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November 17, 2006

Via Electronic Filing and U.S. Mail

Oregon Public Utility Commission
Attention: Filing Center
PO Box 2148
Salem OR 97308-2148

Re: UE 180, UE 181 AND UE 184

Attention Filing Center:

Enclosed for filing in the captioned dockets are an original and five copies of:

- **OPENING BRIEF OF PORTLAND GENERAL ELECTRIC COMPANY**

This document is being filed by electronic mail with the Filing Center.

An extra copy of this cover letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided.

Thank you in advance for your assistance.

Sincerely,

DOUGLAS C. TINGEY

DCT:jbf
Enclosure

cc: Service List – UE 180, 181 and 184

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),

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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 OPENING BRIEF

I. PROCEDURAL BACKGROUND AND INTRODUCTION

A. Procedural Background

During March and April 2006, PGE made three filings that have been consolidated in these proceedings for investigation. The parties to these proceedings have worked together and negotiated a number of stipulations that have resolved many issues. Appendix A contains a description of the Stipulations reached in this docket. PGE is pleased that agreement could be reached on these issues.[1] While the list of issues still disputed is small, the remaining issues are large in impact and of vital importance to PGE and its customers.

B. Introduction

The remaining issues are:[2]

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 Annual Update tariff (Schedule 125); the proposed Power Cost Variance Mechanism (Schedule 126); the forced outage rate assumption calculation; proposed "extrinsic value" adjustments; capacity contract costs, revenue from sale of ancillary services; and the inclusion of Port Westward costs and benefits when the plant begins service to customers.

These remaining issues are interrelated and concern PGE's opportunity to earn a return on its invested capital that meets constitutional and statutory standards. One issue, cost of capital, addresses the level of return that will define PGE's opportunity to earn. In a rate case this issue usually concerns the level, or rate, at which the authorized return on equity is set. That is not the case here, however. The earnings opportunity level is meaningless if PGE does not have a realistic opportunity of achieving it. In this case, Staff proposes to hinder the ability of the PGE's

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[1] There is an additional issue addressed in testimony that no longer requires a Commission decision in this docket: PGE's proposed Automated Metering Infrastructure ("AMI") project. PGE withdrew AMI from this rate case in PGE's final round of testimony. *PGE/3000, Carpenter-Tooman/1*. As indicated in testimony, PGE will bring the AMI project before the Commission in subsequent filings. *Id. at 2*.

[2] In addition to the primary issues regarding cost of capital and power costs, another remaining contested issue involves certain tax issues raised by the City of Portland in its direct testimony.

equity holders to actually earn the allowed return by appropriating some of the potential earnings of equity holders to cover the actual cost of PGE's debt. Several parties propose to thwart PGE's ability to achieve authorized earnings by using something other than PGE's actual capital structure. Each of these proposals represents a discernible and significant obstacle to PGE's ability to earn a reasonable rate of return.

The remaining power cost issues relate to the uncertainty associated with whether the revenues produced by the prices set in this docket reflect the costs of providing service. This uncertainty is cost of service risk. How this uncertainty is managed in ratemaking heavily influences whether PGE will have a realistic opportunity to earn a reasonable rate of return. Some parties propose to impede PGE's ability to recover from customers the costs it actually incurs to provide on-demand retail electric service with (1) an unsupported and inherently unfair allocation of net variable power cost ("NVPC") cost of service risk, and (2) proposals for adjustments for "extrinsic value," capacity contract disallowances, and abandonment of the longstanding four-year rolling average for determining the assumed level of forced plant outages in ratemaking.

PGE proposes a power cost framework that would align customers' prices with the actual costs of providing electric service to customers. Some other parties argue against that simple proposition. They propose to subject both PGE's earnings opportunity and customers' assurance of cost-of-service rates to the vagaries and difficulties of forecasting NVPC, at least until the variances are large enough to pass beyond wide deadbands (in the case of Staff and CUB) or, in the case of ICNU, to preclude the recovery of any variances at all. PGE's proposed power cost framework is consistent with the power cost frameworks of most utilities in the country; Staff's and the intervenors' are not.

The power cost framework and return on equity ("ROE") adopted in this docket are directly related. Cost of service risk imposed on PGE requires compensation, including an ROE that recognizes this risk, and a capital structure that enables PGE to withstand the impacts of that risk. PGE's ROE recommendation in this docket is made on the assumption that the Commission adopts a power cost framework that is fair and in line with comparable companies. If the Commission instead adopts a less comprehensive power cost framework, it will need to raise PGE's authorized ROE accordingly.

PGE recommends that the Commission consider the inter-relationship among the remaining issues in this docket and:

1. Adopt an overall rate of return of 8.87%, which reflects PGE's actual 2007 capital structure of 53% equity and 47% debt.
2. Implement a power cost framework that includes PGE's proposed Annual Update tariff and Variance Tariff, to achieve a better matching of customer prices to the actual costs incurred in providing electric service.
3. Reject the adjustments and proposed changes in policy regarding abandonment of the four-year rolling average to determine plant forced outage rate assumptions for ratemaking purposes, reductions for "extrinsic value," capacity contract disallowances, and ancillary services revenue imputation.
4. Decide the costs changes associated with Port Westward commencing service to customers, and authorize PGE to file compliance tariffs implementing the revenue requirement change at that time.
5. Reject the City of Portland's income tax scheme and other claims.

These issues are addressed below in the order listed.

II. REMAINING CONTESTED ISSUES

A. Cost of Capital

1. Introduction

PGE is requesting an overall rate of return of 8.87%, based on the following capital structure and costs:

PGE's Weighted Average Cost of Capital

Component	Percent of Capital	Cost	Weighted Cost
Long-Term Debt	46.73%	6.73%	3.14%
Preferred Stock	-	-	-
Common Equity	53.27%	10.75%	5.73%
Total	100.00%		**8.87%**

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 as a stand-alone company. Those reviews suggest that PGE requires, and the market expects, strong regulatory support. With a senior secured rating of "BBB+" from Standard & Poor's ("S&P"),[3] PGE has a limited cushion to remain an "investment grade" entity and preserve its access to capital. S&P recently issued a "negative outlook" regarding PGE; that report cited, among other criteria, an "uncertain regulatory environment." *PGE Ex. 2705, Hager-Valach/9.* 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.

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. This filing reflects the addition of Port Westward, a

[3] S&P'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.

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 324 MW (for a total of 450 MW) over the next five years. PGE also faces hydro relicensing investment at its Deschutes, Clackamas and Willamette plants and environmental costs at Boardman. In order to economically raise the funds necessary to support these resource investments, it is essential that the income opportunity this case produces (through the authorized cost of capital and regulatory framework for NVPC) enable PGE to maintain its existing credit rating and to preserve its financial integrity.

2. Governing Legal Standards

The Commission is obligated under ORS 756.040 to "balance the interests of the utility investor and the consumer in establishing fair and reasonable rates." PGE must be allowed an opportunity to earn an ROE that is "commensurate with the return on investments in other enterprises having corresponding risks." *ORS 756.040(1)(a)*.[4] This ROE must also provide a return that is "sufficient to ensure confidence in the financial integrity of the utility, allowing the utility to maintain its credit and attract capital." *ORS 756.040(1)(b)*.[5]

If the Commission grants PGE's requested cost of capital in this proceeding, allocates NVPC cost-of-service risk evenly, and adopts a regulatory framework to mitigate this risk to customers and PGE going forward, the prices set here should allow PGE to achieve the net income necessary to maintain the financial metrics required to support its current "BBB+" rating on senior secured debt. The other parties' recommendations, particularly those of Staff, are far

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[4] This statutory standard codifies the constitutional requirement from *Bluefield Waterworks & Imp. Co. v. West Virginia Public Service Commission*, 262 U.S. 679 (1923), which provides that "[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 . . . ." *262 U.S. at 692-93.*

[5] This standard reflects the U.S. Supreme Court's decision in *Federal Power Comm. V. Hope Natural Gas Co*., 320 U.S. 591 (1944), which provides that the return to the equity owner, in addition to being "commensurate with returns on investments in other enterprises having corresponding risks," must also "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*.

less likely to allow PGE the opportunity to achieve a net income sufficient to maintain these financial metrics, and thus could result in a downgrade of PGE's credit rating. A lower credit rating will increase the cost of capital PGE must raise in the future to ensure safe and adequate service to customers, including engaging in necessary risk management activities. And it would leave PGE with a very small cushion above non-investment grade in the event PGE incurs adverse financial impacts. Given the long-term borrowing associated with the future investments, PGE's customers would bear the higher interest costs attributable to a downgrade for decades into the future.

3. Long-Term Debt

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 PGE now projects the Biglow Canyon wind project to come on line by December 31, 2007, it has included the associated capital needs fully in 2007. PGE 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%. In addition, the update to PGE's long-term debt results in a lower equity ratio (53.3%) which, together with the 10.75% recommended ROE, produce an overall cost of capital of 8.87% – a 16-basis point reduction from that requested in PGE's direct testimony.

Staff recommends that the Commission disallow over 40 basis points – a reduction to 6.30% – of PGE's actual and forecasted cost of long-term debt. This recommendation is based upon a (1) "re-pricing" of six long-term debt issuances (including the disallowance of various issuance costs and call premiums) to eliminate the impacts of an alleged "Enron bankruptcy effect," (2) rejection of costs incurred ***in 1988*** to refinance a 13.5% debt issuance, and (3) use of a shorter (cheaper) 10-year maturity for the long-term debt that PGE will issue in 2007 rather than the 30-year debt PGE actually plans to issue.

a. The Commission Should Reject Staff's Proposed Disallowance of Certain Long-Term Debt Costs Based on an Alleged "Enron Bankruptcy Effect."

Reproduced below is Table 4 from PGE/2000, Hager/Valach/17, showing Staff's proposed adjustments to all PGE debt issuances from January 2002 through August 2006.

