, alternate load growth patterns and alternate regulatory treatments of new baseload generation. I also assisted in EMA's educational seminars where utility personnel were trained in aspects of production cost modeling and other modern techniques of generation planning.

I became a Principal in Kennedy and Associates in 1984. Since then I have performed numerous economic studies and analyses of the expansion plans of several utilities. I have testified on several occasions regarding plant cancellation, power system reliability, phase-in of new generating plants, and the proper rate treatment of new generating capacity. In addition, I have been involved in many projects over the past several years concerning the modeling of market prices in various regional power markets.

In January 2000, I founded RFI Consulting, Inc. whose practice is comparable to that of my former firm, J. Kennedy and Associates, Inc.

The testimony that I present is based on widely accepted industry standard techniques and methodologies,and unless otherwise noted relies upon information obtained in discovery or other publicly available information sources of the type frequently cited and relied upon by electric utility industry experts. All of the analyses that I perform are consistent with my education, training and experience in the utility industry. Should the source of any information presented in my testimony be unclear to the reader, it will be provided it upon request by calling me at 770-379-0505.

PAPERS AND PRESENTATIONS

Mid-America Regulatory Commissioners Conference - June 1984: "Nuclear Plant Rate Shock - Is Phase-In the Answer"

Electric Consumers Resource Council - Annual Seminar, September 1986: "Rate Shock, Excess Capacity and Phase-in"

The Metallurgical Society - Annual Convention, February 1987: "The Impact of Electric Pricing Trends on the Aluminum Industry"

Public Utilities Fortnightly - "Future Electricity Supply Adequacy: The Sky Is Not Falling" What Others Think, January 5, 1989 Issue

Public Utilities Fortnightly - "PoolCo and Market Dominance", December 1995 Issue

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

APPEARANCES

3/84	8924	KY	Airco Carbide	Louisville Gas & Electric	CWIP in rate base.
5/84	830470-EI	FL	Florida Industrial Power Users Group	Fla. Power Corp.	Phase-in of coal unit, fuel savings basis, cost allocation.
10/84	89-07-R	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power	Excess capacity.
11/84	R-842651	PA	Lehigh Valley	Pennsylvania Power Committee	Phase-in of nuclear unit. Power & Light Co.
2/85	I-840381	PA	Phila. Area Ind. Energy Users' Group	Philadelphia Electric Co.	Economics of cancellation of nuclear generating units.
3/85	Case No. 9243	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Economics of cancelling fossil generating units.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Economics of pumped storage generating units, optimal res. margin, excess capacity.
3/85	3498-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear unit cancellation, load and energy forecasting, generation economics.
5/85	84-768-E-42T	WV	West Virginia Multiple Intervenors	Monongahela Power Co.	Economics - pumped storage generating units, reserve margin, excess capacity.
7/85	E-7, SUB 391	NC	Carolina Industrial Group for Fair Utility Rates	Duke Power Co.	Nuclear economics, fuel cost projections.
7/85	9299	KY	Kentucky Industrial Utility Consumers	Union Light, Heat & Power Co.	Interruptible rate design.
8/85	84-249-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Prudence review.
1/86	85-09-12	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power Co.	Excess capacity, financial impact of phase-in nuclear plant.
1/86	R-850152	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Phase-in and economics of nuclear plant.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power	Optimal reserve margins, prudence, off-system sales guarantee plan.
5/86	86-081-E-GI	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Generation planning study , economics prudence of a pumped storage hydroelectric unit.
5/86	3554-U	GA	Attorney General & Georgia Public	Georgia Power Co.	Cancellation of nuclear plant.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
			Service Commission Staff		
9/86	29327/28	NY	Occidental Chemical Corp.	Niagara Mohawk Power Co.	Avoided cost, production cost models.
9/86	E7- Sub 408	NC	NC Industrial Energy Committee	Duke Power Co.	Incentive fuel adjustment clause.
12/86	9437/ 613	KY	Attorney General of Kentucky	Big Rivers Elect. Corp.	Power system reliability analysis, rate treatment of excess capacity.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power	Economics and rate treatment of Bath County pumped storage County Pumped Storage Plant.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
6/87	PUC-87-013-RD E002/E-015 -PA-86-722	MN	Eveleth Mines & USX Corp.	Minnesota Power/ Northern States	Sale of generating unit and reliability Power requirements.
7/87	Docket 9885	KY	Attorney General of Kentucky	Big Rivers Elec. Corp.	Financial workout plan for Big Rivers.
8/87	3673-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear plant prudence audit, Vogtle buyback expenses.
10/87	R-850220	PA	WPP Industrial Intervenors	West Penn Power	Need for power and economics, County Pumped Storage Plant
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Cost allocation methods and interruptible rate design.
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Nuclear plant performance.
1/88	Case No. 9934	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Review of the current status of Trimble County Unit 1.
3/88	870189-EI	FL	Occidental Chemical Corp.	Fla. Power Corp.	Methodology for evaluating interruptible load.
5/88	Case No. 10217	KY	National Southwire Aluminum Co., ALCAN Alum Co.	Big Rivers Elec. Corp.	Debt restructuring agreement.
7/88	Case No. 325224	LA Div. I 19th Judicial District	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization gas sales and revenues.
10/88	3799-U	GA	Georgia Public Service Commission	United Cities Gas Co.	Weather normalization of gas sales and revenues.

