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September 21, 2006

**VIA E-FILING & FIRST CLASS MAIL**

Oregon Public Utility Commission
Attn: Filing Center
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P. O. Box 2148
Salem, OR 97308-2148

Re: *UM 1234*

Attention Filing Center:

Enclosed for filing in the above-referenced docket are the original and five copies of the Reply Brief of Portland General Electric Company. This document is being filed electronically per the Commission's eFiling policy to the electronic address PUC.FilingCenter@state.or.us, with copies being served on all parties on the service list via U.S. Mail. A photocopy of the PUC tracking information will be forwarded with the hard copy filing.

Very truly yours,

Leslie Hurd

Leslie Hurd, Legal Assistant to
David F. White

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Enclosures
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**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**UM 1234**

| | |
|---|---|
| In the Matter of<br><br>PORTLAND GENERAL ELECTRIC COMPANY,<br><br>Application for Deferred Accounting of Excess Power Costs Due to Plant Outage. | **REPLY BRIEF OF PORTLAND GENERAL ELECTRIC COMPANY** |

## I. INTRODUCTION

Portland General Electric Company ("PGE") submits this Reply Brief in support of its deferred accounting application (the "Application"). In this docket, we ask the Commission to decide which is the better regulatory tool to apply to the extraordinary Boardman outage during the deferral period: deferred accounting or rate-making treatment in a rate case process. We recommend that the Commission use deferred accounting. We will abide by whatever the Commission decides in this docket regarding the selection of a rate-making alternative for the deferral period.

Certain other parties in this docket effectively suggest that *neither* rate-making alternative is appropriate. These parties present a series of contradictory positions, including the following:

- In arguing against deferred accounting treatment, they claim that forced outages, like the Boardman outage, are included in rates; nevertheless, these same parties urge the Commission to exclude the Boardman outage when modeling and forecasting future power costs; and
- The nature of the event that triggers a deferred accounting application is one of the two critical issues under the Commission's review, but these parties suggest that all events, no matter their nature, are subject to a 250 basis point no-deferral band.

Based on the record in this docket, there is little question that the Commission should grant PGE's application. The Boardman outage was an extraordinary event that forced PGE to acquire replacement energy and incur between $42 million and $45 million in excess power costs during the deferral period. Staff, CUB and PGE all agree that deferred accounting is appropriate.

The only real question at this stage is whether the extraordinary power costs PGE has incurred, which are otherwise properly deferrable, will be disallowed before the parties and Commission can consider the prudence of PGE's actions or apply an earnings test as required by law. ORS 757.259(5). PGE acknowledges that a finding of imprudence or an earnings test at the amortization phase may prevent *recovery* of amounts properly deferred at this stage. Nevertheless, nothing presented at this stage justifies what some in this docket have proposed: disallowing $41.9 million of PGE's excess power based on a mechanical application of a "250 deadband" from another docket, another utility, at a different time. We urge the Commission to reject the use of such a rigid rule. The Commission should approve PGE's Application without the no-deferral bands and sharing bands proposed in this docket.

## II. PGE IS REQUESTING THE COMMISSION TO DECIDE BETWEEN ALTERNATIVES

The parties' briefs suggest confusion regarding what PGE is requesting in this docket and how that interrelates with our general rate case filing in UE 180. Rather than argue what PGE intended in these filings and whether we have been clear in attempting to address this issue which spans two dockets, we will restate our request here.

It is necessary to clarify first why, and how, this issue spans two dockets. The "why" is because Oregon's practice, since 1984, has been to produce a test-year forecast of net variable power costs that assumed thermal generating plants would be available based on a weighted, rolling average of the most recent four full years prior to the forecast. That forecasting methodology made the 2005 portion of this extraordinary outage at Boardman relevant to a 2007 test year NVPC forecast. To develop a 2007 NVPC forecast for UE 180, a forecast to which contested case procedures would apply, required that we make some assumptions about Boardman's availability in 2007. The 2005 portion of the outage was relevant in UE 180 regardless of whether or not PGE requested a deferral for some or all of that outage.

Because PGE's request to defer the costs of a portion of this outage—from November 18, 2005 (23 days after it began) to February 5, 2006 (when PGE completed repairs on the problem that caused the outage the prior October)—was far from resolved when we made the UE 180 filing, the assumption about Boardman's availability we used in the UE 180 filing had to be in the alternative. Thus, the "how": if the Commission determined that deferral (of whatever amount it found appropriate) was the best regulatory tool for the costs incurred in replacing Boardman's output during the outage, we would assume Boardman was 100% (or 93.5%, depending on the availability assumption used to calculate the amount of power PGE replaced) available during the deferral period; if the Commission determined that deferred accounting was not appropriate because the better regulatory tool for the costs incurred in replacing Boardman's output during the outage was the rolling, four-year average forecasting methodology, then we would include those days (2005—because 2006 was not yet over to use in a 2007 test year) in applying the methodology. Because a change that lowers a rate increase causes fewer "notice" issues for customers, we filed using the second alternative and explained in testimony that we would adjust the application of the methodology based on the Commission's decision. UE 180 PGE/400, Lesh-Niman/5.

