ORDER NO. 07-015

ENTERED 01/12/07

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/ UE 181/ UE 184

In the Matters of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180) Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181) Request for a General Rate Revision relating to the Port Westward Plant. (UE 184)	))))))))))))	ORDER

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UE 180/ UE 181/ UE 184

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SUMMARY

This order addresses two rate requests by Portland General Electric Company (PGE or the Company). In its first request, PGE seeks a general rate increase of $25.1 million or 1.6 percent, in general revenues. We reject this requested increase, and as a result of the adjustments described below, approve new rate schedules that immediately *decrease* rates by $21.6 million, or 1.4 percent. In its second request, PGE seeks an increase in rates to recover the costs of the Port Westward generating facility (Port Westward) when the plant goes into service. We reduce PGE's request by $2.8 million and authorize a Port Westward rate increase of $42.1 million, or 2.8 percent. If Port Westward goes into service as scheduled in early March, the combined effect of these rate changes at that time will be an overall increase of $20.5 million, or 1.3 percent in general revenues. The decisions in this order are quantified in Appendix E and summarized as follows:

Modifications to MONET Model:

- Extrinsic value: The Commission makes no adjustment for the extrinsic value of PGE's generating plants and purchase contracts, other than for the Super Peak contract, discussed below.

- Stochastic Modeling: The Commission does not require stochastic modeling in this order, but directs the Company to submit a report on the feasibility of using stochastic modeling to estimate power costs.

- Capacity Tolling Contracts: The Commission includes the costs of the Super Peak and Cold Snap contracts in rates, but reduces power costs by $1.4 million to account for the extrinsic value of the Super Peak contract.

- Forced Outage Rate: The Commission continues the use of the four-year rolling average to determine forced outage rates, but excludes the late-2005 outage at the Boardman plant from the calculation. This adjustment reduces PGE's power costs by approximately $4.6 million.

- Ancillary Services: The Commission recognizes net revenues from the Company's sale of ancillary services and reduces PGE's request by $1.43 million.

Power Cost Recovery Framework:

- Annual Update: The Commission approves the Annual Update of the power cost forecast proposed by PGE but extends the filing and review schedule.

- Annual Variance Tariff: The Commission adopts a Power Cost Adjustment Mechanism (PCAM) with an asymmetrical deadband of -75/+150 basis points, and beyond that, an allocation of 90 percent of the variance to customers and 10 percent to the Company. The PCAM will also have an earnings test that allows the Company to recover 90 percent of its power costs up to 100 basis points below its authorized return on equity (ROE), and refund 90 percent of its power costs to customers after the Company earns more than 100 basis points over its ROE.

Rate of Return:

- Capital Structure: The Commission approves use of a capital structure of 50 percent equity and 50 percent debt to determine PGE's rate of return.

- Cost of Debt: The Commission reduces PGE's cost of debt from 6.73 to 6.48 percent, in part to remove the harmful effects of Enron ownership.

- Cost of Equity: The Commission approves a 10.1 percent return on the cost of equity, instead of the 10.75 percent return proposed by PGE.

- Overall Rate of Return: The Commission's adjustments for capital structure, debt cost, and return on equity have the effect of reducing PGE's requested rate of return from 8.87 percent to 8.29 percent. This reduces PGE's proposed rate increase by $20.1 million

Additional Issues:

- Port Westward: The Commission reduces PGE's request by $2 million to reflect the full annual dispatch benefits of Port Westward. The Commission also establishes a process for reexamining the Port Westward rate increase if the opening of the plant is significantly delayed.

- Tax Issues: The Commission declines to adopt the income tax suggestions proposed by the City of Portland.

- Recovery of Trojan Expenses: The Commission authorizes PGE to reduce the amount it sets aside for Trojan expenses and claim a refund for customers. The Commission also states that PGE may recover for Trojan expenses beyond the previous 2011 deadline.

INTRODUCTION

Procedural Background

On March 15, 2006, Portland General Electric Company (PGE) filed Advice No. 06-8, an application for revised tariff schedules, docketed as UE 180. The application requested a rate increase of $25.1 million, or 1.6 percent, and sought approval of an Annual Update mechanism and an Annual Variance tariff to recover most of the actual amount of power costs. With the tariffs for the general rate increase, PGE also filed its annual Resource Valuation Mechanism (RVM), in compliance with the decision made in the last general rate case, docket UE 115. *See* Order No. 01-777, 18-20. This filing, docketed as UE 181; requested an increase of $72.7 million, or 4.8 percent. In addition, on April 24, 2006, PGE filed Advice No. 06-10 for implementation after Port Westward goes into service, docketed as UE 184. This filing requested a $44.9 million, or 2.9 percent increase in retail revenues. Pursuant to a motion filed by PGE, dockets UE 180, UE 181, and UE 184 were consolidated.

At the April 11, 2006, Public Meeting, the Commission found good cause to investigate the filing and suspend Advice No. 06-8 pursuant to ORS 757.215. Because the Commission determined that the rate investigation could not be completed within an initial six-month suspension period, it ordered that the filing be suspended for a total period of nine months from April 14, 2006. *See* Order No. 06-178. The rates will go into effect on January 14, 2007.

On April 4, 2006, a prehearing conference was held in this docket. The Citizens' Utility Board of Oregon (CUB) had submitted its notice of intervention on March 20, 2006. Industrial Customers of Northwest Utilities (ICNU), Bonneville Power Administration, Fred Meyer Stores and Quality Food Centers Divisions of Kroger Co. (Fred Meyer Stores), Sempra Global, PacifiCorp, SP Newsprint Co., and the Community Action Directors of Oregon and Oregon Energy Coordinators Association (CADO/OECA) each submitted petitions to intervene. The petitions were approved at the prehearing conference. At the conference, schedules were set for docket UE 181, the RVM proceeding, as well as dockets UE 180 and UE 184.

Subsequently, petitions to intervene were granted for the following parties: the City of Portland, Eugene Water & Electric Board (EWEB), Northwest Natural Gas Company (NW Natural), Elster Electricity LLC, Cellnet Technology, Inc., Hunt Technologies, Inc., the League of Oregon Cities, Dan Meek, Ken Lewis, Utility Reform Project, Epcor Merchant and Capital (US), Inc. (EPCOR), Constellation NewEnergy, Inc., and the City of Gresham.

On May 17, 2006, a public comment hearing was held in Salem, Oregon, and on May 24, 2006, a public comment hearing was held in Portland, Oregon. A total of five rounds of testimony were submitted in the rate case, and, because parties waived cross-examination, the hearing was canceled. Oral arguments were held on December 12, 2006, and PGE, ICNU, CUB, EWEB, the City of Portland, and Commission Staff (Staff) addressed the Commissioners in those arguments.

Commission Orders

During the course of the proceeding, the Commission issued several orders relating to specific matters in the case. On March 10, 2006, the Commission issued Order No. 06-111, granting PGE's motion for a protective order.

On August 22, 2006, PGE, Staff, ICNU, Fred Meyer Stores, City of Portland, Constellation NewEnergy, Inc., EPCOR, and Sempra Global filed a stipulation and supporting testimony regarding direct access issues. The stipulation was approved by Commission Order No. 06-528, on September 14, 2006.

On August 24, 2006, PGE, Staff, ICNU, and CUB filed a settlement and supporting brief regarding the RVM. The settlement was approved by Commission Order No. 06-575, on October 9, 2006, and the attachment was corrected by errata Order No. 06-588, issued October 19, 2006.[1]

Additional stipulations were submitted to be resolved in the final decision on the rate case, and are discussed below.

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[1] On November 9, 2006, PGE submitted its final RVM net variable power costs. *See* UE 180/ UE 181, Updated Monet runs; RVM run, GRC w/o Port Westward, and GRC run with Port Westward (filed Nov 9, 2006). Additionally, on November 15, 2006, PGE filed compliance tariffs increasing PGE's revenues by $74.1 million, or 5.1 percent, on January 1, 2007. *See* Advice No. 06-27.

STIPULATIONS

Revenue Requirement

On August 25, 2006, PGE, Staff, CUB, ICNU, and Fred Meyer Stores submitted a stipulation regarding certain revenue requirement issues. The parties agree to reduce the amount included in rates for taxes, by $0.8 million for payroll taxes, and $1.4 million for Oregon property taxes, to properly reflect the escalation of actual 2005 taxes. No adjustments were made for federal or state income taxes, because they will be automatically adjusted based on the final operating income of this case.

The parties also agree to reduce non-labor administrative and general (A&G) and operations and maintenance (O&M) expenses by $6.551 million, which includes a $34,000 reduction in transmission O&M, $1.6 million in distribution O&M, and $4.9 million in A&G expense.

For incentives, the parties agree to remove 100 percent of officers' incentives and 25 percent of employee incentives based on PGE's 2007 labor costs, resulting in a $5.6 million reduction. The parties further agree to allocate $4.4 million of this reduction to O&M and the remaining $1.3 million to rate base. PGE also accepts Staff's adjustment for wages and salaries, based on the guidelines followed in docket UE 88. The calculation was based on escalated actual 2004 labor costs, applying a 10 percent band, and splitting the difference 50-50 with the Company, resulting in a reduction to test year O&M of $3.5 million and a reduction in rate base of $1.0 million.

The parties also agree to a compromise on PGE's historical capital expenditures, reducing rate base by $7 million, and a reducing O&M by $82,000 for memberships. In addition, the parties agree that there should be no adjustments for system losses or tenant improvements. Further, Staff, CUB, and PGE negotiated a $1.6 million reduction to O&M for advertising and customer service costs.

Finally, the parties agree to remove $69,000 in costs related to low-income weatherization programs, because other organizations have similar programs. The stipulation preserved the ability of PGE and other parties to later argue that the Commission should continue to include PGE's weatherization program in rates which CUB also supports.

Resolution

We note that the parties did not make any additional arguments related to the weatherization program; therefore we rely on the terms of the stipulation agreed to by all parties. We have reviewed the Revenue Requirement Stipulation and find the proposed adjustments contained therein to be reasonable. Accordingly, the Stipulation, set forth in Appendix A, attached hereto, is adopted.

In addition to the stipulated adjustments, PGE accepted Staff's revenue requirement adjustments related to ratemaking treatment of the Beaver 8 generation plant, per Order No. 04-740, and the UM 1233 depreciation stipulation adopted by Order No. 06-581. *See* PGE/1900, Tinker-Schue-Drennan/47, 59; PGE/3109/24-25. PGE also filed an adjustment to reflect the net variable power costs associated with the final Monet model run for 2007. This adjustment modified test period revenues to be consistent with the load forecast used in the final Monet model run. *See* PGE/3109/25, adjustments to PGE-5 and PGE-PW-3, and November 9, 2006, Update Monet Runs for PGE's 2007 RVM and GRC.[2] *We* adopt these adjustments, as well.

Rate Spread and Rate Design

On October 4, 2006, PGE, Staff, CUB, ICNU, and Fred Meyer Stores submitted a stipulation and supporting brief regarding rate spread and rate design. The agreement contains six parts, described below.

First, the Company will design an inverted blocked rate for residential customers. The first 250 kWh used by a customer will fall in the first pricing block, and any additional power will be accounted for by the second pricing block. There will be price differential of at least 1.75 cents per kWh between the first and second pricing blocks.

Second, because there are no Schedule 83 and 583 single-phase primary voltage customers, nor any Schedule 32 primary delivery service customers, the Schedule 83 primary service Facility Capacity Charge tariff will be revised to reflect only three-phase service. This change reduces the Facility Capacity Charge for primary service to $0.13 per kW-month and increases the Schedule 83 secondary service charge by $0.01 per kW-month. Further, the primary delivery service Demand Charge will use a single flat rate, but the secondary delivery service Demand Charge will use a blocked design, in order to provide a smooth transition for Schedule 32 customers.

Third, in light of a concern that PGE's initial proposal impacted customers receiving primary voltage delivery service significantly more than those receiving secondary voltage delivery service, PGE agrees to modify its rate design between those two classes of customers. This results in slightly higher rates for secondary voltage delivery service customers, an estimated 0.03 mills/kWh charge, to mitigate the impact on primary voltage delivery service customers.

Fourth, if a customer's maximum demand occurs during an off-peak time, it will have no impact on the costs of sizing the transmission system; therefore, PGE agrees to implement anon-peak demand transmission charge for Schedule 83 when the appropriate metering, which can supply interval data, is installed. When implemented, the resulting on-demand charge will likely be slightly higher than the otherwise applicable non-time differentiated Schedule 83 transmission demand charge.

[2] PGE also accepted Staff's proposed coal loss adjustment. (*See* PGE/1900, Tinker-Schue-Drennan/47). But, because PGE's final Monet model run excluded the company's coal loss factor, coal loss expense is not reflected in the net variable power costs and no additional adjustment is required.

Fifth, the stipulating parties agree to several provisions in Schedule 75, which governs Partial Requirements service for large nonresidential customers. A customer's Baseline Demand will be based on that customer's historical loads prior to the installation of generation, and will also include planned sales of power. There is also an option for a customer to reduce loads and avoid reserve charges for those supplemental reserves, if the customer provides a load reduction approved by PGE. Additionally, the parties agree to Special Condition 9, a tiered notice requirement for changes in Baseline Demand: for changes of 5 MW or less, customers must provide a six month notice; for changes greater than 5 MW, customers must provide 13 months notice, with the change effective on January 1st of the applicable year. Special Condition 8 clarifies that Partial Requirements customers will be subject to notice rules for changes in load requirements similar to that of customers that do not have on-site generation serving load. Further, Schedule 75 will only apply to customers with 2 MW of generation or more, increased from the current 1 MW threshold.

Finally, the Customer Impact Offset (CIO) will be limited to a 2.0 times overall average rate increase percentage to all schedules. No CIO credit to mitigate rate impact will exceed 3.5 cents/kWh, and a CIO credit will not be applied to rate schedules with a rate increase of less than five percent. This will move toward charging customers the cost of service while mitigating rate impacts.

Resolution

We have reviewed the Rate Spread and Rate Design Stipulation and find the proposed provisions contained therein to be reasonable. Accordingly, the Stipulation, set forth in Appendix B, attached hereto, is adopted.

Streetlight Service and Critical Account Priority Issues

On November 1, 2006, PGE and the League of Oregon Cities, the City of Portland, and the City of Gresham ("the Cities") submitted a settlement agreement and stipulation and supporting testimony regarding streetlight service and critical account priority issues. Initially, the Cities submitted testimony disputing PGE's proposals regarding designation of critical accounts for restoration priority and direct communications between the Cities' critical service personnel and PGE's Operation Center staff, Schedule 91 maintenance charges for Option A and Option B luminaires, the number of "burn hours" for streetlights, and restrictions on Option C lights that bar a city from performing maintenance if the cost is lower than PGE's proposed charges, and to switch from Option B to Option C if that choice is cost-effective for that city. *See* COP/COG/LOC/200; COP/COG/LOC/250.

In the settlement, the parties agree to identify critical accounts, facilities, and consumers for purposes of prioritizing service restoration and related protocols in PGE's current Rule C. The Cities will provide PGE with a list of accounts deemed critical to public welfare and safety, along with the names and 24-hour contact information for personnel assigned to each account. PGE will, in turn, provide the name and 24-hour contact information of its employees responsible for coordinating restoration to those accounts.

The parties also compromised on a test period lighting maintenance amount of $2.646 million for rate spread purposes, and a final level of 4,100 operating hours for streetlights.

Finally, the parties agree to certain provisions regarding Option B and Option C lights. Option B lights are owned by the customer for which PGE performs maintenance; Option C lights are owned and maintained by the customer. PGE will identify problematic Option C lighting installations and work with the applicable public agency on an individual basis to reduce energy diversion. The parties agree to work together to develop and submit tariff provisions that allow each municipality to convert existing Option B lights to Option C lights, and use qualified personnel to maintain the Option C lights attached to PGE poles, subject to the conditions contained in the stipulation.

Resolution

We have reviewed the Streetlight Service and Critical Account Priority Issues Stipulation and find the proposed provisions contained therein to be reasonable. Accordingly, the Stipulation, set forth in Appendix C, attached hereto, is adopted.

Economic Replacement Power Tariff (Schedule 76R)

On November 9, 2006, PGE, Staff, and ICNU filed a stipulation and supporting brief regarding the Economic Replacement Power (ERP) tariff. In PGE's opening filing for this case, the Company proposed a tariff that included Schedule 76R. ICNU filed testimony asserting that the current Schedule 76R structure, which uses a real-time price, makes it difficult for a Partial Requirements customer to determine whether buying economic replacement power is an economic option. The hourly index price is a real-time price that is not known until after the fact. Since Schedule 76R provides a pass-through of market prices, PGE should offer more options consistent with what is available in the marketplace. ICNU asserts that providing more options will not adversely impact PGE or its customers, since PGE will recover its costs. *See generally* ICNU/206. Staff generally supports ICNU's testimony, referring to similar options available under PacifiCorp's tariffs. *See generally* Staff/1700.

The stipulated tariff would implement two new options for ERP service and further defines the terms of ERP service. The tariff contains four items:

First, the revised tariff allows continuation, with certain modifications, of hourly or short-notice economic replacement power – a Partial Requirements customer must provide 90 minutes notice that the customer will use one or more hours of short-notice economic replacement power, priced at the hourly rate of the Dow Jones Mid-

Columbia Hourly Price Index, plus a 5 percent adder and wheeling charges, adjusted for losses.

Second, the parties agree to a new daily ERP option, in which a Partial Requirements customer must notify PGE on the morning of the day before delivery with its energy needs forecast (ENF), including the amount of power, the day(s) of delivery, and the hour(s) of delivery. The price will be based on an energy price quote from PGE, plus a 5 percent adder and wheeling charges, adjusted for losses. PGE and the customer will then communicate as to whether the customer accepts the price, and PGE will accept the ENF.

Third, the new monthly ERP option will be similar to the daily option, but will require the customer to provide its ENF no fewer than seven business days before the last trading day for the upcoming month. The pricing and communications requirements are also similar to those of the new daily option.

Finally, the parties agree to an energy imbalance provision, which applies to the difference between actual energy usage and the ENF for the three options described above. The difference will be credited or charged to the customer at the following rates: for differences up to ±7.5 percent of the hourly ENF, it will be the amount of the Dow Jones Mid-Columbia Hourly Price Index, plus wheeling charges, adjusted for losses; for differences exceeding ±7.5 percent of the hourly ENF, the customer will either be charged (or credited) the Dow Jones Mid-Columbia Hourly Price Index plus (or minus) 10 percent adder and wheeling charges, adjusted for losses. Actual energy usage will be determined as the amount of energy above the customer's Schedule 75 Baseline Energy, during the times when Economic Replacement Power is being delivered.

The parties agree that the stipulation and revised Economic Replacement Power Schedule 76R tariff are in the public interest and will produce rates that are fair and reasonable.

Resolution

We have reviewed the Economic Replacement Power Schedule 76R Stipulation and find the proposed tariff to be reasonable. Accordingly, the Stipulation, set forth in Appendix D, attached hereto, is adopted.

CONTESTED ISSUES

The remaining contested issues in this case are divided into several categories: adjustments to PGE's forecast of power costs for the test year; the power cost recovery framework; PGE's cost of capital, including capital structure, cost of debt, and cost of equity issues; the treatment of Port Westward, scheduled to go into service in March 2007; tax issues raised by the City of Portland; and finally, Trojan decommissioning issues raised by EWEB. We review these subjects below.

POWER COST MODEL ADJUSTMENTS

The parties dispute several factors in PGE's MONET model, which is used to estimate net variable power costs (NVPC). First, we analyze the extrinsic value of PGE's plants and power purchase contracts. Second, we consider the need for stochastic modeling to predict power costs. Next, we review ICNU's arguments regarding whether to include the capacity tolling contracts and their extrinsic value in the model. Then, we discuss the method for calculating the forced outage rate for PGE's plants. Finally, we evaluate the sale of ancillary services.

Extrinsic Value

PGE uses specific forecasts of market prices for natural gas and electricity in its MONET model to estimate power costs. The parties disagree about whether to adjust the power cost estimate for the "extrinsic value" of certain generating plants and power purchase contracts. The extrinsic value of a resource is the value associated with the ability to adjust its operation in response to market conditions that are different from those forecast. For example, when the difference between the market price of power and the cost of running a generator is higher than expected, PGE may be able to make more sales in the wholesale market and reduce its net power costs. If the difference between wholesale electricity prices and operating costs is lower than expected, PGE may be able to save money by buying power instead of running its generator. This operational flexibility has value and can be used to reduce net power costs when market prices are volatile, even if they are no higher, on average, than the forecasts used in the MONET model.

Parties' Arguments

Staff asserts that PGE has two power plants and three purchase power contracts with unused capacity in the 2007 test year for which PGE should consider extrinsic value: the Beaver and Coyote Springs plants, which have 85 and 39 percent unused capacity, respectively, and the Cold Snap, Super Peak, and Morgan Stanley tolling contracts, which have 100 percent, 100 percent, and 12 percent unused capacity respectively. *See* Staff/200, Wordley/11. Staff seeks an adjustment for an estimate of that extrinsic value, which Staff calculated by applying alternative bids to PGE's 2004 RFP for resource capacity. *See* Staff opening brief, 6-7.