Table 4

Month/Year	Issue	Effective All-In Debt Rate	Amount Issued ($000's)	Proposed Adjustment(s)
October 2002	FMB 8.125%	8.421%	$150,000	(see FMBs 6.31% and 6.26%)
October 2002	FMB 5.6675%	7.420%	$100,000	Remove $12 million issuance cost
April 2003	FMB 5.279%	6.434%	$50,000	Remove $4 million issuance cost
August 2003	FMB 5.625%	6.266%	$50,000	Use PacifiCorp as proxy for PGE coupon rate
August 2003	FMB 6.750%	7.220%	$50,000	Use PacifiCorp as proxy for PGE coupon rate
August 2003	FMB 6.875%	7.282%	$50,000	Use PacifiCorp as proxy for PGE coupon rate
April 2006	FMB 6.31%	6.704%	$175,000	Remove $7.74 million call premium
April 2006	FMB 6.26%	6.753%	$100,000	Remove $5.16 million call premium

The portions of Staff's proposed disallowance based on "Enron-related" impacts fall into three categories:

- Removal of issuance costs for two issues (the 5.6675% and 5.279% issuances in October 2002 and April 2003), and repricing the first issue using rates from NW Natural's issuance *four months later* as the fictional "proxy" to measure the interest rates PGE "should" have secured;
- Removal of the call premium resulting from the May 2006 refunding of the 8.125% series issued October 2002; and

- Lowering of the interest rate on three August 2003 issuances, using PacifiCorp as the fictional "proxy" to measure the interest rates PGE "should" have secured.

All of Staff's "Enron-related" 41-basis point debt cost reductions flow from one critical assumption: *but for PGE's association with Enron*, the one notch downgrading of PGE by Standard & Poor's would not have occurred. Staff uses the "A" credit rating that was in place for PGE on November 29, 2001, just prior to Enron's bankruptcy, as the "baseline" for its "Enron-related" adjustments. *Staff/1200, Conway/9*. Staff further assumes that it can calculate what debt would have cost an "A" rated PGE by looking at debt costs of Northwest Natural Gas Company and PacifiCorp, two utilities with which PGE bears little or no resemblance. As stated in Staff's testimony:

> "I *assume* this difference [in credit ratings] between two Oregon utilities [PGE and PacifiCorp*] is due to PGE's relationship with Enron* and I subtract 27.5 basis points from each of the three PGE August issuances." *Staff/1200, Conway/18 (emphasis added)*.

Proceeding from these fundamental assumptions, Staff simply "re-prices" six debt issuances to remove what it claims are the effects of "PGE's relationship with Enron." Staff provides no support for either assumption and the Commission should reject them along with the disallowance.

(i) PGE's Downgraded Rating as of October 2002 Related Primarily to Industry-Wide Issues, not the Enron Bankruptcy.

Staff's entire approach is based upon a fundamentally flawed assumption: that any decline in PGE's credit rating during the period beginning in late 2001 and continuing to October 2002 – the date of PGE's first long-term bond issuance – was due ***solely*** to "PGE's relationship with Enron." This assumption requires that one ignore the widespread decline in creditworthiness suffered by *all* utilities during the 2001 – 2003 period as a result of the deterioration in the financial and wholesale energy markets during the Western energy crisis.

The evidence in the record shows that:

- *Almost all* the other electric utilities operating in the Western power markets were downgraded at about the same time as the PGE downgrading cited by Staff. PGE was downgraded from "A" to "BBB+" by S&P in December 2001 and from "A2" to "A3" and then to "Baa2" by Moody's in November 2001 and May 2002. These downgrades were in line with electric utilities as a whole. *PGE/1100, Hager-Valach/14*. During 2001 and 2002, there were 420 downgrade rating actions taken by the three major rating agencies. *PGE Ex. 1104/2*.
- Analyzing PGE's debt issuances on a portfolio level, the evidence shows that PGE's all-in cost of debt for issuances since Fall 2001 have compared favorably with market indices for similarly rated utilities. Specifically, the costs of the six issuances between 2001 and 2003 were either close to the "BBB"/"Baa" index or below. In fact, PGE's debt issuance costs at times were lower than the "A"/"Aa" issuances. *PGE Ex. 1105; PGE Ex. 2014; PGE/2000, Hager-Valch/10.*
- 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. *PGE/2000, Hager-Valach/23*. The credit rating agencies viewed these ring-fencing provisions favorably *(PGE/2000, Hager-Valach/23)*, as noted in Staff witness Conway's presentation at the 2004 meeting of the Society for Utility and Regulatory Financial Analysts. According to that presentation, "Oregon has been recognized by rating agencies for successful ring-fencing activities." *PGE/2000, Hager-Valach/24*. If the ring-fencing was successful, as Staff concluded in 2004, then Staff's proposed reduction to debt costs here has no basis.
- Any effect of the Enron bankruptcy on PGE was primarily on short-term debt because PGE did not issue any long-term debt until October 2002, after PGE issued the

> "Golden Share" of preferred stock with the Commission's approval. *PGE/2000, Hager-Valach/10*. Issuance of the Golden Share" provided additional ring-fencing assurance to S&P and other rating agencies and stabilized PGE's credit ratings. *PGE/1100, Hager-Valach/13-14*. While PGE had difficulty accessing the short-term debt market during Fall 2001, the evidence does not show that any "Enron bankruptcy effect" carried over to the cost of PGE's long-term bonds issued after the "Golden Share."

It is unlikely at best that Enron's bankruptcy had any continuing effect on the PGE's credit rating as of October 2002 given the downgrade that most of the industry experienced in 2001 or that Enron's bankruptcy remained the reason PGE has not received additional upgrades. This period has seen PGE experience power cost disallowances, several years of lower-than-average hydro production and other drivers of higher NVPC which have left PGE with a significant amount of power cost variances to absorb during the period since Fall 2001. *See Table 1 at PGE/2400, Lesh/4*. A conclusion that the Enron bankruptcy was (and remained) the cause of the downgrade from Fall 2001 continuing to the present is simply unsupportable.

(ii) Even if Enron Was (and Remained) All or Part of the Reason for PGE's Downgrade, Staff's Method of Measuring the Effect by Comparisons to Two Significantly Different Utilities Is Unsupportable.

For the $100 million issued on October 2002 at 5.6675%, Staff simply re-prices the bonds as if PGE were "A"-rated – as it was in November 2001 – and uses an "A"-rated utility – NW Natural –as the proxy. Staff takes the "projected spreads" for January 2003 as calculated by NW Natural, and substitutes 5.19% for the actual 5.6675% incurred by PGE. Staff disregards any of the obvious differences between PGE and a natural gas distribution company, such as NW Natural's ability to recover nearly all energy cost variations through its PGA mechanism and the absence of a similar mechanism for PGE. *PGE/2000, Hager-Valach/19*. Staff also disregards the difference in spreads between October 2002 – when PGE's bonds were issued – and January 2003 – the date NW Natural calculated its "projected spreads." The evidence shows, however, that the spreads for "A" and "BBB" rated electric utilities narrowed considerably between October 2002 and January 2003. *PGE Ex. 1105*.

Similarly, Staff reprices three PGE debt issuances from August 2003 using PacifiCorp as the proxy company, assuming – as noted above – that the "difference between the two Oregon utilities is due to PGE's relationship with Enron." *Staff/1200, Conway/18*. This results in a 27.5 basis point reduction in each of the three PGE August 2003 issuances. *Id*. Apart from the obvious differences between PGE and PacifiCorp that are unrelated to "PGE's relationship with Enron," Staff's proposed reduction disregards the fact that interest rates declined by 18 basis points during the month between the PGE issuance and the PacifiCorp "proxy" issuance. *PGE Ex. 1105*. It also ignores that the spreads between utility yields for "Baa" and "A" rated bonds during the second half of 2003 was fairly volatile, increasing from the low teens to 30 basis points between June and August 2003. *PGE/2000, Hager-Valach/21*.

Staff also adjusted two issuances – the 5.6675% FMB from October 2002 and the 5.279% FMB from April 2003 – to remove the issuance costs, claiming that these were "high issuance costs" as a "result of PGE choosing to have the FMBs insured by Ambac." *Staff/1200, Conway/16*. (These were "insurance wrapped" bonds whereby the insurance company (Ambac) insures the bonds for a negotiated upfront fee or insurance cost, and the bonds are then marketed with a "AAA" guarantee.) *PGE/2000, Hager-Valach/18*. After taking these costs into account, the "all-in" costs for the two securities were approximately 7.4% and 6.4%, ***lower*** than what PGE would have been able to issue in the market by itself. *Id*. In its analyses recommending approval of these issuances to the Commission, Staff found that "[t]he rates and issuance expenses are within a reasonable range" *(Docket UF 4190, Order No. 02-477)* and that "[t]he issuance and underwriting costs appear reasonable" *(Docket UF 4187, Order No. 02-292)*.

Staff also proposes to disallow the call premium associated with an October 2002 debt issue for 8.125%. This $12.9 million premium, which was paid by PGE to redeem the debt, was spread to two subsequent issuances in April 2006, which replaced the October 2002 issue. In effect, Staff's disallowance of the call premium requires that one believe PGE could have issued this 8.125% debt in October 2002 at an extremely low rate of 5.456% rate, which was impossible given the significant deterioration of the financial and wholesale energy markets for electric utilities in 2002. *PGE/2000, Hager-Valach/20.*

b. Staff's Proposed Rejection of Refinancing Costs Associated with a 13.5% Issue Is Unsupported by the Precedent Cited by Staff and Adopting this Approach Would Represent Bad Policy.

Staff proposes that the Commission reject the actual costs PGE incurred ***in 1988*** to reacquire a $75 million First Mortgage Bond ("FMB") issuance carrying an interest rate of 13.5%. Staff argues that PGE failed to demonstrate the benefits of this early redemption, and that recovery of such costs would be inconsistent with Commission precedent. *Staff/1200, Conway 4-5*. Staff is wrong on both counts.