With this background, we clarify our request that the Commission decide, in this docket, which regulatory tool it prefers to use for this extraordinary Boardman outage. We recommend deferred accounting as the better approach, as we explained in the testimony and in our Opening Brief. If the Commission decides that the use of the rolling four-year average NVPC forecasting methodology is appropriate in this case, then it can decide in UE 180, with input from the parties, how PGE should apply the thermal plant availability factor to the Boardman outage for purposes of the 2007 NVPC test-year forecast. If the Commission decides in this docket that deferred accounting is the better regulatory tool for this outage, then it can also decide in this docket the amount PGE may defer for potential amortization following a prudence review and earnings test. The Commission will then decide in UE 180, with input from the parties, whether PGE appropriately removed the outage from Boardman's availability factor for forecasting purposes. We do, in this brief, suggest that Staff's approach to doing this is better than ours: Staff proposed in UE 180 simply to remove the days, and Boardman's performance during those days, from the weighted average calculations altogether.[1]

We hope that a misunderstanding regarding what we requested is why CUB's brief makes the suggestion that our approach is a "not so veiled threat" to the Commission. CUB Brf. at 8. Although it is difficult to understand how filings subject to contested case procedures such as these can "threaten" the decision-maker on those same filings, we certainly intended no threat.

The reason for ICNU's confusion regarding our requests is simpler. ICNU assumes PGE has proposed something that is, actually, not yet an issue: the availability factor for Boardman in a 2008 NVPC test year forecast and how Boardman's operation after the deferral period will or will not be included in such a forecast. ICNU Brf. at 18. The Commission will have that issue before it only if PGE has a 2008 test year, and when it does so will have the aid of its decisions in UM 1234 and UE 180, as well as the parties' input in such a test-year proceeding.

## III. USE OF THE TERMS "DEADBAND" AND "NORMAL BUSINESS RISK" DO NOT FIT THESE FACTS NOR THIS STAGE OF A DEFERRAL PROCEEDING

The parties' arguments in this docket reveal a disconnection between the terminology used and the facts in this docket. The parties argue at length that the Commission can approve no deferral, this one included, until it has applied deadband and sharing percentages so that the utility bears normal business risk. Staff Brf. at 8; CUB Brf. at 6-7; ICNU Brf. at 18.

[1] UE 180 also contains proposals to abandon the 1984 thermal plant availability factor forecasting methodology altogether. We are not addressing those here and do not intend to be arguing them by noting our agreement with a different alternative, Staff proposal in that case.

A deadband, however, implies a positive and negative amount around a central point; normal business risk encompasses good results and bad. Thus, Staff:

> [R]ecommends a 250 basis point deadband to capture the normal business risk that the company is generally exposed to between rate cases. Staff believes that 250 basis points of ROE represents normal variability that would not trigger a rate filing by the company or a show cause request by other parties.

Staff/100, Owings-Galbraith/20.

This deferral concerns an event, a plant outage, that can only increase cost, and it did so from the day the outage began. There was never any positive side of a "deadband" that could apply under these facts. Nor is a positive side foreseeable in any future period such that parties could demonstrate or argue, or the Commission conclude, that the possibility of Boardman achieving an availability greater than that forecast in any one or more years such that the additional days of operation balance the past days of outage. PGE/400, Lesh-Tinker/13. If Boardman's extraordinary outage is an example of normal business risk, it is a one-sided risk only. Moreover, the parties who propose a 250 basis point deadband also take the position the Boardman outage should not be taken into account in setting Boardman's availability factor in the future. Staff/100, Owings-Galbraith/21-22; UE 180 CUB/100, Jenks-Brown/7; UE 180 ICNU/103, Falkenberg/12. The right term for this is disallowance, not deadband.

Two further thoughts flow from grasping this disconnection. The first concerns the nature of the facts in this deferral compared to the deferrals the parties cite in support of their positions that the deferred amount should range from nothing to $655,000. CUB Brf. at 10, ICNU Brf. at 19, Staff/100, Owings-Galbraith/20. The second concerns the mismatch between the theory underlying a deadband and its application at the authorization phase of a deferral proceeding rather than the amortization phase.

On the first point, this deferral application concerns significantly different facts from those that applied in UM 995. UM 995 concerned the difference between forecasted NVPC and actual NVPC for a period of almost a year. PGE/400, Lesh-Tinker/18. The facts also differ in another deferral the parties frequently cite, notwithstanding that it was a settlement and, therefore, not precedent for anything. Dockets UM 1008/1009 involved competing deferral applications for the difference between PGE's 2001 forecast and actual NVPC: one by Staff who believed the actual NVPC could be significantly lower than the forecast, and one by PGE, based on our belief the actual could be significantly higher. Order No. 01-231 (March 14, 2001). Finally, in UM 1071, the triggering event in that docket, hydro-electric generation does, at least, present the opportunity for output significantly above the forecast output assumptions. UM 1071, Order No. 04-108 at 9 (March 2, 2004) ("Hydro variability, for example, causes costs to swing above and below the average included in rates"). That is not a possibility for extraordinary outages like the Boardman outage. PGE/400, Lesh-Tinker/12-13; PGE Brf. at 10-11.

On the second point, the theory underlying use of a deadband is that it represents normal business risk and, indeed, the measure typically suggested is of a certain number of basis points of the utility's opportunity to earn its required return on common equity. A utility earns this return, however, on the entire business. And, on the entire business, normal business risk encompasses income both higher than expected and lower than expected. This is best addressed by an earnings test at the amortization stage. It allows the Commission to ensure that a deferral does not interfere with the utility bearing normal business risk. PGE/400, Lesh-Tinker/17. If a utility already has earned an adequate return from the business during the period in which a deferred cost occurred, the Commission can limit or preclude recovery. Similarly, if the deferral is of a cost reduction, the Commission can apply the earnings test to ensure that amortizing that refund to customers does not preclude the utility from experiencing its normal business risk. But applying an earnings test at the deferral stage has the opposite effect: it prevents the Commission from applying an earnings test at the recovery phase as a means of ensuring that the utility bears normal business risk. This is particularly true given that a deadband appears to apply only to deferrals of additional costs that will, of necessity, lower the utility's return.