Expert Testimony Appearances
of
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Date	Case	Jurisdict.	Party	Utility	Subject
			Staff		
12/88	88-171-EL-AIR 88-170-EL-AIR	OH OH	Ohio Industrial Energy Consumers	Toledo Edison Co., Cleveland Electric Illuminating Co.	Power system reliability reserve margin.
1/89	I-880052	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Nuclear plant outage, replacement fuel cost recovery.
2/89	10300	KY	Green River Steel K	Kentucky Util.	Contract termination clause and interruptible rates.
3/89	P-870216 283/284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power	Reserve margin, avoided costs.
5/89	3741-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Prudence of fuel procurement.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Need and economics coal & nuclear capacity, power system planning.
10/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Power system planning, economic and reliability analysis, nuclear planning, prudence.
10/89	89-128-U	AR	Arkansas Electric Energy Consumers	Arkansas Power Light Co.	Economic impact of asset transfer and stipulation and settlement agreement.
11/89	R-891364	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Sale/leaseback nuclear plant, excess capacity, phase-in delay imprudence.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Sale/leaseback nuclear power plant.
4/90	89-1001-EL-AIR	OH	Industrial Energy Consumers	Ohio Edison Co.	Power supply reliability, excess capacity adjustment.
4/90	N/A	N.O.	New Orleans Business Counsel	New Orleans Public Service Co.	Municipalization of investor-owned utility, generation planning & reliability
7/90	3723-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization adjustment rider.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirements gas & electric, CWIP in rate base.
9/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Power system planning study.
12/90	U-9346	MI	Association of Businesses Advocating Tariff Equity (ABATE)	Consumers Power	DSM Policy Issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
5/91	3979-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	DSM, load forecasting and IRP.
7/91	9945	TX	Office of Public Utility Counsel	El Paso Electric Co.	Power system planning, quantification of damages of imprudence, environmental cost of electricity
8/91	4007-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Integrated resource planning, regulatory risk assessment.
11/91	10200	TX	Office of Public	Texas-New Mexico Utility Counsel	Imprudence disallowance. Power Co.
12/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Year-end sales and customer adjustment, jurisdictional allocation.
1/92	89-783-E-C	WVA	West Virginia Energy Users Group	Monongahela Power Co.	Avoided cost, reserve margin, power plant economics.
3/92	91-370	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Interruptible rates, design, cost allocation.
5/92	91890	FL	Occidental Chemical Corp.	Fla. Power Corp.	Incentive regulation, jurisdictional separation, interruptible rate design.
6/92	4131-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Integrated resource planning, DSM.
9/92	920324	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Cost allocation, interruptible rates decoupling and DSM.
10/92	4132-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Residential conservation program certification.
10/92	11000	TX	Office of Public Utility Counsel	Houston Lighting and Power Co.	Certification of utility cogeneration project.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Direct)	Production cost savings from merger.
11/92	8469	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, revenue distribution.
11/92	920606	FL	Florida Industrial Power Users Group	Statewide Rulemaking	Decoupling, demand-side management, conservation, Performance incentives.
12/92	R-009 22378	PA	Armco Advanced Materials	West Penn Power	Energy allocation of production costs.
1/93	8179	MD	Eastalco Aluminum/ Westvaco Corp.	Potomac Edison Co.	Economics of QF vs. combined cycle power plant.
2/93	92-E-0814 88-E-081	NY	Occidental Chemical Corp.	Niagara Mohawk Power Corp.	Special rates, wheeling.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
3/93	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Surrebuttal)	Production cost savings from merger.
4/93	EC92 21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	GSU Merger prodcution cost savings
6/93	930055-EU	FL	Florida Industrial Power Users' Group	Statewide Rulemaking	Stockholder incentives for off-system sales.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers & Attorney General	Big Rivers Elec. Corp.	Prudence of fuel procurement decisions.
9/93	4152-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Cost allocation of pollution control equipment.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minn. Power Co.	Analysis of revenue req. and cost allocation issues.
4/94	93-465	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Review and critique proposed environmental surcharge.
4/94	4895-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co	Purchased power agreement and fuel adjustment clause.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Light Co.	Rev. requirements, incentive compensation.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue annualization, ROE performance bonus, and cost allocation.
8/94	8652	MD	Westvaco Corp.	Potomac Edison Co.	Revenue requirements, ROE performance bonus, and revenue distribution.
1/95	94-332	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Environmental surcharge.
1/95	94-996-EL-AIR	OH	Industrial Energy Users of Ohio	Ohio Power Company	Cost-of-service, rate design, demand allocation of power
3/95	E999-CI	MN	Large Power Intervenor	Minnesota Public Utilities Comm.	Environmental Costs Of electricity
4/95	95-060	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Company	Six month review of CAAA surcharge.
11/95	I-940032	PA	The Industrial Energy Consumers of Pennsylvania	Statewide - all utilities	Direct Access vs. Poolco, market power.
11/95	95-455	KY	Kentucky Industrial	Kentucky Utilities	Clean Air Act Surcharge,
12/95	95-455	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Clean Air Act Compliance Surcharge.
6/96	960409-EI	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Polk County Power Plant Rate Treatment Issues.
3/97	R-973877	PA	PAIEUG.	PECO Energy	Stranded Costs & Market

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Date	Case	Jurisdict.	Party	Utility	Subject
					Prices.
3/97	970096-EQ	FL	FIPUG	Fla. Power Corp.	Buyout of QF Contract
6/97	R-973593	PA	PAIEUG	PECO Energy	Market Prices, Stranded Cost
7/97	R-973594	PA	PPLICA	PP&L	Market Prices, Stranded Cost
8/97	96-360-U	AR	AEEC	Entergy Ark. Inc.	Market Prices and Stranded Costs, Cost Allocation, Rate Design
10/97	6739-U	GA	GPSC Staff	Georgia Power	Planning Prudence of Pumped Storage Power Plant
10/97	R-974008 R-974009	PA	MIEUG PICA	Metropolitan Ed. PENELEC	Market Prices, Stranded Costs
11/97	R-973981	PA	WPII	West Penn Power	Market Prices, Stranded Costs
11/97	R-974104	PA	DII	Duquesne Light Co.	Market Prices, Stranded Costs
2/98	APSC 97451 97452 97454	AR	AEEC	Generic Docket	Regulated vs. Market Rates, Rate Unbundling, Timetable for Competition.
7/98	APSC 87-166	AR	AEEC	Entergy Ark. Inc.	Nuclear decommissioning cost estimates & rate treatment.
9/98	97-035-01	UT	DPS and CCS	PacifiCorp	Net Power Cost Stipulation, Production Cost Model Audit
12/98	19270	TX	OPC	HL&P	Reliability, Load Forecasting
4/99	19512	TX	OPC	SPS	Fuel Reconciliation
4/99	99-02-05	CT	CIEC	CL&P	Stranded Costs, Market Prices
4/99	99-03-04	CT	CIEC	UI	Stranded Costs, Market Prices
6/99	20290	TX	OPC	CP&L	Fuel Reconciliation
7/99	99-03-36	CT	CIEC	CL&P	Interim Nuclear Recovery
7/99	98-0453	WV	WVEUG	AEP & APS	Stranded Costs, Market Prices
12/99	21111	TX	OPC	EGSI	Fuel Reconciliation
2/00	99-035-01	UT	CCS	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
5/00	99-1658	OH	AK Steel	CG&E	Stranded Costs, Market Prices
6/00	UE-111	OR	ICNU	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
9/00	22355	TX	OPC	Reliant Energy	Stranded cost
10/00	22350	TX	OPC	TXU Electric	Stranded cost

