BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1234

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

OF THE

CITIZENS' UTILITY BOARD OF OREGON

June 1, 2006

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My name is Bob Jenks, and my qualifications are listed in CUB Exhibit 101.

I. Introduction

The issues that need to be addressed in this phase of the docket are whether the Boardman replacement power costs should be deferred, and, if so, what costs should be deferred. We agree with PGE that the Boardman outage is extraordinary, and that the replacement power costs meet the deferral criteria set out in UM 1071 and UM 1147. We also find the Company's method of using the specific cost of replacement power for Boardman rather than overall net variable power costs acceptable, but only with the understanding that this method of quantification will be used consistently, in good hydro years and bad, and that an appropriate deadband and sharing bands will be used as a buffer to absorb other cost increases and decreases that are part of the normal stochastic variation of power costs.

PGE's testimony is strangely silent, however, on establishing a deadband and sharing bands for the costs to be deferred. We are puzzled by this, as, once the Commission determines that Boardman replacement power costs are appropriate for deferral, the share of the costs to be deferred must be calculated using a deadband and sharing bands, which are typical in power cost deferrals in Oregon. Establishing an appropriate deadband and sharing bands is usually a central issue in this phase of a deferral, and PGE has said nothing about it.

PGE's testimony does, on the other hand, explore forced outage rates and taxes, neither of which are topics for this deferral docket. Clearly taxes are not a subject in this docket, as they are established in a general rate case, and a future tax methodology is being developed in AR 499, not here. Likewise, forced outage rates are used to forecast future costs in a rate case, and an outage of this duration, addressed in a deferral, is the type of event typically normalized out of any rate case calculations. We should also note that this phase of the docket does not address the prudence of the deferral costs, as the root cause analysis has not yet been presented, and so the parties have no basis upon which to evaluate the Company's prudence as it relates to Boardman's outage.

II. Boardman Replacement Power Cost Appropriate For Deferral

In its Orders in UM 1071 and UM 1147, the Commission laid out the two factors to be considered when deciding to authorize a deferral: the type of event and the magnitude of the event's financial effect.[1]

[1] UM 1147, Order No. 05-1070, page 3.

A. Boardman Outage Is A Significant Event

Though unplanned outages are forecast stochastically, the data provided by PGE indicates that the duration of Boardman's outage is greater than typically experienced[2] by generating units of similar size to Boardman.[3] In its Order in UM 1071, the Commission distinguished between a stochastic forced outage and a scenario forced outage (Trojan).

> While rates are typically set using four year average forced outage rates to forecast NVPC, the duration and cost of the Trojan outages were not within the range considered when we set base energy rates.

UM 1071, Order No. 04-108, page 10.

Under these circumstances it is unclear whether the Boardman outage is stochastic or scenario. Forced outages are modeled, but this one is a bit unusual. However, because of the financial impact of the Boardman outage, we do not need to decide whether it is stochastic or scenario.

The Commission has established that stochastic risks have a substantial financial impact to be considered for deferred accounting, while scenario risks have a lower standard of material impact.[4] As with any deferral, this docket concerns the financial impact of the deferral period. While Boardman came off-line a short period before the Company filed for deferral and remained off-line after the deferral period, PGE elected not to seek recovery for those periods, and so they are not at issue here. The deferral period, November 18th through February 5th, represents approximately 270 basis points of

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[2] PGE/302/Drennan-Tinker-Hager.
[3] PGE/300/Drennan-Tinker-Hager/4.
[4] UM 1147, Order No. 05-1070, page 7.

ROE[5] for PGE, and CUB agrees with the Company that this financial impact is significant enough to make the Boardman outage eligible for deferral.

B. Boardman Outage Not Appropriate In Forced Outage Rate

This Boardman outage is not the kind of event that should be included in a four-year average of a utility's forced outage rate for the purposes of setting future rates. It was a catastrophic plant failure, which required the plant to be closed for months. A forced outage rate is a tool for forecasting routine outages. It would not be reasonable to include this kind of catastrophic failure in a utility's forced outage rate, as an outage of this magnitude is unlikely to repeat itself, and, therefore, should not be forecast in the future.

In addition, due to the extended duration of this kind of catastrophic outage, the financial impact of the event will hinge significantly on the hydro conditions, electricity prices, and natural gas prices at the time of the event. Recovery for the costs of such an extended outage through the Company's forced outage rate would result in over- or under-recovery, because the hydro and market conditions in the future will, of course, be different than they were when the event costs were incurred. It makes far more sense, with an event such as this, to use a deferred account to isolate the actual costs of the event, and allow the utility to recover a reasonable share of the costs. This is how the Commission has dealt with similar catastrophic failures of base-load generating plants in the past, such as PGE's Trojan nuclear power plant and PacifiCorp's Hunter coal-fired power plant.