This debt reacquisition occurred eighteen years ago, and the rate for debt issued throughout the period since the redemption has been less than the 13.5% rate on the FMBs. Customers obviously benefit from a utility taking advantage of reduced interest rates to reacquire higher-priced debt and replace it with lower-priced debt. Given the interest rate swings that occurred in April 1988, PGE was able to redeem the FMBs with short-term borrowings. *PGE/2000, Hager-Valach/14*. Staff argues that because PGE did not replace the FMBs immediately with new long-term debt, PGE should not recover the costs of reacquiring the debt, relying on the Commission decision in Docket UE 116. *Staff/1200, Conway/4*. Docket UE 116 supports no such result, however. In UE 116, PacifiCorp redeemed certain Quarterly Income Debt Securities, or QUIDS, and exchanged them for preferred stock. PacifiCorp sought to include the QUIDS issuance costs as part of the cost of preferred stock. *Order No. 01-787 at 18.*

Staff characterized the PacifiCorp transaction as simply "an exchange of debt for equity" that did not produce benefits for customers given that equity is more expensive than debt. *Id. at 19*. The Commission agreed that where "no new debt was incurred" the "usual circumstances" – where "issuance costs would roll forward into the new debt instrument" – did not apply. Moreover, the Commission stated that merely because "the cost of debt fell does not establish that the overall cost of capital also fell," given that debt was replaced equity. *Id.*

This precedent is inapposite to the circumstances of this case, where PGE replaced an obviously high cost debt issuance – carrying a rate of 13.5% – with short-term borrowings on an interim basis. (In the longer term, as PGE's capital needs required the issuance of additional debt, lower-cost long-term debt was issued.) The benefits of PGE refinancing this 13.5% debt are obvious. PGE issued no higher cost equity – such as in Docket UE 116 – that would require "persuasive evidence" as to how customers specifically benefited. *Order No. 01-787 at 19.* Staff's proposed reduction to long-term debt costs here represents the poor regulatory policy about which the Commission warned in Docket UE 116 when it stated: "We do not want the parties to interpret this particular decision as an attempt to discourage companies from redeeming long-term debt . . . ." Staff's proposal would do precisely that: PGE would have been better off (by not creating the circumstances leading to this proposed disallowance), and customers worse off, if PGE had not reacquired the 13.5% debt. The Commission should reject Staff's proposal.

c. The Cost of Long-Term Debt the Commission Adopts in this Case Should Reflect the Type of Securities PGE Actually Intends to Issue in 2007.

Staff proposes to reduce PGE's allowed long-term debt costs by forecasting that PGE issues a shorter, cheaper 10-year maturity in 2007, rather than the 30-year debt that PGE will actually issue. As described above, PGE updated its financing plans for 2007 in its last round of testimony. Instead of issuing $100 million of 30-year first mortgage bonds – which was the circumstance upon which Staff based its proposal – PGE 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%. These maturities reasonably match the term of the debt with the useful life of the underlying assets being financed. *PGE/2000, Hager-Valach/13*. Moreover, the 30-year maturity reflects PGE's strategy to stagger the maturity dates of its various bond issuances to ensure that significant amounts of debt do not mature at the same time. *Id*.

No party disputes that the anticipated interest costs for a 10-year maturity are about thirty basis points lower than for a 30-year maturity. *Staff/1201, Conway/4*. Thus, while Staff disingenuously claims that proposing this reduction does not direct PGE to use a particular maturity *(Staff/1200, Conway/6)*, 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 for $150 million in April 2007. The Commission previously rejected this Staff tactic in Docket UE 116, where Staff proposed to use a seven-year maturity for long-term debt rather than the ten- and thirty-year maturities that PacifiCorp planned to issue. In rejecting Staff's adjustment, Order No. 01-787 states:

> We are inclined to agree that PacifiCorp will issue long-term debt with a variety of maturity dates. While we understand Staff's rationale for selecting a seven-year maturity date, we think PacifiCorp's position that its mix would result in a greater average maturity is reasonable. *Order No. 01-787 at 17*.

The Commission should reject Staff's proposal here for the same reasons. Sound financial reasons support PGE's plan to issue 10- and 30-year maturities, such as matching the maturities with the lives of the underlying assets and staggering the various due dates.

4. PGE's Actual 53.3% Equity Ratio in 2007 Is Necessary to Maintain Financial Integrity and to Provide PGE with the Required Flexibility to Finance the Addition of New Generation.

PGE's forecasted actual equity ratio for 2007 will be 53.3%, after taking into account the updated financing plan for 2007. This equity ratio is necessary to provide PGE with the ability to raise capital on reasonable terms to fund the capital expenditures PGE will soon be making, including the development of 126 MW of wind generation. In addition, PGE faces hydro relicensing investment for its Deschutes, Clackamas and Willamette River plants and environmental costs at Boardman. PGE's equity ratio must also take into account 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. *PGE/1100, Hager-Valach/44*. The amount of imputed debt from long-term purchased power contracts and operating leases in 2007 is projected to be approximately $250 million, which adds about 5.6% of additional debt to PGE's balance sheet. *PGE/2000, Hager-Valach/29*. ICNU-CUB acknowledge that the impact of adjusting the debt ratio to reflect off-balance sheet debt equivalence – under the analysis performed by S&P – would increase PGE's total adjusted debt ratio to 55%. *ICNU-CUB/300, Gorman/10*.

Staff initially proposed an equity ratio of 48.5%, based exclusively on the average equity ratio from the sample group of companies relied upon by Staff for its ROE recommendation. *Staff/1000, Morgan/5*. Staff performed no independent analysis whether any PGE-specific circumstances may require a higher equity ratio, such as debt imputation or anticipated capital expenditures. *Morgan Deposition, Ex. 3102 at 58*. In its surrebuttal testimony, Staff revised its equity ratio recommendation upward to 50%, without any explanation. *Staff/1400, Morgan/52*. Staff also suggests that its 50% equity ratio is not a "recommendation," as PGE is "free to optimally manage its capital structure going forward," including a percentage of equity capital higher than 50%. *Id. at 8*. This ignores, of course, the impact on revenue requirement associated with allowing an equity return based on a 50% equity ratio if PGE's actual equity ratio is 53%. Following Staff's "recommendation" would provide PGE with an equity return only the first 50% of its actual capital structure, and any equity over and above 50% would be allowed the *lower* return associated with debt. For all practical purposes, this amounts to a disallowance of PGE's capital costs, whether it is characterized as a "recommendation" or not.[6]

ICNU-CUB, for their part, also propose an equity ratio of 50.0%, which they claim is "more reasonable" than PGE's actual 2007 equity ratio of 53.3%. *ICNU-CUB/300, Gorman/9*. A party is not free to simply substitute a different capital structure for the utility's actual capital structure on the grounds that the hypothetical capital structure may be, according to such party, "more reasonable." Rather, the party must demonstrate that PGE's actual equity ratio of 53.3% is unreasonable or imprudent. *See, In re Baltimore Gas and Electric Company, Case No. 9036, 96 Md.P.S.C. 334, Order No. 80460 (December 2005)* (recognizing "long-standing principle" to use actual capital structure unless doing so results in customers bearing unreasonable or undue financial costs); *In re Potomac Electric Power Company, Case No. 7384, 71 Md.P.S.C. 157, Order No. 64268 (April 1980)* (substitution of hypothetical capital structure warranted only where it is found that the debt-equity ratio renders actual capital structure "clearly unreasonable"). As stated by the Maine Supreme Court in *New England Telephone and Telegraph Company v. Public Utilities Commission, 390 A.2d 8, 39 (Me. 1978):*

> There are two well-recognized circumstances in which a utility commission might disregard a utility's "actual" capital structure and adopt a "hypothetical" capital structure for ratemaking purposes. This first occurs when the utility's actual debt-equity ratio may be deemed to be inefficient and unreasonable, because it contains too much equity and not enough debt, thereby necessitating an inflated rate of return . . . [t]he second

[6] The court in *New England Tel. & Tel. Co. v. Pub. Util. Comm'n*, 390 A.2d 8 (Maine 1978) recognized the practical impact of allowing a lower equity ratio than actual: "[T]he adoption of a hypothetical capital structure will *coerce* management to move toward the ideal capital structure in the future because the utility can no longer collect the higher rate of return necessitated by its present capital structure." 390 A.2d at 39 (emphasis added). It is disingenuous for Staff to suggest that its adjustment does not result in such "coercion."

circumstance occurs when the utility is part of a holding company system.

ICNU-CUB have not made any demonstration that PGE's actual capital structure for 2007 is "clearly unreasonable" or that there is a basis for deeming it to be "inefficient and unreasonable." In the absence of such a demonstration, PGE's actual capital structure for 2007 should be used.

Another reason cited by ICNU-CUB in support of their 50% equity ratio recommendation is that PGE's actual, higher equity ratio is "related to Enron's ownership," and that "[r]atepayers should be protected" from such costs. *Id. at 13*. This approach is backward-looking, and is unsupported by the evidence. The need for PGE's actual 53.3% equity ratio is based upon PGE's forward-looking capital needs for 2007 and the metrics that are required by the rating agencies in order for PGE to maintain its existing credit rating. These metrics include the additional equity necessary to offset the high amount of imputed debt attributed to PGE as a result of its reliance on long-term purchased power agreements. Although ICNU-CUB acknowledge that the impact of adjusting the debt ratio to reflect off-balance sheet debt equivalence would increase PGE's total adjusted debt ratio to 55% *(Id. at 10),* PGE does not agree that the equity ratio produced by ICNU-CUB's recommendation would support PGE's current secured bond rating of "BBB+." Several PGE-specific risks support PGE's need for a higher equity ratio, including increased capital expenditures, the need to maintain liquidity for unexpected margin calls as wholesale prices fluctuate, and unresolved issues such as litigation and SB 408. *PGE/2000, Hager-Valach/31*.