Expert Testimony Appearances
of
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Date	Case	Jurisdict.	Party	Utility	Subject
10/00	99-263-U	AR	Tyson Foods	SW Elec. Coop	Cost of Service
12/00	99-250-U	AR	Tyson Foods	Ozarks Elec. Coop	Cost of Service
01/01	00-099-U	AR	Tyson Foods	SWEPCO	Rate Unbundling
02/01	99-255-U	AR	Tyson Foods	Ark. Valley Coop	Rate Unbundling
03/01	UE-116	OR	ICNU	PacifiCorp	Net Power Costs
6/01	01-035-01	UT	DPS and CCS	PacifiCorp	Net Power Costs
7/01	A.01-03-026	CA	Roseburg FP	PacifiCorp	Net Power Costs
7/01	23550	TX	OPC	EGSI	Fuel Reconciliation
7/01	23950	TX	OPC	Reliant Energy	Price to beat fuel factor
8/01	24195	TX	OPC	CP&L	Price to beat fuel factor
8/01	24335	TX	OPC	WTU	Price to beat fuel factor
9/01	24449	TX	OPC	SWEPCO	Price to beat fuel factor
10/01	20000-EP 01-167	WY	WIEC	PacifiCorp	Power Cost Adjustment Excess Power Costs
2/02	UM-995	OR	ICNU	PacifiCorp	Cost of Hydro Deficit
2/02	00-01-37	UT Plant	CCS	PacifiCorp	Certification of Peaking
4/02	00-035-23	UT	CCS	PacifiCorp	Cost of Plant Outage, Excess Power Cost Stipulation.
4/02	01-084/296	AR	AEEC	Entergy Arkansas	Recovery of Ice Storm Costs
5/02	25802	TX	OPC	TXU Energy	Escalation of Fuel Factor
5/02	25840	TX	OPC	Reliant Energy	Escalation of Fuel Factor
5/02	25873	TX	OPC	Mutual Energy CPL	Escalation of Fuel Factor
5/02	25874	TX	OPC	Mutual Energy WTU	Escalation of Fuel Factor
5/02	25885	TX	OPC	First Choice	Escalation of Fuel Factor
7/02	UE-139	OR	ICNU	Portland General	Power Cost Modeling
8/02	UE-137	OP	ICNU	Portland General	Power Cost Adjustment Clause
10/02	RPU-02-03	IA	Maytag, et al	Interstate P&L	Hourly Cost of Service Model
11/02	20000-Er 02-184	WY	WIEC	PacifiCorp	Net Power Costs, Deferred Excess Power Cost
12/02	26933	TX	OPC	Reliant Energy	Escalation of Fuel Factor
12/02	26195	TX	OPC	Centerpoint Energy	Fuel Reconciliation
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	UE-134	OR	ICNU	PacifiCorp	West Valley CT Lease payment
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor

**Expert Testimony Appearances
of
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Date	Case	Jurisdict.	Party	Utility	Subject
1/03	26186	TX	OPC	SPS	Fuel Reconciliation
2/03	UE-02417	WA	ICNU	PacifiCorp	Rate Plan Stipulation, Deferred Power Costs
2/03	27320	TX	OPC	Reliant Energy	Escalation of Fuel Factor
2/03	27281	TX	OPC	TXU Energy	Escalation of Fuel Factor
2/03	27376	TX	OPC	CPL Retail Energy	Escalation of Fuel Factor
2/03	27377	TX	OPC	WTU Retail Energy	Escalation of Fuel Factor
3/03	27390	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27511	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27035	TX	OPC	AEP Texas Central	Fuel Reconciliation
05/03	03-028-U	AR	AEEC	Entergy Ark., Inc.	Power Sales Transaction
7/03	UE-149	OR	ICNU	Portland General	Power Cost Modeling
8/03	28191	TX	OPC	TXU Energy	Escalation of Fuel Factor
11/03	20000-ER -03-198	WY	WIEC	PacifiCorp	Net Power Costs
2/04	03-035-29	UT	CCS	PacifiCorp	Certification of CCCT Power Plant, RFP and Bid Evaluation
6/04	29526	TX	OPC	Centerpoint	Stranded cost true-up.
6/04	UE-161	OR	ICNU	Portland General	Power Cost Modeling
7/04	UM-1050	OR	ICNU	PacifiCorp	Jurisdictional Allocation
10/04	15392-U 15392-U	GA	Calpine	Georgia Power/ SEPCO	Fair Market Value of Combined Cycle Power Plant
12/04	04-035-42	UT	CCS		PacifiCorp Net power costs
02/05	UE-165	OP	ICNU	Portland General	Hydro Adjustment Clause
05/05	UE-170	OR	ICNU	PacifiCorp	Power Cost Modeling
7/05	UE-172	OR	ICNU	Portland General	Power Cost Modeling
08/05	UE-173	OR	ICNU	PacifiCorp	Power Cost Adjustment
8/05	UE-050482	WA	ICNU	Avista	Power Cost modeling, Energy Recovery Mechanism
8/05	31056	TX	OPC	AEP Texas Central	Stranded cost true-up.
11/05	UE-05684	WA	ICNU	PacifiCorp	Power Cost modeling, Jurisdictional Allocation, PCA
2/06	05-116-U	AR	AEEC	Entergy Arkansas	Fuel Cost Recovery
4/06	UE-060181	WA	ICNU	Avista	Energy Cost Recovery Mechanism
5/06	22403-U	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Audit