PGE opposes any adjustment to its MONET model for extrinsic value. The Company argues that such an adjustment would "cherry-pick" one aspect of uncertain power cost forecasts, simply to justify a reduction in forecast NVPC. *See* PGE opening brief, 44. PGE introduced evidence showing that baseline NVPC forecasts are often underestimated, and that a more complete assessment, which captured the uncertainty of power cost forecasts, would increase net variable power costs. *See id.* at 45. PGE argues that its report by PA Consulting Group (PA report) shows that stochastic power cost modeling would increase the NVPC forecast, which underestimates the cost of net variable power, on average, by $10 million. *See id.* Staff acknowledges that NVPC forecasts are more likely to underestimate NVPC than overestimate it, and that stochastic modeling would increase NVPC forecasts. *See* Staff/1500, Galbraith/4.

Even if the Commission were to adjust for extrinsic value, PGE argues that Staff's estimate, using the extreme Super Peak contract and extrapolating it to routinely used generating plants, is flawed. *See* PGE opening brief, 46. PGE views ICNU's models as flawed, as well. *See id.* Additionally, PGE argues that its September 29, 2006, MONET update credited customers more than they would have received under ICNU's proposal. *See id.*

Staff responds that, because PGE concedes that there is extrinsic value to these assets that the MONET model fails to capture, the Company should propose a more accurate estimate rather than simply attack Staff's adjustment as imperfect. *See* Staff opening brief, 8. Further, Staff contends that PGE should use its own estimate of extrinsic value that it uses for long-term resource planning. *See id.* at 10. Until PGE develops and implements stochastic power cost modeling, Staff recommends that the Commission adjust the NVPC estimates for the extrinsic value of PGE's resources to ensure that customers receive the benefits from the Company's flexible power resources for which they are already paying in rates. *See id.*

CUB supports Staff's criticism of PGE's MONET model for failing to recognize the extrinsic value of capacity resources. *See* CUB/100, Jenks-Brown/10. CUB asserts that customers who pay the fixed costs of generation plants and capacity contracts should also receive the benefit of sales of excess power from these sources. *See id.* CUB argues that the value of the these resources is not captured by the MONET model, and, in response, proposes two possible adjustments: the Commission could impute revenue to account for the additional revenue that the plants and capacity contracts can be expected to produce, or the Commission could reduce the share of fixed costs charged to ratepayers in order to represent the share of fixed costs associated with normalized usage. *See id.* at Jenks-Brown/12.

ICNU proposes using stochastic modeling to account for extrinsic value of PGE's gas-fired plants. *See* ICNU opening brief, 25. PGE says that it does not have the capacity to perform such modeling, so ICNU proposes a $5.9 million adjustment to account for extrinsic value based on using historical spreads and calculating the probability of cost-savings from each particular gas-fired resource. *See id.* at 25-26. In its arguments, ICNU contends that the Commission should reject PGE's arguments against using stochastic power cost modeling, arguing that the PA report varies significantly from the MONET results, and so cannot be relied upon. *See id.* at 26. ICNU argues that PGE's inputs biased the study results which showed MONET forecasts usually underestimate NVPC, and therefore, ICNU claims that the results of the study are not valid. *See id.* at 26-28.

Resolution

We believe that there is inherent extrinsic value to capacity resources that are not counted in the MONET model runs. However, we are also persuaded by the record that the current MONET model underestimates NVPC. Any consideration of the extrinsic value must take into account the inherent bias in the MONET model, and to only consider one factor would not be reasonable. Therefore, we make no adjustments for the extrinsic value of PGE's generating plants and power purchase contracts, except as discussed below for the Super Peak contract.

Stochastic Modeling

Staff recommends PGE use stochastic modeling in the future to model the optionality of its resources, would eliminate the need for future extrinsic value adjustments. *See* Staff opening brief, 7. PGE opposes this recommendation. We concur with Staff that stochastic modeling has potential benefits, in terms of improved power cost forecasting. Therefore, we urge PGE to develop stochastic modeling to develop its NVPC forecast. PGE should submit a report on the feasibility of using stochastic modeling in the Annual Update by September 1, 2007.

Capacity Tolling Contracts

Parties' Arguments

PGE asserts that the Super Peak and Cold Snap contracts should be included in its test year power costs. *See* PGE opening brief, 47. PGE's 2002 Integrated Resource Plan (IRP) Final Action Plan calls for PGE to acquire 400 MW of tolling capability for peak purposes, and the Super Peak and Cold Snap contracts meet that need. *See id.* (citing Order No. 04-375, 4). The contracts are not intended to dispatch frequently, but are necessary for extreme circumstances to maintain the reliable delivery of power to customers. *See id.*

ICNU argues that these contracts should not be included in estimating power costs because PGE's MONET model indicates that the contracts will not be used in 2007, nor have they been used in past years when they were in rates. *See* ICNU opening brief, 28. Because "'only expenditures necessary for furnishing utility service should be reflected in rates,'" the Cold Snap contract and the Super Peak contract should be removed from rates. *See* ICNU opening brief, 28 (quoting UT 125, Order No. 97-171, 74). If the Commission includes these contracts in rates, ICNU argues that the Commission should include the extrinsic value of the contracts. The proposed adjustment for the extrinsic value of the Super Peak contract is approximately $1.4 million. *See* ICNU/103, Falkenberg/3. PGE did not estimate the extrinsic value of the Cold Snap contract, so ICNU proposes removing it from rates entirely, resulting in an adjustment of approximately $1.75 million. *See id.*

Resolution

We agree that the costs of the contracts should be included in PGE's test year power costs. The contracts assure supply for peak loads and emergency events, and therefore provide service to customers. For this reason, we include both contracts in rates. However, even though we reject an overall extrinsic value adjustment for PGE's resources, we believe the extrinsic value of these two contracts should be recognized in test year power costs. The Super Peak and Cold Snap contracts can be distinguished from the Company's other resources because they do not dispatch at all in the MONET run used to estimate test year power costs. Without an extrinsic value adjustment, customer rates would include all of the costs, and none of the benefits of the contracts. The record contains evidence on the extrinsic value of the Super Peak contract, but not the Cold Snap contract. Therefore, we accept ICNU's alternative proposal to include the extrinsic value of the Super Peak contract in rates, and adjust PGE's proposed test year power costs by $1.4 million.

Method for Calculating the Forced Outage Rate

To determine test period power costs for ratemaking, the Commission uses a "forced outage rate" to determine normalized generating unit availability. *See* Staff opening brief, 3. A forced outage is an unplanned failure of a generating unit, and is calculated as a proportion of forced outage hours to total hours a unit is capable of providing service on an annual basis. *See id.* Since 1984, the Commission has generally used a four-year rolling average of actual unit forced outage rates to determine a unit's normal forced outage rate. *See id.* at 4. The policy arose from a Staff recommendation which argued that the four-year rolling average "is sufficient to average out variations and yet not include generally irrelevant experience from history long past." *See* PGE opening brief, 42 (citing Staff/102, Galbraith/1-21).

Parties' Arguments

PGE argues that the Commission should adhere to its past practice of 20 years of using a four-year rolling average of forced outages to calculate a test year forced outage rate assumption. *See* PGE opening brief, 41. PGE contends that the original policy remains valid, and that continued use of the four-year rolling average is consistent with Staff's position in previous dockets and the Commission's decision in docket UE 179. *See id.* at 41-42. PGE argues that the customary practice is not flawed, and parties are reacting to extreme outage events at the Boardman plant (Boardman). *See id.* at 43. In lieu of the new method proposed by Staff and intervenors, PGE recommends using similar adjustments for the Boardman and Colstrip (Colstrip) plants as those proposed by Staff for the unusual outage at the Hunter 1 facility in past PacifiCorp rate cases. *See id.* In addition, Staff proposed an adjustment for the Boardman outage in its initial testimony. *See id.* Moreover, PGE asserts that ICNU and Staff did not object to the traditional treatment of the outages during recent RVM proceedings. *See id.* at 44. PGE argues that if the Commission were to change its policy from the four-year rolling average to generic data, it should do so in a generic docket. *See id.*

Staff recommends that PGE discontinue use of actual outage rates for its Boardman and Colstrip plants because that approach would give too much weight to recent extreme events, resulting in unrealistic forced outage rates. Instead, Staff advocates use of industry-wide averages from the North American Electric Reliability Council (NERC). *See* Staff opening brief, 4. Staff asserts that the new method should only apply to Boardman and Colstrip because no other plants had extreme outage events between 2002 and 2005. *See id.* Staff would consider using a standard peer group, as an adjustment to NERC's benchmarking services, and believes even this adjustment to its initial proposal is better than using the current system. *See id.*

Staff disputes PGE's claims that the four-year rolling averages remain useful because the prolonged forced outages are offset by shorter planned outages. Staff explains that planned outages are less expensive to the Company because it can plan for replacement power, while the Company has less flexibility in obtaining replacement power for forced outages, and so that power will likely be more expensive. *See* Staff/1500, Galbraith/18. Staff also counters PGE's assertions that NERC has indicated a standard peer group may not suit all types of units, arguing that NERC offers benchmarking services which would result in a peer group that would serve as a reasonable proxy for normalized outages of Boardman and Colstrip. *See id.* at Galbraith/19.

CUB rejects PGE's attempt to put the extraordinary 2005-06 Boardman outage in the four-year rolling average. CUB asserts that the outage would be better reviewed in the deferred accounting docket, currently under Commission consideration in docket UM 1234. *See* CUB/100, Jenks-Brown/3-7. CUB argues that such an extraordinary event should be "normalized out" when forecasting a future test year. *See* id. at Jenks-Brown/1-2. CUB supports Staff's approach of using NERC data to establish forced outage rates, because it would use "independently-produced, verifiable data for modeling inputs [which] increases transparency, while reducing controversy and regulatory burden." CUB/300, Jenks-Brown/44.

ICNU also argues that allowing PGE to use the four-year rolling average of historical forced outage rates overstates PGE's NVPC. *See* ICNU opening brief, 31. ICNU argues that the four-year average is not the best method because it provides a disincentive to improve plant reliability and may include unusual outages. *See id.* at 31-32. ICNU proposes that the Commission use NERC average outage rates for plants that are comparable to PGE's plants, and further recommends that the Commission use the NERC Equivalent Availability Factor to implement stochastic modeling for PGE's plant outage rates. *See id.* at 32. ICNU asserts that this will provide an objective and verifiable means of estimating power costs without delving into the prudence of PGE's resource management, and remove the disincentive to fail to maintain plants. *See id.* at 33. At a minimum, ICNU recommends that the Commission not allow PGE to include the 2005 Boardman outage when calculating outage rates. *See id.*

Resolution

In determining a method for establishing the forced outage rate, we seek the most accurate forecast of forced outages at the relevant plants. We continue to believe that past performance is the best predictor of a plant's outage rate. For this reason, we adhere to our long-standing practice of using actual plant outage rates to predict the future activity of that plant. In this case, we use the four-year rolling average for the Coyote Springs, Colstrip, and Beaver plants.

However, we recognize the extreme outage at Boardman in 2005. To account for that anomaly, we adjust the traditional four-year average calculation of Boardman's "normal" forced outage rate by removing the hours in the November 18, 2005, through December 31, 2005, deferral period from the forced outage hours and the period hours used in the traditional calculation. *See* Staff/100, Galbraith/7. This is similar to the adjustment we made in PacifiCorp rate cases for the extreme outages the Hunter facilities. *See id.* at Galbraith/7-8. In this case, inputting the adjusted rate into PGE's MONET model results in a nearly $4.6 million reduction to net variable power costs. *See id.* at Galbraith/7.

While we decide that this is the best decision for this case, we appreciate the concerns of the parties that the four-year rolling average may not always be the most accurate forecast of future outages. For this reason, we will open a new generic docket to examine this issue.

Ancillary Services

Ancillary services are defined as those services necessary to support the transmission of capacity and energy from the resources to the loads while maintaining reliable operation of the provider's transmission system in accordance with good utility practice.

Parties' Arguments

PGE argues that its test year NVPC forecast should not be reduced for revenues from the sale of ancillary services. *See* PGE opening brief, 47. PGE argues that an accurate adjustment is difficult to determine because it has not sold ancillary services for a very long period of time, and the value of its sales has varied widely. *See id.* Further, if an adjustment is made, PGE argues that the amount should be net of grid management charges imposed by the California Independent System Operator (ISO). *See id.* PGE estimates that the California ISO charges totaled approximately $100,000 for the time period considered as the basis for the adjustment. *See* PGE/2600, Tinker-Schue-Drennan/16. Staff based its proposed adjustment on a twelve-month period sales figure, without consideration of California ISO charges. *See* PGE opening brief, 48. PGE argues that any consideration of ancillary service sales can, and should be, accounted for in the Annual Variance tariff proposed by PGE in this case. *See id.* In the absence of such a mechanism, PGE asserts that there is an insufficient basis on which to make this adjustment. *See id.*

Staff recommends including both revenues and costs for ancillary service sales revenues in the 2007 test year revenue requirement. *See* Staff opening brief, 5. This would result in an adjustment of approximately $1.53 million. *See* Staff/1600, Wordley/1. In response to PGE's argument that ancillary services sales should be considered only in the power cost adjustment mechanism, Staff asserts that PGE has not shown that Staff incorrectly estimated revenues. *See* Staff opening brief, 6. Moreover, Staff contends that Commission consideration of this mismatch should not be delayed by putting off resolution to another tariff. *See id.*

Resolution

We are persuaded to adopt Staff's proposal to include revenues for ancillary services. Further, we adjust Staff's estimate of revenues for the California ISO charges cited by PGE. This results in an adjustment of approximately $1.43 million. This adjustment is made to Other Revenues in revenue requirement. Furthermore, in light of PGE's argument that its ancillary service revenues are difficult to forecast, the difference in revenues should also be incorporated in calculation of the annual PCAM, adopted below.

POWER COST RECOVERY MECHANISMS

PGE defines cost-of-service risk as the variance between cost-of-service rates and the actual cost of service. *See* PGE opening brief, 31. PGE urges the Commission to minimize cost-of-service risk by providing for an even allocation of risk in power cost forecasts and minimizing the variance of prices from costs. *See id.* To meet these goals, PGE proposes an Annual Update, a forecasting mechanism similar to the RVM, which would evenly allocate cost-of-service risk on a prospective basis, and an Annual Variance tariff, which would reconcile actual and projected NVPC and allocate 90 percent of the difference to ratepayers. *See id.* PGE asserts that using the MONET model with these two tariff mechanisms would align the cost-of-service prices more closely with the prudently incurred cost of providing electric service. *See id.* at 32. In addition, PGE argues that any adjustment mechanism should also take into account the effects of Senate Bill 408 (SB 408).[3]

Staff characterizes Commission policy regarding power cost adjustment mechanisms (PCAMs) as evolving over time, and contends that PGE's proposed framework disregards the Commission's statements regarding recovery of power costs. *See* Staff opening brief, 10-12. For instance, in dockets UE 165/ UM 1187, the

[3] Senate Bill 408 (SB 408) was passed by the 2005 Legislative Assembly and is generally codified at ORS 757.268. It requires certain public utilities, including PGE, to file annual tax reports and other information with the Commission. If the amounts collected for taxes differ from the amounts paid by more than $100,000 for any utility, SB 408 requires this Commission to direct the public utility to implement a rate schedule with an automatic adjustment clause to account for the difference.

Commission rejected a proposed stipulation but, in so doing, articulated specific criteria for a hydro-related PCAM that PGE ignores here. *See* Order No. 05-1261. Staff recommends that the Commission adhere to its past statements and reject PGE's proposals. *See* Staff opening brief, 12. Further, Staff recommends rejection of a forecast mechanism and proposes its own PCAM.

CUB also argues for rejection of PGE's proposed power cost recovery framework. It claims that a forecasting mechanism is inaccurate, and if a properly designed PCAM were in place, needlessly redundant. *See* CUB opening brief, 7-9. CUB also urges the Commission to reject a forecast mechanism and adopt CUB's proposed PCAM. ICNU opposes use of any PCAM, as well as an RVM. However, if the Commission must adopt a PCAM, ICNU recommends the proposal set forth by CUB.

Annual Update

Currently, PGE employs an RVM, which was adopted as part of a power cost stipulation in PGE's last general rate case, docket UE 115. *See* Order No. 01-777, 18-20. The RVM effectively updates the forecast of power costs that is included in customer rates. PGE submits model runs for these prices by November 15 each year, for the following calendar year. In this case, PGE has proposed an Annual Update to replace the current RVM.

Parties' Arguments

PGE is proposing tariff Schedule 125, which is similar to the current RVM, but more narrowly designed. *See* PGE opening brief, 32. The Annual Update tariff would change rates each year on January 1 to reflect updated NVPC. The updated power costs would be obtained through the results from the MONET model with fewer input updates than are now conducted in the RVM. *See id.* (list of inputs is located at PGE/400, Lesh-Niman/25). PGE believes that its Annual Update proposal will resolve many of the disputes that have developed over the RVM process, and argues that a forecast mechanism is critical to ensure that PGE is able to charge for the costs actually incurred to provide service. *See* PGE opening brief, 32-33. PGE asserts that NVPC forecasts and actual prices paid have been very volatile over the last several years, and that, without an Annual Update, PGE will likely file more frequent rate cases. *See id.* at 33.

Staff recommends that the Commission reject PGE's Annual Update mechanism, because it would be cumbersome and time-consuming. *See* Staff opening brief, 24. Staff asserts that the regulatory burden on parties would outweigh the benefits of the Annual Update. *See id.* Staff further expresses concern that the process would be more expedited than the current RVM, limiting Staff's time to examine PGE's annual filing and pursue discovery. *See id.* Finally, Staff believes that a forecast mechanism is not necessary if the PCAM is properly designed. *See id.*

ICNU opposes the Annual Update, arguing that it is unnecessary, particularly if the Commission adopts a PCAM. *See* ICNU opening brief, 22. ICNU argues that the initial RVM was approved at a time of extremely volatile energy prices, and was intended to capture those variations; by extension, ICNU implies that prices are not as volatile now. *See id.* at 23. ICNU challenges PGE's assertion that an annually updated forecast mechanism is part of PCAMs around the country, citing the report PGE commissioned by the National Economic Research Associates (NERA report). *See id.* (citing PGE/2400, Lesh/2; PGE/400, Lesh-Niman/12). ICNU argues that the NERA report does not, in fact, address an annual update mechanism such as PGE's proposal. *See* ICNU opening brief, 23. ICNU also points to the Washington PCAMs of Avista Corporation and Puget Sound Energy, which PGE cited in support of its arguments, as lacking the annually updated forecast mechanism requested by PGE. *See id.* at 24.

CUB also opposes PGE's proposed Annual Update, arguing that it is not needed if there is a PCAM. *See* CUB opening brief, 7. CUB argues that an additional forecast mechanism "becomes overkill and time-consuming, if not outright redundant" *Id.* Moreover, implementation of an Annual Update, or RVM, makes frequent rate changes more likely, as opposed to a PCAM with certain deadbands, which would only change rates if earnings were outside a reasonable range. *See id.* CUB also dismisses PGE's argument that a forecast mechanism is needed to maintain an "even allocation" of risk. *See* CUB reply brief, 7. CUB asserts that risk should be fairly allocated, but the utility ultimately bears the responsibility to manage its risk. *See id.* Considering these factors, CUB urges the Commission to reject an annual net variable power cost forecast mechanism, currently structured as an RVM, and proposed by PGE as an Annual Update.

Resolution

We adopt the Annual Update proposed by PGE with the exceptions in the filing and review process noted below. We believe it is important to update the forecast of power costs included in rates to account for new information, *e.g.*, on expected market prices for electricity and natural gas, and for new PGE purchase power contracts.

The main objection raised by the parties is that a PCAM would render the Annual Update moot. We disagree. The mechanisms serve different purposes. The Annual Update revises the forecast of power costs, while all the PCAMs proposed in this case address the difference between forecast and actual power costs. The Annual Update resets the base power cost estimate around which a PCAM would operate. As discussed below, we adopt a PCAM with a deadband designed so that PGE will bear normal business risk associated with actual power costs varying from forecast. If the forecast is not updated each year, then PGE will be exposed to more than normal business risk: through application of the deadband, it will bear the net effect of both expected changes in power costs (up or down) and unpredictable variations in power costs throughout the year.

We accept PGE's move to limit the number of model enhancements. Model changes or updates could be considered, not in the Annual Update process, but in a separate docket. We share CUB's and Staff's concerns about not having enough time to review the filings each year. Therefore, we apply the current timeline for the RVM to the Annual Update: PGE should make its initial filing on April 1, and the remainder of the schedule will be set a subsequent prehearing conference. It is too soon to say whether a full schedule would be needed, but to allow for concerns that PGE's Annual Update schedule is too abbreviated, we require PGE to submit its initial Annual Update filing on April 1 to forecast costs for the following calendar year.

