BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/ UE 181/ UE 184

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180), In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181), In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision relating to the Port Westward Plant (UE 184).	**PORTLAND GENERAL ELECTRIC COMPANY'S PREHEARING BRIEF**

Pursuant to the schedule set forth in Prehearing Conference Report issued by Judge Christina Hayes on April 5, 2006, Portland General Electric Company ("PGE") submits this Prehearing Brief in advance of the November 1-2, 2006 hearing.

I. INTRODUCTION

This case is about power costs, PGE's cost of capital, and the cost of capital implications associated with PGE's ongoing ability to recover from customers the power costs it actually incurs to provide on-demand retail electric service.

PGE's immediate need for higher prices is driven almost entirely by power cost increases and the proposed addition of the Port Westward Generating Plant ("Port Westward") to rate base. Administrative & general expenses, operations & maintenance expenses, and other non-power costs in the 2007 test year actually *decline*, in aggregate, under the terms of the various stipulations reached by the parties in this proceeding. As compared with power cost increases PGE has faced in recent years and the cost increases attributable to general inflation, PGE's requested increase is fairly small.

In addition to the impact of power costs on the current revenue requirement, this case concerns the regulatory framework for power costs going forward: How to forecast them and what to do when the forecast is wrong because of uncertainty that the best modeling cannot remove. Power costs in total represent about two thirds of PGE's revenue requirement; Net Variable Power Costs ("NVPC") alone represent over one half of PGE's revenue requirement. It is essential that the regulatory framework adopted provide PGE with both the ability to recover its costs and an opportunity to earn its allowed return. Given PGE's relatively small rate base, it does not have an earnings margin sufficient to bear significant shortfalls in power cost recovery. PGE is proposing a power cost recovery framework that reduces the risk of variations in power costs for both PGE and its customers, while preserving PGE's incentive to control actual power costs through a sharing percentage.

This is a particularly critical case for PGE. For the first time since 1997, PGE's common equity stock is publicly traded, and the financial community is evaluating it on a stand-alone basis. Those reviews currently suggest that PGE requires strong regulatory support. With a senior secured rating of BBB+ from Standard & Poor's,[1] PGE does not have a sizable cushion to remain an "investment grade" entity and preserve its access to capital. Standard & Poor's recently issued a "negative outlook" regarding PGE; that report cited, among other things, an "uncertain regulatory environment." The capital structure, cost of debt and cost of equity established for PGE in this proceeding must fairly compensate PGE's investors for the risks they take in providing capital for retail electric service, to ensure that PGE can continue to attract capital on reasonable terms. Although the cost of capital is not a big slice of PGE's revenue requirement (about 11%), the choices have significant implications for PGE and customers, now and into the future. Without strong financials, PGE's ability to manage near-term power cost volatility through many active trading partners, with many transactions that work to hedge risk, will be lessened. Without strong financials, PGE will not be able to take least cost resource actions on behalf of customers when those actions require PGE investment. Overshadowing both issues is SB 408 and its major change to ratemaking caused by a true-up of taxes without regard to the income generated by utility business in a given year.

The importance of this case for PGE is heightened by the capital needs PGE anticipates as it reduces the environmental impact of its existing generation and makes new resource choices that are least cost over the long term. As noted above, this filing reflects the addition of Port Westward, a combined-cycle combustion turbine generating plant expected to begin providing service to customers in March 2007. In addition, PGE is developing 126 MW of wind generation and may increase that by up to 324 MW (for a total of 450 MW) over the next five years, if that proves best for customers. PGE also faces hydro relicensing investment and

[1] Standard & Poor's rating for PGE's senior unsecured debt is BBB. Moody's ratings are Baa1 for PGE's senior secured and Baa2 for senior unsecured debt. Fitch's ratings are A- for PGE's senior secured debt and BBB+ for senior unsecured debt.

environmental costs at Boardman. In order to economically raise the funds necessary to support these resource acquisition efforts, it is essential that PGE receive adequate rate relief that will enable it to maintain its existing credit rating and to preserve its financial integrity.

II. PROCEDURAL BACKGROUND

During March and April 2006, PGE made three filings which have been consolidated in these proceedings for investigation. First, on March 15, 2006, PGE filed Advice No. 06-8 for a general rate revision to increase its retail rates by about 8.9% or $98 million (Docket UE 180). Second, on March 28, 2006, PGE filed its annual adjustments to Schedule 125, PGE's resource valuation mechanism ("RVM") (Docket UE 181). Third, on April 24, PGE filed Advice No. 06-10, to reflect in rates Port Westward when it comes into service for customer, currently anticipated to be March 2007 (Docket UE 184).[2]

The parties to these proceedings have negotiated a number of stipulations that have resolved many issues. They are:

- Stipulation Regarding Direct Access Issues, which was approved by the Commission on September 14, 2006 in Order No. 06-528.[3]
- Stipulation Regarding RVM Issues, which was approved by the Commission on

[2] PGE also filed an updated detailed depreciation study on November 9, 2005. That study was docketed as UM 1233. A stipulation between PGE and Staff was entered into on August 17, 2006, settling all issues in that docket. The Commission approved the stipulation on October 13, 2006, Order No. 06-581. The revised depreciation parameters approved in that docket will be used in this rate case.