ICNU/102

Excerpt of PGE Form 10-K
(Mar. 16, 2006)

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2005
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Transition period from _______________ to _______________

Commission File Number 1-5532-99

PORTLAND GENERAL ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

Oregon	**93-0256820**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

121 SW Salmon Street, Portland, Oregon 97204
(Address of principal executive offices) (zip code)

Registrant's telephone number, including area code: **(503) 464-8000**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
None	

Securities registered pursuant to Section 12(g) of the Act:

Title of each class
Portland General Electric Company 7.75% Series, Cumulative Preferred Stock, no par value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ___ No _X_

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ___ No _X_

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes _X_ No ___.

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer [ ]   Accelerated filer [ ]   Non-accelerated filer [X]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ___ No _X_

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter: $0.

Number of shares of Common Stock outstanding as of February 28, 2006: 42,758,877 shares of common stock, $3.75 par value. (All shares are owned by Enron Corp.)

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation

Overview

PGE is a single integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the State of Oregon, as well as the wholesale sale of electricity and natural gas throughout the western states. PGE's mission is to be a company that customers depend on to provide electric service in a safe and reliable manner with excellent customer service at a reasonable price. The OPUC establishes tariffs and retail revenue requirements based upon the cost to serve retail customers and a fair return on investment, using a forecasted test year and an original cost rate base. Wholesale power and transmission prices are regulated by the FERC.

While Oregon's electricity restructuring law provides for both direct access to competing energy suppliers and for market price options, the Company remains obligated to provide service to all of its retail customers, the large majority of which buy electricity at prices determined by the cost of service. Subject to regulatory review and timing, PGE expects the OPUC to recognize all prudently-incurred costs in setting prices, although there can be no assurance that the Company will have an opportunity to fully recover its costs through prices set in the regulatory process. While customer prices applicable to projected power costs are currently adjusted on an annual basis, prices applicable to non-power costs are adjusted only in a general rate proceeding. As electricity prices are fixed during the year, fluctuations in energy sales, hydro output, plant availability, and power and fuel prices can significantly impact the Company's earnings.

Future Ownership of PGE - Enron and PGE are moving forward to distribute new PGE common stock to the Debtors' creditors holding allowed claims in accordance with the Chapter 11 Plan, with applications approved by all required regulatory agencies. The issuance of new PGE common stock is currently expected to take place on or about April 3, 2006, and PGE has filed an application to list the stock on the New York Stock Exchange. Following the issuance, PGE will no longer be a subsidiary of Enron. Enron has also indicated that it will continue to consider credible offers to purchase PGE's common stock until the new common stock is issued. The transition from Enron's ownership of PGE has continued, with control of employee benefit and retirement savings plans returned to the Company at the beginning of 2005. The Company's Board of Directors has been expanded, with six new members appointed in January 2006. For further information, see "Future Ownership of PGE" in "Financial and Operating Outlook" of this Item 7.

Customers - PGE continues its focus on customer service and recognizes the importance of reliability, restoration response, safety, and reasonable rates in maintaining overall customer satisfaction. The Company meets regulatory standards for safety and service quality related to outage frequency and duration.

Like most utilities, PGE's business is affected by the general economy and by population growth in its service territory. The Company continues to experience customer growth, adding approximately 55,000 retail customers in the last five years (including 13,000 in 2005), and now serves over 780,000 retail customers as the largest supplier of electricity in the state. Although slowing somewhat in the last half of 2005, the state's economy has generally continued to rebound from the 2001-2003 period, adding over 100,000 jobs (including over 16,000 in manufacturing) during the last two years, resulting in annual average payroll gains of 2% in 2004 and 3.4% in 2005. Non-farm employment (seasonally adjusted) in December 2005 exceeded the previous peak, with the unemployment rate falling from a high of 8.5% in July 2003 to 7.0% at year-end 2004 to 5.7% at the end of 2005. Continued high energy prices and rising short-term interest rates, however, could affect future growth of both the national and state economy.

PGE seeks to exert a positive influence on the long-term economic strength of the Company's service area and continues to play an active role in supporting growth and business development in the region. The Company works with local, state and regional agencies to assist existing businesses with operating and expansion plans and to provide assistance to businesses considering new activity in Oregon. PGE has played a key leadership role in assisting communities in the Company's service area with economic development strategies, including those initiated at the recent Oregon Business Plan Summit, and has been instrumental in the growth of key industry clusters representing a large number of metals and transportation equipment businesses in the state.

Power Supply - PGE manages its power supply to secure reasonably priced power for customers by effectively using the Company's generating assets and marketing and operational expertise. PGE can meet approximately 75% of its peak load requirement with output from its generating plants and long-term hydro contracts, with the remaining 25% met with short-term and other long-term power purchases in the wholesale market. The portion of retail load met with power purchases can increase if it becomes more economic to purchase electricity than to generate it with the Company's thermal resources.

PGE's twelve diversified generating plants (40% gas/oil, 34% coal, and 26% hydro) have both base-load and peaking capabilities, with fuel for thermal plants supplied under short-term agreements and spot-market purchases, allowing the Company to dispatch its thermal resources based upon the market price of wholesale power relative to the market price of natural gas or coal. Wholesale energy market prices have continued to increase over the last year, reflecting higher natural gas prices and below-normal regional hydro conditions. PGE remains active in wholesale energy markets in order to meet retail load requirements. The Company utilizes wholesale electricity and fuel purchases, as well as its generating plants, to maintain a balanced position.