Deferral decisions in the 1990s show a different way to approach the deferral and amortization/earnings test decisions that do not involve the mismatch described above. In

UM 445, the Commission considered and approved PGE's application to defer excess power costs associated with one of the early Trojan outages, assigning 10% of the deferred cost to PGE, not customers, to account for "normal variation in plant operation." UM 445, Order No. 91-1781, Appendix A at 6 (Dec. 20, 1991). No deadband or earnings test applied at the deferral authorization phase. In the course of determining the amount of this deferral it would allow PGE to amortize, the Commission applied an earnings test using a deadband of 50 basis points above and below PGE's authorized return on equity at the time. UM 445/UE 82, Order No. 93-257 at 11-12 (Feb. 22, 1993). Order No. 93-257, found in this record in PGE/400, Lesh-Tinker/17, provides a thorough discussion of the role of the earnings test.

PGE urges that the Commission, in recognition of the disconnection and mismatches resulting from indiscriminate and rigid application of a "250 basis point deadband," reject the parties' arguments and instead apply "a flexible, fact-specific review approach that acknowledges the wide range of reasons why deferred accounting might be beneficial to customers and utilities." UM 1147, Order No. 05-1070 at 1, 5 (Oct. 5, 2005). The Commission has expressly rejected attempts to reduce its review to a mathematical formula, numerical criteria or matrix, electing an approach that "provides more flexibility for the Commission to exercise its discretion." *Id.* at 7; UM 1071, Order No. 04-108 at 9. Such a flexible approach is essential given that the Commission must decide a variety of applications filed by very different utilities—some gas, some electric companies; some multi-state utilities, some not— in dockets in which not all utilities are participants, with an opportunity to be heard.

## IV. THE COMMISSION SHOULD REJECT ARGUMENTS THAT SEEK A DEPARTURE FROM THE FACT-SPECIFIC REVIEW IT ARTICULATED IN UM 1147

In UM 1147, the Commission set forth its framework for how it exercises discretion under the deferred accounting statute, elaborating that it focuses on the nature of the events—"modeled in rates or not, foreseeable or not"—and the magnitude of the financial harm. Order No. 05-1070 at 7. Staff and CUB apply this framework in new ways that, while they differ from each other, reach the same result: a disallowance of 250 basis points from the amount eligible for deferral.

CUB agrees the Boardman outage was so unusual that it qualifies as a scenario risk (i.e., neither modeled in rates nor foreseeable in the ordinary course of events) and subject to a "less-restrictive" financial harm standard. CUB Brf. at 4. Nevertheless, CUB claims that "less restrictive" requires that the Commission first disallow $41.9 million[2] of the Boardman replacement power cost before approving the deferral. *Id.* at 6. The Commission has never endorsed or even suggested such a view. For example, in UM 1071, the Commission declined to adopt a numerical criteria for the higher financial harm test, but it gave as an example the 250 basis point deadband in UM 995. UM 1071, Order No. 04-108 at 9. This at least implied that "material" financial harm was lower than "substantial" financial harm. Indeed, the Commission specifically distinguished deferred accounting cases such as UM 445 and UM 529, in which the Commission imposed no deadbands, on the grounds that a lower financial threshold is appropriate when the event is "not within the range considered when we set base rates." *Id.* at 10.

Staff's position in some ways is more extreme. It claims that the characterization of the event is simply irrelevant. No matter the type of event—modeled or not modeled in rates, foreseeable or not foreseeable in the ordinary course of events, extraordinary or ordinary, stochastic or scenario—the Commission must disallow $41.9 million of excess costs before authorizing any deferral, much less recovery, of the additional incurred costs. Staff Brf. at 11-12. Staff's position ignores the entire framework the Commission articulated in UM 1071 and developed into guidance in UM 1147. Central to that framework is the nature of the triggering event. In fact, that is the first issue the Commission addresses, demanding that the utility "bear the burden of identifying the event and showing its significance." UM 1147, Order No. 05-1070

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[2] 250 basis points of PGE's authorized earnings opportunity.

at 7. The Commission elaborated that it examines "the nature of the event, its impact on the utility, treatment in ratemaking, and other factors used to evaluate whether a deferred account is appropriate." *Id.* None of these issues are relevant to Staff's one-size fits all rule, which simply applies a blanket 250 basis point no-deferral band to all power cost deferrals.

Some parties continue to make UM 995 the foundation of their position, suggesting that it is binding precedent for this docket. *See, e.g.*, Staff Brf. at 9, ICNU Brf. at 10. In our Opening Brief, we highlighted the reasons UM 995 should not govern in this case, and we will not repeat those arguments here. PGE Brf. at 14-16. We want to underscore here the way in which the parties stretch the Commission's ruling beyond recognition. The parties seem to argue that, in UM 995, the Commission intended to establish for all utilities, in all circumstances, at all times, a disallowance of the first 250 basis points in power costs greater than those forecasted in a test year. We disagree that UM 995, a docket that involved just one utility and one specific set of facts, can bear this weight.