Annual Variance Tariff (PCAM)

PGE

PGE's proposed Annual Variance tariff is designed to change cost-of-service prices for a portion of the difference between actual NVPC and forecasted NVPC set in the Annual Update. The Annual Variance tariff will share the difference between the forecasted and actual NVPC costs, 90 percent allocated to customers and 10 percent allocated to PGE. *See* PGE opening brief, 31. PGE argues that pairing the Annual Variance tariff with an Annual Update will ensure that cost-of-service rates accurately reflect the costs of service. *See id.* at 32.

PGE describes its Annual Variance tariff, Schedule 126, as a power cost variance mechanism, under which PGE would:

- Track the difference between its forecast NVPC set in the Annual Update and its actual NVPC for that year;
- Eliminate the effects of load changes (increases or decreases) on that difference;
- Absorb 10 percent of the difference and allocate the remaining 90 percent to customers in the form of a per kWh rider under a schedule set by the Commission; and
- Demonstrate each year that earnings in the prior year, with the effects of the power cost mechanisms, do not exceed a reasonable amount, and share half of any earnings above a threshold ROE with customers.

See PGE opening brief, 34.

Notably, PGE's proposed Annual Variance tariff has no deadband within which PGE would absorb an initial difference in costs, and PGE argues vigorously against any imposition of a deadband. *See* PGE opening brief, 35-41. Staff and CUB argue strongly for a deadband, each with its own proposal. *See* Staff opening brief, 17-

23; CUB opening brief, 7-9. PGE presents eight arguments in opposition. First, PGE argues that a deadband would increase the cost-of-service risk to PGE and its customers, asserting that PGE has little control over variable power costs, and that customers would be at risk for power cost estimates that would be too high. *See* PGE opening brief, 35. Staff counters that a deadband does not increase cost-of-service risk, because any PCAM reduces cost of risk more than a regulatory structure without a PCAM. *See* Staff opening brief, 17. Staff views it from the other direction: a PCAM with a deadband merely reduces cost-of-service risk less than a PCAM without a deadband. *See id.* Staff asserts that the comparator for a PCAM for PGE should be a regulatory framework without a PCAM. *See id.*

Second, PGE argues that a deadband in a PCAM would depart significantly from this Commission's prior policies. *See* PGE opening brief, 36. PGE points to the PCAM in effect from 1979 through 1987 with no deadband or earnings test, and an 80/20 sharing ratio with customers. *See id.* Also, the Commission approved a mechanism in docket UM 445 so that PGE only absorbed 10 percent of the increased NVPC after the closure of Trojan. *See id.* PGE further compares its PCAM to that used by gas distribution companies, arguing that PGE's NVPC, which is 50 percent of its revenue requirement, is very similar to the gas costs of Oregon's local gas distribution companies, such as NW Natural, where purchased gas costs represented 57 percent of its overall revenue requirement. *See id.* PGE asserts that if a deadband must be applied, it should be applied only to power cost variations and not to the earnings test. *See id.* Staff argues that historic practice regarding PCAMs is not persuasive, and that PGE should instead look to recent orders by the Commission. *See* Staff opening brief, 17. CUB expresses concern that PGE's proposal would require customers to pick up 90 percent of *any* variation of costs. *See* CUB/300, Jenks-Brown/2-3. PGE's update mechanisms strongly resemble the gas utilities' purchased gas adjustment mechanisms, but CUB argues that there are important differences between PGE and a gas utility. A gas utility's rate base consists primarily of pipes, while an electric utility's rate base includes not just its distribution plant, but also expensive generating plants; gas utilities must take the price offered on the gas market, while electric utilities have more ability to "optimize resource decisions." CUB/ 200, Jenks-Brown/10-11. For this reason, CUB asserts that PGE is not entitled to the same kind of power cost adjustment mechanism as a gas distribution company. *See* CUB opening brief, 10.

Third, PGE argues that other states rarely require deadband or sharing mechanisms. Pointing to the NERA report, PGE asserts that it is a common regulatory practice to allow recovery of 100 percent of the differences between forecasted and actual NVPC. *See* PGE opening brief, 37. Any significant variation from these usual practices would result in Oregon being seen as a negative regulatory environment, leading to a possible downgrade in PGE's credit ratings. *See id.* Staff asserts the Commission typically does not rely on the practice of other state commissions. *See* Staff opening brief, 18. Moreover, Staff is unpersuaded by PGE's arguments regarding the view of credit rating agencies regarding the regulatory environment, in light of PGE's role in reviewing and editing the most recent Standard & Poor's (S&P) report. *See* Staff opening brief, 18-21 (citing ICNU/412).

Fourth, PGE asserts that ratepayers only pay for the low embedded, fixed costs of PGE's resources in base rates, and so should also be responsible for the higher cost of NVPC in adjustments. *See* PGE opening brief, 37. Moreover, PGE argues that by shielding ratepayers from the true cost of service, customers cannot make wise decisions about consumption. *See id.* Staff takes the broader view of the Company's costs as considered in a rate case, and argues that the Commission determines the full fixed costs, as well as the full variable costs, through consideration of normalized NVPC, in a general rate case. *See* Staff opening brief, 21. Therefore, Staff argues that ratepayers already shoulder the full amount of the cost of service, and a PCAM with a deadband would not shield customers from paying the full cost of the Company's resources. *See id.*

Fifth, PGE asserts that a deadband policy that focuses on the authorized return on common equity does not properly consider the amount that each utility has invested in generating resources, as opposed to its total investment. *See* PGE opening brief, 37-38. Staff argues that the PCAM set in this case will only apply to PGE, so the arguments made by PGE that a deadband on total investment is too generic are unpersuasive. *See* Staff opening brief, 21. The deadband in this case, which would exclude a reasonable range of normal variations in power costs from triggering the PCAM, would be particular to PGE, and so should apply to total investment. *See id.*

Sixth, PGE argues that power costs are such a large proportion of its costs, that any large variation could not be offset by cutbacks in its non-power costs. *See* PGE opening brief, 38. PGE does not have a sufficient cushion to offset negative variations in power costs, especially in the case of several consecutive years of drought. *See id.* Staff asserts that PGE is exaggerating the impact of a deadband, because large variations in power costs would be passed on to customers through a sharing mechanism after a certain threshold has been reached. *See* Staff opening brief, 22. Further, Staff contends that the utility need not be able to offset costs; instead, "the appropriate consideration is the ability of the utility to absorb costs between rate cases." *Id.*

Seventh, PGE contends that a mechanism with a deadband would not be sustainable. *See* PGE opening brief, 38. Particularly in a string of bad years, the utility could take repeated hits to its earnings that could not be endured. *See id.* Staff counters that this argument is speculative and should be given no weight. *See* Staff opening brief, 22.

Finally, PGE argues that the "unusual event" standard proposed by Staff does not have a sound factual basis. *See* PGE opening brief, 38-39. PGE argues that it is difficult to define what is "unusual," especially where there is no basis to conclude that the past is indicative of future power costs. *See id.* Staff responds that its reliance on professional judgment as to what constitutes an "unusual event" is based on the Commission's order in docket UM 995, among others. *See* Staff opening brief, 22.

PGE contends that if the Commission determines that a deadband is necessary, it should consider certain factors. *See* PGE opening brief, 39. The Commission should consider the size of PGE's generation rate base in determining the amount of the deadband. *See id*. Moreover, the NVPC variance deadband should be limited to a portion of the risk premium associated with generation investment, and not the more arbitrary designation of basis points above or below ROE. *See id.* at 39-40. PGE proposes a deadband of 50 percent of the risk premium in basis points, if the Commission must apply a deadband, combined with 90/10 sharing of costs beyond the deadband. *See* PGE opening brief, 40. PGE also requests that the Commission consider the impact of the SB 408 "double whammy" in calculating PGE's cost-of-service risk.[4] *See id.* at 40-41. If the Commission does impose a deadband, it should be based on the utility's investment in generating resources. *See* PGE opening brief, 37-38. Staff and CUB urge the Commission to reject PGE's proposal for a deadband in its sursurrebuttal testimony as untimely, arguing that Staff and intervenors had no time to analyze or make arguments about the last-minute proposal. *See* Staff opening brief, 23; CUB opening brief, 15.

Staff

Staff asserts that the Annual Variance tariff is inconsistent with Commission policy as set forth in docket UE 165, particularly the order's limitation of the use of a PCAM to "unusual events." *See* Staff opening brief, 14. Staff argues that PGE is trying to redefine the risk of variations in power costs as a "cost-of-service" risk, in which the price of retail electricity service will not reflect the actual cost of service. *See id*. Staff counters that PCAMs are designed to resolve the risk of extreme, or at least unusual, variations in NVPC. *See id.* Staff claims that PCAMs shift the risk of power cost variations from shareholders to ratepayers, and reduce PGE's incentive to efficiently manage its operation. *See id.* at 14-15.

Intervenors

In its opening brief, at pages 4 and 5, CUB sets out its own principles to analyze any PCAM:

- The PCAM should properly allocate risk. Because a utility is paid a rate of return to manage and absorb normal business risk, it is the utility's responsibility to manage a reasonable amount of cost variation. If costs reach a "substantial level," customers may share in those costs. *See id.* at 5.

[4] In AR 499, Order No. 06-532, 10, we described the "double whammy" problem, as one that "arises because taxes vary with a utility's earnings. When lower than expected earnings reduce the amount of taxes that will be paid, provision of service is more expensive than was predicted in the rate case, and consumers pay less than the utility's actual costs. At the same time, customers will receive a SB 408 refund because income taxes are less than expected. Utilities argue that this result is unreasonable because it exacerbates their under-recovery and customers do not bear the higher cost of service. Conversely, when a utility's earnings are higher than expected as a result of higher revenues or lower costs, income taxes will also rise, and SB 408 requires a surcharge on ratepayers to compensate for those higher taxes. This would result in further increases in the utility's earnings."

- An ongoing PCAM should promote fairness and be revenue neutral. The Commission should also examine the utility's return on equity and revenue neutrality to ensure fairness in allocation of power costs.

- The PCAM should reduce rate volatility, which can make it difficult for customers to plan their budgets.
- Regulation should provide incentives for a utility to manage power costs effectively and react in changing circumstances.

- A PCAM structure should minimize the regulatory burden on participants, including the number of filings and amount of litigation involved in each adjustment. Expectations of risk and reward should be established to reduce the contention in each annual PCAM adjustment.

In applying these principles to the dockets before the Commission, CUB argues that a PCAM is a better tool for regulating power cost variations than deferrals or the current RVM. *See* CUB opening brief, 6. CUB asserts that an established PCAM will be less contentious and absorb all power cost variations, positive and negative, rather than a deferral which is filed at the discretion of the utility. *See id.* Moreover, a properly designed PCAM with a deadband would smooth out rate variations. *See id.* at 7.

CUB asserts that a properly designed PCAM includes a power cost deadband, sharing bands, and an earnings test. *See id.* at 7. CUB defines a deadband as "defin[ing] the range of power cost variation that is reasonable for a utility to absorb in the normal course of doing business." *Id.* Consequently, a PCAM with a deadband will only be triggered for events outside the normal course of business. *See id.* From CUB's perspective, the cost of equity compensates a utility to manage its risks, including the risk of power cost variation, and any PCAM that removed all risk of cost variation should translate into a lower cost of equity. *See id.* at 7-8. CUB reviewed recent Commission orders, which distinguished between normal, unusual, and exceptional events, and allowed power cost variations outside of the normal range to be shared with customers. *See id.* at 8. CUB uses these distinctions to form the basis of its proposed sharing bands, which would increase the utility's ability to recover the variations in costs as the variations become more extreme. *See id.* at 8-9. Finally, CUB argues that a utility should not be able to recover for power cost changes when its earnings are within a reasonable range. *See id.* at 9.

Regarding PGE's proposed PCAM, CUB argues that it "fails any measure of fairness," because it does not have a deadband, tiered sharing bands, or an earnings test as that term has been used by the Commission. *See* CUB opening brief, 10-11. CUB cites testimony from docket UE 165, PGE's application for deferral of power costs in a year with insufficient hydroelectric power, to show that replacement costs in poor hydro years will outweigh the benefits of additional power in good hydro years, indicating the need for asymmetrical deadbands. *See id*. at 12-13. CUB also attacks PGE's PCAM proposal for its lack of an earnings test, which "would require surcharges even if the Company were over-earning." *Id.* at 13. Finally, CUB notes the likelihood of rate volatility and redundant regulatory proceedings under PGE's power cost recovery framework. *See id.* at 13-14. CUB asserts that the Commission should consider past proceedings such as deferrals, which PGE argues are not on point precedent for this case. *See id.* at 14.

ICNU doubts PGE's claims that a forecast and a look-back mechanism are needed to bolster its credit ratings. *See* ICNU opening brief, 6. ICNU argues that, after reviewing the Commission's historic use of PCAMs, such mechanisms are not used on a long-term comprehensive basis, but only for limited periods when there are unusual circumstances. *See id.* at 16. Further, ICNU advocates its own set of principles: that a PCAM should be limited to unusual events, result in no recovery if overall earnings are reasonable, be revenue neutral over time, operate over a long period of time, and apply only to customers that were taking the cost-of-service option while the PCAM was in effect. *See id.* at 17 (citing UE 165, Order No. 05-1261, 8-10, 13). In being limited to unusual events, ICNU argues that a PCAM should have a deadband in which PGE would absorb a certain amount of variation in costs before sharing an additional amount with ratepayers. *See* ICNU opening brief, 17-19. ICNU further asserts that PGE's proposed "earnings test" – where PGE would share 50/50 the amount by which the "normalized actual ROE" exceeds the "baseline ROE" by 100 basis points, updated annually – is far removed from the deadband proposed by the Commission in Order No. 05-1261. That order called for an earnings test with a deadband that would result in recovery of amounts up to, for example, 100 basis points less that PGE's authorized ROE. *See* ICNU opening brief, 19-20. PGE's baseline ROE would be adjusted annually to account for changes in interest rates. *See id.* at 19. To be revenue neutral, the Commission has also acknowledged that asymmetric deadbands may be required. *See id.* at 20.

ICNU also notes that Staff has recommended that direct access customers should be excluded from the PCAM; PGE contends that the PCAM should apply to all customers. ICNU agrees with Staff because direct access customers already pay for variability of power costs, and should not be forced to pay twice through the PCAM. *See* ICNU opening brief, 21-22.

Proposed Alternatives

Staff proposes a long-term PCAM that would do the following:

- Track the difference between the actual unit NVPC and the unit NVPC reflected in rates;
- Determine the annual variance amount by multiplying the difference between unit NVPC by the normalized loads reflected in rates;

- Use a power cost deadband equal to plus and minus 150 basis points of ROE to exclude normal variation from triggering the mechanism;

- Place ninety percent of all amounts exceeding the power cost deadband in a balancing account for later offset or amortization;

- Use an earnings test with a deadband equal to plus or minus 100 basis points of ROE to override any surcharges or surcredits when the Company's earnings are within a reasonable range; and

- Apply any surcharges or surcredits to customers that were charged cost-of-service rates during the PCAM year, and exclude direct access customers.

See Staff opening brief, 24-25.

CUB proposes its own PCAM that captures extraordinary conditions and includes the use of an asymmetrical deadband and a tiered sharing ratio as the variation increases. CUB also recommends an amortization cap and a prudence review in application of the adjustment, as well as revised tax treatment of the proposed adjustment, in light of the effects of SB 408. *See* CUB/200, Jenks-Brown/21-23. In CUB's proposed mechanism, PGE would absorb power costs that vary 75 basis points below or 150 basis points above ROE; the Company and ratepayers will share 50-50 power costs between 75 and 120 basis points below, and 150 and 240 basis points above, ROE; and the Company will pass on to ratepayers 90 percent of the results of extraordinary events, less than 120 points below, and more than 240 points above, ROE. *See* CUB opening brief, 15. In addition, the PCAM would have an earnings deadband of 100 basis points above or below ROE. *See id.* at 15. Finally, CUB would replace the RVM with a PCAM, which would result in fewer rate changes. *See id.* at 16. CUB argues that its PCAM would provide a better incentive for PGE to actively and aggressively manage power costs management. *See id.*

CUB asserts that Staff's proposal shares many of the same principles of its proposed PCAM. *See* CUB opening brief, 18-20. Both Staff and CUB agree that the PCAM should have a deadband and maintain some sharing to incent the utility to manage its power costs effectively. *See id.* CUB asserts that Staff agrees with its principle of revenue neutrality, but argues that Staff's proposal does not achieve that because it does not have an asymmetric deadband and sharing bands. *See id.* at 19. Also, CUB separates its sharing bands into three layers – for normal, unusual, and extraordinary events – while Staff only has two layers. *See id.* at 19-20. Because Staff's proposal is not revenue neutral and does not appropriately allocate normal, unusual, and extraordinary power cost variations, CUB urges the Commission to adopt CUB's proposal. *See id.* at 20.

Resolution

The Commission has recently considered the on-going use of a power cost adjustment mechanism by PGE. *See* UE 165/UM 1187, Order No. 05-1261. In that case, the Commission rejected a proposed stipulation for a deferral of power costs related to a poor hydro year. The Commission rejected that proposal but, in so doing, set forth four primary design criteria for a hydro-related PCAM – it must be limited to unusual events, there will be no adjustments if overall earnings are reasonable, it must be revenue neutral, and it must operate in the long-term. *See id*.

We conclude that a PCAM should be adopted to capture power cost variations that exceed those considered part of normal business risk. [5] In this case, normal business risk for PGE includes all of the circumstances to which it is exposed, such as hydro variability.

First, the Commission will apply an earnings test to determine whether the utility is earning an acceptable rate of return. An earnings test serves to protect customers from paying for higher-than-expected power costs when the utility's earnings are reasonable, while it protects the Company from refunding power cost savings when it is underearning. We establish an earnings deadband of ± 100 basis points around the company's allowed ROE, for two reasons. First, although we use a specific ROE to set rates, there is a range of acceptable returns on equity. *See Duquesne Light Co. v. Barasch*, 488 US 299, 312 (1989). Second, an earnings review does not determine a company's actual ROE with the same accuracy as a full rate case, because the company's costs are not examined as thoroughly in the earnings review. If PGE is earning within +/-100 basis points of this authorized rate of return, there will be no power cost adjustment for that year. If the Company's earnings are more than 100 basis points below its authorized ROE, it will be allowed to recover excess power costs, after application of the deadband and 90-10 sharing described below, up to an earnings level that is 100 basis points less than its authorized ROE. If the Company's earnings are more than 100 basis points above its authorized ROE, it will be required to refund to customers power cost savings, after application of the deadband and sharing, down to the ROE plus 100 basis points threshold. We will apply the earnings test to PGE's authorized ROE, and decline to accept its suggestion that the return should be updated annually. We find that using PGE's authorized ROE for the earnings review is reasonable, and the Company has discretion to propose an updated ROE in general rate filing.

Second, we will set a deadband so that PGE will absorb some normal variation of power costs. We are persuaded by CUB's arguments, in this case and in dockets UE 165 and UM 1187, that an asymmetric deadband is necessary to ensure that the PCAM is revenue neutral. *See* UE 165/UM 1187, Order No. 05-1261, 10. The deadband for the power cost variation will be range from 75 basis points ROE below the base level of NVPC included in rates, to 150 basis points ROE above. As we noted in

[5] In approving a PCAM for PGE, we decline to rely on PGE's arguments related to the S&P report dated September 25, 2006, and instead rely on other evidence in the record.

AR 499, we are well aware of the double whammy effect on SB 408, *see* Order No. 06-532, 10, and we have considered that impact in the design of this mechanism. Further, we agree with Staff that the ability to absorb power cost increases depends on a utility's total rate base, and that this PCAM is narrowly tailored to suit PGE; therefore, we decline to accept PGE's arguments that a deadband should focus on a return on generation assets only. The ROE deadband should be calculated based on PGE's overall rate base. If the power cost variation is within this deadband, there will be no power cost rate adjustment

Third, for any power costs above or below that range, customers will bear 90 percent of the adjustment, and PGE will bear 10 percent of the adjustment. The 10 percent share for PGE should provide it with an incentive to manage its costs effectively, while sharing costs that are beyond normal business risk.

In addition, we adopt CUB's proposal and will limit amortization of deferred amounts under the PCAM in any one year to six percent of PGE's revenues for the preceding calendar year. *See* CUB/200, Jenks-Brown/22. ORS 757.259(8) applies such a cap to deferrals of electric utilities. While some may argue that deferrals under an ORS 757.210 automatic adjustment clause are subject to ORS 757.259 requirements as a matter of law, we have consistently applied the deferral authorization and amortization caps contained in the deferred accounting statute to these types of deferrals; for example, the purchased gas adjustment mechanisms for the natural gas utilities. *See, e.g.,* UG 174/ UM 1275, Order No. 06-609, Appendix A at 16 (describing the three percent cap review and reauthorization of deferrals under ORS 757.259 in NW Natural's November 2006 purchased gas adjustment). Based on this past practice, we conclude that CUB's proposal is appropriate for this mechanism.