Regional water conditions in 2005 were below both average and 2004 levels, resulting in reduced generation from PGE's hydro projects. Output from mid-Columbia River hydro projects, with which PGE has long-term power purchase contracts, was slightly higher in 2005. Regional hydro conditions, including those on both the Clackamas and Deschutes river systems where the Company's facilities are located, are currently projected to be near normal for 2006.

Renewable generation purchased from a 27 MWa wind farm became available on December 1, 2005, with the 50-turbine project generating enough electricity to power 18,000 homes. This is PGE's largest renewable power purchase to date and marks the first major step toward meeting the Company's renewable power supply goal of 200 MW. The Company continues to implement its Integrated Resource Plan to meet the future electricity needs of customers, with construction of the 400 MW natural gas-fired Port Westward plant proceeding on schedule, with completion expected in the first quarter of 2007.

In June 2005, the FERC approved a 50-year joint license application for the Pelton Round Butte hydro project and in December 2005 a new 30-year license was issued for PGE's 16 MW Willamette River project. A settlement agreement related to the previously filed license application for the Company's four Clackamas River projects has been signed by participating parties and will be submitted to the FERC for review and approval. These facilities continue to provide a low-cost source of power for PGE customers.

Operations - In October 2005, following the detection of vibrations in Boardman's steam turbine rotor, the plant was taken out of service, with the rotor removed in mid-November and shipped to an east coast facility for repair. During the process of returning the plant to operation in early February 2006, the generator rotor was damaged and subsequently removed for further examination and repairs. It is currently estimated that the plant will be operational by late April 2006. Replacement power costs of approximately $41 million were incurred during the fourth quarter of 2005, with first quarter 2006 costs estimated at $45 million. Estimated replacement power costs for April 2006 are expected to range from $200,000 to $300,000 per day. During the plant's extended outage, annual maintenance requirements, originally scheduled for the second quarter of 2006, were completed.

Aside from the extended repair outage at Boardman, PGE's generating plants continued to operate well in 2005, with total output approximating that of 2004. Required annual maintenance at the Company's thermal facilities was successfully completed by the end of the year's third quarter.

PGE utilized its mix of generating assets and activities in the wholesale marketplace to meet the 2005 electricity needs of its customers and offset the adverse effects of the year's moderate drought conditions and the extended repair outage at Boardman. Increased retail energy deliveries (including those to commercial and industrial customers that purchase their energy from ESSs) reflect continued customer growth and an improved economy, with gains in all major customer sectors. Weather adjusted retail energy deliveries to PGE and ESS customers are expected to increase by approximately 2% in 2006.

PGE continues to invest in its transmission and distribution systems and in additions and upgrades to its generating facilities. Decommissioning of the closed Trojan nuclear plant is proceeding, and in May 2005, following the completion of radiological decommissioning and approval by the NRC, the plant's facility operating license was terminated. PGE has accelerated the planned demolition of major non-radiological structures at Trojan, including the cooling tower and those buildings that once housed the plant's turbine, reactor, and spent fuel pool.

2005 Financial Performance - Due largely to Boardman's extended repair outage during most of the fourth quarter of 2005, PGE's earnings declined about 30% from 2004. The unplanned outage required that PGE replace its portion of the plant's generation with higher-priced wholesale power purchases and increased natural gas-fired generation, resulting in a significant decrease in PGE's net operating income and a net loss for the fourth quarter of 2005. Earnings for 2005 were also negatively affected by higher operating expenses and by PGE's decision, as part of a settlement, to make refunds and payments totaling $10 million to Multnomah County customers for business income taxes collected in prior years.

Despite the challenges of poor hydro conditions in 2005, the lack of any power cost adjustment mechanism, and the extended Boardman outage, PGE continues to maintain adequate liquidity and stable operating cash flow. The Company secured a new $400 million five-year credit facility in May 2005 and continues to effectively invest in its systems, acquire and plan for new power supply resources, and maintain operational efficiency.

Regulatory Matters - The "Resource Valuation Mechanism" (RVM) process, by which retail prices are adjusted annually with changes in projected power costs, has enabled PGE to adjust customer prices on a more timely basis to reflect the expected variable cost of power. This process resulted in moderate average rate increases for 2005 and 2006. A previously-filed Hydro Generation Adjustment tariff and deferral application, which would have allowed for the deferral and future rate recovery of a portion of power cost changes caused by variations in hydro conditions, was denied by the OPUC.

PGE has also filed an application with the OPUC seeking deferral, for future ratemaking treatment, of excess replacement power costs related to Boardman's outage for repairs to the plant's steam turbine rotor, which ended on February 5, 2006. PGE has determined, however, that it will not file an application to defer such costs related to the outage resulting from damage to the generator rotor, which began February 6, 2006. For further information, see "Boardman Coal Plant - Extended Outage" in "Financial and Operating Outlook" of this Item 7.

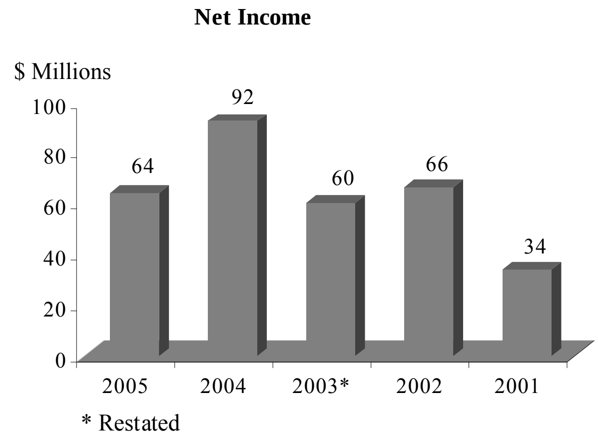
A new law, Oregon Senate Bill 408, seeks to more closely match amounts collected for income taxes under the ratemaking process with income taxes paid to governmental entities by investor-owned utilities or their consolidated group. PGE is participating in the Commission's comprehensive rule-making process to implement the new law. The Company has filed a report, as required by the new law, on taxes "collected" and "paid" (as defined under temporary rules and Senate Bill 408) for the years 2002-2004. Under the law, however, the first rate adjustment applies only to taxes paid and amounts collected from customers beginning in 2006. There is considerable uncertainty regarding several provisions of the law and the Company continues to evaluate its potential effects.