First, neither the Commission nor any of the parties has followed such a blanket edict. Since UM 995, the Commission has granted a number of deferrals, both of additional and reduced costs, with no deadband.[3] Second, the Commission's order in UM 995 made no decision regarding what level of disallowance might be appropriate to a relatively straightforward plant outage. Recall, in UM 995 there were record high energy prices, severe drought conditions, cold weather and a plant outage. UM 995, Order No. 01-420 at 28-29 (May 11, 2001); Order No. 01-753 at 6 (Aug. 28, 2001). Oregon's share of the excess power costs was $259 million before application of the deferred accounting framework, and $160 million after. UM 995, Order No. 02-469 at 2. The circumstances in that case were unprecedented, a "perfect storm" that the Commission handled within a framework that applied in that case and that case alone. Last, it overstates matters to claim the Commission "expressly adopted" the parties' assertions in that docket that 250 basis points "captured the normal business risk the company is generally

[3] *See* deferred accounting orders cited in PGE's Opening Brief at 12, footnote 10.

exposed to between rate cases." Staff Brf. at 9. In UM 995, the Commission adopted Staff's proposed framework for the deferral and responses to specific questions. As we read it, the Order did not adopt Staff's or any other parties' rationale in that proceeding. In fact, the Commission has since resisted attempts to place a numerical criterion or rigid formulas on its exercise of discretion on multiple occasions. UM 1071, Order No. 04-108 at 9; UM 1147, Order No. 05-1070 at 7.

## V. THE BOARDMAN OUTAGE WAS NOT MODELED IN RATES

ICNU's principal basis for arguing against the deferral is that test-year forecasts include an assumption about forced outages. ICNU Brf. at 1. As a threshold matter, ICNU mischaracterizes the relationship between whether test-year forecasting includes an assumption encompassing a certain event (or is stochastic as ICNU claims) and deferred accounting treatment. Events within the range of those used to establish the assumptions needed for test-year forecasting are eligible for deferred accounting treatment; however, they must meet a higher financial threshold.

Moreover, the relevant question is not whether test-year forecasting requires an assumption for the type of event involved, but rather whether the test-year forecast in question assumed this particular event. For example, in UM 1071 the Commission concluded that the method by which PGE created an assumption for hydroelectric generation for test year forecasting included once-in-4.5 year events, and that the costs in question related to this "modeled" event. UM 1071, Order No. 04-108 at 9. Test-year forecasting methods did not include more extraordinary drought years[4] or drought years combined with other factors[5] and, thus, were more appropriate for deferred accounting treatment in such circumstances. For purposes of this docket, what is important is that the test year forecast included a Boardman availability assumption based on its performance over four specific years. That performance did

[4] Order No. 04-108 at 10 (citing UM 480, Order No. 92-1130 (Aug. 5, 1992)).

[5] Order No. 04-108 at 9 (citing UM 995).

not include any outage even close to the one in question. PGE/400, Lesh-Tinker/5-6. Given this, we find puzzling ICNU's assertion that the Boardman outage "represents a stochastic risk that the Commission considered in establishing PGE's 2005 and 2006 power costs." ICNU Brf. at 5. At face value, this statement is false.

ICNU also claims that the Commission has included in rates outage rates for other plants that were "of equal or greater magnitude than what the Company experienced for Boardman in 2005." ICNU Brf. at 8. ICNU's claim misstates the extent of the Boardman outage, which did not end in 2005; it continued until February 5, 2006. Therefore, limiting the outage to 2005 misstates the length of the outage by almost 50%.

It bears noting that ICNU offered no testimony on this point but relied instead on a spreadsheet entered into the record at the hearing. ICNU Ex. 200. The data in that spreadsheet represents annual forced outage rates and not an event-by-event itemization of forced outages. PGE's Application concerns a specific outage, which the record demonstrates is extremely rare. PGE/300, Drennan-Tinker-Hager/4-5 (NERC study shows that the Boardman outage represents 0.238% of the outages in the comprehensive 20-year survey). ICNU presents no evidence regarding any forced outage events for Colstrip, Coyote or Beaver. Moreover, Coyote and Beaver are gas-fired plants, which operate close to market prices. Boardman is a base load coal plant, which operates well below market prices. The financial impact of a forced outage at Boardman is, therefore, very different from the effect of an outage at Beaver or Coyote. Finally, ICNU provides no evidence regarding the market price of electricity in 2002 and 2003—the years ICNU identifies—and how it compares with current market prices. The market price of electricity in 2002 and 2003 was much lower than it is today. Again, this softens the financial impact of the forced outages at Beaver, Colstrip and Coyote during 2002 and 2003 and multiples the impact of the Boardman outage in 2005 and 2006.

## VI. PGE'S APPLICATION MEETS THE LEGAL REQUIREMENTS

ICNU continues to argue that the Application does not meet the legal requirements of ORS 757.259(2)(e), notwithstanding the Commission's recent rejection of the "temporal matching" requirement ICNU had sought to impose. UM 1256, Order No. 06- 483 at 5 (Aug. 22, 2006). No other party shares ICNU's view; both Staff and CUB agree the Application meets the legal requirements. Staff Brf at 8, CUB Brf at 2.

In light of the collapse of its temporal matching argument, ICNU seeks to change the subject by focusing on the timing mismatch that occurs through use of the rolling four-year average to forecast rates. ICNU Brf. at 16. Like any forecasting methodology, the four-year rolling average forecast may not, in any given year, reflect actual plant operation in the year forecasted. That is the nature of the test-year component of any regulatory framework. Mismatches that are inherent in the four-year rolling and general rate-making principles are irrelevant to PGE's Application, which serves to better match costs and benefits by having customers pay for the cost of the power they use.

## VII. THE COMMISSION SHOULD CONSIDER THE SB 408 EFFECT ON THE BOARDMAN OUTAGE

The parties do not dispute the impact of SB 408. In the final order in AR 499, the Commission acknowledged that its rules for implementing SB 408 will result in a "double whammy." AR 499, Order No. UM 06-532 at 10-11 (Sept. 14, 2006). Variations from forecasted costs have an associated tax impact on the utility, which the SB 408 rules will pass through to customers. This will serve to exaggerate and enhance the impact on utilities by requiring a refund in the case of higher-than-expected costs and a surcharge when costs are lower than forecasted. The Commission reaffirmed that it would consider this unintended impact of SB 408 in other rate-making proceedings. *Id.* at 11 (citing Order No. 06-400 at 9).