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[5] [45,383,755 ÷ 16,766,000 x 100] = 270.7 basis points. PGE/300/Drennan-Tinker-Hager/4 & PGE/301/Drennan-Tinker-Hager.

III. Quantifying The Costs To Defer

The costs to be deferred are those incurred during the deferral period, November 18, 2005 through February 5, 2006. How those costs should be calculated, however, has been the subject of considerable controversy, and is a concern to CUB.

A. Quantify The Costs Specific To The Event In Question

PGE's proposed method of calculating the costs to be deferred is to quantify both the cost of replacement power and the avoided costs of operating Boardman and the spring planned outage. While CUB generally supports this method of calculating deferral costs, it is not the only method that has been used. CUB has argued that deferrals should be limited to the event in question, and should not be used to absorb other power cost variations that are properly captured by the expected power cost variations in forward-looking ratemaking.

B. Quantify Net Power Cost Variation Between Forecast & Deferral Period

In quantifying the costs to be deferred for PacifiCorp's Hunter outage, the net power cost variation, rather than the specific event cost, was used. The advantage to this quantification method is that it includes other cost variation in the deferral period such that the deferral cost can be offset with other costs that have declined. Unfortunately, this also means that other cost increases that are not associated with the event in question are also included.

C. Consistency Is Key

Using two different quantification methodologies allows a utility to pick the method that works in its favor. PacifiCorp's Hunter outage occurred during a period of low hydro and rapid system load growth, and PacifiCorp had already requested a deferral that included all net power costs. This allowed PacifiCorp to include costs associated with the stochastic variation of hydro and a poor load forecast into its deferral for a plant outage.

In the case of Boardman, PGE is in a period of good hydro, and the quantification method the Company has proposed will not capture either the use of additional hydro production to offset Boardman's lost generation or any additional power sales into the market that could offset the outage costs. We acknowledge that the Boardman outage happened early in the hydro year, and so PGE could not reasonably have predicted its hydro availability. Given this, the Company's strategy of replacing the lost generation with forward purchases appears prudent on the surface – though we plan take a closer look at this issue during the prudence phase.

Though the Boardman outage happened early in the hydro year, PGE's choice of quantifying the event costs specifically, as opposed to net power cost variation, came later, and the Company is in the best position to know which of the two quantification methods yields the greatest deferral amount. PGE used one method to estimate the cost of the deferral in their application, but reserved the right to propose a different methodology "later in this docket."[6] While narrowly-defined deferrals are better suited to specific events, such as this Boardman outage, we are troubled by the prospect of quantifying deferrals with net power cost variation in bad hydro years (allowing the utility to recoup costs beyond the deferral event), and using event-specific quantification in good hydro years (allowing the utility to keep the benefits of additional hydro). While

[6] UM 1234, Application for Deferred Accounting, page 2

hydro conditions are the most obvious example, this is also a problem for any condition that impacts a utility's power costs.

A utility should not be allowed to choose – depending upon circumstances beyond the deferral event – between a method that allows it to defer increased power costs generally, and one that allows it to defer only the increased costs of a specific event. In CUB's Comments in UM 1147, we explained why the information imbalance between a utility and the other parties gives utilities a leg-up in the use of deferrals. Giving utilities the choice of which method to use in quantifying a deferral would give the utilities another way to systematically bend deferrals in their favor.

D. Quantifying The Cost Of The Boardman Outage

Using PGE's proposed, event-specific quantification method, and thereby ignoring the value of additional hydro generation, is acceptable to CUB under two conditions: 1) event-specific deferral quantification should be used consistently, in both good and bad water years; and 2) an appropriate deadband and sharing bands should be used as a buffer to absorb other cost variations that may offset the deferral costs. This is especially important when hydro is plentiful, as it is this year, and additional hydro generation brings value beyond what was forecast.

E. Appropriate Deadband & Sharing Bands

CUB supports the deferral because the Boardman outage is a significant event. While stochastic and scenario events have different thresholds to determine whether they are eligible for deferred accounting, we will examine how the Commission has treated recent power cost scenario events with regards to deadbands and sharing, since scenario events have the lower threshold. According to the Commission Order in UM 1071:

> Staff has established a distinction between risks that can be predicted as part of the normal course of events and those that are not susceptible to prediction and quantification. Staff calls the former stochastic risks and the latter, paradigm or scenario risks. An example of a scenario risk is the "perfect storm" of 2000-01, a cascade of effects that included poor hydro conditions, cold weather, and extremely volatile markets (UM 995). We find this distinction useful to characterize the type of risk we consider appropriate for deferral.