In order to align PGE's rate structure to sufficiently cover its operating costs, the Company filed a general rate case in March 2006 for consideration by the OPUC. Major components of the filing include power costs and the recovery of PGE's investment in Port Westward. The Commission's review is estimated to take from nine to ten months, with rate adjustments expected to become effective in early 2007.

Results of Operations

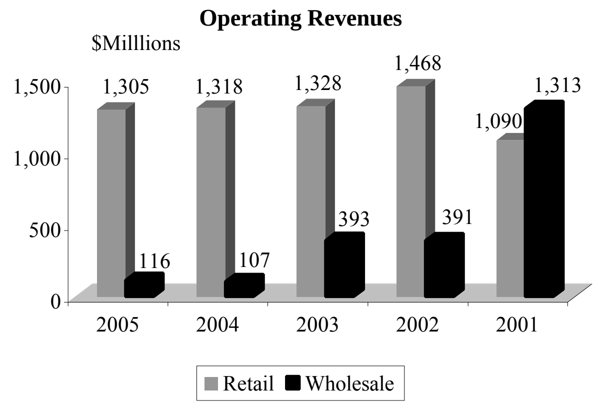
2005 Compared to 2004

PGE's net income in 2005 was $64 million compared to $92 million in 2004. The decrease was due primarily to reduced margins on energy sales, caused by replacement power costs for the extended, unplanned outage at the Boardman coal plant for repair of the plant's turbine rotor. In addition, results for 2005 were adversely affected by higher administrative and general expenses (including the settlement of certain asserted claims), a reserve for the refund to customers of previously collected local income taxes, and higher expenses related to preventive maintenance of the Company's distribution facilities.

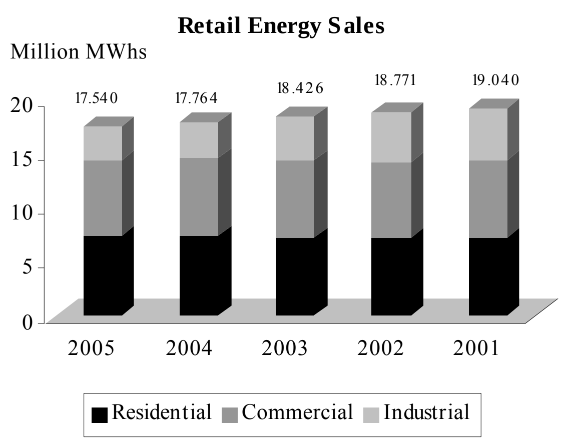


The following table summarizes Operating Revenues and Energy Sold and Delivered for 2005 and 2004:

Operating Revenues (In Millions)	2005	2004	Increase/ (Decrease)
Retail Operating Revenues:			
Retail	$ 1,305	$ 1,311	$ (6)
Direct Access Customer Revenues	-	7	(7)
Total Retail Revenues	1,305	1,318	(13)
Wholesale (Non-Trading)	116	107	9
Other Operating Revenues:			
Trading Activities - net	-	1	(1)
Other	25	28	(3)
Total Operating Revenues	$ 1,446	$ 1,454	$ (8)
Energy Sold and Delivered (In Thousands of MWhs)			
Retail Energy Deliveries			
Retail Energy Sales	17,540	17,764	(224)
Energy Delivered to Direct Access Customers	1,214	776	438
Total Retail Energy Deliveries	18,754	18,540	214
Wholesale (Non-Trading)	2,094	2,539	(445)
Trading Activities	815	9,699	(8,884)
Total Energy Sold and Delivered	21,663	30,778	(9,115)



Total Retail Revenues decreased about 1% from 2004. A decrease in energy sales and a $23 million reduction in amounts recovered from customers related to power cost adjustment mechanisms in effect in 2001 and 2002 (fully offset within Purchased Power and Fuel expense) were partially offset by a 1.4% average rate increase for 2005. (For further information, see "Resource Valuation Mechanism" in "Financial and Operating Outlook" of this Item 7). The decrease in Direct Access Customer Revenues, consisting of service charges for electricity delivered to customers who purchase their energy requirements from ESSs, was attributable to "transition adjustment" credits, reflecting the difference between the cost and market value of PGE's power supply portfolio, as provided by Oregon's electricity restructuring law. Total Retail Energy Sales decreased 1%, with declines in both commercial and industrial usage partially offset by increased residential use resulting from colder weather in the fourth quarter of 2005 and an approximate 11,000 increase in customers served. Declines in commercial and industrial energy sales of 2.5% and 3.1%, respectively, were largely related to customers who chose to purchase their energy requirements from ESSs beginning in 2005. PGE continues to deliver energy to these customers, with about one-third of the increase in Total Retail Energy Deliveries in 2005 attributable to a single large industrial customer.



Wholesale revenues increased by about 8% in 2005 due primarily to a 32% increase in average price, driven largely by higher natural gas prices. This was partially offset by an approximate 18% reduction in wholesale electricity sales resulting from reduced market activity.

The decrease in Other Operating Revenues from last year was caused primarily by reduced margins on the sale of natural gas in excess of plant requirements.