We also agree with Staff's and ICNU's arguments that the PCAM should not apply to direct access customers. Those customers already bear the risk of variable power costs through their pricing structure. In addition, ancillary services, the revenues from sales as well as the costs from the services, should also be taken into account in the mechanism.

COST OF CAPITAL/ RATE OF RETURN

PGE requests an 8.87 percent rate of return, based on a capital structure with a 53.3 percent equity ratio, 10.75 percent ROE, and 6.73 percent cost of debt. *See* PGE opening brief, 3-4. Staff recommends a capital structure of 50 percent debt and 50 percent equity, a 6.2 percent cost of debt and a 9.4 percent ROE, for a 7.8 percent overall rate of return. *See* Staff opening brief, 25. ICNU calls for an 8.05 percent overall rate of return, based on Staff's proposed capital structure and cost of debt, but a 9.9 percent ROE. *See* ICNU opening brief, 34 (revised to adopt Staff's amended cost of debt). PGE notes with concern that Staff's recommendation is 36 basis points lower than the authorized rate of return for PacifiCorp in docket UE 179, and 50 basis points lower than ICNU-CUB's recommendation in this docket. *See* PGE reply brief, 4.

Legal Standard

Several decisions by the U.S. Supreme Court form the basis for the Commission's standards for determining an appropriate rate of return: *Duquesne Light Co. v. Barasch*, 488 US 299 (1989); *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 US 591 (1944), and *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n of W. Virginia*, 262 US 679 (1923). Under these decisions, a utility's authorized rate of return, and the resulting overall rates, should be sufficient to maintain financial integrity, allow the utility to attract capital under reasonable terms, and be commensurate with returns investors could earn by investing in other enterprises of comparable risk. This standard has been codified in Oregon law. *See* ORS 756.040. To determine a utility's rate of return, the Commission first identifies the costs and components of the utility's capital structure. Then, the Commission estimates the costs of each capital component and weighs each component according to its percentage of total capitalization. Finally, the Commission combines the weighted costs of capital to calculate the overall cost of capital. This overall cost of capital is the utility's allowed rate of return on rate base.

To analyze the elements of PGE's cost of capital, we first review PGE's capital structure, and the arguments made by PGE, Staff, and ICNU. Then we evaluate PGE's cost of debt, and the adjustments proposed by Staff and rebuttal arguments made by PGE. Finally, we examine the issues related to cost of equity, and the models and positions set forth by PGE, Staff, and ICNU.

Capital Structure

Parties' Arguments

PGE proposes that its rates be set to reflect its actual capital structure, and states that its forecasted actual equity ratio will be 53.3 percent for 2007. *See* PGE/2700, Hager-Valach/5. This level of equity will allow PGE to raise capital on reasonable terms to fund its capital expenditures, including the development of wind generation, as well as deal with hydro relicensing investments at several plants and environmental costs at Boardman. *See* PGE opening brief, 15. Further, PGE asserts that it must consider the metrics required by rating agencies in order for PGE to maintain its existing credit rating. *See id.* at 17. PGE expresses concern that it must maintain a higher level of equity "to maintain liquidity for unexpected margin calls as wholesale prices fluctuate, and unresolved issues such as litigation and SB 408." *Id.* PGE distinguishes itself from other companies in Staff's sample group by arguing that it is more reliant on purchased power, and therefore must consider debt imputation related to a debt equivalent analysis that S&P performs to address risks associated with long-term power purchase agreements. *See* PGE reply brief, 9-10. All of these factors, PGE argues, require that the Commission use PGE's actual ratio of 46.7 percent debt and 53.3 percent equity in calculating its cost of capital. Moreover, PGE argues that the capital structure for the test year must be used for purposes of calculating PGE's revenue requirement, unless a party can show "that

PGE's actual equity ratio of 53.3 percent is unreasonable or imprudent." PGE opening brief, 16. An adjustment to the capital structure, while not mandating the capital structure that must be used, would constitute a disallowance of costs.

Staff recommends a capital structure of 50 percent common equity and 50 percent debt, which mirrors the common equity ratio of the companies in Staff's sample group. *See* Staff opening brief, 43. Because PGE has not been publicly traded for some time, Staff argues that it is difficult to pinpoint its capital structure and resulting cost of equity. Staff asserts that a good estimate can be obtained by using a comparable sample of companies. *See id.* at 44. By using the representative sample's capital structure and resulting cost of equity, a reasonable estimate can be obtained. *See id.* Staff contends that estimating a cost of equity using a set of comparable companies requires an "apples-to-apples" comparison, which requires using a level of capitalization that is similar to these same companies. *See* Staff/1400, Morgan/8. To match PGE to the representative sample of companies, Staff asserts that the Commission must either lower PGE's cost of equity or adjust the capital structure to reach the right balance. Staff prefers the second choice, arguing that the Commission should adjust the capital structure to be more accurate and less subjective in estimating the cost of equity. *See* Staff reply brief, 5-6. Staff further maintains that by using a capital structure and cost of equity similar to that of the sample group of companies would best represent the current requirements for PGE's cost of equity. *See* Staff/1400, Morgan/7. Staff notes that the Commission adjusted ROE based on capital structure in PGE's last rate case: four basis points for each point change in the equity capitalization percentage. *See id.* at Morgan/8-10. Staff does not suggest that PGE be required to adopt this capital structure, but argues that the cost of equity should be established with an eye towards PGE's intended equity ratio. *See id.* at Morgan/8. Staff notes that PGE has, in other forums, expressed a projected equity level of 50 percent. *See* Staff opening brief, 44; Staff/1400, Morgan/6.

ICNU and CUB argue that PGE's proposed 53 percent equity structure is too high and reflects the lingering effects of Enron ownership and unnecessarily increases PGE's proposed revenue requirement. *See* ICNU opening brief, 35; CUB opening brief, 31-32. As ICNU notes, "common equity is the most expensive form of capital and its revenue requirement cost is more than 2 ½ times greater than debt." *See* ICNU opening brief, 40. Because common equity is substantially more expensive than debt, customers should not have to shoulder the extra costs of excess equity. *See id.* ICNU counters PGE's arguments that it must maintain additional equity to prepare for the impact of PGE-specific risks. Instead, ICNU asserts that PGE's capital structure contains additional equity as a buffer against the liquidity crunch after PGE's parent, Enron, filed for bankruptcy. *See* ICNU opening brief, 39-40. Because customers are protected from capital costs related to Enron's ownership of PGE, pursuant to conditions in the Commission's orders approving Enron's acquisition of PGE and PGE's spin-off from Enron, *see* UM 814, Order No. 97-196, Appendix A, 2; UM 1206/ UF 4218, Order No. 05-1250, Appendix A, 4, ICNU argues that these costs should be removed from PGE's cost of capital.

ICNU and CUB's expert, Mr. Michael P. Gorman, also supports a capital structure with 50 percent common equity and 50 percent long-term debt.[6] *See* ICNU opening brief, 35. He asserts that it will support PGE's financial strength, which he proved by comparing S&P credit rating benchmark financial ratios to the total debt ratio under his proposed PGE capital structure. The results indicated that a PGE with a 50 percent equity capital structure would be well within the acceptable range for its current S&P credit ratings. *See id.* at 36-37. Further, Mr. Gorman testified that PGE's proposed 53 percent common equity ratio exceeds the average for a proxy group of comparable utilities, and more specifically, recently authorized equity ratios for Northwest utilities. *See id.* at 35. Mr. Gorman contends that PGE's own cost of capital analysis relied on proxy groups with common equity ratios in the range of 45 to 52 percent or lower proving the reasonableness of a 50 percent equity ratio and showing that PGE's proposed structure is out of line with comparable utilities. *See id.* at 37. ICNU also points to Staff evidence that PGE expected to have a capital structure with an equity level of 51 percent in 2007, and a 50 percent common equity ratio in 2008 through 2010, comparable to the structure recommended by ICNU and Staff. *See id.* at 38-39.

PGE contends that Staff's proposed capital structure has no foundation, and would inappropriately disallow a portion of PGE's cost of equity, applying the lower return provided for debt on the remaining three percent of equity. *See* PGE opening brief, 15-16. PGE disputes that it is maintaining a higher level of equity due to Enron ownership, and argues that it must maintain a higher equity ratio to support its bond rating. *See id.* at 17. Because no party has shown that PGE's proposal of 53 percent equity is unreasonable or imprudent, and only asserted that the 50-50 capital structure would be "more reasonable," PGE argues that the Commission must allow for a return on a 53 percent equity capital structure. *See id.* at 16. Further, PGE disputes ICNU's examples of a 50 percent equity ratio capital structure by noting that those examples either reflected the actual capital structure of the utility, or a stronger equity ratio than the utility actually had – the opposite of PGE's situation. *See* PGE reply brief, 11-13. For these reasons, PGE urges the Commission to reject Staff and intervenors' recommended 50 percent equity/ 50 percent debt capital structure.

Resolution

The Commission is not required to adopt PGE's actual capital structure, but can select an alternative capital structure in consideration with the other factors that affect the cost of capital. *See, e.g., In the Matter of Petition by Zia Natural Gas Company v. New Mexico Public Utility Commission*, 998 P2d 564, 568 (2000). Therefore, we adopt the capital structure of 50 percent equity and 50 percent debt proposed by Staff and ICNU.[7] This structure is more in line with comparable companies and PGE's own

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[6] ICNU and CUB jointly sponsored cost of capital testimony prepared by Mr. Michael P. Gorman. ICNU thoroughly briefed arguments based on that testimony.

[7] Staff submitted attachments to its opening brief that it characterized as an update to its analysis of PGE's cost of debt put forth in PGE's last round of testimony. In that testimony, PGE stated it would issue additional debt, which would impact its capital structure. Staff's attachments were excluded from the

projected equity level. Contrary to PGE's assertion, this decision does not amount to a disallowance of a portion of PGE's ROE. Instead, we are considering all components of the cost of capital that, in total, will result in a fair and reasonable rate of return.

Cost of Debt

Staff proposes an adjustment of 53 basis points from PGE's cost of debt estimate: 41 basis points that Staff attributes to Enron-related costs, and 12 basis points attributable to other causes. *See* Staff opening brief, 25-26. PGE argues that its debt costs were prudently incurred and should not be disallowed. *See generally* PGE opening brief, 7-14. Moreover, PGE contends that debt costs that Staff attributes to an Enron effect are more accurately tied to PGE's exposure to the purchased power market during the energy crisis and subsequent years of variable power costs. *See id.* at 8-10.

Enron Adjustments

In testimony, *see* Staff/1200, Conway/9, Staff proposes adjustments to the following PGE's existing debt issuances, as a consequence of Enron's ownership of PGE:

1. $100 million issued on October 28, 2002, at 5.6675%, with an issuance cost of over $12 million, for an all-in rate of 7.4%.
2. $150 million issued on October 10, 2002, at 8.125%, redeemed with a make whole premium of $12.9 million allocated to debt issued on April 1, 2006.
3. $50 million issued on April 8, 2003, at 5.279%, with an issuance cost of over $4 million, for an all-in rate of 6.4%.
4. $50 million issued on August 4, 2003, at 5.35%.
5. $50 million issued on August 4, 2003, at 6.75%.
6. $50 million issued on August 4, 2003, at 6.875%.

Parties' Arguments

Staff argues that these six debt issuances were higher priced than they would have been if Enron had not owned PGE. *See* Staff opening brief, 32-41; Staff/1200, Conway/7-19. Staff notes that, as a condition of the stipulation in the recent spin-off docket, PGE had agreed to not "seek recovery of increases in the allowed return on common equity and other costs of capital due to Enron's ownership * * * for purposes of rate setting." Staff opening brief, 33-35 (quoting UM 1206/ UF 4218, Order No. 05-1250, Attachment A, 4, Condition 6(a)). Staff reasons that, because PacifiCorp's rating held steady at A- by S&P from 2001 through 2003, PGE's rating also should have held steady during that period. PGE's rating fell from an A to BBB+ in 2001. *See* Staff/1201, Conway/6-7 (copy of 07-Dec-2001 S&P report). Staff attributes the drop in rating, and concurrent rise in interest rates on PGE debt, to the developments at Enron.

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record as new evidence, and Staff filed a motion for reconsideration for certification. Because we adopt Staff's capital structure, we find that Staff's motion is moot.

See Staff opening brief, 35-36. To account for the rise in debt costs, Staff repriced the six debt issuances "to account for the Enron effect." *Id.* Staff does not question the prudence of the debt issuances, only the amount of the cost that PGE seeks to put into its cost of debt. *See id.* at 33. As a result, Staff proposes adjustments by repricing the debt issuances as follows:

1. The $100 million issued on October 28, 2002, was "insurance wrapped," that is, a $12 million premium was paid so that it could be issued at a 5.6675 percent interest rate, akin to the rate for a AAA-rated bond. *See* PGE opening brief, 11. Staff proposes to reprice the debt using NW Natural's later issuance as a comparator, assuming an all-in interest rate of 5.19 percent. *See* Staff opening brief, 34-35. PGE responds that, without the insurance wrapping, it could not have issued the bonds for that rate, and that Staff's assumed rate is unrealistically low. *See* PGE opening brief, 11.

2. The debt with the 8.125 percent interest rate had a make-whole premium associated with it, that Staff asserts was not beneficial to consumers, so PGE shareholders should shoulder that cost. Staff recommends a disallowance of the premium. *See* Staff/1200, Conway/17. PGE argues that disallowance of the call premium results in an assumption that it could have issued the debt at a very low interest rate, 5.456 percent; PGE argues that it could not have issued the debt at such a rate without the call premium, so it should not be disallowed. *See* PGE opening brief, 12.

3. The $50 million issued on April 3, 2003, was also "insurance wrapped," with an all-in interest rate of 6.4 percent. *See* PGE opening brief, 11. Staff repriced the debt by comparing it to a NW Natural issuance, again, assuming an all-in interest rate of 5.19 percent. *See* Staff opening brief, 34. The parties made the same arguments as those for the first debt in this series.

4-6. The three debt issuances on August 4, 2003, were repriced by Staff by comparing them to PacifiCorp's October 2003 debt issuances. Staff argues that PacifiCorp was also exposed to the energy crisis, and so is a reasonable comparator for PGE. *See* Staff opening brief, 40-41. As a result, Staff proposes an adjustment of 17.5 basis points per issuance. *See id.* at 41. PGE asserts that, by August 2003, it was well-insulated from the Enron effect, and that its interest rates reflect the strength of the Company in light of its exposure to the purchased power market. *See* PGE opening brief, 8-10. PGE continues to argue that, if the Commission does make this adjustment, it should account for the fact that interest rates were higher in August 2003 than they were in October 2003 *See* id. at 11.

Staff argues that PGE's statements before the Commission and the Securities and Exchange Commission (SEC), that the Enron effect reduced its access to capital markets from 2001 through 2003, support Staff's adjustments to PGE's cost of debt. *See* Staff opening brief, 37-41.

ICNU supports Staff's recommendation to reduce PGE's cost of long-term debt to reflect the impact of Enron ownership, particularly in light of PGE's update on the amount of debt that it plans to issue in 2007. *See* ICNU opening brief, 57. ICNU urges the Commission to hold PGE to its commitments to absorb any Enron-related costs of debt, and adopt Staff's recommendations. *See id.* ICNU argues that these appropriate adjustments will not have a negative impact on PGE because the Company has $40 million in excess liquidity set aside to absorb adjustments such as these, as required in UM 1206/ UF 4218, Order No. 05-1250. *See* ICNU reply brief, 24-25.

PGE opposes Staff's efforts to adjust its debt issuances from January 2002 through August 2006. PGE asserts that its ratings downgrade by S&P did not arise from its affiliation with Enron. The Company further argues that it should not be compared to PacifiCorp or NW Natural because it bears little resemblance to either utility. *See* PGE opening brief, 8. PGE contends that all utilities suffered a decline in credit worthiness due to the energy crisis of 2001 through 2003, and PGE's decline was on par with other utilities. *See id.* at 9. PGE further asserts that its cost of debt measures favorably with costs for other similarly rated utilities. *See id.* Moreover, PGE claims that the Commission's ring-fencing conditions, particularly the issuance of the "Golden Share," protected PGE from Enron's effects on its long-term debt costs. *See id.* at 9-10. PGE argues that it is more likely that its downgrade was related to power cost disallowances, several years of lower-than-average hydro productions, and other drivers of high power costs that the Company absorbed. *See id.* at 10.

The record contains several reports from credit ratings agencies that provide information as to why PGE's ratings sank in 2001 and stayed the same for the next several years: the S&P report which dropped PGE's rating from an A to BBB+ on December 7, 2001, primarily considers Enron's bankruptcy and the highly leveraged nature of the then-pending NW Natural purchase of PGE, but also discusses the volatility of the wholesale power markets, *see* Staff/1201, Conway/6-7; the Fitch Ratings Report from August 8, 2002, in which the agency discussed its recent downgrade of PGE to BBB, notes the ongoing pressure from Enron ownership, *see id.* at Conway/48-49; and the S&P report from 2003, which reviews PGE's exposure to "hydro-risk" and the wholesale power markets, *see* PGE/2010, Hager-Valach/1-10.

Other utilities also suffered downgrades due to the energy crisis. *See* PGE/1104, Hager-Valach/2. In particular, PacifiCorp's rating was dropped from an A2 to an A3, the Moody's equivalent of an S&P drop from an A to an A-, because of the Western energy crisis. *See* Staff/1201, Conway/52-53 (Moody's report, dated 15 Nov. 2001). The Commission addressed PacifiCorp's exposure to the volatile energy market at that time. *See* UM 995, Order No. 01-085, 12 ("We agree with PacifiCorp that the expenses for which it seeks deferred accounting are based on extraordinary behavior of the power markets and are not ordinary power cost expenses."). Additionally, even though PGE has been freed from Enron ownership, its ratings have remained the same. *See* PGE/1104, Hager-Valach/4 (S&P rating of BBB+ as of September 20, 2005). PGE argues that this supports its contention that its increased borrowing costs are a result of its exposure to volatile purchased power markets.

Resolution

Based on the record, we find that, for the period under consideration, PGE's ratings downgrade and additional debt cost were caused mainly by the Company's ownership by Enron and its exposure to the wholesale power market. Consistent with the conditions of the stock spin-off, *see* UM 1206/ UF 4218, Order No. 05-1250, Attachment A, 4, Condition 6(a), customers should not pay for debt costs that are higher due to Enron ownership. To account for the effect of Enron ownership, we attribute one step of the two-step downgrade from A to BBB+ to Enron ownership and adjust the six issuances under consideration using the interest rate spreads reported in PGE/2104. The specific adjustments are as follows:

1. For the October 28, 2002, issuance, we conclude that the coupon rate should be reduced by 42.3 basis points, and issuance costs should be reduced by the ratio of the adjusted coupon rate to the actual interest rate on the debt. We obtained the basis point adjustment by taking the average of the S&P and Moody's three-step spreads for October 2002, *see* PGE/2104, Hager-Valach/1, 4, and then dividing that amount by three to estimate the effect of a one-step downgrade.

2. For the October 10, 2002, issuance, we conclude that the coupon rate, assuming an A- rating, should have been 7.547 percent. We arrived at this rate by relying on PGE/2014, Hager-Valach/1, which shows a three-step difference from A debt issuances to BBB debt issuances of 161 basis points, and calculated a one-third difference based on that chart and added that difference to the A rated rate for October 2002. We then recalculated the make whole premium based on a coupon rate of 7.547, instead of 8.125 percent.

3. For the April 8, 2003, issuance, we reduced the coupon rate of 5.279 percent by 37 basis points, and issuance costs should be reduced by the ratio of the adjusted coupon rate to the actual interest rate used for that debt.

4-6. For the three August 2003, PGE bond issuances, we reject Staff's recommendation that we substitute PacifiCorp's cost of debt for PGE's issuances. There is no need to speculate on how representative PacifiCorp's cost of debt is to PGE's cost; or how interest rates changed between the time PGE and PacifiCorp issued their respective debt. We conclude that the August 2003 debt coupon rates issued by PGE should be reduced by 22.7 basis points. This adjustment is calculated by taking one-third the basis points difference for the August 2003 rates. *See* PGE/2014, Hager-Valach/2.

The sum of these adjustments results in a nearly $1 million reduction in PGE's proposed cost of debt.

Other Cost of Debt Adjustments

PGE's IRR Calculation. PGE calculated its internal rate of return (IRR), but did not provide its work papers. Staff recreated the calculation, and found a difference of one-half of a basis point. *See* Staff opening brief, 25. Because Staff found that its method was clear and reproducible, it reported its result and recommends that an adjustment for the IRR calculation. *See id.* at 27.