PGE urges that the Commission reject the disallowance bands some have proposed in this docket. Nevertheless, should the Commission adopt such bands or sharing mechanisms, the Commission should adjust them to reflect the SB 408 impact. Such an adjustment would not run counter to the intent of SB 408. It would adjust a financial impact test to reflect the actual impact of variations in costs on the utility. It is undisputed that the bands proposed in this docket do not reflect the SB 408 impact. PGE/400, Lesh-Tinker/23.

CUB expressly does not oppose such an adjustment. CUB Brf. at 9 ("CUB does not oppose redrawing the deadband and sharing bands so that post-SB 408 bands have the same after-tax impact as pre-SB 408 bands"). It does not appear that Staff opposes such an adjustment. Staff Brf. at 13.

## VIII. CONCLUSION

For the reasons stated above and in PGE's Opening Brief, the Commission should approve PGE's Application without the disallowances proposed in this docket.

DATED this 21st day of September, 2006.


PORTLAND GENERAL
ELECTRIC COMPANY

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## CERTIFICATE OF SERVICE

I hereby certify that on this day I served the foregoing **REPLY BRIEF OF PORTLAND GENERAL ELECTRIC COMPANY** by mailing a copy thereof in a sealed envelope, first-class postage prepaid, addressed to each party listed below, deposited in the U.S. Mail at Portland, Oregon.

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**BEFORE THE PUBLIC UTILITY COMMISSION**

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The parties' briefs suggest confusion regarding what PGE is requesting in this docket and how that interrelates with our general rate case filing in UE 180. Rather than argue what PGE intended in these filings and whether we have been clear in attempting to address this issue which spans two dockets, we will restate our request here.

It is necessary to clarify first why, and how, this issue spans two dockets. The "why" is because Oregon's practice, since 1984, has been to produce a test-year forecast of net variable power costs that assumed thermal generating plants would be available based on a weighted, rolling average of the most recent four full years prior to the forecast. That forecasting methodology made the 2005 portion of this extraordinary outage at Boardman relevant to a 2007 test year NVPC forecast. To develop a 2007 NVPC forecast for UE 180, a forecast to which contested case procedures would apply, required that we make some assumptions about Boardman's availability in 2007. The 2005 portion of the outage was relevant in UE 180 regardless of whether or not PGE requested a deferral for some or all of that outage.

Because PGE's request to defer the costs of a portion of this outage—from November 18, 2005 (23 days after it began) to February 5, 2006 (when PGE completed repairs on the problem that caused the outage the prior October)—was far from resolved when we made the UE 180 filing, the assumption about Boardman's availability we used in the UE 180 filing had to be in the alternative. Thus, the "how": if the Commission determined that deferral (of whatever amount it found appropriate) was the best regulatory tool for the costs incurred in replacing Boardman's output during the outage, we would assume Boardman was 100% (or 93.5%, depending on the availability assumption used to calculate the amount of power PGE replaced) available during the deferral period; if the Commission determined that deferred accounting was not appropriate because the better regulatory tool for the costs incurred in replacing Boardman's output during the outage was the rolling, four-year average forecasting methodology, then we would include those days (2005—because 2006 was not yet over to use in a 2007 test year) in applying the methodology. Because a change that lowers a rate increase causes fewer "notice" issues for customers, we filed using the second alternative and explained in testimony that we would adjust the application of the methodology based on the Commission's decision. UE 180 PGE/400, Lesh-Niman/5.

With this background, we clarify our request that the Commission decide, in this docket, which regulatory tool it prefers to use for this extraordinary Boardman outage. We recommend deferred accounting as the better approach, as we explained in the testimony and in our Opening Brief. If the Commission decides that the use of the rolling four-year average NVPC forecasting methodology is appropriate in this case, then it can decide in UE 180, with input from the parties, how PGE should apply the thermal plant availability factor to the Boardman outage for purposes of the 2007 NVPC test-year forecast. If the Commission decides in this docket that deferred accounting is the better regulatory tool for this outage, then it can also decide in this docket the amount PGE may defer for potential amortization following a prudence review and earnings test. The Commission will then decide in UE 180, with input from the parties, whether PGE appropriately removed the outage from Boardman's availability factor for forecasting purposes. We do, in this brief, suggest that Staff's approach to doing this is better than ours: Staff proposed in UE 180 simply to remove the days, and Boardman's performance during those days, from the weighted average calculations altogether.[1]

We hope that a misunderstanding regarding what we requested is why CUB's brief makes the suggestion that our approach is a "not so veiled threat" to the Commission. CUB Brf. at 8. Although it is difficult to understand how filings subject to contested case procedures such as these can "threaten" the decision-maker on those same filings, we certainly intended no threat.

The reason for ICNU's confusion regarding our requests is simpler. ICNU assumes PGE has proposed something that is, actually, not yet an issue: the availability factor for Boardman in a 2008 NVPC test year forecast and how Boardman's operation after the deferral period will or will not be included in such a forecast. ICNU Brf. at 18. The Commission will have that issue before it only if PGE has a 2008 test year, and when it does so will have the aid of its decisions in UM 1234 and UE 180, as well as the parties' input in such a test-year proceeding.

## III. USE OF THE TERMS "DEADBAND" AND "NORMAL BUSINESS RISK" DO NOT FIT THESE FACTS NOR THIS STAGE OF A DEFERRAL PROCEEDING

The parties' arguments in this docket reveal a disconnection between the terminology used and the facts in this docket. The parties argue at length that the Commission can approve no deferral, this one included, until it has applied deadband and sharing percentages so that the utility bears normal business risk. Staff Brf. at 8; CUB Brf. at 6-7; ICNU Brf. at 18.