[3] This stipulation, dated August 22, 2006, is among PGE, Staff of the Public Utility Commission of Oregon ("Staff"), the Industrial customers of Northwest Utilities ("ICNU"), Fred Meyer Stores, the City of Portland, Constellation NewEnergy, Inc., EPCOR Merchant and Capital (US) Inc., and Sempra Global. This stipulation resolved all direct access issues raised in the docket including (a) modifications to Schedules 483 and 489, (b) support for the proposed split load option, (c) new quarterly direct access windows, (d) the extension through 2009 of the Schedule 130 Shopping Incentive Rider, (e) terms for a short-term power supply transition adjustment and related tariff changes, (f) the addition of a direct access option for Schedule 38 customers, and (g) changes to Schedules 32 and 128.

October 9 in Order No. 06-575.[4] This stipulation resolved issues relating to the RVM portion of this docket and the RVM adjustment rates that will go into effect on January 1, 2006. This stipulation included an assumed reduction to the forecast annual Net Variable Power Costs of $8,588,000.

- Stipulation Regarding Revenue Requirement Issues dated August 24, 2006,[5] which settled all revenue requirement issues except cost of capital, power costs, Port Westward, and AMI. This stipulation resulted in a reduction of about $20 million in PGE's revenue requirement.

- Stipulation Regarding Rate Spread and Rate Design Issues, dated October 4, 2006.[6]

- In addition, PGE has reached agreement in principle with the Cities on streetlight service costs and terms of service. This stipulation and supporting testimony will be filed with the Commission presently.

Given the issues resolved by these stipulations, the only remaining issues are:

1. **Cost of Capital**, including long-term debt cost, return on equity, the relationship between capital costs and power cost recovery, and capital structure.

2. **Power cost-related issues**, including: the proposed Power Cost Variance Mechanism (Schedule 126); the proposed Annual Update tariff (Schedule 125); the forced outage rate calculation; proposed "extrinsic value" adjustments;

[4] This stipulation, dated August 24, 2006, is among PGE, Staff, ICNU, and the Citizens Utility Board ("CUB"). It is anticipated that these RVM rates will be in effect only until January 17, 2006. This stipulation also contains a provision regarding the ratemaking treatment of certain gas transportation costs that are currently subject to rate case proceedings before the Federal Energy Regulatory Commission.

[5] This stipulation is among PGE, Staff, CUB, ICNU and Fred Meyer Stores, and specifically addresses eleven proposed adjustments.

[6] This stipulation is among PGE, Staff, CUB, ICNU and Fred Meyer Stores. This stipulation settled all rate spread and rate design issues except issues regarding Schedule 76R raised by ICNU. The stipulation contains provisions regarding pricing for Schedule 102, the rate design of Schedules 83/583, application of the Customer Impact Offset credit, and modifications to Schedule 75. This stipulation has no revenue requirement impact.

revenue from sale of ancillary services; and the inclusion of Port Westward costs and benefits when the plant begins service to customers.

3. Terms of service for partial requirements customers under Schedule 76R.

4. Certain tax issues raised by the City of Portland in their direct testimony.[7]

There is one additional issue addressed in testimony – PGE's proposed Automated Metering Infrastructure ("AMI") project. In PGE's final round of testimony, however, PGE withdrew AMI from this rate case so no decision by the Commission is necessary at this time. As indicated in testimony, PGE will bring the AMI project before the Commission in subsequent filings.

Each of the remaining issues for which a Commission decision is necessary is addressed below.

III. STATEMENT OF PENDING ISSUES

A. Cost of Capital

1. Introduction

The governing standard for determining a utility's cost of capital derives from two oft-cited U.S. Supreme Court cases, *Bluefield Waterworks & Imp. Co. v. West Virginia Public Service Commission*, 262 U.S. 679 (1923) ("*Bluefield*") and *Federal Power Comm. V. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*"). According to *Bluefield*:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties . . .

[7] PGE's rebuttal testimony identified numerous errors in this testimony and the scheme upon which it was based. The City of Portland did not file any testimony attempting to rebut PGE's testimony. As a result, it is unclear whether the City of Portland is still advocating the positions contained in this testimony.