Purchased Power and Fuel expense for 2005 increased $4 million (1%) from 2004. An 11% increase in PGE's average variable power cost was largely offset by both a reduction in total system load and a $24 million decrease related to the amortization of costs deferred under power cost adjustment mechanisms in effect during 2001 and 2002, which were later recovered from customers (fully offset within Retail revenues). The increase in average variable power cost was caused primarily by approximately $41 million of incremental power costs incurred to replace coal-fired generation at Boardman, which was taken out of service in mid-October 2005 for removal and repair of the plant's turbine rotor. Lower hydro production in 2005 (due to low stream flows) also contributed to the year's higher average variable power cost. Such cost increases were partially offset by higher unrealized gains from derivative instruments. Company generation decreased about 4% from 2004, with 17% and 9% reductions, respectively, in combustion turbine and hydro production partially offset by increased coal-fired generation, primarily from Colstrip. Total generation met approximately 42% of PGE's retail load in 2005, compared to 43% in 2004.

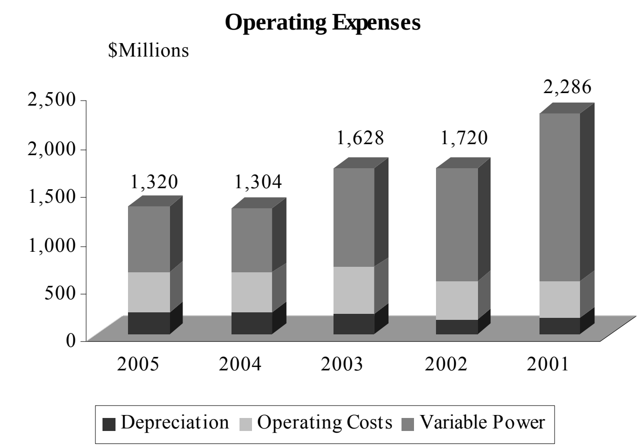
The following table indicates PGE's total system load (including both retail and wholesale) for the last two years. Average variable power costs exclude unrealized gains and losses from derivative instruments and the effect of credits to purchased power and fuel costs related to PGE's power cost adjustment mechanisms, as discussed above.

Megawatt-Hours/Variable Power Costs

	Megawatt-Hours (thousands)		Average Variable Power Cost (Mills/KWh)	
	2005	2004	2005	2004
Generation	7,821	8,114	13.7	15.0
Term Purchases	11,705	12,017	35.3	30.9
Spot Purchases	1,361	1,343	57.4	41.4
Total System Load	20,887	21,474	31.3*	28.2*

(* includes wheeling costs)

Production, distribution, administrative and other expenses increased $21 million (8%) from 2004 due primarily to increased employee benefit expenses (including medical and pension costs), the settlement of certain asserted claims, and an increase in distribution and preventive maintenance expenses. These were partially offset by a reduction in maintenance and other expenses at the Company's thermal generating plants.



Income taxes related to utility operations decreased $11 million primarily due to lower pretax operating income.

Other Income (Miscellaneous) decreased $5 million due primarily to the establishment of a $10 million reserve related to the future refund to Multnomah County customers of previously-collected income taxes, pursuant to a settlement agreement. For further information, see "Class Action Lawsuit - Multnomah County Business Income Taxes" in "Financial and Operating Outlook" of this Item 7.

Power Cost Price Decrease - 2003 PGE's first annual revision of its power supply costs under the RVM tariff forecasted a reduction in the cost of power from that included in the Company's 2001 general rate case. Accordingly, the OPUC authorized an approximate 7% average reduction in the Company's retail prices for 2003. Price decreases ranged from 2% for residential customers to between 9% and 17% for commercial and industrial customers, which were affected more by a reduction in wholesale energy market prices. These price decreases reduced PGE's 2003 revenues by approximately $90 million.

Power Cost Price Increase - 2004 Based upon projections in PGE's 2004 RVM filing, the OPUC authorized an approximate 0.4% average retail price increase for 2004. Price adjustments ranged from a 2.3% decrease for large non-residential customers to increases of 2.8% and 1.9% for small non-residential and residential customers, respectively. Price adjustments varied between customer classes primarily because of different collection periods for a power cost adjustment mechanism that was in effect for the period 2001-2002. Such adjustments increased PGE's 2004 revenues by approximately $4 million.

Power Cost Price Increase - 2005 Based upon projections in PGE's 2005 RVM filing, the OPUC authorized an approximate 1.4% average retail price increase for 2005. Price adjustments ranged from a 0.7% decrease for small non-residential customers to increases of 0.3% and 3.3% for residential and large non-residential customers, respectively. Such adjustments increased PGE's 2005 revenues by approximately $17 million.

Power Cost Price Increase - 2006 Based upon projections in PGE's 2006 RVM filing, the OPUC authorized an approximate 3.7% average retail price increase for 2006, due largely to substantial increases in the cost of wholesale power and continued high prices for natural gas. Increases (including the effect of all credits and adjustments) range from 1.7% for residential customers to 5.3% and 5.4%, respectively, for small and large non-residential customers. Such adjustments are expected to increase PGE's 2006 revenues by approximately $47 million.

Boardman Coal Plant - Extended Outage

On October 22, 2005, following the detection of vibrations in Boardman's steam turbine rotor, the plant was taken out of service. Following repeated unsuccessful efforts to return the plant to service, the rotor was removed and shipped to an east coast facility for repair. On February 6, 2006, during the process of returning the plant to operation, the generator rotor was damaged. The generator rotor has been removed for repairs. Although the actual time required to repair the generator rotor has not yet been determined, PGE estimates that Boardman will be operational by late April 2006. Due to the extended outage, annual maintenance requirements, originally scheduled for the second quarter of 2006, have been completed.

The extended outage has required that PGE replace its portion of Boardman's generation with both higher cost purchases in the wholesale market and increased generation from the Company's natural gas-fired generating plants. PGE's incremental power costs to replace its share of Boardman's generation in the fourth quarter of 2005 were estimated at $41 million, with first quarter 2006 incremental power costs estimated at $45 million. Estimated replacement power costs for April 2006 are expected to range from $200,000 to $300,000 per day. Incremental power costs related to the initial portion of the outage (October 23, 2005 through February 5, 2006) are estimated at $64 million, with incremental power costs related to the outage from February 6, 2006 to the end of the first quarter of 2006 currently estimated at $22 million.