5. Return on Equity

a. Overview of ROE Testimony

The issue presented by the parties' ROE testimony is whether the Commission should consider all available information in determining PGE's required cost of equity capital, or whether the determination should be made based solely on the results of a discounted cash flow

("DCF") methodology. A leading expert on utility cost of capital, Dr. Roger Morin, offers the following observation on this issue:

> It is dangerous and inappropriate to rely on only one methodology in determining the cost of equity. For instance, in relying solely on the DCF model at a time when the fundamental assumptions underlying the DCF model are tenuous, a regulatory body greatly limits its flexibility and increases the risk of authorizing unreasonable rates of return. The results from one method are likely to contain a high degree of measurement error. The regulator's hands should not be bound to one methodology of estimated equity costs, nor should the regulator ignore relevant evidence and back itself into a corner. *Morin, Roger A., Regulatory Finance, Public Utilities Reports, Inc., 1994, p. 28.*

Each of the parties presenting cost of capital testimony – PGE, Staff and ICNU-CUB – presented analyses based upon the DCF methodology. PGE and ICNU-CUB, however, also offered analyses based on several different approaches and sources of information. The risk positioning and risk premium models presented by PGE and ICNU-CUB, for example, produce very similar results: PGE's two different risk positioning approaches suggest a range of 10.5% to 11.3%, while ICNU-CUB's risk premium analysis produced an average return estimate of 10.4%. PGE also presented two other risk premium models – which produced estimates of 11.0% and 10.75%, respectively – as well as information regarding the ROE decisions from other commissions. (The average ROE allowed for electric or combination utilities since January 2005 is 10.47%. *PGE Exhibit 2706*.) ICNU-CUB, for their part, also included a Capital Asset Pricing Model ("CAPM") analysis that confirms the 10.4% ROE suggested by their risk premium analysis.

In sharp contrast to the approaches of PGE and ICNU-CUB, which take into account the wealth of information available to estimate PGE's required ROE and produce a consensus range of 10.4% to 11.0%, Staff limits its inquiry to three versions of the DCF model. Staff's DCF analysis produced an extreme recommendation – an allowed ROE for PGE of only 9.40% – and Staff would unwisely exclude other relevant data that should be considered in evaluating the reasonableness (or unreasonableness) of this ROE recommendation. Moreover, Staff's DCF analysis contains several errors, both in calculation and in methodology. If corrected, Staff's DCF analysis would support an ROE recommendation in the range of PGE's proposed 10.75%.

The sections below include a more complete discussion of ROE analyses, presented in the following order:

- PGE's and ICNU-CUB's risk positioning and risk premium analyses;
- The parties' DCF analyses;
- Other sources of information the Commission should consider; and
- The various ranges produced by the parties' analyses, and why PGE's 10.75% ROE recommendation is reasonable.

b. PGE's and ICNU-CUB's Risk Positioning and Risk Premium Analyses Produce a Similar Range of Results (10.4% to 11.3%).

PGE used a risk positioning model, or RPM, that estimates the required ROE by adding an explicit premium risk to a current or expected interest rate. Under the RPM used by PGE, the risk premium is calculated as the difference between the yield on Treasuries (or corporate bonds) and the cost of equity found appropriate in non-stipulated, authorized ROE decisions by regulatory bodies, on average, since 1983. *PGE/1100, Hager-Valach/30*. PGE used two forms of the RPM, estimating the risk premium over the yields on (1) electric utility corporate bonds, and (2) Treasuries. The required ROE suggested by the first analysis ranged from 10.486% to 10.493%. *Id. at 32*. The required ROE suggested under the second analysis ranged from 11.13% to 11.34%. *Id. at 34*.

ICNU-CUB's Risk Premium Model produced very similar results to those suggested by PGE's RPM analysis. ICNU-CUB estimated the risk premium on the basis of regulatory commission-authorized returns for electric companies over the period 1986 through June 2006.

ICNU-CUB/300, Gorman/21. This risk premium analysis produced an average return estimate of 10.4%. *Id. at 23*.

In its rebuttal testimony, PGE offered two additional risk premium analyses, based on the sample group of companies relied upon in Staff's DCF analysis. In the first analysis, PGE used the actual earned ROEs for the period 1996-2005 for the utilities in Staff's sample as proxies for the costs of equity. *PGE/2100, Zepp/34*. PGE determined the annual average risk premiums by subtracting contemporaneous Treasury rates from these equity cost proxies. The equity cost range was then determined by adding the 5-year and 10-year averages of those risk premiums to forecasts of the respective Treasury rates. *Id*. The results, presented in PGE Exhibit 2109, suggest an average cost of equity for the utilities in Staff's sample of 11.0% in 2007.

The second risk premium analysis used annual market holding period returns, contemporaneous interest rates, and the assumption that investors expect the future risk premium to be similar to the average risk premium in the past. *PGE/1200, Zepp/35*. The results, presented in PGE Exhibit 2110, show an average risk premium of 3.55%, calculated as the difference between the annual holding period returns and the Baa corporate bond rate for the period 1950 to 2005. Given expected Baa rates of 7.20% for 2007, the indicated benchmark cost of equity is 10.75%. *PGE/2100, Zepp/36*. This is a conservative indication of the cost of equity, considering that the Baa rate of 7.20% for 2007 is lower than the average of Baa rates during 1950-2005 (8.00%), which suggests that the average future risk premium is expected to be higher today than in the simple average based on past data. *Id*.

The various risk positioning and risk premium analyses performed by PGE and ICNU-CUB thus produce a consistent range of results: all fall within the range of 10.4% to 11.3%, using a variety of approaches.

c. The Parties' DCF Analyses

(i) PGE's DCF Analysis Produced a Range of 8.10% to 11.20%, and Other Data Suggest that the Required ROE Should be Towards the Top of this Range.

PGE used a multi-stage DCF analysis based on several samples of comparable utilities because of the relatively short period of time that PGE's common stock has been publicly traded. *PGE/1100, Hager-Valach/26*. PGE's sample groups included a combined sample of the utilities in Moody's Electric Utility Index and in S&P's Electric Utility Index; a comparable sample group prepared by PGE by outside experts; and the sample group from Docket UE 170 that was found acceptable by Staff in that proceeding. *Id.* The samples were screened based on criteria intended to eliminate utilities experiencing unusual circumstances, such as the reduction or elimination of dividends or involvement in merger activity, that could skew the results. DCF estimates were prepared using the month-high closing price, month-low closing price, and the month-end price for each of the last three months. *Id. at 29*. The different ranges for the required ROE suggested by the DCF multi-stage analyses were 8.10% to 11.20%. *Id.; PGE/1109, Hager-Valach/1-3.*

(ii) ICNU-CUB's DCF Analysis Resulted in a Range of 7.38% to 12.58%, which Includes the 10.75% ROE Recommended by PGE.

In its DCF analysis, ICNU-CUB followed a well-defined and correctly applied screening process in developing its sample group of companies, in sharp contrast to Staff's flawed sample selection process. ICNU-CUB's sample group, for example, had an average bond rating from S&P and Moody's that is identical to PGE's, and had an average S&P business profile score of 5, which matches PGE's. *ICNU-CUB/300, Gorman/15*. The DCF estimates produced by the ICNU-CUB sample ranged from 7.38% to 12.58%, which includes the ranges that PGE developed from its DCF estimates. *PGE/2000, Hager-Valach/66*. Rather than using a range, however, ICNU-CUB used a DCF point estimate of 9.5%, which fails to capture, and fully compensate for, the risks associated with PGE. Had ICNU-CUB relied upon its range and then developed a point estimate based on PGE's unique characteristics compared to the sample group, a figure closer to PGE's 10.75% would have been suggested. *Id. at 66*.

(iii) Staff's DCF Analysis Suggests an ROE of 9.40% Which, if Corrected for Errors in Calculation and Methodology, Would Support an ROE Approaching PGE's Recommended 10.75%.

Staff recommended an ROE of 9.30% in its initial testimony, which it "updated" to 9.40% in its surrebuttal testimony. 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. Staff's DCF analysis is flawed in the following respects:

- The sample group relied upon by Staff was flawed, as it contained companies that failed to satisfy Staff's own criteria. *PGE/2000, Hager-Valach/38-39*. Staff admitted its errors in its surrebuttal testimony, and purportedly recalculated its ROE recommendation after excluding two companies from its sample group. *Staff/1400, Morgan/2*. Staff's sample selection process also included several other problems. Staff's sample group of companies (1) has a less risky business profile than PGE (3.9 for the sample group versus 5.0 for PGE) *(PGE/2100, Zepp/8)*; (2) has an average bond rating that is higher than PGE's ("A" versus PGE's "BBB+") *(Id.)*; (3) has much less reliance on purchased power than PGE (35% versus 49%) *(Id.)*; (4) failed to take into account the impact of a utility cutting its dividend *(PGE/2000, Hager-Valach/40)*; and (5) includes several utilities that are "poles and wires" only companies and not subject to purchase power and generation risk *(Id. at 40-41)*.
- Following its DCF analysis of the sample group of companies, 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. *PGE/2000, Hager-Valach/41-43*. Staff justifies its failure to address PGE-specific risks on the basis of its understanding of the Modern Portfolio Theory which, according to Staff, means that the risks associated with investing in PGE need not be compensated if they can simply be diversified away. *Staff/1003, Morgan/32-33*. The effect of this misapplication of the Modern Portfolio Theory is to disregard the clear constitutional and statutory requirements that *it is the risks of investing in PGE that must be compensated*. *PGE/2000, Hager-Valach/43-44*. Staff provides no details on how PGE-specific risks – such as those associated with hydro availability or the impact of SB 408 – can be diversified away. Rather, these risks are simply assumed not to exist, under Staff's analysis, since they allegedly are "diversifiable."

- Staff's DCF analysis inappropriately relies on a one-day spot price to calculate the dividend yield component. *PGE/2000, Hager-Valach/45-46; PGE/2100, Zepp/25-27*. There are no estimates of "spot" growth rates and thus an analyst using spot prices will be using growth rates that investors did not rely upon when they priced stocks at the current levels. *PGE/2800, Zepp/8*.
- The recommended 9.40% ROE is only 220 basis points higher than a consensus of analysts' forecasts of investment grade (Baa) bond rates for the second quarter of 2007 which, when compared to past data, is a very low premium above investment grade bond rates. *PGE/2100, Zepp/7*.