PGE responds that the adjustment was too insignificant to even discuss, and professes to not understand why Staff even raised the issue. *See* PGE/2000, Hager-Valach/11.

Resolution

We adopt Staff's adjustment. PGE did not produce its workpapers, nor did it effectively refute Staff's arguments. Staff's adjustment should be adopted.

Average gross proceeds versus Actual Costs. PGE originally planned a $100 million issue in July 2007, but calculated its debt using a monthly average balance of $54 million. *See* Staff opening brief, 27. This created a mismatch, in which PGE used a monthly average for the proceeds, but did not average the expected fees in the same way. *See id.* at 27-28. Staff recommends substituting the actual amount of the issuance because PGE's mismatch results in an inflated IRR as well as an inflated estimate of PGE's embedded cost of debt. *See id.*

PGE responds that the fees are a one-time event and are embedded in the cost of the debt. *See* PGE/2000, Hager-Valach/12. For this reason, PGE argues that there is no "mismatch" as asserted by Staff. *See id.* Further Staff's adjustment reflects an assumed maturity of 10 years; PGE objects because it plans a 30-year issuance, discussed below. *See id.*

Resolution

We adopt Staff's recommended adjustments. As Staff notes, it is important to account for the debt and the fees on the same basis, that is, to consider the full impact of the fees along with the full amount of the issuance in order to arrive at a normalized adjustment. In an extreme example, using PGE's approach, it would be possible to issue debt on December 31 of the test year, and include the full amount of the fees and only 1/365th of the proceeds from the debt. By making Staff's proposed adjustments, we match the full amount of the proceeds to the issuance costs, resulting in a more appropriate embedded cost of debt. This annualization method is adopted by the Commission for the full amount of the debt to be issued in 2007.

Time-limit on maturity of PGE's debt issuance. Staff also proposed an adjustment by assuming a 10-year maturity on PGE's proposed 2007 debt issuances to determine the cost of the debt. *See* Staff opening brief, 28. PGE objects because the cost of a 10-year issuance is less than the cost of a 30-year issuance, and Staff's adjustment would result in a disallowance of the difference in costs. *See id.* PGE states that it intends to issue debt with a 30-year maturity, and that Staff should not be engaged in scheduling when PGE's debt matures. *See id.* at 28-29. Staff responds that it did consider the scheduled maturities of PGE's debt, and that it is not directing the Company to take any particular course of action is issuing its debt. *See id.* Staff acknowledges that the cost of debt could vary from its estimates due to changes in the Treasury rate and spreads produced by PGE. *See id.* at 30. However, Staff remains concerned that, if it accepts the 30-year maturity, the Company could game the system by then using a 10-year issuance, and the shareholders would benefit by the difference in the cost of the debt. *See id.* at 29.

PGE disputes Staff's proposed adjustment which would result in a disallowance of 30 basis points of debt costs. *See* PGE opening brief, 13-14. PGE argues that the Commission rejected this approach in docket UE 116, where Staff proposed to use a seven-year maturity for long-term debt rather than the maturity dates that PacifiCorp had proposed. *See* PGE opening brief, 14. Further, PGE argues that there are valid reasons for it to issue 30-year securities, such as staggering of the maturity dates. *See id* at 14.

Resolution

We find that based on PGE's Testimony at its word that it will issue 30-year debt. Further, based on the evidence in the record, those costs are prudent and should be allowed. We note that PGE must apply with the Commission for permission to incur this debt, and we will carefully review that application. Because PGE has persuaded us that it needs to incur the cost of 30-year debt, we will not make Staff's proposed disallowance by pricing it as 10-year debt. In calculating the cost of debt, the Commission will include \$150 million in 10-year and \$150 million in 30-year debt, as set forth in PGE's testimony. In addition, we take official notice of the Form 8-K that PGE filed with the SEC on December 22, 2006, in which PGE stated the coupon rate will be 5.8 percent.[8]

<u>Losses on reacquired debt</u>. In its cost of long-term debt, PGE also included losses on reacquired debt. Staff excluded those losses because the debt is no longer outstanding and no replacement debt has been identified, and because the expenses are non-recurring. *See* Staff opening brief, 30. Staff argues that, because PGE did not show that ratepayers benefited from the early redemption, ratepayers should not be shouldered with losses on new debt that does not benefit customers. *See id.* at 30-31. Staff compares these losses with the unamortized expense associated with PacifiCorp's

[8]We may take official notice of documents of which the courts of the State of Oregon may take notice. *See* OAR 860-014-0050. Official notice may be made on the initiative of the Commission, and may take notice of any fact that is not subject to reasonable dispute in that it is either generally known within the Commission's jurisdiction, or capable of accurate and ready determination by resort to sources whose accuracy cannot reasonably be questioned. *See* ORS 40.070; ORS 40.065. A party may object to the fact noticed within 15 days of the date of the issuance of this order. *See* OAR 860-014-0050(2).

Quarterly Income Debt Securities (QUIDS) that were excluded in docket UE 116, Order No. 01-787, 19. *See id.* at 31. The QUIDS were similar to the long-term debt here; it had been redeemed, and no replacement debt had been issued. *See id.* The Commission stated that redemption of the QUIDS did not benefit customers, so the increased costs could not be passed on to customers, and that, as a non-recurring expense, the costs should not be passed on in rates. *See* Order No. 01-787, 31. Staff contends that PGE is responsible for showing the cost-effectiveness of redeeming the debt. *See* Staff opening brief, 32.

At the outset, PGE notes that the redemption occurred in 1988. *See* PGE opening brief, 12. PGE argues that the 13.5 percent interest rate long-term debt was replaced in the interim by lower interest rate short-term debt. *See id.* at 12-13. By redeeming the high interest debt, PGE argues that customers benefited by not being required to pay the extra interest and were not burdened by additional equity issuances. *See id.* at 13.

Resolution

We find that PGE's costs were prudent at the time they were incurred. For that reason, we decline to adopt Staff's proposed disallowance.

Return on Equity

PGE estimates its required return on equity (ROE) to be 10.75 percent and seeks an authorized ROE at or above that level. PGE contends that this return is the appropriate rate and is supported by a variety of economic models. Staff contends that PGE's proposed ROE is too high and recommends the Commission adopt a 9.4 percent ROE for the company. PGE argues that Staff's recommended ROE is artificially low because Staff only relies on one type of economic modeling, the discounted cash flow (DCF) model, without cross-referencing other accepted methods of estimating cost of equity (ROE) and considering PGE's unique circumstances. ICNU also put forth a DCF model, as well as other models, and recommends a 9.9 percent ROE. In this section, we first discuss the parties' economic models, review ROE award in other jurisdictions, examine overall arguments and conclude with the Commission's resolution.

Discounted Cash Flow Model

PGE, Staff, and ICNU all present ROE estimates based on the discounted cash flow (DCF) model. In docket UE 115, the Commission defined the DCF model as follows:

> The DCF model estimates the cost of equity by determining the present value of the future cash flows that investors expect to receive from holding common stock. The current stock price is assumed to reflect investors' expectations for the stock, including future dividends and price

> appreciation. The return on equity under the DCF model is the rate that equates the current stock price and expected cash flows to investors.

Order No. 01-777, 24. The model estimates a regulated firm's actual cost of capital; that is, the return on investment required to entice investors into buying the firm's common stock. The DCF model has three components: a current stock price, an expected dividend, and an expected growth rate in dividends. *See* ICNU opening brief, 44.

PGE's DCF model

PGE uses a multi-stage DCF analysis. The model uses several samples of comparable utilities because of the relatively short period of time during which PGE's stock has been publicly traded. *See* PGE opening brief, 21. The sample includes a combined sample of the utilities in the Moody's and S&P Electric Utility Indices, a comparable sample group prepared by outside experts, and the sample group from docket UE 170 found acceptable by Staff. *See id.* Extraordinary events were screened out, and DCF estimates were prepared using the month-high closing price, the month-low closing price, and the month-end price for each of the last three months. *See id.* The ranges for ROE suggested by this approach varied from 8.10 to 11.2 percent. *See id.*

Staff urges the Commission to reject PGE's DCF analysis because it is based on unrealistic historic Gross Domestic Product (GDP) growth estimates. In fact, PGE's long-term growth assumptions for the proxy companies are higher than the projected growth rate of the economy. *See* Staff reply brief, 11. Because that assumption is likely in error, Staff argues that the Commission should disregard that analysis. *See id.* Further, Staff asserts that, without that outlying model, the remaining DCF analyses include long-term growth estimates between 4 and 5 percent, which supports a range of ROE estimates from 8.2 to 10.1 percent. *See id.* at 11-12. Staff contends that this range supports its ROE recommendation of 9.4 percent, discussed below. *See id.* at 12.

ICNU also attacks PGE's DCF analysis for using an unreasonable GDP growth estimate. *See* ICNU opening brief, 48-49. Mr. Gorman notes that utilities have high dividend yields and lower growth rate prospects, but PGE's DCF analysis assumes that the Company will have both high dividend yields and strong growth prospects, and the projected high dividend yield estimates are too high. *See id* at 48-49. When this unreasonable outlying result is removed, PGE's DCF results in a range from 8.1 to 10.1 percent. That result includes a high-end estimate within Mr. Gorman's range of 9.5 to 10.4 percent, which is discussed below. *See id.* at 49.

Staff's DCF model

Staff applies two different multi-stage DCF models, as well as a single stage DCF model, to a proxy group of 12 companies, and then conducts a sensitivity analysis, to obtain its ROE estimate. *See* Staff opening brief, 45-46. These models produce the following results:

Model	**Range of Results**
Single-stage DCF	8.56 – 9.4 %
2-stage 150-year DCF	8.5 – 9.4 %
3-stage 40-year DCF	8.8 – 9.8 %

PGE asserts that Staff's ROE recommendation, which relies solely on its DCF models, is flawed for several reasons. First, PGE argues that Staff's DCF analysis is in error because the sample group is not representative of PGE: the sample group has an S&P business profile of 3.9, not 5 as PGE has; the sample group bond rating is A, which is higher than PGE's actual BBB+ rating; the sample group relies less on purchased power than PGE does; and Staff fails to consider the impact of a utility cutting its dividend. *See* PGE opening brief, 22. Staff responds that it amended its proxy group in response to PGE's criticisms, but that overall, "Staff's selection process was more detailed than PGE's process." Staff opening brief, 49. PGE further argues that, after its DCF analysis, Staff did not consider PGE-specific risks, such as reliance on purchased power, the absence of a power cost recovery mechanism, the perceived negative regulatory environment stemming from SB 408, and PGE's lack of jurisdictional diversity. *See* PGE opening brief, 22-23. Staff replies that the Commission has historically not considered utility-specific risks, and that PGE did not provide convincing evidence that would compel the Commission to change its practice. *See* Staff opening brief, 49-50. Further, PGE asserts that Staff's DCF analysis inappropriately relies on a one-day spot price to calculate the dividend yield component. *See* PGE opening brief, 23. Staff replies that using the one-day spot price is consistent with Commission precedent in docket UG 152, and that Staff's reliance on a cohort sample of companies reduced the impact of any anomalous pricing. *See* Staff opening brief, 51. In addition, PGE argues that Staff's recommended ROE of 9.4 percent is only 220 basis points higher than projected bond rates for the second quarter of 2007, which is a very low premium. *See* PGE opening brief, 23.

Next, PGE argues that Staff made several calculation mistakes in its DCF models. PGE contends that Staff made two calculation errors that understate its ROE recommendation by 20 basis points. *See* PGE opening brief, 23. According to testimony, Staff underestimates the internal rate of return by basing its calculations on average book equity, not year end equity. Further, Staff's annual book equity estimates rely upon annual data calculated for that year, and not returns on beginning of period equity, multiplied by beginning of period book equity. *See* PGE/2800, Zepp/19. PGE asserts that its proposed fixes to these errors increases Staff's ROE estimate by approximately 20 basis points. *See id.* at 19.

PGE also contends that Staff made multiple methodological errors. One such error, argues PGE, was in omitting sustainable growth from its DCF analysis. PGE defines sustainable growth as the sum of growth from retained earnings (called "br" growth) and sales of stock above book value (called "sv" growth). *See* PGE opening brief, 24. PGE argues that Staff does not include "sv" growth in its sustainable growth calculations in this case, although it had in past cases. *See id.* This results in an exclusion of almost 50 basis points of growth from its estimates, which, if corrected, would increase Staff's ROE recommendation from 9.4 to 9.9 percent. *See id.* Staff counters that it appropriately considered historic information in determining its cost of equity estimate, but has a valid dispute over whether the appropriate long-term growth rate to use for a DCF analysis should be based on historic GDP growth. *See id.* at 51. Staff contends that PGE's DCF analysis on historic GDP growth rates are unreasonably high, and that PGE's remaining DCF analyses support a ROE estimate similar to Staff's recommendation. *See* Staff opening brief, 45-46. Staff assumes long-term growth rates of 4 to 5 percent, based on its analysis of market consensus growth rates, sustainable growth, and historical utility growth rates. *See id.* at 46-47. PGE also uses three methods to estimate long-term growth: a sustainable growth method similar to Staff's, with an average estimate of 4.78 percent; a forecast of GDP growth, with an estimate of 5.01 percent; and the historic GDP model method, based on a 40-year calculation, with a result of 6.76 percent. *See id.* at 47. Staff contends that the last model results are unreasonably high and should be discarded. *See id.* If that method is discarded, along with PGE's improper use of the RPM, PGE's estimate of ROE would be similar to Staff's estimate. *See id.*

Finally, PGE argues that the results of DCF models generally underestimate the proper cost of equity due to the mismatch between the capital structure considered by investors when they buy stocks and the capital structure used in an original cost jurisdiction like Oregon. *See* PGE opening brief, 24. In testimony, PGE's witness asserted that, "investors buy common stocks at market prices above book values and thus the equity ratio of concern to them is higher than the more leveraged equity ratio used by regulators to set rates." PGE/2100, Zepp/27. As there is a difference between the market-value capital structure and the capital structure used to set rates, so too is there a difference in the amount of financial risk and consequently, the cost of equity. Not accounting for these differences could lead to allowed rates of return on equity that is below the costs of equity required by utility shareholders. *See id.* at Zepp/28 (quoting A. Lawrence Kolbe, Michael J. Vilbert, and Bente Villadsen, "Business & Money – Measuring Return on Equity Correctly," 11 www.fortnightly.com/pubs/4572.cfm, August 2005), 3. This is in keeping with PGE's general arguments that the Commission should consider the impact of its decision on PGE's standing with credit ratings agencies. Staff responds that such arguments are speculative and not supported by a solid factual foundation. *See* Staff opening brief, 53. Staff asserts that PGE's criticisms improperly characterize how ratings agencies establish credit ratings, and that ratings are not set on a single year's expectations but consider metrics over several years. *See* Staff/1400, Morgan/16; *see generally* Staff/1400, Morgan/16-21. Moreover, ratings agencies consider more than just return on equity; they also consider other regulatory mechanisms which stabilize a utility's recovery of its costs. *See id.* at Morgan/17.

ICNU's DCF model

Mr. Gorman also offers an ROE estimate based on a DCF analysis. Mr. Gorman estimates current stock prices using the average of the weekly high and low PGE stock prices over a 13-week period ending July 7, 2006. *See* ICNU opening brief, 44. Mr. Gorman estimates dividends by using the most recently paid quarterly dividend. *See id.* To estimate dividend growth, Mr. Gorman averages three published sources of customer growth rate estimates available on July 11, 2006, resulting in a consensus growth rate of 4.63 percent, which Mr. Gorman concluded was reasonably consistent with the five-year projected GDP growth rate. *See id.* The result was a DCF analysis that yielded a 9.5 percent average estimated ROE for the proxy group. *See id.* In fact, the testimony indicates a range from 7.38 percent to 12.58 percent, with an average of 9.466 percent; without the high and low points, the range extends from 7.82 to 10.98 percent. *See* ICNU-CUB/306, Gorman/1.

PGE supports ICNU's DCF analysis because it uses a sample group that had an average bond rating identical to PGE's and an average S&P business profile score that matches PGE's. *See* PGE opening brief, 21. PGE notes that the resulting range of ICNU's DCF analysis closely matches PGE's range of ROE estimates; however, PGE argues that ICNU's DCF point estimate of 9.5 percent fails to fully capture PGE-specific risks. *See id.* at 21. PGE asserts that, if ICNU had more fully considered the risks that PGE faces, it would have supported a point closer to 10.75 percent. *See id.* at 21-22.

Risk Positioning Method

In the last PGE rate case, the Commission discussed the risk positioning method (RPM):

> The Risk Positioning Method is a risk premium model that estimates the cost of equity by adding a premium for risk to a current or expected interest rate. In this analysis, PGE contends that the non-stipulated ROE decisions by regulatory bodies provide, on average, unbiased estimates of the cost of equity for electric utilities. By measuring differences between the authorized returns on equity and the yields on electric utility corporate bonds and yields on U.S. Treasuries, PGE calculates ranges of estimates of the equity risk premium. The company then adds the equity risk premia estimates to the current bond and treasury yields to derive a range for cost of equity.

Order No. 01-777, 32. PGE uses a risk positioning model in its capital ROE analysis. *See* PGE opening brief, 19-20. ICNU uses a risk premium model, which is based on the principle that investors require a higher rate of return to assume greater risk, and therefore the rate of return is calculated as the current yield to maturity on bonds, plus a premium. *See* ICNU opening brief, 45.

PGE's RPM

PGE first uses the RPM to calculate the difference between the cost of equity found appropriate in non-stipulated, authorized ROE decisions by regulatory bodies, on average, since 1983, and either electric utility corporate bonds or Treasuries. *See* PGE opening brief, 19. The first analysis yields a range of 10.486 to 10.493 percent; the second analysis yields a result in the range of 11.13 to 11.34 percent. *See id.* In rebuttal testimony, PGE offers two additional risk premium analyses, based on the sample group of companies relied upon in Staff's DCF analysis. *See id.* at 20. PGE uses the actual earned ROEs to proxy for the costs of equity, and then determines the annual average risk premiums by subtracting contemporaneous Treasury rates from those equity cost proxies. *See id.* The results suggest an average cost of equity of 11.0 percent in 2007. *See id.* The other risk premium analysis uses annual market holding period returns, contemporaneous interest rates, and the assumption that investors expect the future risk premium to be similar to the average past risk premium. *See id.* The results show an average risk premium of 3.55 percent, which is the difference between the annual holding period returns and the Baa corporate bond rate for 1950 to 2005. *See id.* Added to the expected Baa rates for 2007 of 7.2 percent, the indicated benchmark cost of equity is 10.75 percent. *See id.*

Staff and ICNU both object to PGE's risk positioning analysis, arguing that the Commission rejected use of this type of model in the last PGE rate case, docket UE 115, Order No. 01-777, 33. *See* Staff opening brief, 55; ICNU opening brief, 50. Staff further argues that PGE does not prove why the Commission should deviate from its earlier decision to not use the RPM. *See* Staff opening brief, 55.

In addition, Staff contends that PGE's RPM has several infirmities. Staff argues that PGE's RPM relies on decisions in other regulatory jurisdictions, leading to circular reasoning in which the Oregon commission relies on the Washington commission, which relied on the Oregon commission to make its ROE decision. *See* Staff opening brief, 56. Moreover, the model considers those decisions over a long period of time, which may take into account capital market conditions that may have changed. *See id.* at 56-57. Staff argues that PGE's RPM is not widely accepted and does not have a sound theoretical foundation. *See id.* at 57. PGE's RPM also does not consider such relevant factors as capital structure, resulting in omitted variable bias. *See id.* at 57-58.

ICNU notes that PGE uses a seven-year Treasury bond for its model, which ICNU argues is not reasonable because it reflects short-term market forces resulting in significant volatility. *See* ICNU opening brief, 50. ICNU requests that PGE perform its RPM using 30-year treasury bonds and notes that this adjustment reduces PGE's estimated ROE by 40-45 basis points. *See id.*

ICNU's Risk Premium Model

Mr. Gorman uses two risk premium methods to develop an ROE estimate first producing estimates of the equity risk premium. First he determines the difference between required return for utility equity investments and contemporary "Baa" rated utility bond yields on an annual basis from 1986 through June 2006, producing a range of equity risk premiums between 3 and 4.5 percent. *See* ICNU opening brief, 45. Using these results, Mr. Gorman adds the equity risk premium to the current 13-week average yield on "Baa" rated utility bonds for the period ending June 7, 2006, which was 6.6 percent, yielding an ROE in the range of 9.6 to 11.1 percent, with a midpoint of 10.4 percent. *See id.* The other method determines the difference between the required return for utility equity investments and Treasury bonds from 1986 through June 2006, using commission-authorized ROEs. *See id.* This results in a range of 4.4 to 5.9 percent, to which the estimated equity risk premium range to a projected long-term Treasury bond yield of 5.3 percent is added. *See id.* at 45-46. This produces an estimated ROE range of 9.7 percent to 11.2 percent, with a midpoint of 10.4 percent. The end result of the risk premium analysis is an estimated ROE of 10.4 percent. *See id.* at 46.