262 U.S. at 692-93. *Hope* states that:

> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

320 U.S. at 603.

In Oregon, the Constitutional requirements from *Bluefield* and *Hope* have been codified in ORS 756.040, which states that:

> The commission shall balance the interests of the utility investor and the consumer in establishing fair and reasonable rates. Rates are fair and reasonable for the purposes of this subsection if the rates provide adequate revenue both for operating expenses of the public utility or telecommunications utility and for capital costs of the utility, with a return to the equity holder that is:
>
> (a) Commensurate with the return on investments in other enterprises having corresponding risks; and
>
> (b) Sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital.

As described in the Introduction above, it is vitally important that the Commission set PGE's costs of capital at a level that allows it to maintain its financial integrity and to attract capital on reasonable terms. PGE's requested cost of capital in this proceeding will produce the financial metrics that will place it comfortably within the benchmarks associated with its current BBB+ rating on senior secured debt. The recommendations of Staff, however, likely would result in a downgrade of PGE's credit rating, and thereby jeopardize PGE's access to the capital necessary to fund its acquisition of generating resources and support risk management activities.

Given the long-term borrowing associated with these resources, PGE's customers would bear the higher interest costs attributable to a downgrade for decades into the future.

2. Long-term Debt

Issues Presented: **Should the Commission adjust PGE's actual cost of debt because Enron's bankruptcy might have contributed to a one-step downgrade in PGE's credit rating in 2001, at the same time that electric utilities throughout the West were being downgraded?**

Should the Commission reduce PGE's projected cost of long-term debt by pricing PGE's debt issuance for 2007 at a rate for a 10-year maturity rather than the 30-year debt PGE will actually issue?

In its sur-surrebuttal testimony, PGE updated the long-term debt component of its capital structure to reflect an increase in the amount of debt it plans to issue in 2007 from $100 million to $300 million. Because the Biglow Canyon wind project is now projected to come on line by December 31, 2007, the associated capital expenditures were moved into 2007. PGE now expects to issue approximately $150 million of 30-year first mortgage bonds in April 2007 at 6.15%, and to issue an additional $150 million of 10- year first mortgage bonds in August 2007, with an estimated coupon of 5.77%. The effect of this update is to lower the average cost of debt to 6.73%.

Staff is recommending a disallowance of over 40 basis points – to 6.30% – in PGE's cost of long-term debt. Staff's proposed reduction is based upon a "re-pricing" of six long-term debt issuances. Staff claims that such a reduction is warranted because of an asserted "Enron bankruptcy effect" that caused PGE to incur higher interest costs than PGE would have otherwise.

PGE's credit rating was, in fact, downgraded in Fall 2001, just prior to the Enron bankruptcy of December 2001. PGE had plenty of company: *almost all* the other electric utilities operating in the Western power markets were downgraded at about the same time.

During 2001 and 2002, there were 420 downgrade rating actions taken by the three major rating agencies (PGE Exhibit 1104, page 2). It is impossible to isolate the impact of Enron's bankruptcy on PGE's long-term debt costs, as Staff's adjustment purports to do. The evidence suggests that the impact of the Enron bankruptcy on PGE, if any, was limited only to PGE's access to short-term debt. The ring-fencing provisions adopted by the Commission in UM 814 protected PGE's credit and, thereby, PGE's customers from adverse impacts associated with Enron.

A second aspect of Staff's proposed reduction is a re-pricing of PGE's forecasted $100 million debt issuance based on a shorter, cheaper 10-year maturity, rather than using the interest costs associated with the 30-year debt that PGE will actually issue. This 30-year maturity reasonably matches the term of the debt with the useful life of the underlying assets being financed. The evidence is undisputed that the anticipated interest costs for a 10-year maturity are about thirty basis points lower than for a 30-year maturity. Thus, while Staff disingenuously claims that proposing this reduction does not direct PGE to use a particular maturity, the practical consequence of adopting Staff's position is to disallow the higher interest costs PGE will incur if it proceeds with its plan to issue a 30-year security.

3. Return on Equity

Issues Presented: **Should the Commission adopt a return on equity (ROE) for PGE within the range supported by PGE and CUB/ICNU witnesses, reflecting the risks PGE's investors face, or should the Commission give weight to the Staff recommendation of an ROE that would be the lowest granted for any electric utility in the US?**

In determining PGE's required ROE, should the Commission consider all relevant information, such as recent ROE decisions in other jurisdictions and the outcomes produced by methodologies other than the discounted cash flow (DCF) model, such as a Risk Positioning model, or should the Commission follow Staff's approach and consider only a DCF analysis?

PGE is proposing an ROE of 10.75%, based on a DCF analysis and a risk-positioning, or risk premium, method. Staff, for its part, recommended an ROE of 9.30% in its initial testimony, which it "updated" to 9.40% in Staff's sur-rebuttal testimony. CUB/ICNU recommend an ROE of 9.9%, using a combination of DCF, Risk Premium and Capital Asset Pricing Model ("CAPM") analyses.