[1] UE 180 also contains proposals to abandon the 1984 thermal plant availability factor forecasting methodology altogether. We are not addressing those here and do not intend to be arguing them by noting our agreement with a different alternative, Staff proposal in that case.

A deadband, however, implies a positive and negative amount around a central point; normal business risk encompasses good results and bad. Thus, Staff:

> [R]ecommends a 250 basis point deadband to capture the normal business risk that the company is generally exposed to between rate cases. Staff believes that 250 basis points of ROE represents normal variability that would not trigger a rate filing by the company or a show cause request by other parties.

Staff/100, Owings-Galbraith/20.

This deferral concerns an event, a plant outage, that can only increase cost, and it did so from the day the outage began. There was never any positive side of a "deadband" that could apply under these facts. Nor is a positive side foreseeable in any future period such that parties could demonstrate or argue, or the Commission conclude, that the possibility of Boardman achieving an availability greater than that forecast in any one or more years such that the additional days of operation balance the past days of outage. PGE/400, Lesh-Tinker/13. If Boardman's extraordinary outage is an example of normal business risk, it is a one-sided risk only. Moreover, the parties who propose a 250 basis point deadband also take the position the Boardman outage should not be taken into account in setting Boardman's availability factor in the future. Staff/100, Owings-Galbraith/21-22; UE 180 CUB/100, Jenks-Brown/7; UE 180 ICNU/103, Falkenberg/12. The right term for this is disallowance, not deadband.

Two further thoughts flow from grasping this disconnection. The first concerns the nature of the facts in this deferral compared to the deferrals the parties cite in support of their positions that the deferred amount should range from nothing to $655,000. CUB Brf. at 10, ICNU Brf. at 19, Staff/100, Owings-Galbraith/20. The second concerns the mismatch between the theory underlying a deadband and its application at the authorization phase of a deferral proceeding rather than the amortization phase.

On the first point, this deferral application concerns significantly different facts from those that applied in UM 995. UM 995 concerned the difference between forecasted NVPC and actual NVPC for a period of almost a year. PGE/400, Lesh-Tinker/18. The facts also differ in another deferral the parties frequently cite, notwithstanding that it was a settlement and, therefore, not precedent for anything. Dockets UM 1008/1009 involved competing deferral applications for the difference between PGE's 2001 forecast and actual NVPC: one by Staff who believed the actual NVPC could be significantly lower than the forecast, and one by PGE, based on our belief the actual could be significantly higher. Order No. 01-231 (March 14, 2001). Finally, in UM 1071, the triggering event in that docket, hydro-electric generation does, at least, present the opportunity for output significantly above the forecast output assumptions. UM 1071, Order No. 04-108 at 9 (March 2, 2004) ("Hydro variability, for example, causes costs to swing above and below the average included in rates"). That is not a possibility for extraordinary outages like the Boardman outage. PGE/400, Lesh-Tinker/12-13; PGE Brf. at 10-11.

On the second point, the theory underlying use of a deadband is that it represents normal business risk and, indeed, the measure typically suggested is of a certain number of basis points of the utility's opportunity to earn its required return on common equity. A utility earns this return, however, on the entire business. And, on the entire business, normal business risk encompasses income both higher than expected and lower than expected. This is best addressed by an earnings test at the amortization stage. It allows the Commission to ensure that a deferral does not interfere with the utility bearing normal business risk. PGE/400, Lesh-Tinker/17. If a utility already has earned an adequate return from the business during the period in which a deferred cost occurred, the Commission can limit or preclude recovery. Similarly, if the deferral is of a cost reduction, the Commission can apply the earnings test to ensure that amortizing that refund to customers does not preclude the utility from experiencing its normal business risk. But applying an earnings test at the deferral stage has the opposite effect: it prevents the Commission from applying an earnings test at the recovery phase as a means of ensuring that the utility bears normal business risk. This is particularly true given that a deadband appears to apply only to deferrals of additional costs that will, of necessity, lower the utility's return.

Deferral decisions in the 1990s show a different way to approach the deferral and amortization/earnings test decisions that do not involve the mismatch described above. In

UM 445, the Commission considered and approved PGE's application to defer excess power costs associated with one of the early Trojan outages, assigning 10% of the deferred cost to PGE, not customers, to account for "normal variation in plant operation." UM 445, Order No. 91-1781, Appendix A at 6 (Dec. 20, 1991). No deadband or earnings test applied at the deferral authorization phase. In the course of determining the amount of this deferral it would allow PGE to amortize, the Commission applied an earnings test using a deadband of 50 basis points above and below PGE's authorized return on equity at the time. UM 445/UE 82, Order No. 93-257 at 11-12 (Feb. 22, 1993). Order No. 93-257, found in this record in PGE/400, Lesh-Tinker/17, provides a thorough discussion of the role of the earnings test.

PGE urges that the Commission, in recognition of the disconnection and mismatches resulting from indiscriminate and rigid application of a "250 basis point deadband," reject the parties' arguments and instead apply "a flexible, fact-specific review approach that acknowledges the wide range of reasons why deferred accounting might be beneficial to customers and utilities." UM 1147, Order No. 05-1070 at 1, 5 (Oct. 5, 2005). The Commission has expressly rejected attempts to reduce its review to a mathematical formula, numerical criteria or matrix, electing an approach that "provides more flexibility for the Commission to exercise its discretion." *Id.* at 7; UM 1071, Order No. 04-108 at 9. Such a flexible approach is essential given that the Commission must decide a variety of applications filed by very different utilities—some gas, some electric companies; some multi-state utilities, some not— in dockets in which not all utilities are participants, with an opportunity to be heard.