Staff asserts that ICNU's risk premium methodology has not been previously used by the Commission, and so there is no guidance on whether it is an appropriate tool to estimate ROE or measure the reasonableness of a ROE estimate. *See* Staff reply brief, 10. In any event, Staff notes that the model yields a 10.4 percent ROE estimate, below PGE's request of 10.75 percent ROE. *See id.*

PGE cites ICNU's risk premium model as supportive of PGE's cost of equity recommendation, because it produced a range of results similar to PGE's risk premium model, with an average return of 10.4 percent. *See* PGE opening brief, 19-20. ICNU notes that PGE did not dispute Mr. Gorman's recommendations as supporting a strong "BBB" and a weak "A" bond utility rating at PGE's business risk profile score of five. *See* ICNU opening brief, 51.

Capital Asset Pricing Model

The Commission also discussed the CAPM in docket UE 115:

> The CAPM is a risk premium analysis that calculates the expected equity return by adding a risk premium to a "risk free" rate of return. Risk is represented by the term "beta," which measures the stock's volatility relative to the market as a whole. The beta for the market is equal to one. Therefore, a stock with a beta greater than one is more risky than the average stock, while a stock with a beta of less than one is less risky than the average stock. The risk premium is generally calculated by multiplying the company's beta by the difference between the expected market return and the risk free rate.

Order No. 01-777, 29. The CAPM analysis contains three elements: the company's beta, the risk-free rate, and the market risk premium. *See* ICNU opening brief, 46.

PGE produces no CAPM analysis. Staff proposes a CAPM analysis as a "check" on its cost of equity estimate. *See* Staff/1400, Morgan/48. PGE asserts that Staff's CAPM analysis was faulty because it used an unsupported beta of 0.85. *See* PGE opening brief, 25.

Mr. Gorman does offer a CAPM analysis. First, he determines the value of the beta, which represents the investment risk that cannot be diversified away when the security is held in a diversified portfolio. *See* ICNU opening brief, 46. Mr. Gorman examines current and historical trend in beta estimates for his comparable group. *See id.* After adjusting for market conditions and the increasing utility risk, he uses an adjusted beta of 0.80. *See id.* To estimate the risk-free rate, he uses the projected 30-year Treasury bond yield of 5.3 percent. *See id.* To estimate the market risk premium, he uses a forward-looking estimate of 6.5 percent, and an historical estimate of 6.3 percent. *See id.* at 47. Putting the CAPM elements together, Mr. Gorman's analysis produces an ROE estimate of 10.4 percent. *See id.*

Decisions in Other Jurisdictions

PGE argues that Staff's recommended ROE is out of step with other state commission decisions around the country. *See* PGE opening brief, 25-27. PGE compiles a list of the authorized ROEs for companies used by Staff in its DCF analysis, indicating a range of ROEs from 10.8 to 11.1 percent. *See* PGE/2100, Zepp/12; PGE/2103, Zepp/1. In addition, PGE creates a chart showing ROEs adopted by regulatory commissions in recent months; the average ROE for electric or combined utilities is 10.47 percent. *See* PGE/2706, Hager-Valach/1. Further, PGE points to a recent Colorado commission decision allowing an ROE of 10.5 percent on a capital structure of 60 percent equity and 40 percent debt, for an overall rate of return of 8.85 percent and a PCAM account that allowed power costs to be trued-up using a deferred account. *See* PGE opening brief, 26. PGE argues that this decision supports its request for a 10.75 percent ROE because PGE has a more leveraged capital structure and a less complete power cost recovery framework than the utility considered by the Colorado commission. *See id.* at 27.

Staff argues that "the market sets the required ROE, not other Commissions." Staff/1400, Morgan/12. If the Commission were to consider decisions in other states, Staff urges consideration of the capital structures and other factors underlying the ROE decisions in other states. *See id.* at Morgan/13-14. Ultimately, Staff counters that "neither authorized COEs in other jurisdictions, taken alone, nor the order of the [Colorado Public Utilities Commission] are probative of the appropriate ROE for PGE." Staff reply brief, 9.

Overall Analysis

PGE

PGE advocates for an ROE range of 9.25 to 11.3 percent, with a point estimate of 10.75 percent, and a return on equity based on a 53.3 percent equity to 46.7 debt ratio. *See* PGE opening brief, 27. All of this assumes that the Commission approves the power cost adjustment mechanism requested by PGE; if the Commission does not, PGE argues that it will be subject to greater risks from volatile power costs, and the Commission should then approve a greater ROE to compensate for that risk. *See id.* at 27-28.

PGE recommends that the Commission use several sources of information to confirm the reasonableness of the results of the DCF models. *See* PGE opening brief, 25. PGE suggests that the Commission consider risk positioning and risk premium models, earned and authorized ROEs from other jurisdictions, use of the CAPM model as a check on DCF results, and other information. *See id.* PGE compares the ROEs of other companies to indicate the available opportunity cost that should be considered in a *Hope* or *Bluefield* analysis of PGE's ROE. *See id.* at 25-26. PGE also points to a chart showing the average ROE allowed for electric or combined utilities since January 2005 is 10.47 percent, and ICNU's CAPM analysis that reaches an ROE of 10.4 percent. *See id.* at 26. PGE also urges the Commission to consider risks specific to the Company: its reliance on purchased power, the absence of a power cost recovery mechanism, the perceived negative regulatory environment stemming from SB 408, and PGE's lack of jurisdictional diversity.

In Order No. 01-777, the Commission adopted guidelines for cost of equity witnesses, which stated that parties arguing a new or previously rejected approach should explain why the Commission should deviate from its past practice and adopt the other approach. Staff contends that PGE has not provided that explanation in advocating that the Commission, for the first time, consider Company-specific risk in estimating ROE. *See* Staff opening brief, 41-42. Moreover, Staff asserts that PGE has not quantified PGE-specific risk nor provided persuasive evidence as to what effect that risk should have on its ROE. *See id.* at 42. In addition, PGE's ROE estimate is based in part on an RPM, which the Commission has stated should not be used as a basis for a ROE estimate but may be used to measure the reasonableness of ROE estimates produced by other models. *See id.* Staff notes that the range results of PGE's RPM are much higher than the results produced by other models used in this case. *See id.* Staff also argues that the ROE that it recommends falls within the range considered acceptable by PGE, even though PGE's range is artificially high due to the use of the RPM model. *See id*. Finally, Staff notes that PGE based its ROE estimate on a capital structure of 56 percent equity to 44 percent debt, and the Company stated that the ROE would be reduced if the amount of equity would be reduced. In the final round of testimony, PGE proposes a reduction in its equity level, to 53 percent, with no corresponding adjustment to its ROE. *See id.* at 43.

Staff

Staff argues that PGE is entitled to an ROE in the range of 9.0 to 9.75 percent, specifically 9.40, coupled with a 50 percent equity layer and 50 percent debt ratio. Staff uses a variety of DCF models to a sample group of companies, along with a sensitivity analysis, to obtain its cost of equity estimate. *See* Staff opening brief, 45. Staff recommends that the Commission adhere to its traditional method of determining ROE by examining the integrity of the models used by the parties and the reasonableness of the models' results. *See id.* at 41. The Commission followed this method in dockets UE 115, UE 116, and UG 132. *See id.* Staff also urges the Commission to reject PGE's suggestion to consider *ad hoc* determinations about specific risks faced by PGE in Oregon. *See id.*

PGE asserts that Staff's ROE estimate is flawed because it is based on one methodology, the DCF formula, and does not benefit from cross-references with other models. *See* PGE opening brief, 18. PGE argues that Staff's recommended rate of return is 36 basis points lower than authorized for PacifiCorp in docket UE 179 and 50 basis points lower than the overall rate of return recommended by ICNU-CUB. *See id.* at 29 (updated figures from PGE reply brief, 4). PGE contends that Staff's recommended ROE, combined with its proposed disallowance of long-term debt costs and capital structure would result in a very low rate of return that does not reflect PGE's circumstances, including its reliance on purchased power and the related debt imputation. *See* PGE opening brief, 29. Staff's exclusive reliance on the DCF model yields an extremely low recommendation of 9.4 percent, and Staff does not consider other information that would indicate that their recommendation is too low. *See id.* at 18-19. Moreover, Staff's analysis contains several errors, argues PGE, which if corrected, would support an ROE closer to 10.75 percent. *See id.* at 19.

PGE characterizes Staff's recommended ROE as extremely low, and a possible threat to PGE's stock price. *See* PGE opening brief, 28. PGE has a current secured bond rating of BBB+, and a rating for unsecured debt of BBB, which the Company argues is a slim margin. *See id.* at 29. PGE argues that a low ROE by this Commission would indicate an unfavorable regulatory environment, thereby driving down its credit ratings. *See id.* at 30. Staff responds that PGE's assertion that adoption of Staff's recommendation would drive down its credit ratings is highly speculative, and that, because evidence shows that PGE intends an equity level of 50 percent, the Commission should set a corresponding cost of equity. *See* Staff opening brief, 53.

ICNU

ICNU's and CUB's expert, Mr. Gorman, recommends a 9.9 percent ROE for PGE based on applying three different analyses to his proxy group of comparable utilities. *See* ICNU opening brief, 41. Those three analyses employ three models: the constant growth DCF model, the bond yield plus equity risk premium model, and the CAPM. *See id.* at 42. Mr. Gorman applies these models to a proxy group of publicly traded utilities that are comparable to PGE in terms of total risk, based on criteria that reflect bond ratings and overall business risk similar to PGE. *See id.* at 42-43. Applying the three ROE models to the proxy group yielded a range of ROE estimates from 9.5 percent to 10.4 percent, with the constant growth DCF analysis producing a low-end estimate, and the risk premium and CAPM analyses produced the high-end estimate. *See id.* at 43.

ICNU asserts that PGE does not refute ICNU's analysis, only argues that there are PGE-specific risks that make it more risky than the companies in Mr. Gorman's sample group. *See* ICNU opening brief, 47. However, ICNU claims that PGE has not provided evidence regarding PGE-specific risk. *See id.* at 47, 51-57. ICNU disputes PGE's proposed 10.75 percent ROE, asserting that the estimate relied on a number of growth rate estimates that significantly overstate PGE's current cost of equity. *See id.* at 48. After PGE's unreasonable assumptions are removed, PGE's analysis of its cost of equity falls within Mr. Gorman's recommended range of 9.5 to 10.4 percent. *See id.*

PGE argues that ICNU's recommended ROE of 9.9 percentage points does not fairly reflect their analysis and does not consider PGE-specific risks. *See* PGE opening brief, 28. PGE contends that ICNU's risk premium analysis and average return estimate of 10.4 percent is similar to the Company's risk positioning models which produced a range of 10.5 percent to 11.3 percent. *See id.* at 18. For these reasons, PGE asserts that ICNU's analysis supports PGE's recommended ROE.

Resolution

We begin with a review of the approaches discussed in this case. We affirm the position taken by the Commission in docket UE 115, that the Commission will not rely on rates authorized in other jurisdictions to determine ROE, but will use those decisions to gauge the reasonableness of our decision. *See* Order No. 01-777, 34. In addition, for the reasons given in docket UE 115, we reject the risk positioning model. *See id.* at 33. We find, based on the evidence in this record, that the reasoning expressed in that order remains sound.

In reviewing the positions advocated by each party, we find that the results of Staff's DCF models were uniformly low, based on PGE's testimony that Staff's sample was not representative of PGE. On the other hand, PGE's estimate, based on an unrealistically ambitious rate of growth and unproven PGE-specific risks, was too high.

We find Mr. Gorman's framework to be a suitable starting point for our discussion of ROE. His framework uses a group of proxy companies that PGE found suitable, and he cross-checked his DCF results against several other methods. However, we note that PGE still has significant exposure to the wholesale market, particularly when compared to PacifiCorp which has a 10.0 percent cost of equity. Therefore, in balancing the results of the models, and in consideration of PGE's risk exposure, we find that a more appropriate cost of equity for PGE is 10.1 percent. Moreover, in combination with our decisions on PGE's cost of debt and PGE's capital structure as 50 percent equity and 50 percent debt, we conclude that this will provide PGE with a fair and reasonable rate of return.

Accordingly, we adopt this 10.1 percent as a fair and reasonable cost of equity for PGE. Evidence shows that this return will allow PGE to maintain a sound financial structure and attract capital at a reasonable cost. Using this figure in connection with other stipulated capital costs and the other decisions made in this order yields a rate of return for PGE of 8.29 percent.

Capital Component	**Ratio**	**Cost**	**Weighted Cost**
Debt	50 %	6.48%	3.24%
Equity	50 %	10.1 %	5.05 %
Total	100 %		8.29%

PORT WESTWARD RELATED ISSUES

ICNU and CUB raise several arguments regarding the impact of Port Westward on PGE's estimates of power costs. Further, CUB expresses concern about whether the decisions made in this case will still be valid if the opening of Port Westward is significantly delayed, which are acknowledged by PGE, and PGE and CUB propose conditions to resolve those concerns. Finally, CUB voices a general concern about PGE's progress on its Integrated Resource Plan (IRP) Action Plan and how elements or items in that plan are implemented and reflected in rates. We address each issue in turn.

Impact of Port Westward on Power Costs

Rates Before Port Westward Goes Into Service

CUB believes PGE's model results in inappropriately high costs for the months of replacement power until Port Westward goes into service. *See* CUB opening brief, 27-28. CUB describes PGE's modeling for the power costs for January and February as follows: the MONET input contains an actively managed position for January and February, and MONET fills the open position for March through December based on market price forecasts, which are not actively managed. *See id.* at 28. The model then adds together the lesser costs for the first two months with the higher costs for the next 10 months, and prorates the costs for January and February, resulting in inappropriately high costs for January and February. *See id.* CUB asserts that the model should instead account for Port Westward's costs in the last 10 months, so that costs for January and February are not inappropriately weighted and more closely resemble the anticipated costs. *See id.* at 29. CUB notes that PacifiCorp agreed to a similar position in docket UE 170. *See id.* at 30.

PGE counters that Port Westward's impact on rates should not be considered until it is "used and useful" and fully included in rates. *See* PGE reply brief, 37. Further, PGE argues that the effect of the phantom open position on the MONET model is the same as the calculation with Port Westward. *See id.* PGE concludes that CUB's position should be rejected because it is unnecessarily complicated and would not produce dramatically different results. *See id.*

Resolution

CUB's argument is predicated on the assumption that rates based on the unmanaged position assumed for the last 10 months are necessarily higher than rates based on a managed position for the entire year. However, it does not provide evidence for that assumption; in fact, there are scenarios in which advance contracts signed during a time of elevated prices could result in higher rates than spot purchases on the open market. In any event, the proper comparator is the amount of the costs that reflect a managed position that PGE could have taken, not the costs of Port Westward. We do not find evidence in the record to make that determination, and so decline to make the adjustment recommended by CUB.

Rates After Port Westward Goes Into Service

ICNU argues that PGE understated the value of the Port Westward dispatch benefits by $2 million. *See* ICNU opening brief, 30. The Company computed the Port Westward effect by taking the ratio of the 10-month dispatch benefit to the 10-month load, times the 12-month load. ICNU believes that this methodology understates the value of the dispatch benefit. ICNU asserts that it is reasonable to assume that Port Westward would run without interruption in the first two months of the year, providing a conservative estimate of the dispatch benefit because it could include hours when the market price is below the dispatch cost, and resulting in a "negative credit" for those hours. *See* ICNU/103, Falkenberg/21-22. ICNU's proposed resolution would result in an adjustment that would take place when Port Westward goes into rates. *See* ICNU opening brief, 30.

PGE responds that it properly computed Port Westward in rates that would be in effect only during the period when the plant would be in service, and that ICNU's assumptions for January and February are irrelevant to the calculation. *See* PGE reply brief, 36.

Resolution

We adopt ICNU's adjustment. PGE concedes that it did not properly consider the full 12 months of operation of Port Westward. *See* PGE/1900, Tinker-Schue-Drennan/51. After consideration of a full year of Port Westward operation, we conclude that ICNU's adjustment is appropriate.

Provisions for Delay in Opening Port Westward

CUB argues that, by examining Port Westward now, the Commission is unable to evaluate the other costs that may be offset by the new plant, and that PGE is attempting to defeat the regulatory lag between approval of the final tariffs in this rate case and the date on which Port Westward goes online. *See* CUB opening brief, 25-26. Port Westward represents a $45 million addition to PGE's revenue requirement, and a $279 million addition to rate base, an almost 16 percent increase. *See id.* at 26. To mitigate its concerns, CUB proposes the following conditions for recovery of Port Westward costs:

- The tariff associated with Port Westward should only be valid within 30 days of March 1, 2007.

- If Port Westward is not used and useful within 30 days, PGE must reopen docket UE 180, and Staff and intervenors should be provided a limited period of time to review PGE's actual costs to determine whether there is new information that requires a re-examination of PGE costs before Port Westward is included in rates.

- After six months, if Port Westward is not used and useful, the Company must file a new rate case in order to add the plant to rate base when it meets the used and useful standard.

See CUB opening brief, 27.

PGE acknowledges CUB's concerns, but asserts that the 2007 test year revenue requirement will not become stale in the short periods recommended by CUB. *See* PGE opening brief, 49. Instead, PGE recommends that, if the Commission adopts CUB's conditions, the Commission should allow three months before reopening docket UE 180, and not require a new rate case unless Port Westward does not open in 2007. *See id.* CUB appreciates PGE's acknowledgement of its concerns, but seeks approval of its initially proposed conditions. *See* CUB opening brief, 27.

Resolution

As PGE agrees, CUB raises a legitimate point as to the validity of the assumptions regarding Port Westward if its opening is delayed. To allow flexibility for PGE, we conclude that the decisions made in this consolidated case will prevail, as long as Port Westward becomes operational within 60 days of the estimated March 1, 2007, online date. If Port Westward becomes operational on or after April 30, and before September 1, 2007, Staff and intervenors will have 15 days from the online date to determine whether there is new information that requires a re-examination of PGE's costs in rates. If Port Westward does not become operational until after September 1, 2007, PGE must file an entirely new rate case to add the plant to rate base when it meets the used and useful standard.

Progress on Integrated Resource Plan

CUB believes that development of Port Westward may be considered prudent if PGE is also making progress in developing the significant renewable energy component, but Port Westward may not be prudent in the absence of development of renewable energy resources in PGE's IRP Action Plan. *See* CUB opening brief, 21. CUB claims that Staff's initially agreed with this position, but later stated that individual resource decisions may be prudent even if the Action Plan implementation is imperfect. *See id.* (citing Staff response to PGE Data Request #085, PGE/2501, Lobdell/1). PGE presented additional evidence regarding its development of wind resources at the Biglow Canyon site, so CUB is satisfied with PGE's progress, but remains concerned about the perceived shift in Staff policy. *See* CUB opening brief, 21-24.

PGE argues that it has made sufficient progress on the Biglow Canyon project to show advancement in all areas of its final action plan. *See* PGE opening brief, 48-49. PGE contends that the Commission did not require that all actions must be completed at the same time, or in a particular order, and that such a condition would unduly restrict PGE's ability to acquire resources at the best prices for customers. *See id.* at 49. Further, PGE expresses concern with CUB's suggestion that the Commission could later find costs related to Port Westward imprudent if it does not acquire renewable resources on a schedule acceptable to CUB. *See* PGE reply brief, 34-35.

Resolution

We appreciate CUB's concerns that PGE make adequate progress on all aspects of its IRP, particularly in the area of renewable resources, and we will continue to monitor the Company's ongoing efforts. However, we review costs for prudence in light of the circumstances present at the time that the commitment is made to incur those costs. If at a later time we find that PGE is not making proper decisions regarding acquisition of renewable resources, we will evaluate those alternative resource decisions for prudence, not the decisions related to Port Westward.

TAX ISSUES

The City of Portland (City) raises several issues related to PGE's tax planning and past activities, and requests that the Commission require certain actions by PGE. The Company responds in testimony and brief, and Staff comments in its reply brief; both urge the Commission to reject the City's arguments.

First, the City argues that the Commission should impute the tax benefits of reasonable and prudent steps that PGE could have taken to reduce its effective tax rate. One option would have been for PGE to convert its corporate form to a limited liability company (LLC). *See* COP/100, Jubb/5-10. The City later states that it does not advocate that PGE should have been required to follow a specific process of corporate reorganization; rather, the City asserts that utility management could have engaged in reasonable tax planning that would have benefited ratepayers. *See* COP opening brief, 4. PGE responds that the City's LLC proposal would have generated little, if any, net savings for customers, but would potentially have exposed PGE and its customers to penalties, accrued back taxes and interest, rendering the process imprudent and impractical. *See* PGE/1700, Piro-Tamlyn/8. Moreover, PGE would have had to secure approvals from a wide variety of entities, including Enron and the IRS, incur substantial legal costs in evaluating and implementing the plan, and possibly create additional risk for PGE which would have led to elevated borrowing costs. *See id.* at Piro-Tamlyn/ 13-15. Staff adds that the City was neither able to quantify the benefits of the corporate structure change nor completely evaluate the negative consequences of such a change. *See* Staff reply brief, 35-36.