Staff's ROE recommendation is based solely on a DCF analysis, which it prepared on the basis of the average ROE derived from Staff's sample group of companies. The sample group relied upon by Staff was flawed, as it contained companies that failed to satisfy Staff's own criteria. Staff admitted its errors in its sur-rebuttal testimony, and purportedly recalculated its ROE recommendation after excluding two companies from its sample group. Staff provided no evidence, however, that would demonstrate how this modification affected Staff's ROE recommendation.

In addition, Staff made no adjustment to the sample group DCF to reflect PGE-specific risks, such as the risks associated with heavy dependence on purchased power (including the historic Mid-Columbia contracts), the absence of a power cost recovery mechanism, the perceived negative regulatory environment as a result of the enactment of SB 408, and PGE's lack of jurisdictional diversity, being located entirely within Oregon. Staff's ROE and capital structure recommendations would place PGE at the bottom end of S&P's benchmark guidelines for a BBB+ rating on senior secured debt, and thus potentially result in a downgrade for PGE at a time when it is seeking to raise capital to support necessary investment.

Staff's ROE recommendation is extremely low, and is far below any ROE adopted by any regulatory commission in the country over the past 18 months. The average ROE allowed for electric or combination utilities since January 2005 is 10.47% (PGE Exhibit 2706). Adoption of the punitive ROE which Staff recommends would cause repercussions throughout the financial community, and would indicate a lack of regulatory support for PGE at this critical time in PGE's history. Another consequence would likely be a dramatic reduction in PGE's stock price: insofar as Staff's 9.4% ROE recommendation is intended to drive PGE's market price down to book value, it would result in a drop in PGE's stock price of 22.5%.

As a point of reference, ICNU/CUB witness Gorman is recommending an ROE of 9.9%, which is at the bottom of a range of reasonableness. Staff's recommendation is far below an acceptable range, and the Commission should not give it serious consideration.

4. Relationship Between Capital Costs and Recoverability of Power Costs

Issue Presented: Must the Commission's determination on ROE and capital structure take into account the Commission's actions with respect to adoption of PGE's proposals for an Annual Update Tariff and a Power Cost Variance Mechanism?

The regulatory framework the Commission adopts for PGE's power costs will materially affect PGE's risk profile, and thus the ROE necessary to compensate PGE's investors for the risks associated with their equity investment in PGE and the equity ratio necessary to maintain an acceptable credit rating. Both equity investors and providers of debt capital consider the ability of a utility to recover its prudently incurred power costs a key factor in determining whether the regulatory climate is supportive or punitive. The required ROE indicated in PGE's cost of capital testimony is expressly predicated on adoption of the power cost framework PGE proposes in this proceeding. The power cost regulatory framework PGE proposes is most like those used for similar, vertically integrated electric utilities, as corroborated by the comprehensive report on power cost adjustments prepared by National Economic Research Associates (PGE Exhibit 401). If the Commission instead wishes to construct a regulatory framework with a greater cost of service risk for PGE and its customers both from year-to-year and within each year, the Commission must correspondingly choose an authorized return on common equity and an equity ratio that reflect the risk PGE bears and variability associated with that framework and adequately compensate investors for bearing that risk. An unproven (and unprovable) assumption that customers' and PGE's risk will balance over time is not compensation for the portion of the risk PGE bears.

5. Capital Structure

Issue Presented: Should the Commission use PGE's actual 2007 capital structure for test year ratemaking, or choose a lower level of equity that disregards PGE's near-term capital requirements and leverage effects of the purchased power currently in PGE's portfolio?

As a result of increasing the amount of debt PGE will issue in 2007 from \$100 million to \$300 million, as described above, PGE's forecasted actual equity ratio for 2007 falls from 56.6% to 53.3%.

Staff initially proposed an equity ratio of 48.5%, based exclusively on that being the equity ratio from the sample group of companies relied upon by Staff for its ROE recommendation. Staff performed no independent analysis whether any PGE-specific circumstances may require a higher equity ratio, such as debt imputation or anticipated capital expenditures. In its sur-rebuttal testimony, Staff inexplicably revised its equity ratio recommendation upward to 50%. CUB/ICNU, for their part, also propose an equity ratio of 50.0%.

An equity ratio in excess of 50% is necessary given the capital expenditures PGE will soon make, and the need to compensate for the "debt imputation" or debt equivalent analysis that S&P performs to address the risks associated with long-term power purchase agreements.