On November 18, 2005, PGE filed with the OPUC an "Application for Deferred Accounting of Excess Power Costs Due to Plant Outage". The application requested an order authorizing PGE to defer for later ratemaking treatment excess power costs associated with Boardman's turbine rotor outage, effective on the date of the application. The application seeks deferral of the difference between Boardman's variable power costs used in setting rates for 2005 and 2006 (under the Company's RVM) and replacement power costs incurred during the turbine rotor outage. The deferral period for the outage ended on February 5, 2006 with the installation of the repaired turbine rotor. The deferral amount is currently estimated at approximately $45 million. No deferral was recorded in 2005. A procedural schedule has been adopted for further consideration of the deferral by the Commission. Management cannot predict the timing or the ultimate outcome of a decision by the OPUC on the Company's application. Under the RVM process, a 4-year rolling average of historical forced outages of PGE’s generating plants is used in setting expected power costs. To the extent the Company is not allowed to recover replacement power costs for Boardman under the deferred accounting application, impacts of the turbine rotor forced outage (October 23, 2005 through February 5, 2006) may be included in the 4-year rolling average component of rates requested under the RVM process beginning in 2007.

PGE has determined that it will not file an application to defer incremental power costs related to the outage resulting from damage to the generator rotor, which began on February 6, 2006. The Company is evaluating, however, whether to propose including this outage in the 4-year rolling average of forced outages in its RVM filings starting in 2008.

Hydro Generation Adjustment

The effect of adverse hydro conditions in recent years has required that PGE acquire replacement power resources for shortfalls in hydro-based power, incurring substantially higher variable power costs than those included in the Company's electricity prices. In 2004, PGE requested OPUC consideration of a hydro generation adjustment tariff that would allow rate adjustment reflecting changes in power costs caused by variations in hydro conditions. The Company also filed an application to defer costs or benefits due to variances in hydro generation, beginning in 2005.

In 2005, PGE and OPUC Staff entered into stipulations for a mechanism that would defer for future recovery in rates a portion of power cost changes caused by variations in hydro conditions, power market prices, and natural gas prices during 2005 and 2006. Following hearings and consideration of the stipulations, the OPUC on December 21, 2005 issued an order that rejected the stipulations but left the dockets open and established criteria by which it would approve a hydro-related power cost adjustment mechanism. In February 2006, PGE withdrew its deferred accounting application and notified the OPUC that the Company will not pursue a hydro generation adjustment tariff, but has instead included a long-term general power cost adjustment mechanism in its current general rate case.

Port Westward Generating Plant

In February 2005, pursuant to PGE's strategy to meet the electric energy needs of its customers outlined in its Integrated Resource Final Action Plan, PGE began construction of Port Westward, a 400 MW natural gas-fired facility located in Clatskanie, Oregon. Construction is proceeding on schedule, with completion expected in the first quarter of 2007. Total cost of the plant is estimated between $275 million and $295 million (including AFDC).

Hydro Relicensing

The 30-year license for PGE's four hydro projects on the Clackamas River expires in August 2006. The Company filed an application with the FERC in 2004 to relicense the projects. A settlement agreement, resolving most of the issues raised in the relicensing proceeding and providing for a 45-year license term, was signed by the thirty-three participating parties on March 2, 2006 and will be submitted to the FERC for review and approval. Pending approval of the new license, the plants will

ICNU/103

PGE Response to
ICNU Data Request No. 2.6

February 17, 2006

TO: S. Bradley Van Cleve
Davison Van Cleve, P.C.

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1234
PGE Response to ICNU's Data Request 2.6
PGE Renumbered to 007
Dated February 3, 2006

Request:

Please provide PGE's actual hydro generation for each month in 2005 and compare that to normal or average levels and to PGE's forecasts for 2005.

Response:

Attachment 007-A contains monthly comparisons of 2005 actual hydro generation to the 2005 RVM forecast. PGE's RVM forecasts are based on "average" water, normal plant, and normal weather conditions. Until PGE files its 2005 SEC Form 10-K, Attachment 007-A is Confidential and Subject to Protective Order No. 06-022 and is provided under separate cover.

Attachment 007-A

Comparison of Hydro Generation for 2005 (MWH)

	January	*February*	*March*	*April*	*May*	*June*	*July*	*August*	*September*	*October*	*November*	*December*	***Total***
Forecast	532,189	471,855	419,434	432,659	421,006	405,934	334,745	312,231	256,031	309,678	368,790	448,110	4,712,662
Actual	419,656	364,115	378,639	360,898	417,572	382,078	366,653	337,849	263,824	313,909	382,660	408,625	4,396,478
Actual - Forecast	(112,533)	(107,740)	(40,795)	(71,761)	(3,434)	(23,856)	31,908	25,618	7,793	4,231	13,870	(39,485)	(316,184)

ICNU/104

PGE Response to
ICNU Data Request No. 2.5

February 17, 2006

TO: S. Bradley Van Cleve
Davison Van Cleve, P.C.

FROM: Patrick G. Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UM 1234
PGE Response to ICNU's Data Request 2.5
PGE Renumbered to 006
Dated February 3, 2006

Request:

In determining PGE's positions and requirements, does the Company normally make assumptions about levels of power needed to replace plants on outage? If so, please explain those assumptions and how they are factored into PGE's position forecasts.

Response:

No, PGE does not explicitly reserve additional energy for forced outages, other than WECC mandated operating and spinning reserves. PGE Power Operations assumes that its thermal plants will be available for full operation, outside of planned maintenance periods. The thermal plants (Boardman, Coyote, Beaver and Colstrip) are dispatched based on market conditions. However, the coal plants (Boardman and Colstrip) typically have a lower dispatch cost than the prevailing market. Therefore, we assume these plants will run at capacity. When the coal plants are in planned maintenance the output is set to zero.