Second, the City argues that PGE should refund to ratepayers the tax payments made to Enron without prior express authorization by the Commission. The City points to conditions in the Enron acquisition of PGE, in which Enron was required to give notice to the Commission if it transferred more than five percent of PGE's retained earnings within a six month period, received a special cash dividend from PGE, or received a quarterly common stock cash dividend payment from PGE. *See* COP opening brief, 10-11 (citing UM 814, Order No. 97-196). The City argues that these tax payments were actually payments in exchange for Enron's net operating losses, which eliminated PGE's tax liability, and so should have been made pursuant to an affiliated interest contract. *See* COP opening brief, 11-14. PGE notes that the matter was resolved discussed in UM 1262, and referred to its arguments made in that docket. *See* PGE reply brief, 41. Staff further argues that PGE's payments were not made under an affiliated interest contract, and so did not need Commission approval. *See* Staff reply brief, 36.

Third, the City argues that PGE should undertake practical and prudent tax planning methods to reduce income tax burdens upon ratepayers. *See* COP opening brief, 15-16. In its initial filing, PGE asks the Commission to adopt a tax rate of 39 percent. *See* PGE/200, Tooman-Tinker/14. The City argues that PGE has no incentive to engage in tax planning where the Company can simply pass the costs along to ratepayers. *See* COP opening brief, 16. For this reason, the City asks the Commission to actively monitor PGE's effective tax rates and related tax planning. *See id.* at 16-17. PGE counters that it has incentives to engage in prudent tax planning as it is, and must file annual tax reports with the Commission pursuant to the SB 408 process. *See* PGE/1700, Piro-Tamlyn/4-6. For these reasons, PGE disagrees that any additional steps recommended by the City are necessary. *See id.*

Fourth, the City argues that as PGE's deferred income taxes become due, they will be included in the annual SB 408 adjustment clause, resulting in a double-billing to customers who already paid for taxes in their rates. *See* COP opening brief, 17-18. The City argues that PGE should refund to ratepayers the amount of deferred taxes to prevent this double-billing. *See id.* PGE argues that the SB 408 adjustment clause is adjusted for deferred taxes, and to follow the City's recommendation would violate normalization requirements and "cost customers approximately $25 million per year by elimination of the rate base offset for deferred income taxes." PGE/1700, Piro-Tamlyn/16. Staff responds that the City misunderstands how income tax expense is calculated for ratemaking purposes. *See* Staff reply brief, 36-37. Staff points to SB 408, in which all deferred tax effects will be recognized, and asserts that the City's argument should be rejected. *See id.*

Resolution

In reviewing prior actions of PGE, the Commission examines whether the resulting costs would have been incurred by reasonable utility management, in good faith, under the same circumstances, and at that point in time. In hindsight, it may be clear that a management decision was wrong, but the Commission's task is to review the prudence of the utility's actions and the resulting costs based on the particular circumstances existing either at the time the costs were actually incurred, or at the time the utility became committed to incur those expenses. *See New England Power Company*, 31 FERC P61,047, 1985 FERC LEXIS 3217, ** 18 (April 11, 1985) (cited with approval by *City of New Orleans v. FERC*, 67 F3d 947, 954 (1995)).

Applying this analysis to PGE's action to not convert to an LLC, we cannot conclude that PGE's course of action was imprudent. In light of the financial pressures that PGE was facing during the time of Enron's bankruptcy, we are persuaded by PGE's testimony that this action would have exposed the Company to greater financial risk, and that PGE acted prudently in not following the course of action advocated by the City. The City also asks the Commission to impute tax benefits from other tax reduction tactics, but does not specify what those tactics might be, or quantify any resulting benefits. However, the City does not point to any other particular tax reduction strategies that PGE should have taken, or cite actions taken by PGE that were imprudent. In light of the aforementioned legal standard, the City's first argument does not provide sufficient information for our consideration.

As to the City's second argument, that the Commission should revisit PGE's tax payments to Enron as illegal affiliated interest payments, we note that the Commission has already addressed these arguments in docket UM 1262. In dismissing the City's complaint in that case, the Commission concluded that the Tax Allocation agreement was not an affiliated interest contract. *See* Order No. 06-636, 6-7. Further, PGE does not seek in this proceeding to put into rates any payments under that agreement. The City's second argument is also rejected.

As to the City's third argument, the Commission has reviewed this rate case thoroughly to determine that the rates are just and reasonable. Moreover, the Commission will continue to review PGE's rate filings for whether the Company's actions were prudent, and will review future tax filings and carefully evaluate PGE's annual tax automatic adjustment clause.[9] Additional proceedings would be redundant and unnecessary, so we decline the City's suggestions to require further filings from PGE.

Finally, the City's suggestion that PGE should repay deferred taxes in light of the SB 408 adjustment misunderstands how income tax expense is calculated for

[9] In the annual SB 408 tax report filing, the utilities must identify the amount of income taxes paid, either by the public utility itself, or its consolidated group, and properly attributed to the utility, and the amount of taxes authorized to be collected in rates during specified time periods.

ratemaking purposes. Ratepayers are not charged twice for deferred taxes. Instead, rates reflect book depreciation, not tax depreciation under tax normalization rules. Thus, income tax expense reflected in customer rates inherently contains temporary differences and is higher in the early years of an asset and lower by the same amount in later years. Under SB 408, all deferred tax effects will be recognized, including the lower tax expense for ratemaking when the deferred tax liability reverses. For these reasons, we decline to adopt the City's request for a refund for deferred taxes.

RECOVERY OF TROJAN EXPENSES

PGE and EWEB both pay into a fund for Trojan decommissioning. *See* PGE/1000, Quennoz-Nichols/2-9; EWEB brief, 1. PGE proposes to reduce the annual amount it pays to the Nuclear Decommission Trust (NDT) from $14.04 million, to $4.65 million, and to take $20 million out of the NDT for a one-time refund to customers. *See* PGE/1000, Quennoz-Nichols/1. EWEB asserts that, whether or not the Commission approves this request, it should state that PGE can collect from ratepayers for decommissioning until it is complete, beyond the currently stated 2011 deadline. *See* EWEB brief, 2. EWEB argues that the 2011 deadline is no longer valid because the federal government is taking longer than expected to build the waste repository than was originally projected. *See id.* at 1. EWEB and PGE now expect to maintain waste on-site until at least 2023. *See id.* at 2. PGE states that EWEB's request is consistent with its proposal, and PGE does not object to EWEB's request. *See* PGE reply brief, 46.

Resolution

The Commission originally stated that the collections from ratepayers for Trojan decommissioning would continue through 2011. *See* UE 88, Order No. 95-322, 57. Originally, the collections were to coincide with the period for which Trojan would provide power to PGE customers, so that the customers who would have benefited from Trojan also paid for its decommissioning. *See* UE 88, Order No. 95-322. In light of PGE's request and change in its tariffs, which have not been challenged, we find EWEB's arguments to be compelling. We conclude that PGE has the authority to continue collecting money from ratepayers until decommissioning is complete.

CONCLUSIONS

1. Portland General Electric Company (PGE) is a public utility subject to the Commission's jurisdiction.

2. The stipulations, attached as Appendices A, B, C, and D should be adopted.

3. Based on the record in this case, PGE's rates that result from the stipulations and the Commission's conclusions in the body of this order are just and reasonable. A summary of the Commission's decisions is attached as Appendix E, and the results of operations spreadsheet is attached as Appendix F.

4. The Commission should open a new docket to review the appropriate method for determining the forced outage rate for generating plants, and after PGE submits its report on stochastic modeling, the Commission should open a new docket to consider whether stochastic modeling should be used to forecast net variable power costs.

ORDER

IT IS ORDERED that:

1. Advice No. 06-8, filed on March 15, 2006, and Advice No. 06-10, filed on April 24, 2006, by Portland General Electric Company are permanently suspended.

2. The stipulations attached as Appendices A, B, C, and D are adopted in their entirety.

3. PGE shall file revised tariffs consistent with findings of fact and conclusions of law contained in this order, to be effective no earlier than January 14, 2007, for rates excluding costs related to the Port Westward generating facility.

4. PGE shall file revised tariffs consistent with the findings of fact and conclusions of law contained in this order related to Port Westward no earlier than March 1, 2007, and no later than April 30, 2007. The filing must include attestation by a PGE corporate officer that Port Westward's operational testing has been completed and the plant has been released to the system dispatcher for full communal operation.

5. The Commission shall open a new docket to review the appropriate method for determining the forced outage rate for generating plants after PGE submits its report on stochastic modeling, the Commission shall open a new docket to consider whether stochastic modeling should be used to forecast net variable power costs.

Made, entered, and effective JAN 1 2 2007.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

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),	STIPULATION REGARDING REVENUE REQUIREMENT ISSUES
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision relating to the Port Westward Plant (UE 184).	

This Stipulation ("Stipulation") is among Portland General Electric Company ("PGE") Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board of Oregon, the Industrial Customers of Northwest Utilities, and Fred Meyer Stores, (collectively, the "Stipulating Parties").

I. INTRODUCTION

On March 15, 2006, PGE filed Advice No. 06-8 for a general rate revision to increase its retail rates by about $98 million. The filing was based on a projected test year of 2007 and was docketed as UE 180. The advice filing was suspended by the Commission, and on April 4, 2006, the Administrative Law Judge held a Prehearing Conference and established a procedural schedule. On April 24, 2006, PGE filed Advice No. 06-10, to reflect in rates the Port Westward generation plant when it comes into service for customers, currently anticipated to be about March 1, 2007. That filing was docketed as UE 184, and was also suspended by the Commission. Dockets UE 180, UE 184 and UE 181 (PGE's 2007 RVM filing), have all been consolidated.

Pursuant to the procedural schedule adopted by the Administrative Law Judge, Staff and Intervenors published settlement proposals on July 6, 2006. Staff also published a revised settlement proposal on July 12, 2006. Settlement Conferences were commenced on July 13, 14 and 17, 2006, and were continued on July 20 and 24. The Settlement Conferences were open to all parties. As a result of those settlement discussions, the Stipulating Parties have agreed to a reduction in PGE's requested revenue requirement with respect to specified adjustments. The Stipulating Parties submit this Stipulation to the Commission and request that the Commission adopt orders in this docket implementing the following.

II. TERMS OF STIPULATION

1. This Stipulation is entered to settle all revenue requirement issues except cost of capital, power costs, Port Westward, and AMI.

2. The Stipulating Parties agree that PGE will reduce its revenue requirement request, and make rate base modifications, to reflect the adjustments listed in Attachment A to this Stipulation. The parties agree to calculate the revenue requirement impact of the adjustments listed in Attachment A consistent with the final Commission approved cost of capital in this case.

3. The Stipulating Parties recommend that the Commission approve the various tariff, rate base, expense and other revenue adjustments described in Attachment A.

4. The Stipulating Parties agree that this Stipulation represents a compromise in the positions of the parties. As such, conduct, statements, and documents disclosed in the negotiation of this Stipulation shall not be admissible as evidence in this or any other proceeding. The Stipulating Parties agree that they will not cite this Stipulation as precedent in any other proceeding other than a proceeding to enforce the terms of this Stipulation.

5. The Parties agree that this Stipulation is in the public interest and will result in rates that are fair, just and reasonable.

6. If this Stipulation is challenged by any other party to this proceeding, or any other party seeks a revenue requirement for PGE that departs from the terms of this Stipulation, the Stipulating Parties reserve the right to cross-examine witnesses and put in such evidence as they deem appropriate to respond fully to the issues presented, including the right to raise issues that are incorporated in the settlements embodied in this Stipulation. Notwithstanding this reservation of rights, the Stipulating Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation.

7. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order which is not contemplated by this Stipulation, each Party reserves the right to withdraw from this Stipulation upon written notice to the Commission and the other Parties within five (5) business days of service of the final order that rejects this Stipulation or adds such material condition.

8. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR § 860-14-0085. The Stipulating Parties agree to support this Stipulation

throughout this proceeding and in any appeal, provide witnesses to sponsor this Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained herein. The Stipulating Parties also agree to cooperate in drafting and submitting the explanatory brief or written testimony required by OAR § 860-14-0085(4).

9. By entering into this Stipulation, no Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other Party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

10. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this 24th day of August, 2006.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

throughout this proceeding and in any appeal, provide witnesses to sponsor this Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained herein. The Stipulating Parties also agree to cooperate in drafting and submitting the explanatory brief or written testimony required by OAR § 860-14-0085(4).

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DATED this 24th day of August, 2006.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

CITIZENS' UTILITY BOARD OR OREGON

INDUSTRIAL CUSTOMERS OF
NORTHWEST UTILITIES

FRED MEYER STORES

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Attachment "A"

The Stipulated adjustments to PGE's advice filing are described below. The revenue requirement impact of each adjustment will be determined once the Cost of Capital issue is decided.

S-1	Taxes Other Than Income:	Reduce O&M costs by $2,267,000.
S-3	O&M / A&G:	Reduce O&M costs by $6,551,000, which consists of $34,000 in Transmission O&M, $1,623,000 in Distribution O&M, and $4,894,000 in A&G.
S-5	Incentives:	Reduce O&M costs by $4,366,000, and reduce rate base by $1,271,000.
S-6	Wages/Salaries:	Reduce O&M costs by $3,534,000, and to reduce rate base by $1,029,000.
S-8	Other Revenue:	Increase Other Revenue by $40,000.
S-9	Capital Expenditures:	Reduce rate base by $7,000,000.
S-11	System Losses:	No change to PGE's filed Line Loss Study.
S-12	Memberships:	Reduce O&M costs by $82,000.
S-13	Tenant Improvements:	No change to PGE filed case.
S-14	Weatherization:	Reduce O&M costs by $69,000, with the ability of PGE and other parties to present testimony and argument, and seek a Commission decision, regarding the policy behind these expenses.
S-15	Customer Service/Accounts:	Reduce O&M costs by $1,575,000.

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),	STIPULATION REGARDING RATE SPREAD AND RATE DESIGN ISSUES
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision relating to the Port Westward Plant (UE 184).	

This Stipulation ("Stipulation") is among Portland General Electric Company ("PGE") Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board of Oregon, the Industrial Customers of Northwest Utilities, and Fred Meyer Stores, (collectively, the "Stipulating Parties").

I. INTRODUCTION

On March 15, 2006, PGE filed Advice No. 06-8 for a general rate revision to increase its retail rates by about $98 million. The filing was based on a projected test year of 2007 and was docketed as UE 180. The advice filing was suspended by the Commission, and on April 4, 2006, the Administrative Law Judge held a Prehearing Conference and established a procedural schedule. On April 24, 2006, PGE filed Advice No. 06-10, to reflect in rates the Port Westward generation plant when it comes into service for customers, currently anticipated to be about March 1, 2007. That filing was docketed as UE 184, and was also suspended by the Commission. Dockets UE 180, UE 184 and UE 181 (PGE's 2007 RVM filing), have all been consolidated.

Settlement conferences regarding rate spread and rate design issues were held on August 25, 2006 and September 5, 2006. As a result of those settlement discussions, the Stipulating Parties have agreed to the terms of this Stipulation, and request that the Commission adopt orders in this docket implementing the following.

II. TERMS OF STIPULATION

1. This Stipulation is entered to settle all rate spread and rate design issues among the Parties except issues regarding Schedule 76R, Economic Replacement Power raised by ICNU.

2. The Stipulating Parties support the rate spread/rate design proposal filed by PGE in this docket with the following changes:

   a. The parties agree that the pricing for Schedule 102 Regional Power Act Exchange Credit will be on an equal cents per kWh basis for all Schedules except Schedule 7. The Schedule 102 pricing for Schedule 7 will be on an inverted block basis. The first block will remain at the current level of 250 kWh with the second block consisting of all kWh greater than 250. A price differential of at least 1.75 cents per kWh will be maintained between the two blocks.

b. Regarding the Schedule 83/583 primary voltage facilities charge, the costs associated with single-phase service will be removed from the calculated prices in a manner similar to that proposed in PGE Response to Fred Meyer data request No. 002. Additionally, the distribution demand charge for Schedule 83/583-P will not be blocked, but rather implemented as a flat demand charge for this Schedule. The distribution demand charge for Schedule 83/583-S will continue to be blocked in order to provide a smooth transition for customers who migrate between Schedules 32 and 83-S.

c. In order to mitigate the rate change differential between Schedule 83/583-S and Schedule 83/583-P, the parties agree to an additional CIO credit of 0.50 mills/kWh applied to Schedule 83/583-P, recovered from Schedule 83/583-S. PGE estimates that this will result in an additional 0.03 mills/kWh charge for Schedule 83/583-S.

d. PGE agrees to seek implementation of transmission demand charges based on on-peak demand for Schedule 83 should the appropriate metering be installed for all Schedule 83 customers prior to PGE's next general rate case.

e. Schedule 75, Partial Requirements Service, will be modified as shown in Attachment "A" to this Stipulation.

f. The parties agree that the calculation of the Customer Impact Offset (CIO) will be made such that for all Schedules the rate increase will be limited to 2.0 times the overall increase when compared to 2006 prices, except that the maximum CIO credit is 3.5 cents/kWh. Furthermore, no Schedule that otherwise would receive a rate increase of less than 5% will receive a CIO credit.

3. The Stipulating Parties request and recommend that the Commission approve all tariff revisions necessary to implement the terms of this Stipulation.

4. The Stipulating Parties agree that this Stipulation represents a compromise in the positions of the parties. As such, conduct, statements, and documents disclosed in the negotiation of this Stipulation shall not be admissible as evidence in this or any other proceeding. The Stipulating Parties agree that they will not cite this Stipulation as precedent in any other proceeding other than a proceeding to enforce the terms of this Stipulation.

5. The Parties agree that this Stipulation is in the public interest and will result in rates that are fair, just and reasonable.

6. If this Stipulation is challenged by any other party to this proceeding, or any other party seeks a revenue requirement for PGE that departs from the terms of this Stipulation, the Stipulating Parties reserve the right to cross-examine witnesses and put in such evidence as they deem appropriate to respond fully to the issues presented, including the right to raise issues that are incorporated in the settlements embodied in this Stipulation. Notwithstanding this reservation of rights, the Stipulating Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation.

7. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order which is not contemplated by this Stipulation, each Party reserves the right to withdraw from this Stipulation upon written notice to the Commission and the other Parties within five (5) business days of service of the final order that rejects this Stipulation or adds such material condition.

8. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR § 860-14-0085. The Stipulating Parties agree to support this Stipulation throughout this proceeding and in any appeal, provide witnesses to sponsor this Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained herein. The Stipulating Parties also agree to cooperate in drafting and submitting the explanatory brief or written testimony required by OAR § 860-14-0085(4).

9. By entering into this Stipulation, no Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other Party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

10. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this 4th day of October, 2006.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

8. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR § 860-14-0085. The Stipulating Parties agree to support this Stipulation throughout this proceeding and in any appeal, provide witnesses to sponsor this Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained herein. The Stipulating Parties also agree to cooperate in drafting and submitting the explanatory brief or written testimony required by OAR § 860-14-0085(4).

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DATED this day of September, 2006.

PORTLAND GENERAL ELECTRIC COMPANY

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CITIZENS' UTILITY BOARD OR OREGON

INDUSTRIAL CUSTOMERS OF
NORTHWEST UTILITIES

FRED MEYER STORES

Attachment A , Rate Spread / Rate Design Stipulation
SCHEDULE 75
PARTIAL REQUIREMENTS SERVICE

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers supplying all or some portion of their load by self-generation operating on a regular basis, where the self-generation has a total nameplate rating of 2 MW or greater. A Large Nonresidential Customer is a Customer that has exceeded 30 kW at least twice within the preceding 13 months, or with seven months or less of service has had a Demand exceeding 30 kW.

MONTHLY RATE

The sum of the following charges at the applicable Delivery Voltage per Point of Delivery (POD)*:

	Delivery Voltage		
	Secondary	Primary	Subtransmission
Basic Charge	$130.00	$230.00	$1,000.00
Transmission and Related Services Charge			
per kW of monthly On-Peak Demand	$0.66	$0.66	$0.66
Distribution Charges			
The sum of the following:			
per kW of Facility Capacity			
First 1,000 kW	$2.33	$2.17	$2.17
Over 1,000 kW	$0.40	$0.24	$0.24
per kW of monthly On-Peak Demand	$2.45	$2.45	$1.28
Generation Contingency Reserves Charges			
Spinning Reserves			
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234
Supplemental Reserves			
per kW of Reserved Capacity > 2,000 kW	$0.234	$0.234	$0.234
System Usage Charge			
per kWh	0.206 ¢	0.186 ¢	0.178 ¢
Energy Charge			
per kWh	See Energy Charge Below		

* See Schedule 100 for applicable adjustments.