6. Overall Rate of Return

Issue Presented: **Should the Commission adopt PGE's proposed overall rate of return of 8.87%, which would be sufficient to ensure confidence in PGE's financial integrity and allow PGE to maintain its existing credit rating, or use Staff's recommended overall rate of return of 7.86%, which is 30 basis points lower than that recently authorized for PacifiCorp in Docket UE 179 and 44 basis points lower than the 8.30% overall return recommended by ICNU-CUB in this proceeding?**

The update to PGE's long-term debt results in a lower equity ratio (53.3%) and a lower average cost of debt (6.73%) which, together with the 10.75% recommended ROE, produce an overall cost of capital of 8.87%. This represents a 16-basis point reduction from that requested in PGE's direct testimony. This overall rate of return is sufficient to ensure confidence in PGE's financial integrity, to allow PGE to maintain its existing credit rating and to attract capital on reasonable terms, all as required by Oregon statute. This is vitally important, given the capital that PGE will be raising in the coming years to support the acquisition of generating resources to provide an economical power supply for our customers over the long term.

In contrast, Staff is recommending an overall rate of return of 7.86%, which is 30 basis points lower than recently authorized for PacifiCorp in Docket UE 179 and 44 basis points lower than the 8.30% overall return recommended by ICNU-CUB in this proceeding. Staff combines its punitive 9.4% ROE recommendation with an unsupported disallowance of long-term debt costs and a proposed capital structure that fails to reflect PGE's circumstances, such as PGE's reliance on purchased power, total reliance on Oregon's regulatory environment, and the debt imputation associated with this reliance. Staff's position on cost of capital is so extreme as to strip it of any credibility, and should be accorded little, if any, weight.

B. Power Costs

1. Introduction

PGE has proposed a power cost regulatory framework that includes an Annual Update tariff, similar (but not identical) to the current RVM, that would reset prices annually based on a test year forecast of NVPC for the coming year. PGE also proposes an annual Variance Tariff. This mechanism will change cost of service prices for a portion of the difference between actual NVPC and the NVPC set in the Annual Update. The Variance Tariff will include in cost of service ratemaking 90% of the difference, either positive or negative, between actual and base NVPC. The Commission would determine the timing and size of price changes resulting from these variances.

In debating the power cost framework to be adopted in this docket, the parties have taken interesting and sometimes disconcerting positions. PGE proposed two tariff mechanisms that would, together and separately, align cost of service prices more closely with the prudently incurred cost of providing electric service. The other parties oppose one of these mechanisms in its entirety, and seek limitations on the other that would insure a gap between prices and the costs of service. In short, PGE is arguing that cost of service rates should accurately reflect the costs of service. Other parties are arguing against that proposition.

Staff has gone as far as stating that, under the current power cost regulatory framework and PGE's existing resource base, it is more likely that PGE will under-recover its power costs than over-recover. If that is the case, PGE does not have a reasonable expectation of earning its authorized ROE, and rates set under such a framework are not fair, just and reasonable. What is truly disconcerting, however, is that Staff makes this statement in an attempt to support its position that a PCA should include a large deadband to preserve this inequity.

2. Power Cost Variance Mechanism.

Issues Presented: **Should the Commission include in ratemaking most of the actual NVPC that PGE incurs to serve cost-of-service customers?**

Is it necessary to include a deadband so that PGE and customers continue to bear some cost-of-service risk associated with the difference between forecasted and actual NVPC, or will such a mechanism result in systematic under-recovery of actual power costs?

Should the Commission limit the inclusion of actual NVPC in ratemaking if that inclusion would result in excessive PGE earnings or should the Commission apply an earnings test that eliminates some variances because of other changes in PGE's cost of service from the amount forecast in test year ratemaking?

PGE proposes Schedule 126, an annual Power Cost Variance Mechanism. This mechanism will change cost of service prices for a portion of the difference between actual NVPC and the NVPC set in the Annual Update. Under this tariff, PGE would place 90% of the difference, either positive or negative, between actual and base NVPC in the Power Cost Variance Account for amortization as directed by the Commission. Schedule 126 also includes an earnings review similar to that used in the Commission-approved purchased gas adjustments.

Staff and CUB recognize the need for a power cost adjustment ("PCA") mechanism and each propose an alternative PCA. ICNU opposes any PCA. The principal point of contention is the need for and size of any deadband, and the sharing percentages for power cost variances. Staff proposes a PCA mechanism with a deadband of plus or minus150 basis points of ROE, an additional earnings test deadband of plus or minus 100 basis points of ROE, and 90/10 sharing of any amounts outside these deadbands. CUB proposes stepped asymmetric deadbands with different sharing levels. It varies from no sharing for variances in power costs of up to125 basis points below those assumed in rates and 250 basis points above the costs assumed in setting rates to, after increases in two steps, to 90/10 sharing for variances of 200 basis points when actual costs are below the cost used in setting rates and 400 basis points when actual costs are higher than those used in setting rates. CUB also proposes an additional earnings deadband of plus or minus 100 basis points of ROE. CUB also adds a cap on the amortization of any variances to 6% of rates.