Staff's ROE analysis also contains calculation errors. The exhibits upon which Staff relies for its 9.40% ROE recommendation – Staff/1401, Morgan/7 and Staff/1401, Morgan/9 – contain two significant errors that understate ROE by approximately 20 basis points. *PGE/2800, Zepp/19*.

With respect to methodological errors, Staff's DCF analysis omits a portion of sustainable growth. *PGE/2100, Zepp/15*. Sustainable growth should be computed as the sum of growth from retained earnings (called "br" growth) and sales of stock above book value (called "sv" growth). Although previous Staff cost of capital witnesses routinely included "sv" growth in previous cases, Staff in this case excludes "sv" growth from its sustainable growth calculations, without explanation. *Id. at 18*. In doing do, Staff excludes almost 50 basis points of growth from all of its estimates of sustainable growth which, if corrected, would increase the ROE recommendation from 9.4% to 9.9%. *Id*.

Staff also recommends that past growth be considered by the Commission, but Staff fails to include estimates of such past growth in its DCF models. *Id*. If Staff's 40-year three-stage model is modified to (1) include "sv" growth in the analysis, (2) to reflect investors' reliance on past growth in earnings per share ("EPS") when they formed their expectations of cash flows, and (3) include Value Line's 12.5% assumed ROE during the second stage of the analysis rather than the 12.0% used by Staff, the derived internal rate of return for Staff's DCF analysis increases to 10.5%. *Id.; PGE Exhibit 2105*.

Another problem with DCF estimates that is not addressed by Staff involves the mismatch of capital structure considered by investors when they buy stocks and the capital structure used in an original cost jurisdiction like Oregon. *PGE/2100, Zepp/27*. When investors buy common stock at market prices above book value, the equity ratio of concern to them is higher than the more leveraged equity ratio used by regulators to set rates. For Staff's sample, the book equity ratio (used in ratemaking) is 49% *(Staff/1002, Morgan/9)*, and the market to book ratio is 1.73. *Id. at 6*. Based on simple arithmetic, these data imply the market capitalization ratios are 38% for debt and 62% for common equity. Assuming a debt cost of 7% and an equity cost derived from market data of 10.25%, the authorized ROE would need to be adjusted upward by 75 basis points to reflect the difference in market leverage and leverage used to set rates. *Id. at 28*. Based on Staff's corrected 9.6% DCF estimate of the cost of equity, this approach would support a return on book equity for the benchmark sample of 10.35%. PGE/2800, Zepp/25. The fair ROE for PGE would be higher since PGE is more risky than Staff's benchmark sample.[7]

d. The Commission Should Consider Other Sources of Information to Confirm the Reasonableness of the Results Produced by Modeling.

A wealth of information is available to assist the Commission in estimating PGE's required ROE. *PGE/2800, Zepp/5*. Rather than relying solely on the DCF model – as recommended by Staff – the Commission should consider, among other factors, (1) risk positioning and risk premium models, as offered by PGE and ICNU-CUB and described above, (2) earned and authorized ROEs from other jurisdictions, (3) use of other models, such as the capital asset pricing model ("CAPM"), as a "check" on DCF results,[8] and (4) other information. *Id*.

Two obvious measures of the opportunity cost of equity that are available to investors are ROEs currently being earned and ROEs the utilities are authorized to earn. If regulators authorize rates and rate adjustment mechanisms that allow utilities a reasonable chance to earn their costs of equity, an average of earned ROEs for the sample as well as an average of authorized ROEs provide measures of that opportunity cost of equity. PGE Exhibit 2103 provides a list of earned and authorized ROEs for the companies in Staff's sample. Taking into account that PGE is more risky than companies in Staff's sample, the evidence in PGE Exhibit 2103 indicates the opportunity cost of equity for investors in PGE stock is above the

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[7] This concept was recognized by the Pennsylvania PUC in a 2002 decision involving Philadelphia Suburban Company, Docket No. R-00016750, where the PUC increased the authorized ROE by 80 basis points finding that: "the financial risk adjustment is indeed necessary to reconcile the divergence between [Philadelphia Suburban Company's] market and book values."

[8] In this regard, the CAPM "analysis" offered by Staff as a "reasonableness check" *(Staff/1400., Morgan/48)* is of no value. Staff itself admits its analysis was not "rigorous." *Staff/1400, Morgan/49*. Staff used a 10-year Treasury rate rather than a long-term security; a speculative and unsupported beta of 0.85; and an understated market risk premium. *See PGE/2800, Zepp/26*.

range of 10.8% to 11/1%. *PGE/2100, Zepp/12*. This analysis does ***not*** depend on the types of models that were used to determine the ROEs or what assumptions were used to produce equity costs with those unknown models. PGE Exhibit 2103 provides a direct estimate of the opportunity cost of equity that must, under the standards of ORS 756.040, *Hope* and *Bluefield*, be considered in determining a fair rate of return on equity. *Id*.

Similarly, PGE Exhibit 2706 shows the ROEs adopted by regulatory commissions throughout 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*.

With respect to CAPM, ICNU-CUB included a CAPM analysis that reached the same estimated return on equity, 10.4%, as suggested by their risk premium model. *Id. at 27.*

With respect to other information that the Commission could consider, PGE Exhibit 3113 provides a helpful point of reference with respect to the inter-relationship among ROE, capital structure and regulatory framework for power cost recovery. PGE Exhibit 3113 is a Stipulation entered into in late October 2006 in the Public Service Company of Colorado ("PSCo") general rate proceeding before the Colorado Public Utilities Commission. *Docket No. 06S-234 EG*. This Stipulation, which included the major parties to the proceeding (Staff, Office of Consumer Counsel and Colorado Energy Consumers, among others), recommends that the Colorado PUC approve: (1) an ROE of 10.50% *(PGE/3113/11)*, (2) a capital structure comprising 60% equity and 40% debt *(Id.),* (3) an overall rate of return of 8.85% *(Id.)*, (4) an Electric Commodity Adjustment mechanism ("ECA"), which is a forward-looking mechanism for recovery of all prudently incurred fuel, purchased energy and purchased wheeling expenses, subject to true-up using a deferred account, and which also includes incentive payments that encourage (a) efficient operation of base load coal plants and (b) cost reductions through purchases of economical short-term energy *(PGE/3113/14; PGE/3113/96-102)*, and (5) revisions to the Purchased Capacity Cost Adjustment mechanism ("PCCA") to recover all prudently incurred costs paid by PSCo under all power purchase agreements that are not included within the ECA. (The ECA recovers fuel, purchased energy, and purchased wheeling expenses, but does not include capacity-related costs under power purchase agreements.) *PGE/3113/13; PGE/1113/91-95.*

Under the PSCo Stipulation, the settling parties agreed upon an ROE of 10.50% for PSCo in the context of an equity ratio of 60% and a regulatory framework for power costs that provides virtually 100% recovery of all power costs, including the opportunity to recover incentive payments over and above actual power costs in certain circumstances. The terms of this Stipulation confirm the reasonableness of PGE's proposals in this case. The slightly higher 10.75% ROE recommended by PGE is warranted given PGE's more leveraged capital structure (as compared to PSCo) and the less complete power cost recovery framework proposed by PGE (as compared with PSCo's ECA and PCCA).

e. PGE's Overall ROE Recommendation of 10.75% Would Adequately Compensate Equity Investors for the Risks Associated with Investing in PGE.

Weighing the results of the DCF and RPM approaches, PGE determined on the basis of its judgment and experience, as well as the operations and price risks undertaken by PGE, that the appropriate range for PGE's required ROE is 9.25% to 11.3%, with a point estimate of 10.75%. *Id. at 39.* PGE's estimate was calculated assuming adoption of PGE's actual equity ratio for 2007, which was updated to 53.3% in PGE's sursurrebuttal testimony.

PGE's estimate further assumes that the power cost regulatory framework proposed by PGE in this proceeding is adopted. *Id. at 40.* 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/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. *PGE/2400, Lesh/30*.

ICNU-CUB, for their part, recommended an ROE of 9.9%, which was the midpoint of the estimated ROE range comprising the 9.5% point estimate using the DCF model, 10.4% using a risk premium analysis, and 10.4% under their CAPM analysis. *ICNU-CUB/300, Gorman/28*. This 9.9% recommendation, however, does not fairly capture the ICNU-CUB analysis. For example, weighting the DCF, risk premium, and CAPM analyses equally would produce an ROE of 10.1%. Moreover, as noted above, ICNU-CUB's DCF analysis produced a range of 7.38% to 12.58%. *ICNU/306, Gorman/1*. PGE has risk characteristics that are not captured by this sample group, and a point estimate at the higher end of this range would be necessary. The 10.4% ROE produced by ICNU-CUB's risk premium and CAPM analyses, for example, is only slightly higher than the midpoint of their DCF analysis.

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. Adoption of the extremely low 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%. *PGE/2800, Zepp/27*. Such a price drop would severely limit PGE’s ability to access the equity and debt financial markets. As discussed in the following section, Staff's cost of capital recommendations would also jeopardize PGE's ability to maintain its current credit rating.

6. The ROE and Equity Ratio Proposed by PGE Will Maintain PGE's Existing Credit Rating and Allow PGE to Attract Capital on Reasonable Terms.

Although the cost of capital does not represent a large portion 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 will not be able to take least cost resource actions on behalf of customers when those actions require PGE investment. The capital structure and required ROE proposed by PGE will support PGE's current secured bond rating of "BBB+." This is based upon S&P's benchmark guidelines for a "BBB+" rated utility. *PGE/2000, Hager-Valach/26*.

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. PGE's current rating for unsecured debt is "BBB," which provides a narrow margin over the lowest investment grade rating ("BBB-") necessary to maintain trading relationships without triggering substantial collateral requirements. If PGE's financial condition deteriorates to below investment grade, it would significantly impact PGE's ability to secure power supplies for customers at the lowest cost possible. *PGE/2500, Lobdell/8*. The vast majority of PGE's unsecured credit lines with its wholesale counter-parties would be reduced to zero and, as a result, these counter-parties would require prepayment and/or adequate margin for all current and forward positions. *Id*.