OPUC Order No. 04-108, pages 8-9.

The Commission cites UM 995 as an example of a scenario risk, so it is a good starting point when considering an appropriate allocation of costs between the Company and its customers. In UM 995 the Commission dealt with a similar failure of a coal-fired plant, Hunter, along with low hydro and high prices, by establishing a deadband equivalent to 250 basis points of ROE, with a 50/50 sharing band for power cost variances between 250 and 400 basis points, and a 75/25 sharing band for costs beyond 400 basis points.[7]

In UM 1008/1009, the Commission also used a 250 basis points deadband in a deferral that was part of the scenario event of the Western Power Crisis for PGE with a 50/50 sharing of costs between 250 and 400 basis points and 90/10 sharing for power cost changes equivalent to more than 400 basis points of ROE.[8]

In UM 1007, the Commission again used the 250 basis points and the 50/50 sharing of costs between 250 basis points and 400 basis points. However, this deferral, which concerned Idaho Power's costs of associated with the Western Power Crisis, had a sharing of 80/20 for costs that were more than 400 basis points.

The recent UE 165 decision also provides us some guidance. While this was not a deferral and was limited to hydro conditions, the Commission Order notes:

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[7] Order No. 01-420
[8] Order No. 01-420 p. 5

> "that the Commission adopted a deadband for recovery of excess power costs equal to a 250-points ROE in authorizing deferrals or approving amortization of deferred accounts in several cases.

OPUC Order No. 05-1261, p. 9

In addition, the Commission found that because a PCA is ongoing and works in both directions (surcharges and refunds), it has a lower threshold. In UE 165, the Commission was willing to adopt a deadband of $15 million with an additional deadband around Company earnings where customers could only be charged costs up to the bottom of an earnings deadband around the Company's allowed ROE.[9] Costs outside of this deadband were shared 80/20. [10]

IV. CUB Recommendation.

We believe that the Boardman outage is eligible for recovery through a deferral. We also approve of limiting the deferral to the actual cost of replacing Boardman power based on actual forward market purchases that were made to replace Boardman power, rather than looking at the change in overall net variable power. While this would eliminate any offset to Boardman costs due to excess hydro beyond what was modeled in the current RVM, we believe it is reasonable as long as it is an approach that is applied consistently in both good and bad water years and as long as the deferral includes a significant deadband.

For a deadband, we propose that the Commission continue the tradition of applying a 250 basis point deadband to deferrals of power cost variations. This is reasonable policy because it recognizes that power cost deferrals, unlike PCAs are one-sided.

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[9] OPUC Order 05-1261, p. 9
[10] OPUC Order 05-1261, p. 4

Finally, with respect to sharing, we note that the 250 basis points absorbs most of the potential deferred power costs so the formula in recent cases of establishing two sharing bands, for costs between 250 and 400 basis points, and for costs above 400 basis points is not necessary. In light of this, we propose to create a single sharing band wherein customers will absorb 70% of the costs above the 250 basis points. We choose the 70/30 sharing because it is the mid-point of the two sharing bands (50/50; 90/10) used in the last PGE power cost deferral.

WITNESS QUALIFICATION STATEMENT

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PREVIOUS EXPERIENCE: Provided testimony or comments in a variety of OPUC dockets, including UE 88, UE 92, UM 903, UM 918, UE 102, UP 168, UT 125, UT 141, UE 115, UE 116, UE 137, UE 139, UE 161, UE 165, UE 167, UE 170, UG 152, UM 995, UM 1050, UM 1071, UM 1147, and UM 1121. Participated in the development of a variety of Least Cost Plans and PUC Settlement Conferences. Provided testimony to Oregon Legislative Committees on consumer issues relating to energy and telecommunications. Lobbied the Oregon Congressional delegation on behalf of CUB and the National Association of State Utility Consumer Advocates.

Between 1982 and 1991, worked for the Oregon State Public Interest Research Group, the Massachusetts Public Interest Research Group, and the Fund for Public Interest Research on a variety of public policy issues.

MEMBERSHIP: National Association of State Utility Consumer Advocates
Board of Directors, OSPIRG Citizen Lobby
Telecommunications Policy Committee, Consumer Federation of America
Electricity Policy Committee, Consumer Federation of America

CERTIFICATE OF SERVICE

I hereby certify that on this 1st day of June, 2006, I served the foregoing Response Testimony of the Citizens' Utility Board of Oregon in docket UM 1234 upon each party listed below, by email and U.S. mail, postage prepaid, and upon the Commission by email and by mailing 6 copies to the Commission's Salem offices.

Respectfully submitted,

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