## IV. THE COMMISSION SHOULD REJECT ARGUMENTS THAT SEEK A DEPARTURE FROM THE FACT-SPECIFIC REVIEW IT ARTICULATED IN UM 1147

In UM 1147, the Commission set forth its framework for how it exercises discretion under the deferred accounting statute, elaborating that it focuses on the nature of the events—"modeled in rates or not, foreseeable or not"—and the magnitude of the financial harm. Order No. 05-1070 at 7. Staff and CUB apply this framework in new ways that, while they differ from each other, reach the same result: a disallowance of 250 basis points from the amount eligible for deferral.

CUB agrees the Boardman outage was so unusual that it qualifies as a scenario risk (i.e., neither modeled in rates nor foreseeable in the ordinary course of events) and subject to a "less-restrictive" financial harm standard. CUB Brf. at 4. Nevertheless, CUB claims that "less restrictive" requires that the Commission first disallow \$41.9 million[2] of the Boardman replacement power cost before approving the deferral. *Id.* at 6. The Commission has never endorsed or even suggested such a view. For example, in UM 1071, the Commission declined to adopt a numerical criteria for the higher financial harm test, but it gave as an example the 250 basis point deadband in UM 995. UM 1071, Order No. 04-108 at 9. This at least implied that "material" financial harm was lower than "substantial" financial harm. Indeed, the Commission specifically distinguished deferred accounting cases such as UM 445 and UM 529, in which the Commission imposed no deadbands, on the grounds that a lower financial threshold is appropriate when the event is "not within the range considered when we set base rates." *Id.* at 10.

Staff's position in some ways is more extreme. It claims that the characterization of the event is simply irrelevant. No matter the type of event—modeled or not modeled in rates, foreseeable or not foreseeable in the ordinary course of events, extraordinary or ordinary, stochastic or scenario—the Commission must disallow \$41.9 million of excess costs before authorizing any deferral, much less recovery, of the additional incurred costs. Staff Brf. at 11-12. Staff's position ignores the entire framework the Commission articulated in UM 1071 and developed into guidance in UM 1147. Central to that framework is the nature of the triggering event. In fact, that is the first issue the Commission addresses, demanding that the utility "bear the burden of identifying the event and showing its significance." UM 1147, Order No. 05-1070

[2] 250 basis points of PGE's authorized earnings opportunity.

at 7. The Commission elaborated that it examines "the nature of the event, its impact on the utility, treatment in ratemaking, and other factors used to evaluate whether a deferred account is appropriate." *Id.* None of these issues are relevant to Staff's one-size fits all rule, which simply applies a blanket 250 basis point no-deferral band to all power cost deferrals.

Some parties continue to make UM 995 the foundation of their position, suggesting that it is binding precedent for this docket. *See, e.g.,* Staff Brf. at 9, ICNU Brf. at 10. In our Opening Brief, we highlighted the reasons UM 995 should not govern in this case, and we will not repeat those arguments here. PGE Brf. at 14-16. We want to underscore here the way in which the parties stretch the Commission's ruling beyond recognition. The parties seem to argue that, in UM 995, the Commission intended to establish for all utilities, in all circumstances, at all times, a disallowance of the first 250 basis points in power costs greater than those forecasted in a test year. We disagree that UM 995, a docket that involved just one utility and one specific set of facts, can bear this weight.

First, neither the Commission nor any of the parties has followed such a blanket edict. Since UM 995, the Commission has granted a number of deferrals, both of additional and reduced costs, with no deadband.[3] Second, the Commission's order in UM 995 made no decision regarding what level of disallowance might be appropriate to a relatively straightforward plant outage. Recall, in UM 995 there were record high energy prices, severe drought conditions, cold weather and a plant outage. UM 995, Order No. 01-420 at 28-29 (May 11, 2001); Order No. 01-753 at 6 (Aug. 28, 2001). Oregon's share of the excess power costs was $259 million before application of the deferred accounting framework, and $160 million after. UM 995, Order No. 02-469 at 2. The circumstances in that case were unprecedented, a "perfect storm" that the Commission handled within a framework that applied in that case and that case alone. Last, it overstates matters to claim the Commission "expressly adopted" the parties' assertions in that docket that 250 basis points "captured the normal business risk the company is generally

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[3] *See* deferred accounting orders cited in PGE's Opening Brief at 12, footnote 10.

exposed to between rate cases." Staff Brf. at 9. In UM 995, the Commission adopted Staff's proposed framework for the deferral and responses to specific questions. As we read it, the Order did not adopt Staff's or any other parties' rationale in that proceeding. In fact, the Commission has since resisted attempts to place a numerical criterion or rigid formulas on its exercise of discretion on multiple occasions. UM 1071, Order No. 04-108 at 9; UM 1147, Order No. 05-1070 at 7.

## V. THE BOARDMAN OUTAGE WAS NOT MODELED IN RATES

ICNU's principal basis for arguing against the deferral is that test-year forecasts include an assumption about forced outages. ICNU Brf. at 1. As a threshold matter, ICNU mischaracterizes the relationship between whether test-year forecasting includes an assumption encompassing a certain event (or is stochastic as ICNU claims) and deferred accounting treatment. Events within the range of those used to establish the assumptions needed for test-year forecasting are eligible for deferred accounting treatment; however, they must meet a higher financial threshold.