Staff's recommended overall rate of return of 7.86% 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 extremely low 9.40% 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 and the debt imputation associated with this reliance. Staff's recommended return would place PGE's financial ratios closer to a downgrade, as they would be at the bottom end of S&P's benchmark guidelines for a "BBB+" rated utility. *Id. at 29*. Staff takes the unsupported position that so long as a company has an investment grade rating, the "capital attraction standard" of *Hope* is met. *Staff/1400, Morgan/18*. An "investment grade" standard, however, is the absolute ***minimum*** standard for being able to raise capital, and would likely be insufficient to provide assurances of financial health. *PGE/2700, Hager-Valach/17*. Most of the entities with corresponding risks with which PGE is competing for capital obviously have credit ratings that are superior to the minimum "investment grade" standard. *Id. at 18*.

Moreover, adoption of Staff's 9.40% ROE recommendation, which would be the lowest authorized ROE in the country, would likely cause credit rating agencies to conclude that Oregon has become a more difficult regulatory environment. *PGE/2700, Hager-Valach/16*. S&P's most recent report on PGE dated September 25, 2006 states that one of the reasons for the negative outlook is "an uncertain regulatory environment" and that "[w]eak financial performance could lead to lower ratings, particularly if it is the result of inadequate rate relief." 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

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 even the best modeling cannot remove. Power costs in total represent about two-thirds of PGE's 2007 revenue requirement; NVPC alone represents 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 sharing.

The power cost framework adopted in this docket will address cost of service risk – the risk that PGE's Commission-set cost-of-service prices do not reflect PGE's actual cost of providing on demand electric service to customers. Both customers and PGE have this risk. PGE agrees with Staff that "[t]he objective should be to avoid allocating cost-of-service risk between shareholders and customer in an uneven manner and to achieve a permanent and fair allocation of power cost risk between shareholders and customers." *Staff/1500, Galbraith 10.*

The Commission should address this cost-of-service risk in two ways: 1) it should provide for an even allocation of the risk in its forecast of power costs, and 2) it should minimize the variance of prices from costs as much as possible while still aligning the interests of the customers and PGE. PGE has proposed a power cost framework that accomplishes this.

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. The Annual Update relates to the need for an even allocation of cost-of-service risk because it is unlikely that the forecast of power costs made in this case will be good for any successive years. An annual reset including expected loads and prices will also reduce the variance of actual costs from costs assumed in ratemaking. 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. The Variance Tariff addresses that part of cost-of-service risk that it is impossible to remove from test year ratemaking.

Use of MONET with supportable assumptions and these two tariff mechanisms would, together and separately, align cost of service prices more closely with the prudently incurred cost of providing electric service. The other parties propose unsupportable assumptions in MONET, and oppose one of these mechanisms in its entirety (the Annual Update), and seek limitations on the other (the Variance Tariff) 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.

PGE's proposed Annual Update tariff and Variance Tariff are discussed in greater depth below. Following that discussion, the changes in policy and adjustments proposed by other parties that move away from cost-of-service ratemaking – abandonment of the long-standing four-year rolling average for determining forces outage rates, "extrinsic value" adjustments, and ancillary services revenue - are discussed. The final portion of this section addresses the inclusion of costs associated with Port Westward when it begins service to customers.

2. Approving PGE's Proposed Annual Update Tariff Would Enable the Commission to Set Prices Using Known, Current Information for the Single Largest Component of PGE's Cost of Service and Would Help Maintain the Allocation of NVPC Cost of Service Risk.

PGE is proposing tariff Schedule 125, under which 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. This tariff is similar to, but narrower than, the current RVM. *PGE/400, Lesh-Niman/25*. The list of inputs to be updated is shown at PGE/400, Lesh-Niman/25. 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. 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. *PGE/1800, Lesh/33*. The annual update would also help the Commission maintain the allocation of NVPC risk it has chosen in creating the test year forecast. *Id*.

Staff opposes the Annual Update Tariff because it believes that year-to-year NVPC forecasts do not exhibit enough change, up or down, to warrant what Staff sees as the regulatory burden associated with the proposed process. *Staff/800, Galbraith/14*. ICNU opposes it. *ICNU/103, Falkenberg/3*. CUB also opposes it and suggests modifications in the event the Commission nonetheless adopts it. *CUB/200, Jenks-Brown/13-14*.

In fact, the prices paid by PGE for actual purchased power and fuel contracts have been quite volatile in recent years. The greatest effect of this volatility on NVPC cost-of-service risk is year-to-year, and not within the year. NVPC forecasts can vary greatly from year to year, as indicated by Figure 1 at PGE/300, Lesh/4, which shows PGE's forecasted annual NVPC for the 1993-2005 period. The cumulative increase from 1998 to 2002 was almost $600 million, and the decrease from 2002 to 2003 was more than $350 million. *PGE/1800, Lesh/4*. PGE's prices have also reflected this volatility, including a one-year drop of over $172 million from 2002 to 2003 and a one-year rise of over $102 million from 2005 to 2006. *PGE/2400, Lesh/4, 27*. Based on this, PGE cannot agree with Staff that year-to-year change in NVPC is not sufficiently volatile to warrant the regulatory burden of an annual update process. Without the Annual Update Tariff, PGE is likely to file general rate cases more frequently, at least when the costs of its market fuel and power purchases are rising. *PGE/2400, Lesh/28*. The burden is far greater to process a general rate filing than the procedure contemplated under the Annual Update proposal. *Id*.

PGE urges the Commission to approve the Annual Update Tariff, as set forth in proposed Schedule 125.

3. The Commission Should Approve PGE's Proposed Power Cost Variance Mechanism as a Reasonable Regulatory Framework for the Recovery of Variations Between Actual and Forecasted NVPC.

PGE proposes Schedule 126, an annual Power Cost Variance Mechanism, under which PGE would:

- Track the difference between its actual NVPC for a given year and its forecast NVPC set in the Annual Update;
- Neutralize the effects of load changes (increases or decreases) on that difference;
- Absorb 10% of the difference and design the remaining 90% into a per kWh rider under an amortization schedule set by the Commission; and
- Demonstrate each year that earnings in the prior year, with the effects of the Annual Update and Annual Variance tariffs, do not exceed a reasonable amount, sharing any earnings above a threshold ROE on a 50%/50% sharing basis between customers and PGE.

PGE/400, Lesh-Niman/33.

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. *Staff/800, Galbraith/15-16.* Although Staff acknowledges 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 *(Staff/1500, Galbraith/7)*, Staff's proposal would do nothing to alter this unevenly allocated cost-of-service risk.

CUB proposes stepped asymmetric deadbands with different sharing levels. As adjusted in its surrebuttal testimony, CUB's proposal varies from no sharing for variances in power costs of up to75 basis points below those assumed in rates and 150 basis points above the costs assumed in setting rates to, after increases in two steps, to 90/10 sharing for variances of 120 basis points when actual costs are below the cost used in setting rates and 240 basis points when actual costs are higher than those used in setting rates. *CUB/300, Jenks-Brown/27*. 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. *Id.*

a. The Annual Variance Tariff Does Not Need a Deadband.

The regulatory framework for power costs should not include a deadband. Including a deadband as part of a power cost recovery mechanism:

- **Would increase the cost-of-service risk to both PGE and its customers.** Both utility customers and utilities bear the risk that prices will not reflect the utility's cost of service. Utilities bear the risk that test year rates, and revenues collected through them, are too low for the costs incurred in providing on-demand retail electric service. *PGE.1800, Lesh/9*. Customers bear the risks that test year rates, and the bills they produce, are too high for the actual costs a utility bears in providing the service. *Id.* Given the uncertainty associated with forecasting NVPC and the little, if any, control the utility has over these costs, the cost of service risk associated with NVPC is high. *Id. at 10-11*. PGE's proposed regulatory framework for power costs significantly reduces this risk by bringing a significant amount of the variance between actual costs and projected costs – 90% – into the ratemaking process. *Id. at 23*. This proposed 90%/10% sharing mechanism, with no deadband, recognizes and incorporates the limited ability PGE has to control power costs, and aligns the interests of PGE and its customers. *Id. at 29*.

- **Would depart significantly from Oregon's prior policies with respect to electric utilities and current policies with respect to natural gas utilities.** Commission policy supported a comprehensive PCA mechanism for PGE from 1979 to 1987. Under that mechanism, PGE produced a new forecast of NVPC every quarter and shared variances between those forecasts and actual costs with customers on an 80%/20% basis. *Order No. 79-380; PGE/1800, Lesh/47*. The standard deviation of possible NVPC outcomes at that time was much smaller than it is today, with market-based prices for natural gas and power. *PGE/2400, Lesh/14*. Yet that PCA mechanism had neither a deadband nor an earnings test. *Id*. Subsequently, in Docket UM 445, the Commission required PGE to absorb only 10% of the increased NVPC resulting from replacing Trojan's output before and after its premature closure. *Order No. 93-257; PGE/2400, Lesh/14*. Oregon has also for many years used a regulatory framework very similar to what PGE is proposing with respect to including actual purchased gas costs in local gas distribution company (LDC) cost of service prices. *PGE/1800, Lesh/47-48*. PGE's NVPC are very similar to the gas costs of Oregon's LDCs, particularly Northwest Natural Gas Company, where purchased gas costs in Docket UG 152 represented 57% of its overall revenue requirement as compared to the 50% of revenue requirement comprised of NVPC for PGE. *Id. at 48*. Even if the Commission concluded that a PCA mechanism for PGE must differ from the Purchased Gas Adjustments (PGAs) used by LDCs because of PGE's investment in generation, a deadband on the variance calculation could address that difference. *PGE/2400, Lesh/15*.
- **Would depart significantly from how other states regulate utilities otherwise comparable to PGE.** The power cost recovery framework PGE proposes is most

like those used for similar, vertically integrated electric utilities. The comprehensive report National Economic Research Associates (NERA) prepared for PGE showed that deadband/sharing mechanisms are rarely used *(PGE/401, Lesh-Niman/33-34*), and that 100% of coverage of differences between forecasted and actual NVPC was a common regulatory practice. *PGE/2400, Lesh/15*. Adoption of a deadband for PGE would continue the current significant difference between PGE's regulatory environment and that of other, comparable, electric utilities, which would reflect negatively on Oregon's regulatory climate and PGE in the national financial markets. *Id. at 15-16*. 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. *Id. at 16*.