Staff expresses its belief that PGE's current set of resources has a greater probability of producing power at *higher* than forecasted costs than at lower than forecasted costs. Assuming this claim is correct, the Commission must significantly reduce this unevenly allocated cost-of-service risk. Otherwise, PGE's investors will be denied a reasonable opportunity to recover the costs associated with the capital they have provided to PGE for investment in utility service. Inclusion of a deadband is a significant departure from how other states regulate utilities otherwise comparable to PGE. This divergence will reflect negatively on Oregon's regulatory climate and PGE in the national financial markets. Inclusion of a deadband suggests a less supportive regulatory climate because it implies that the utility may never recover certain costs, irrespective of whether the costs were prudently incurred or not.

Including a deadband is also unfair with respect to the different types of costs within a utility's power costs. It allows customers to enjoy the benefits of low embedded fixed costs but shields them from the full variable costs of the same resources. The embedded, fixed costs of PGE's resources are just \$16/MWh, while the NVPC associated with these same resources, on a forecasted basis, are \$41/MWh. If customers never experience the full costs of PGE's resources, they cannot make wise decisions about consumption, particularly around long-term equipment and appliance investments.

Part of the debate in this docket regarding the need for and size of any deadbands involves the meaning and application of the outcomes of other Commission dockets. While previous cases are instructive, the power cost regulatory framework the Commission adopts in this docket is primarily a policy issue. At the same time, a "deadband" policy direction that determines the size of the deadband based on a certain number of basis points of the authorized return on common equity is unfair across utilities. This approach ignores how much a particular utility has invested in generation. In PGE's case, only 29% of PGE's rate base is in generation. (That figure increases to 38% with the inclusion of Port Westward.) The investment in generating resources should be considered in determining the size of any deadband, not the utility's entire investment. The Commission should determine and implement a structure that is fair, just and reasonable to all concerned. PGE believes that the structure it has proposed meets that test.

3. Annual Update Tariff

Issue Presented: Should the Commission set PGE's cost of service rates using the most up-to-date information on NVPC each year (i.e. specific contracts entered by PGE) or minimize alleged regulatory burden by assuming that a forecast for one year will be "enough right" for subsequent years?

In this proceeding, PGE is proposing an annual update, tariff Schedule 125. This tariff is similar to, but narrower than, the current RVM. Under this proposed schedule, PGE would revise cost of service prices annually on January 1 through an automatic adjustment clause to reflect a forecast of NVPC developed using the MONET model updated with certain defined inputs of current and projected information for the coming year. The proposed Schedule 125 tariff sheet describes both the input parameters and the process. In PGE's view, this annual update proposal resolves many of the aspects of the RVM proceedings that have caused disagreement in past dockets.

Staff and CUB maintain that basing cost-of-service rates on the most recent information is not worth the regulatory burden. CUB also argues that an annual update shifts risk from PGE to its customers.

The prices paid by PGE for actual purchased power and fuel contracts have been quite volatile in recent years, and the greatest effect of this volatility on NVPC cost-of-service risk is year-to-year, and not within the year. Use of the annual update would ensure that PGE's cost of service prices reflect the costs actually incurred by PGE for power supplies to serve customers over a given year. The annual update would also help the Commission maintain the allocation of NVPC risk it has chosen in creating the test year forecast.

4. Forced Outage Rate Calculation

Issues Presented: **Should the Commission abandon the four-year rolling average methodology for determining the test year assumption for Colstrip's operation, simply to achieve a higher assumed availability factor in 2007 by excluding the relatively troubled year of 2002?**

Should the Commission abandon the four-year rolling average methodology for determining the test year assumption for Boardman's operation, or address the Boardman outage presently the subject of a deferral application by simply removing those days from the calculation?

The parties propose to depart from the Commission's historic practice of calculating an assumed plant outage rate for test year ratemaking purposes. Rather than using a four-year average of actual outages – the Commission's traditional practice – Staff and ICNU are proposing to use certain data compiled by the North American Electric Reliability Council

("NERC").[8] This is a results-driven adjustment that ignores PGE's historically good track record when compared with NERC Equivalent Availability Factors, a more relevant and appropriate yardstick. Moreover, it represents a dramatic departure from the policy underlying the use of four-year actual plant data.

When Staff originally recommended the policy in 1984, Staff intended "to propose a method for calculating performance that can be applied uniformly from plant to plant and from company to company." Using NERC data, as proposed in this proceeding by Staff, ICNU, and supported by CUB, will not meet this original intent. The new proposals will not apply uniformly across companies, only to PGE. The method will not apply uniformly across plants, only a subset of PGE's units. Even the other parties do not apply their various NERC-based methods uniformly: Staff suggests Boardman and Colstrip use NERC data, ICNU includes Coyote, and CUB simply indicates their agreement with the use of NERC data.