Moreover, the relevant question is not whether test-year forecasting requires an assumption for the type of event involved, but rather whether the test-year forecast in question assumed this particular event. For example, in UM 1071 the Commission concluded that the method by which PGE created an assumption for hydroelectric generation for test year forecasting included once-in-4.5 year events, and that the costs in question related to this "modeled" event. UM 1071, Order No. 04-108 at 9. Test-year forecasting methods did not include more extraordinary drought years[4] or drought years combined with other factors[5] and, thus, were more appropriate for deferred accounting treatment in such circumstances. For purposes of this docket, what is important is that the test year forecast included a Boardman availability assumption based on its performance over four specific years. That performance did

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[4] Order No. 04-108 at 10 (citing UM 480, Order No. 92-1130 (Aug. 5, 1992)).

[5] Order No. 04-108 at 9 (citing UM 995).

not include any outage even close to the one in question. PGE/400, Lesh-Tinker/5-6. Given this, we find puzzling ICNU's assertion that the Boardman outage "represents a stochastic risk that the Commission considered in establishing PGE's 2005 and 2006 power costs." ICNU Brf. at 5. At face value, this statement is false.

ICNU also claims that the Commission has included in rates outage rates for other plants that were "of equal or greater magnitude than what the Company experienced for Boardman in 2005." ICNU Brf. at 8. ICNU's claim misstates the extent of the Boardman outage, which did not end in 2005; it continued until February 5, 2006. Therefore, limiting the outage to 2005 misstates the length of the outage by almost 50%.

It bears noting that ICNU offered no testimony on this point but relied instead on a spreadsheet entered into the record at the hearing. ICNU Ex. 200. The data in that spreadsheet represents annual forced outage rates and not an event-by-event itemization of forced outages. PGE's Application concerns a specific outage, which the record demonstrates is extremely rare. PGE/300, Drennan-Tinker-Hager/4-5 (NERC study shows that the Boardman outage represents 0.238% of the outages in the comprehensive 20-year survey). ICNU presents no evidence regarding any forced outage events for Colstrip, Coyote or Beaver. Moreover, Coyote and Beaver are gas-fired plants, which operate close to market prices. Boardman is a base load coal plant, which operates well below market prices. The financial impact of a forced outage at Boardman is, therefore, very different from the effect of an outage at Beaver or Coyote. Finally, ICNU provides no evidence regarding the market price of electricity in 2002 and 2003—the years ICNU identifies—and how it compares with current market prices. The market price of electricity in 2002 and 2003 was much lower than it is today. Again, this softens the financial impact of the forced outages at Beaver, Colstrip and Coyote during 2002 and 2003 and multiples the impact of the Boardman outage in 2005 and 2006.

## VI. PGE'S APPLICATION MEETS THE LEGAL REQUIREMENTS

ICNU continues to argue that the Application does not meet the legal requirements of ORS 757.259(2)(e), notwithstanding the Commission's recent rejection of the "temporal matching" requirement ICNU had sought to impose. UM 1256, Order No. 06- 483 at 5 (Aug. 22, 2006). No other party shares ICNU's view; both Staff and CUB agree the Application meets the legal requirements. Staff Brf at 8, CUB Brf at 2.

In light of the collapse of its temporal matching argument, ICNU seeks to change the subject by focusing on the timing mismatch that occurs through use of the rolling four-year average to forecast rates. ICNU Brf. at 16. Like any forecasting methodology, the four-year rolling average forecast may not, in any given year, reflect actual plant operation in the year forecasted. That is the nature of the test-year component of any regulatory framework. Mismatches that are inherent in the four-year rolling and general rate-making principles are irrelevant to PGE's Application, which serves to better match costs and benefits by having customers pay for the cost of the power they use.

## VII. THE COMMISSION SHOULD CONSIDER THE SB 408 EFFECT ON THE BOARDMAN OUTAGE

The parties do not dispute the impact of SB 408. In the final order in AR 499, the Commission acknowledged that its rules for implementing SB 408 will result in a "double whammy." AR 499, Order No. UM 06-532 at 10-11 (Sept. 14, 2006). Variations from forecasted costs have an associated tax impact on the utility, which the SB 408 rules will pass through to customers. This will serve to exaggerate and enhance the impact on utilities by requiring a refund in the case of higher-than-expected costs and a surcharge when costs are lower than forecasted. The Commission reaffirmed that it would consider this unintended impact of SB 408 in other rate-making proceedings. *Id.* at 11 (citing Order No. 06-400 at 9).

PGE urges that the Commission reject the disallowance bands some have proposed in this docket. Nevertheless, should the Commission adopt such bands or sharing mechanisms, the Commission should adjust them to reflect the SB 408 impact. Such an adjustment would not run counter to the intent of SB 408. It would adjust a financial impact test to reflect the actual impact of variations in costs on the utility. It is undisputed that the bands proposed in this docket do not reflect the SB 408 impact. PGE/400, Lesh-Tinker/23.

CUB expressly does not oppose such an adjustment. CUB Brf. at 9 ("CUB does not oppose redrawing the deadband and sharing bands so that post-SB 408 bands have the same after-tax impact as pre-SB 408 bands"). It does not appear that Staff opposes such an adjustment. Staff Brf. at 13.

## VIII. CONCLUSION

For the reasons stated above and in PGE's Opening Brief, the Commission should approve PGE's Application without the disallowances proposed in this docket.

DATED this 21st day of September, 2006.

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## CERTIFICATE OF SERVICE

I hereby certify that on this day I served the foregoing **REPLY BRIEF OF PORTLAND GENERAL ELECTRIC COMPANY** by mailing a copy thereof in a sealed envelope, first-class postage prepaid, addressed to each party listed below, deposited in the U.S. Mail at Portland, Oregon.

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