- **Would be unfair with respect to the different types of costs within a utility's power costs.** Use of a deadband would allow PGE's customers to enjoy the benefits of low embedded fixed costs of PGE's resource portfolio while shielding them from the full variable costs of the same resources. *Id.* 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. *Id.* 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. *Id. at 17*.
- **Would be unfair across utilities because it ignores how much a given utility has invested in generation.** 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. *Id. at 18*. 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.) *Id.* The investment in generating resources should be considered in determining the size of any deadband, not the utility's entire investment.

- **Would skew the regulatory framework for normal business risk.** In PGE's situation, the potential power cost variances produced by PGE's current resource portfolio are so large that they swamp the normal variation with respect to the other costs required to provide on-demand retail electricity service. *Id. at 19*. PGE's non-power O&M expenses – including customer services, administrative and general costs, and operating and maintenance expenses associated with PGE's system – are approximately $330 million, much of which is for the personnel necessary to run the facilities. *Id*. It is very unlikely that PGE could avoid more than a small percentage of these costs on an ongoing basis, such as PGE might have to do in the event of several consecutive years of drought. In short, PGE simply does not have the "cushion" to absorb power cost variations that would be provided by a large generating rate base.
- **May not produce reasonable results over a multiple year period.** A regulatory framework for power costs must be designed in a manner that will be durable for the indefinite future. While a utility may be able to bear the exclusion in a given year of a significant portion of power cost variations through application of a deadband, it is unsustainable to impose such exclusions over four or five years. The Commission should be able to conclude that the result produced by a PCA mechanism is fair and reasonable over an extended period, not just one year. *PGE/2400, Lesh/19-20*.
- **If based on a distinction among "events," would not have a sound factual basis.** The "unusual event" standard proposed by Staff *(Staff/1500, Galbraith/3)* has no

sound basis. First, it is not possible to define "unusual," without knowing the total cost of supplying power to PGE's customers for each year of the next 20, 30, or 40 years and the ability to create a distribution that might inform a decision about what is "usual" versus "unusual" and what outcomes may reasonably "balance out" over time. *Id. at 20*. Second, there is no basis for concluding that the past is indicative of the future with respect to the distribution of power cost outcomes or the financial effect of those outcomes. This is true for all three of the major sources of forecast-to-actual variance in PGE's resource portfolio (hydro, thermal, and market-based gas and electricity prices). *Id. at 21*.

b. If a Deadband Is Included, It Should Reflect PGE's Particular Circumstances and the Existing Regulatory Environment, Such as SB 408.

If the Commission determines that a deadband is necessary, it should take into account the following parameters in designing the deadband:

- **PGE's test year generation rate base.** Taking into account the size of PGE's generation rate base would fairly distinguish among various electric and natural gas utilities inside Oregon. It would also ensure that PGE's investment in distribution does not, by itself, cause the deadband to increase. *PGE/2400, Lesh/22*.
- **A portion of the "risk premium" associated with the required ROE.** Limiting the NVPC variance deadband to a portion of the risk premium (over the market cost of debt) associated with generating investment is more sensible than using an arbitrary number, such as 250 basis points. It is for this risk premium that equity investors' claims to the assets of the utility are subordinate to the providers of debt capital. *Id.* Under Staff's ROE proposal of 9.40%, the risk premium is 316 basis points,[9] which a

[9] PGE estimates the cost of new debt at 6.24%, based on estimates of new debt placements described in the work papers to PGE Exhibit 2700.

250-basis point deadband would nearly consume (assuming it applied to generating investment – if applied to all investment, it would more than eliminate any return on the generation). *Id*. Under PGE's recommended 10.75% ROE, the risk premium is only 451 basis points. The Commission should not adopt a NVPC variance deadband that consumes the entire risk premium for PGE's side of the NVPC cost-of-service risk.

- **The sharing percentages adopted for variances outside of the deadband.** In determining whether PGE's side of the cost-of-service risk affected by the PCA mechanism is fair to investors, the Commission should consider the combined effect of the deadband and sharing percentage. Notwithstanding the other parties' complaints that the 10% share PGE proposes to bear is small *(CUB/300, Jenks-Borwn/10, Staff/800, Galbraith/6, and ICNU/103, Falkenberg/37)*, even that percentage would significantly affect PGE's ability to earn the return required by investors for providing capital to the business. *PGE/2400, Lesh/23*. PGE suggests that 50% of the risk premium in basis points, applied to generation-related investment only, could be a reasonable NVPC deadband, when combined with 90/10 sharing of variances outside of the deadband, if the Commission decides that a dead-band is necessary. *Id*.
- **The impact of implementation of SB 408.** Unless and until any future legislative action changes SB 408, any PCA mechanism designs must consider the effects of the tax true-up on customers' and utilities' cost-of-service risk. Whatever amount of NVPC cost-of-service risk the Commission would otherwise find reasonable to leave with customers and PGE, it should reduce this to offset the "double whammy" effect of SB 408. *Id*. The Commission acknowledged the "double whammy" problem in its

> final order in Docket AR 499, and indicated that it would be "responsive to concerns related to the consequences of the 'double whammy' problem" which could be addressed in "general rate cases and power cost adjustment mechanism dockets." *Order No. 06-532 at 11.*

With respect to an earnings test deadband, PGE recommends that the Commission apply the policy direction articulated in 1999 for PGA mechanisms, such that the earnings test precludes only excessive earnings rather than act as a duplicate deadband on power cost variances. *PGE/2400, Lesh/23*. If the Commission finds it necessary to add an earnings test deadband to the variance calculation deadband, it should choose an earnings test deadband smaller than the variance calculation deadband. Ideally, PGE would recover additional actual costs up to some number of basis points above the authorized ROE and return lower costs down to some number of basis points below the authorized ROE. Such an approach would preserve much of how the current regulatory framework handles cost-of-service risk on all of the other costs that comprise PGE's provision of on-demand retail electricity service. *Id. at 24*.

4. The Commission Should Continue to Follow Its Historic Practice of Determining the Test Year Forced Outage Rate Assumption Using a 4-Year Average of Actual Outages.

Staff and ICNU argue that the Commission should abandon its long-standing practice of using a four-year rolling average of forced outages to calculate a test year forced outage rate assumption, at least for some PGE generating plants.[10] Notwithstanding that the Commission has used this approach for over 20 years, the parties proposing that the Commission selectively abandon it offer little reason to do so, appearing to rely for support on the results the change achieves instead. Changing the policy in this case is inconsistent with (1) the policy behind use of the four-year rolling average, (2) Staff's own positions in previous dockets, and (3) the

[10] Staff advocates abandoning the four-year rolling average approach for PGE's coal plants: Colstrip and Boardman. ICNU advocates also abandoning the practice for Coyote Springs.

Commission's recent decision in Docket UE 179. The Commission should reject the other parties' forecast reductions that rely on abandoning this long-standing policy.

The Commission's use of a four-year rolling average to calculate forced outage rate assumptions in ratemaking stems from a Staff recommendation in 1984. A copy of Staff's July 18, 1984, memo is in the record as Staff/102, Galbraith/1-21. That recommendation was the result of in-depth, lengthy analysis. The memo indicates that it "represents a 'final' wrap-up of the plant performance project begun in 1983." *Id. at 4*. The memo transmittal letter states that "[e]arlier this year, we had extensive discussions concerning the performance of several thermal plants as used in setting rates." *Id. at 1*. The memo proposes "a method for calculating performance that can be applied uniformly from plant to plant and from company to company." *Id. at 4*. Staff's recommendation was the result of a thorough process and the recommendation was for a policy to apply to all thermal plants of all utilities. The Commission has been operating under this policy since that time.

The use of the four-year average is, for ratemaking purposes, to calculate an assumed level of plant operation during the test period. In its 1984 memo Staff stated that:

> "The reason I propose using a 48-calendar month rolling average is that it reflects recent plant experience, which I think tends to better portray expected operation over the coming year. Four years of experience is sufficient to average out variations and yet not include generally irrelevant experience from history long past." *Id.*

In this docket Staff and ICNU propose to abandon the use of actual experience with the very plants in question, and instead use NERC data. Yet, Staff and ICNU have not shown that the NERC data is more accurate in predicting plant operation. In fact, PGE has raised significant concerns about the NERC data, not the least of which is that NERC itself says that the data is not appropriate to be used in this way. PGE/1900, Tinker-Schue-Drennan/41-46.

The 1984 Staff memo itself explicitly recognized the superiority of actual data to NERC data. At the time the memo was written Colstrip 3 and Boardman had not been operating for a full 48 months. For example, Boardman had been operating for 38 months. To fill the 10 month gap in the four-year rolling average, Staff used a NERC average for coal plants of Boardman's size in their fourth year of operation. The memo states: "In PGE's next general rate filing there will be 48 months of actual data available from Boardman, so the national average data will not be used." *Staff/102, Galbraith/14*. The memo used information other than actual operation of the plant only when that actual data was not available and specifically stated that when actual data is available, it should be used. There is no need to change that policy in reaction to one unusual event that can be removed from the calculation.

Staff proposes this change in policy because, as a result of the extended Boardman outage in 2005, it claims there is a "flaw in the traditional methodology." *Staff/100, Galbraith/7*. Staff is incorrect. Staff's complaint is that the Boardman outage is an extreme event and it would therefore be improper to include the outage in the four-year rolling average.[11] There is no flaw in the methodology. There is an unusual outcome as a result of one unusual event – the extended Boardman outage. The methodology and the policy behind adoption of the four-year rolling average have not changed. There has not been a flaw in that methodology for 22 years.