The Commission should continue using the traditional method of calculating an assumed forced outage rate for test year ratemaking purposes. Any change in methodology should be well-reasoned, not reactionary. A single event – the 2005 Boardman outage – does not require a change in methodology that violates the original intent of using a four-year average of actual data. The proposed use of NERC data should be rejected.

5. Proposed "Extrinsic Value" Adjustments

Issue Presented: **Should the Commission select a 2007 test year NVPC forecast that, to the best of its ability, evenly allocates the risk of higher or lower outcomes, or should the Commission arbitrarily reduce that forecast for the potential revenues from dispatching PGE resources more than the MONET model indicates is economic?**

Staff and ICNU propose to reduce the MONET net variable power cost (NVPC) forecast

[8] Staff proposes to use the five-year average equivalent forced outage rate for the "Coal 400-599 MW" peer group, ICNU also proposes to use the NERC average outage rate for comparable plants.

because they believe that some of PGE's gas-fired resources and heat rate–based contracts will produce margins higher than those in the MONET forecast. Staff claims that until PGE develops and implements stochastic power cost modeling, an extrinsic value adjustment is necessary to ensure that customers receive all the benefits from PGE's flexible power resources.

This proposed reduction is without merit, and without precedent in Oregon. The test year forecast reflects so much of the "value" of PGE's generating resources as is certain. The further assumption proposed by Staff and ICNU to capture what is uncertain is neither necessary nor appropriate. Their assumption is not fair because it fails to incorporate all, or even a reasonably comprehensive subset of, the impacts that uncertainty may have on PGE's forecast of NVPC. By incorporating only one aspect of the impact of forecasting uncertainty on PGE's power costs (*i.e.*, the extrinsic value of thermal resources), Staff is effectively cherry-picking the "good" aspects of uncertainty while ignoring the "bad" aspects.

The only attempt to address the impact of forecasting uncertainty on PGE's power costs is the study undertaken by PA Consulting, which indicates that the base MONET NVPC forecast is *less* than an expected NVPC. According to the PA report, the base forecast is less than an expected NVPC by approximately $10 million. Thus, a more complete assessment of uncertainty indicates that capturing uncertainty in PGE's power cost forecast – if necessary at all – would *increase* the forecast.

ICNU, for its part, offered two alternative approaches. Its Alternative 1 methodology, when corrected and properly compared to the dispatch benefits credited to customers in the MONET forecast, indicates that including uncertain extrinsic value would *increase* the test year NVPC forecast by almost $3 million. The ICNU methodology thus confirms the conclusions of the PA study – that any adjustment for extrinsic value would *increase*, not decrease, NVPC.

6. Revenue from Ancillary Services

Issue Presented: Should the Commission arbitrarily lower PGE's NVPC forecast for the potential revenue from PGE's sale of ancillary services without regard to the costs associated with such sales and only a handful of months of sales on which to base the estimate?

Staff is proposing to reduce PGE's test year NVPC forecast for revenues it assumes PGE can earn by selling ancillary services. PGE began selling these services to the California ISO in June 2005. In PGE's view, there is considerable uncertainty around making a revenue projection for the test year, given the limited experience to date and the substantial variance in revenues from month to month (from less than \$50,000 to more than \$400,000). Moreover, any such revenue projection should be net of the costs associated with providing these services, such as grid management charges imposed by the California ISO.

Notwithstanding the uncertainties in projecting this revenue, Staff proposes to reduce the NVPC forecast by simply extrapolating the actual revenues for a one-year period, from September 2005 through August 2006. Staff does not, however, include any costs associated with providing these services.

The correct approach to handling the uncertainty associated with these revenues is through a comprehensive variance tariff, such as PGE is proposing in this case.

7. Inclusion of Port Westward

Issues Presented: Should the Commission adopt CUB's recommendation to withhold a determination of Port Westward's prudence until PGE signs turbine contracts for Biglow Canyon?

Should the Commission impose conditions that would penalize PGE for a short delay in the on-line date for Port Westward?

PGE is requesting that the Commission decide in this case the cost changes associated with Port Westward commencing service, which is expected to occur in March 2007. Once the plant commences commercial operation, PGE would file compliance tariffs effecting the revenue requirement change.

CUB argues that PGE has not sufficiently demonstrated the prudence of including Port Westward in light of other actions taken consistent with PGE's most recent acknowledged IRP. In particular, CUB expresses concern that PGE does not yet have a signed wind turbine contract for Phase I of its Biglow Canyon wind project and PGE needs Biglow Canyon to complete its IRP action plan.

PGE fully intends to complete its Biglow Canyon Phase I development as soon as possible. PGE is actively negotiating with potential counterparties for the turbines and its target on-line date is still December 31, 2007. In PGE's view, it would not be good regulatory policy to withhold a determination of Port Westward's prudence until PGE signs turbine contracts for Biglow Canyon. The Commission acknowledged PGE's final action plan. It did not acknowledge PGE's final action plan with all actions to be completed at the same time or in a particular order. Such a condition would unduly restrict PGE's ability to acquire the resources at the best prices for customers.