Staff itself has identified a fair method for removing the unusual event from the four-year rolling average – simply removing the hours during the outage from the forced outage hours and the period hours used in the calculation. *Staff/100, Galbraith/7*. As Staff noted, this is similar to the adjustment that was made for the unusual outage at PacifiCorp's Hunter plant in dockets UE 134, UE 147, and UE 170. A comparable adjustment was made in the original calculations in Staff's 1984 memo as well, for an outage at Boardman. *Staff/102, Galbraith/14*. And a similar adjustment can be made in this case. There is no reason or need to abandon the long-standing policy and methodology.

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[11] This outage is the subject of a deferral application in Docket UM 1234. The characterization of this outage as an "extreme event" or otherwise will be decided in that docket. PGE has stated that if the deferral is granted in UM 1234, then the outage hours should be removed from the forced outage rate calculation in this docket.

Staff also proposes to abandon the four-year rolling average for Colstrip units 3 and 4, claiming that it is unreasonable to include the outage rate from 2002 on the grounds that it is an extreme rate. *Staff/110, Galbraith/13*. ICNU makes a similar proposal. Staff and ICNU point to no particular event, they just claim that the rate for the entire year is extreme. Staff and ICNU make this claim notwithstanding that they have stipulated to rates in three RVM dockets that included 2002 in calculating the four-year rolling average. In addition, neither Staff nor ICNU attempted to remove this 2002 rate from the four-year rolling average in PacifiCorp's recently completed rate case, Docket UE 179. It is disingenuous of Staff and ICNU to now claim that the outage rate is extreme and improper to include in a four-year rolling average. And adoption of Staff's or ICNU's position would have the Commission use a different forced outage rate in this docket for the same Colstrip plants than it did just two months ago in the PacifiCorp rate case, Docket UE 179.

If the Commission sees the need to revisit its longstanding policy of using a four-year rolling average to determine forced outage rate assumptions in ratemaking, it should do so in a generic proceeding. Doing so would enable the type of analysis that occurred when the policy was adopted, would give all utilities the ability to provide input, and would also avoid the inherently unfair inconsistency that abandonment for only PGE, and then only some PGE plants, would cause.

5. The Commission Should Reject the Proposed Reductions to NVPC Based on a Claimed "Extrinsic Value" of Resources.

Staff and ICNU propose to make an outboard reduction to the MONET NVPC forecast on the theory that some of PGE's gas-fired generating resources and some heat-rate based contracts will produce margins higher than those in the MONET forecast. The proposed adjustments attempt to cherry-pick one aspect of the uncertainty of power cost forecasts to justify a reduction to forecast NVPC. There is no precedent for this adjustment; it has never been adopted by the Commission, and the proposed reduction is without merit. In fact, the evidence in the record indicates that if an adjustment is made to NVPC, that adjustment would *increase* forecast NVPC.

For some time Staff has advocated stochastic power cost modeling. As part of a stipulation with Staff in another docket, PGE retained the services of PA Consulting to attempt to address the feasibility of stochastic modeling. The report that came out of that analysis (the "PA Report") was submitted as PGE Exhibit 1803. The PA Report sets out the difficult obstacles that would need to be overcome to have meaningful stochastic power cost modeling. That discussion may continue beyond this docket. However, the analysis in the PA Report does address the issue raised by these extrinsic value adjustments – the impact of uncertainty on PGE's power costs. The PA Report is the only analysis in this docket addressing that issue. The PA Report found that the base forecast of NVPC is approximately $10 million *less* than expected NVPC. The PA Report used what is now old data so less emphasis should be put on the actual dollar number, but the significant finding is the direction in which the forecast errs: expected NVPC is higher than forecast NVPC. In other words, the baseline NVPC forecast is too low, and a more complete assessment that captured the uncertainty of power cost forecast would *increase* the forecast. Yet Staff and ICNU propose that until stochastic modeling is used that the baseline forecast should be *decreased* from its already too low level.

Staff's proposal is also directly contradicted by assertions elsewhere in its testimony. In surrebuttal testimony addressing PGE's proposed power cost adjustment, Staff witness Galbraith discusses the risk of actual power costs varying from forecast power costs. That testimony states:

> "Staff believes that increases in NVPC are more likely than decreases in NVPC." *Staff/1500, Galbraith/4*.

This statement is repeated verbatim at Staff/1500, Galbraith7-8. Staff is very clear that it believes that forecast power costs in this rate case are more likely understated than overstated.

Given that assertion, Staff's attempt to create an adjustment to further decrease forecast NVPC cannot be given any credence.

The methodology Staff used in creating its extrinsic value adjustment is also deficient. Staff's extrinsic value estimate for generating plants is derived from one number taken from PGE's ranking of one Super-Peak Contract in connection with a 2003 RFP process. That contract is, as the name suggests, a very limited winter-period capacity contract. The number used by Staff was for ranking the contract in comparison to other responses, it was not a forecast of value. Notwithstanding that, Staff took that one number and extrapolated it to gas-fired generating plants for an entire year. This approach is not theoretically sound. Staff also ignored information about the actual dispatch of the very contract used in its analysis. Staff's analysis of a tolling agreement and dispatchable stand-by generators suffers from similar deficiencies. Even if the concept behind Staff's adjustment were sound, its analysis and methodology would still be deficient.

In its surrebuttal testimony, ICNU offered two approaches in its discussion of extrinsic value, both variants of the analysis presented in its direct testimony. Alternative I contained some methodological corrections proposed by PGE in its rebuttal testimony. However, ICNU did not correctly update the forward curves used in its Alternative I analysis. Correcting this error, and the improper inclusion of Port Westward value in January and February, decrease the ICNU Alternative 1 estimate to about $3.2 million. However, as set out in PGE's sursurrebuttal testimony, the September 29, 2006, update to MONET credits customers with almost $3 million more in combined extrinsic and intrinsic value than ICNU advocates. *PGE/2600, Tinker-Schue-Drennan/8*. The ICNU methodology then confirms the conclusion of the PA Report that an adjustment for extrinsic value would *increase* NVPC.

The proposed extrinsic value adjustments are contrary to the facts in this case, and in the case of Staff, contradictory to its testimony elsewhere in this docket. They should not be adopted.

6. The Commission Should Reject ICNU's Proposed Removal of the Costs of the Cold-Snap and Super-Peak Capacity Contracts.

ICNU argues that the Commission should remove the costs of the Super-Peak and Cold-Snap contracts from test year power costs. ICNU claims that since the contracts are not expected to dispatch in test-year power forecasts, then the costs should be excluded.

ICNU's arguments ignore the nature and purpose of these contracts. They are capacity contracts. In Order No. 04-375, the Commission acknowledged PGE's 2002 IRP Final Action Plan. That least cost plan called for PGE to acquire "400 MW of tolling capability for peak purposes." The Super-Peak and Cold-Snap contracts provide that necessary tolling capability. Such contracts are not expected to dispatch frequently – on the contrary they are needed for extreme circumstances to maintain the reliable delivery of power to customers. The 2002 IRP Final Action Plan determined that capacity contracts in this amount are necessary. The contracts are part of the acknowledged least cost plan to provide electric service to customers. ICNU's proposal to remove the costs of these contracts from test year expenses should be rejected.

7. Revenue from Ancillary Services Should Be Addressed Through the Power Cost Variance Mechanism, and No Separate Adjustment Is Warranted or Supported by the Evidence.

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. *PGE/1900, Tinker-Schue-Drennan/46*. 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 $5,000 to more than $400,000). *Id*. Moreover, any such revenue projection should be net of the grid management charges imposed by the California ISO. *Id*.

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/1600, Wordley/2*. Staff bases its adjustment on a confidential data request response, included at Staff/1601, Wordley/1. That response does not reflect an offset for the grid management 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 the Power Cost Variance Tariff PGE is proposing in this case. These revenues, and the offsetting grid management costs, would be tracked by that mechanism. In the absence of such a mechanism, no adjustment should be made to NVPC in this case. There is an insufficient basis upon which to make such an adjustment, given that PGE has been offering these services only since June 2005 and the revenues have varied substantially form month to month over this limited period.

8. The Commission Should Determine the Costs Associated With Port Westward's Commencement of Service in this Case for Later Inclusion in Rates, Subject to Adjustment in Certain Limited Circumstances.

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. *CUB/300, Jenks-Brown/29*. 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/2500, Lobdell/2*. 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. *Id. at 3*. 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. *Id.*

CUB also proposes three conditions related to potential delays in Port Westward's online date. *CUB/300, Jenks-Brown/31*. 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/2500, Lobdell/6*. 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. The Commission Should Not Consider the Tax Scheme Proposed by the City of Portland in Determining the Amount of Taxes for Ratemaking Purposes.

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. *COP/100, Jubb/5-10*. 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. *Id*.

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. *PGE/1700, Piro-Tamlyn/7-15*. 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. *Id. at 10-11*. 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. *Id. at 16-17*. 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.

III. 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.

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Respectfully submitted,

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APPENDIX "A"

The following Stipulations have been reached in this docket:

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

2. Stipulation Regarding RVM Issues, which was approved by the Commission on October 9 in Order No. 06-575. This stipulation, dated August 24, 2006, is among PGE, Staff, ICNU, and the Citizens Utility Board ("CUB"). 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. 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.

3. Stipulation Regarding Revenue Requirement Issues dated August 24, 2006. This stipulation is among PGE, Staff, CUB, ICNU and Fred Meyer Stores, and specifically addresses eleven proposed adjustments and 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.

4. Stipulation Regarding Rate Spread and Rate Design Issues, dated October 4, 2006. 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 also 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.

5. Joint Settlement Agreement and Stipulation Regarding Street Lighting Service and Critical Account Priority Issues, dated November 1, 2006. This stipulation is among PGE, the League of Oregon Cities, City of Portland, and City of Gresham. This stipulation settled all issues raised by the Cities except those identified in COP/100/Jubb.

6. Stipulation Regarding Partial Requirements Service, dated November 10, 2006. This Stipulation is between PGE, Staff and ICNU. This stipulation settles all issues raised regarding partial requirements service.

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the following OPENING BRIEF OF PORTLAND GENERAL ELECTRIC COMPANY 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 17 th day of November 2006.

DOUGLAS C. TINGEY

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