CUB also proposes three conditions related to potential delays in Port Westward's online date. The first is that tariffs from this rate proceeding would be valid only if Port Westward is used and useful within 30 days of its scheduled on-line date in March 2007. The second is that, if Port Westward is not used and useful by March 31, 2007, PGE must re-open this docket. The third is that, if Port Westward is not used and useful by September 1, 2007, PGE must file a new rate case. While PGE acknowledges CUB's concern, the 30-day period proposed by CUB is unnecessarily restrictive; the 2007 test year revenue requirement is unlikely to become stale within 30 days or even a few months. PGE therefore suggests that the Commission revise the first condition to allow three months before applying the second condition and that the Commission not require a new rate case unless the plant's commercial operation is delayed beyond 2007.

C. Partial Requirements Service

Issue Presented: Should the Commission adopt changes to PGE's Economic Replacement Power tariff to provide a different cost-based pricing option and allow a Schedule 76R customer to purchase economic replacement power from an ESS?

ICNU proposes three changes to the current pricing for Schedule 76R Economic Replacement Power. In response, PGE has proposed tariff changes to fulfill the purposes of two of ICNU's proposals, and explained why the third proposal is not appropriate under PGE's cost of service rates.

First, ICNU proposes that PGE substitute the daily market-price options under proposed Schedules 83/89 for the current hourly pricing provisions of 76R. In response, PGE proposes to replace the current hourly pricing with pricing based on the methodology used by PacifiCorp and discussed in Staff's testimony. PGE believes this satisfies the primary purpose of ICNU's proposal.

Second, ICNU proposes that partial-requirements customers be allowed to purchase economic replacement power through direct access in the same manner as in Schedule 576R. In response, PGE proposes that partial requirements customers receiving service under Schedule 75 be allowed to receive service from an ESS for their economic replacement power needs. This will allow a partial requirements customer to negotiate pricing arrangements for economic replacement power in the manner that they desire.

ICNU's third proposal is that Schedule 76R customers be allowed to purchase Schedule 87, Experimental Real Time Pricing Service economic replacement power subject to the limitations contained in that schedule. PGE does not support this proposal and asks the Commission to reject it. Schedule 87 was not created to be applicable to a customer that can change their hourly energy needs by as much as 50 megawatts from hour to hour. There is no way to know if the adder included in Schedule 87 is sufficient to cover the costs of a customer that may use their on-site generation in a way that their energy requirements vary significantly from hour to hour. In addition, given the ability of a partial requirements customer to receive economic replacement power from an ESS, as discussed in PGE's proposal above, the partial requirements customer can seek any type of pricing arrangement it deems optimal.

D. Tax Issues Raised by City of Portland

Issue Presented: Should the Commission adjust PGE's rates based on the unsupported, hypothetical tax avoidance scheme put for the by the City of Portland?

The City of Portland filed direct testimony of David Jubb. Mr. Jubb advocates reducing PGE's tax expenses based on a hypothetical tax scheme through which PGE would have been liquidated as a corporation and become an entity disregarded as separate from the bankrupt Enron for tax purposes. Under this scheme, after interests in this LLC were distributed, PGE would have reincorporated for tax purposes. According to Mr. Jubb, after implementing this tax scheme, PGE would pay very little, if any, income taxes. Mr. Jubb argues that the Commission should deem that such a tax scheme has happened and reduce PGE's rates on that basis.

PGE's rebuttal testimony explains numerous reasons it would have been imprudent and not feasible for PGE to have undertaken the proposed tax avoidance scheme. The testimony further showed that Mr. Jubb's scheme would not necessarily have saved customers any money and could have subjected PGE to substantial interest and tax penalties. The City of Portland did not respond to or otherwise attempt to rebut PGE's testimony.

Mr. Jubb also made allegations regarding deferred tax balances and claimed improper payments for taxes to PGE's then parent company, Enron. PGE's rebuttal testimony explained why Mr. Jubb's allegations were erroneous. The City of Portland did not respond to or otherwise attempt to rebut PGE's testimony on these issues either.

The Commission should reject the City of Portland's claims for the unrebutted reasons contained in PGE's testimony.

IV. CONCLUSION

For the reasons set forth above, Portland General Electric Company requests that the Commission approve PGE's revised tariff schedules and approve its requested revenue requirement increase in this case.

DATED: October 27, 2006

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CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the following: **PORTLAND GENERAL ELECTRIC COMPANY'S PREHEARING BRIEF** to be served by electronic mail to those parties whose email addresses appear on the attached service list, and by First Class US Mail, postage prepaid and properly addressed, to those parties on the attached service list who have not waived paper service.

Dated at Portland, Oregon, this 27th day of October 2006.

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