SCHEDULE 75 (Continued)

BASELINE DEMAND

Baseline Demand is the Demand normally supplied by the Company to the Large Nonresidential Customer when the Customer's generator is operating as planned by the Customer. Initially, the Customer's Baseline Demand will be the Customer's typical peak Demand for the most recent 12 months prior to installing the generator, adjusted for planned generator operations. Subsequently, Customer may select its Baseline Demand in accordance with the applicable notice requirements set forth in this schedule adjusted for changes in load and planned generator operations. Planned generator operations include the Electricity planned to be produced by the generator as well as the Customer's plans to sell Electricity produced by the generator to the Company or third parties. The Company and Customer may mutually agree to use an alternate method to determine the Baseline Demand when the Customer's Demand is highly variable. Any modification to the Baseline Demand must be consistent with the Special Conditions.

For Customers who are also receiving service under Schedule 76R, monthly Demand charges under Schedule 75 will be based on Demand up to the Baseline Demand.

FACILITY CAPACITY

For the first three months of service under this schedule, the Facility Capacity will be equal to the Customer's Baseline Demand. Starting with the fourth month, the Facility Capacity will be the average of the two greatest non-zero monthly Demands established during the 12-month period which includes and ends with the current Billing Period, but will not be less than the Customer's Baseline Demand.

RESERVED CAPACITY

The Reserved Capacity is the lesser of the nameplate rating of the Customer's generation or the maximum kW of Customer load supplied by the Customer's generation. Additionally, upon agreement with the Customer, the Company will reduce the Reserved Capacity by the Customer's demonstrated, instantaneous load reduction capability in kW associated with generation output reductions.

The Customer and Company will enter into a written agreement that specifies the Reserved Capacity in kW, the load reduction capability in kW (if any), the requirements for Customer notification to the Company of any changes in the Reserved Capacity, the Company's ability to request a demonstration of load reduction capability annually, additional metering requirements and any other necessary notification requirements.

Except during the first three months of operation, if the Customer's operations result in an actual Reserve Capacity requirement above the level specified by the agreement, the Reserved Capacity will immediately be adjusted to the actual kW level for that month and the following three months. Thereafter, the Reserved Capacity will remain at that increased kW level until the Customer has demonstrated to the Company's reasonable satisfaction that the Reserved Capacity should be revised.

SCHEDULE 75 (Continued)

GENERATION CONTINGENCY RESERVES

Generation Contingency Reserves consist of the following components:

Spinning Reserves

Spinning Reserves provide Electricity immediately after a Customer's generator output falls below the Reserved Capacity. Spinning Reserves in combination with Supplemental Reserves transition a Customer's load to Unscheduled Power. A Customer on Schedule 75 must take Spinning Reserves in all Billing Periods that its generator is expected to operate. Spinning Reserves are not required for a Customer with Reserved Capacity of 2,000 kW or less, or when the Customer's generator is not normally scheduled to operate during an entire Billing Period.

Supplemental Reserves

Supplemental Reserves provide Electricity within the first 10 minutes after a Customer's generator output falls below the Reserved Capacity. In lieu of purchasing Supplemental Reserves, a Customer may choose to reduce load within the 10 minutes of generator failure. The Customer's Load Reduction Plan must be approved by the Company.

Self-Supplied Reserves

Customers with nameplate Generation of 15 MW or greater may self-supply needed Generation Contingency Reserves upon agreement between Customer and the Company. The agreement will specify the kW of Contingency Reserves provided by the Customer at 7% of Reserved Capacity, the notification processes for delivery of reserve Energy, the requirements for Customer delivery of requested reserves, the requirements for Customer notification to the Company of any changes in the ability to self-supply reserves, the settlement process to be used when Contingency Reserves are supplied by the Customer, the provisions for an annual demonstration of such capability, any additional metering requirements and other necessary notification requirements. Customers who self-supply Generation Contingency Reserves will not be charged for Spinning and Supplemental Reserves under this schedule.

Supplemental Reserves Load Reduction Plan

In lieu of self supplying Supplemental Reserves through a self-supply agreement, a Customer may provide Supplemental Reserves through the submittal to the Company of a Load Reduction Plan that demonstrates the ability to reduce load within the first ten minutes of generator failure and specifies a kW amount of load reduction equal to 3.5 percent of the Reserved Capacity.

SCHEDULE 75 (Continued)

GENERATION CONTINGENCY RESERVES (Continued)

Supplemental Reserves Load Reduction Plan (Continued)

The Load Reduction Plan also will specify the notification processes for delivery of Supplemental Reserves, the requirements for Customer delivery of requested Supplemental Reserves, the requirements for Customer notification to Company of any changes in the ability to supply Supplemental Reserves, the settlement process to be used when Supplemental Reserves are supplied by the Customer, the provisions for a demonstration of such capability, any additional metering requirements and other necessary notification, plant and financial requirements. The Customer Load Reduction Plan must be approved by the Company. If approved by the Company, and adhered to by the Customer, a credit to the Supplemental Reserves charges will be applied to Customer's bill based on the Supplemental Reserves Level as specified in the Load Reduction Plan.

If Customer fails to follow the Company-approved Load Reduction Plan, all Supplemental Reserves credits for the subsequent three months (Penalty Period) will be forfeited. If the Customer satisfactorily follows the Company-approved Load Reduction Plan during the Penalty Period, the Load Reduction Plan kW credit will be reinstated at the end of the three month Penalty Period.

If the Customer fails to follow the Company-approved Load Reduction Plan a second time during the Penalty Period and the following three months, the Load Reduction Plan shall be terminated.

The duration of the Penalty Period shall not be limited by the establishment of a new service agreement under this schedule.

Following termination or contract expiration, Customer may submit a new Load Reduction Plan to the Company. Company will approve the new Load Reduction Plan if the Customer is able to demonstrate the load reduction capability of the Plan to Company's satisfaction.

Notwithstanding the above, Customer may terminate the Company-approved Load Reduction Plan upon giving 6 month written notice to Company.

ENERGY CHARGE

The Energy Charge is comprised of the following:

Baseline Energy

Unless otherwise agreed to, the Baseline Energy is the Energy normally supplied by the Company to the Large Nonresidential Customer when the Customer's generator is operating as planned. Usage on an hourly basis up to and including the Baseline Demand will be considered Baseline Energy. The Company may, in collaboration with the Customer, develop an alternate method to determine Baseline Energy when the Customer is new to the Company's system or has changed operations from the previous year.

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)

Baseline Energy (Continued)

If other than the typical operations are used to determine Baseline Energy, the Customer and the Company must agree on the Baseline Energy before the Customer may take service under this schedule. The Company may require use of an alternate method to determine the Baseline Energy when the Customer's usage not normally supplied by its generator is highly variable.

Baseline Energy will be charged at the applicable Energy Charge, including adjustments, under Schedule 89. All Energy Charge options included in Schedule 89 are available to the Customer on Schedule 75 based on the terms and conditions under Schedule 89. For Energy supplied in excess of Baseline Energy, the Scheduled Maintenance Energy and/or Unscheduled Energy charges will apply except for Energy supplied pursuant to Schedule 76R.

Any Energy Charge option for Baseline Energy selected by a Customer will remain in effect and continue to be the default option until the Customer has given the required notice to change the applicable Energy Charge Option. To change options, Customers must give notice as specified for that option and must complete the specified term of their current option. The Cost of Service Option will be the default for Customers or new Customers who have not selected another option or Direct Access Service.

Scheduled Maintenance Energy

Scheduled Maintenance Energy is Energy prescheduled for delivery, up to 744 hours per calendar year, to serve the Customer's load normally served by the Customer's own generation (i.e. above Baseline Energy). Scheduled Maintenance must be prescheduled at least one month (30 days) before delivery for a time period mutually agreeable to the Company and the Customer.

When the Customer preschedules Energy for an entire calendar month, the Customer may choose that the Scheduled Maintenance Energy Charge be either the Monthly Fixed or Daily Price Energy Charge Option, including adjustments as identified in Schedule 100 and notice requirements as described under Schedule 89. When the Customer preschedules Energy for less than an entire month, the Scheduled Maintenance Energy will be charged at the Daily Price Energy Option, including adjustments, under Schedule 89.

Unscheduled Energy

Any Electricity provided to the Customer that does not qualify as Baseline Energy or Scheduled Maintenance Energy will be Unscheduled Energy and priced at an Hourly Rate consisting of the Dow Jones Mid-Columbia Hourly Firm Electricity Price Index (DJ-Mid-C Hourly Firm Index) plus 0.236¢ per kWh for wheeling, a 0.300¢ per kWh recovery factor, plus losses.

SCHEDULE 75 (Continued)

ENERGY CHARGE (Continued)

Unscheduled Energy (Continued)

If prices are not reported for a particular hour or hours, the average of the immediately preceding and following reported hours' prices within on- or off-peak periods, as applicable, will determine the price for the non-reported period. Prices reported with no transaction volume or as survey-based will be considered reported.

On-peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

The Company may request that a Customer taking Unscheduled Energy during more than 1,000 hours during a calendar year provide information detailing the reasons that the generator was not able to run during those hours in order to determine the appropriate Baseline Demand.

LOSSES

Losses will be included by multiplying the applicable Energy Charge by the following adjustment factors:

Subtransmission Delivery Voltage	1.0337
Primary Delivery Voltage	1.0488
Secondary Delivery Voltage	1.0834

DIRECT ACCESS PARTIAL REQUIREMENTS SERVICE

A Customer served under this schedule may elect to receive Direct Access Partial Requirements Service from an Electricity Service Supplier (ESS) under the terms of Schedule 575 provided it has given notice consistent with any Baseline Energy option requirements. A Customer may return to Schedule 75 provided it has met any term requirements of Schedule 575 and any requirements needed to purchase Baseline Energy if needed.

MINIMUM CHARGE

The Minimum Charge will be the Basic, Transmission, Distribution, Demand and Generation Contingency Reserves Charges, when applicable. In addition, the Company may require a higher Minimum Charge, if necessary, to justify the Company's investment in service Facilities.

REACTIVE DEMAND CHARGE

In addition to the charges as specified in the Monthly Rate, the Customer will pay 50¢ for each kilovolt-ampere of Reactive Demand in excess of 40% of the maximum Demand. Such charge is separate from and in addition to the Minimum Charge specified.

SCHEDULE 75 (Continued)

ADJUSTMENTS

Service under this schedule will be subject to all adjustments as summarized in Schedule 100. Applicable adjustments will be applied to Baseline Energy and Scheduled Maintenance Energy with the exception of Schedules 108 and 115, which are applied to factors other than usage as required by statute.

SPECIAL CONDITIONS

1. Prior to receiving service under this schedule, the Customer and the Company must enter into a written service agreement specifying the terms and conditions of service, the Customer's Baseline Demand and Energy Pricing Option under Schedule 89, the Customer's Reserved Capacity, the Company's and Customer's contact information, and any other information necessary for implementation of service under this schedule. The term of the service agreement shall be one calendar year (except that the term of the first service agreement shall be the remainder of the year when signed plus the next calendar year) and shall renew annually thereafter for successive one year terms, unless the Customer gives 90 days prior written notice. These terms and conditions will be consistent with this schedule.

2. A Customer must inform the Company within 30 minutes of taking Unscheduled Energy at a rate of five MW or greater and inform the Company of the anticipated time that the generator will return to normal operations.

3. Customers must have Company approved interval metering and meter communications in place prior to initiation of service under this schedule. The Company requires metering that measures the net quantity and direction of flow at the Point of Delivery and total Generator output.

4. If the Customer is served at Primary or Subtransmission Voltage, the Customer will provide, install, and maintain on the Customer's premises all necessary transformers to which the Company's service is directly or indirectly connected. The Customer also will provide, install, and maintain the necessary switches, cutouts, protection equipment, and the necessary wiring on both sides of the transformers. All transformers, equipment and wiring will be of types and characteristics approved by the Company and their installation, operation and maintenance will be subject to inspection and approval by the Company.

5. If during a Billing Period the Customer is billed for Transmission and Related Services under this schedule and Transmission Services under the Company's FERC Open Access Transmission Tariff (OATT) for the purpose of effecting a wholesale power sale from the Customer's generator, the payments for OATT charges for Transmission Service (Schedules 7 or 8) and Schedule 3, Regulation and Frequency Response Service will be credited to the Transmission and Related Services Charge under this schedule. The credit will be the actual OATT demand incurred but will not exceed the Monthly Demand for the Schedule 75 monthly Transmission Demand multiplied by the applicable OATT (OATT Schedules 3, 7 or 8) and such credit will not exceed the Transmission and Related Services Charge incurred under this schedule.

SCHEDULE 75 (Concluded)

SPECIAL CONDITIONS (Continued)

6. The Customer will not use Electricity sold by the Company to directly or indirectly make or continue a delivery of Electricity to another Customer or wholesale power purchaser.

7. A Customer's failure to inform the Company of the use of on-site generation will not relieve the Customer of responsibility for the charges and requirements under this schedule.

8. The Customer's Baseline Demand may be increased or decreased as requested by the Customer for planned, long-term load changes including changes resulting from the addition of long-term energy efficiency measures, load shedding, the addition or removal of equipment or the permanent removal of generating capacity from the Customer location. Such changes will be effective upon verification of the change by the Company. "Long-term" or "permanent" mean changes that are implemented with the purpose of being in place indefinitely.

9. A change in Baseline Demand related to modifications in generating capacity or planned generation operations may be made provided the Customer provides the following notice:
   a) for a change to Baseline Demand that within a one calendar year period does not exceed 5 MW, the Customer may make one such request per calendar year and will provide at least 6 months written notice;

   b) for a change in Baseline Demand that is greater than 5 MW, Customer must provide at least 13 months written notice to the Company with such change effective on January 1 of the applicable year. Any subsequent notice by the Customer under this special condition must be made consistent with these notice requirements.

10. If the Customer's Baseline Demand is increased, any Energy used above the initial Baseline Demand, and below the revised Baseline Demand will be priced at the Daily Price Option contained in Schedule 89 unless the Customer has given the required notice to change the applicable Schedule 89 Energy Charge Option.

11. The Company reserves the right to modify any agreements existing under this schedule as a result of changes in Western Electricity Coordinating Council guidelines.

12. If the Customer is receiving service under this schedule and Schedule 76R, the monthly Basic and Facility Capacity charges may be replaced and billed pursuant to Schedule 76R Special Conditions.

13. A Customer may not change service options until it has satisfied any Baseline Energy term provisions as established in Schedule 89.

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),	)	SETTLEMENT AGREEMENT & STIPULATION REGARDING STREETLIGHT SERVICE AND CRITICAL ACCOUNT PRIORITY ISSUES
In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision relating to the Port Westward Plant (UE 184).	)	

This Settlement Agreement and Stipulation Regarding Streetlight Service and Critical Account Priority Issues ("Stipulation") is by and between Portland General Electric Company ("PGE"), the League of Oregon Cities ("League"), the City of Portland, and the City of Gresham (collectively, the "Stipulating Parties"). The League, City of Portland, and City of Gresham are referred to herein collectively as the "Cities."

I. INTRODUCTION

On March 15, 2006, PGE filed Advice No. 06-8 for a general rate revision to increase its retail rates. The filing was based on a projected test year of 2007 and was docketed as UE 180. The advice filing was suspended by the Commission, and on April 4, 2006, the Administrative Law Judge held a Prehearing Conference and established a procedural schedule. On April 24, 2006, PGE filed Advice No. 06-10, to reflect in rates the Port Westward generation plant when it comes into service for customers, currently anticipated to be March 2007. That filing was docketed as UE 184, and was also suspended by the Commission. Dockets UE 180, UE 184 and UE 181 (PGE's 2007 RVM filing), have all been consolidated.

The Cities filed direct and sur-rebuttal testimony regarding various issues related to (1) streetlight maintenance and energy supply ("Streetlight Service"), and (2) identifying and refreshing PGE's lists of designated critical accounts, facilities and Consumers maintained in connection with its current Rule C protocols governing service restoration priority and exposure to curtailment during system emergencies ("Critical Account Priority"). PGE responded to the Cities' testimony with its own rebuttal and sur-surrebuttal testimony. No other party addressed Critical Account Priority or Streetlight Service issues in testimony. Settlement discussions regarding Critical Account Priority and Streetlight Service issues were held on October 9 and 20, 2006.

As a result of those settlement discussions, the Stipulating Parties have agreed to the terms and adjustments set forth below to settle all Critical Account Priority and Streetlight Service issues raised in this proceeding. The Stipulating Parties will submit this Stipulation to the Commission and request that the Commission adopt an order in this docket implementing the following provisions.

II. TERMS OF SETTLEMENT AGREEMENT AND STIPULATION

1. This Stipulation is entered into for purposes of compromising and settling all issues raised by the Cities in this docket with the exception of those issues identified in COP/100/Jubb.

2. Designation and Maintenance of Lists of Critical Accounts and Associated Contact Information for Purposes of Service Restoration Priorities

PGE's municipal customers directly responsible for public safety or emergency response functions will provide PGE with lists of critical accounts for facilities they deem necessary to protect public safety, health and welfare and which will also be considered critical Consumers under PGE's current Rule C. PGE's municipal customers submitting lists of critical accounts will provide PGE name(s) and 24-hour contact information (cell phone, pager or 24x7 dispatch center phone number) for city personnel assigned to each account for service restoration coordination purposes under Rule C. PGE will provide its municipal customers with the name of at least one individual at PGE responsible for coordinating service restoration for each account under Rule C, and 24-hour contact information (cell phone or pager) for such individual(s). Both PGE and PGE's municipal customers will have a continuing responsibility to notify each other if there are any changes in critical account and associated contact information previously submitted to the other party, and to work together to resolve any questions regarding the critical nature of any account. PGE will meet with the League and any of PGE's interested municipal customers for the purposes of developing protocols and procedures sufficient to ensure that PGE and its municipal customers each can continue to meet their obligations to update and maintain the accuracy of all information required or intended to be exchanged in connection herewith.

3. Streetlight Maintenance Costs: The Stipulating Parties agree that PGE will use $2,646,000 as the allocated test year street and area lighting maintenance costs to determine the charge for service under Schedule 91.

4. Streetlight Operating Hours: The Stipulating Parties agree that PGE will set operating hours under Schedule 91 to 4,100 per year and will use this number of hours in the determination of relevant Schedule 91 energy charges. The City of Portland may perform a streetlight operating hours study at its cost. The City of Portland and PGE agree to consult on the requirements for a statistically valid operating hours study.

5. Metering of New Option C Lights: PGE agrees to withdraw its proposal to meter new Option C streetlights, and to continue to use its existing Rules to enforce prohibitions on diversion of power.

6. Maintenance of Option B Luminaires: The Stipulating Parties agree to work together to develop and submit to the Commission tariff provisions that allow each municipality served by PGE the option of (i) converting its existing Option B luminaires to Option C luminaires and (ii) using its own qualified personnel, or qualified personnel hired by or working on its behalf, to maintain its Option C lights attached to PGE-owned poles. Notwithstanding the foregoing, these conversion and self-maintenance rights shall be subject to the following requirements:

a. A municipality must convert all of its current Option B luminaires to Option C luminaires at one time and may only do so if it provides notice to PGE sufficiently in advance of such conversion so as to allow PGE to manage its workforce and modify its records. Additionally, all new luminaires installed by a municipality after exercise of the one-time conversion option must be either Option C or Option A luminaires. As Option C luminaires, PGE will not be obligated to provide any maintenance of them. Prior to or upon conversion, a municipality must notify its residents that street light maintenance/repair issues are to be directed to the municipality and not PGE.

b. All personnel or contractors employed by a municipality to maintain streetlights located on PGE-owned poles must be qualified to perform such maintenance services in a manner consistent with applicable codes and safety requirements.

   1. Qualified workers must perform the work in compliance with the applicable requirements of OSHA, OPUC Safety Rules, the NESC and/or NEC. A "Qualified Worker" means one who is knowledgeable about the construction and operation of the electric power generation, transmission, and distribution equipment as it relates to his or her work, along with the associated hazards, as demonstrated by satisfying the qualifying requirements for a "qualified person" or "qualified employee" with regard to the work in question as described in 29 CFR 1910.269 effective January 31, 1994, as it may be amended from time to time. In this case, a Qualified Worker will be a journeyman lineman, or someone who has the equivalent training, expertise and experience to perform journeyman lineman work.

   2. To the extent permitted by the Oregon Constitution and subject to the limits of the Oregon Tort Claims Act, a municipality shall hold PGE harmless and indemnify it for any personal injury, property damage or damage to PGE's electrical system that is caused by the acts or omissions of the municipality's officers, employees, contractors or agents performing streetlight

maintenance for the municipality on PGE-owned poles. PGE shall be named an additional insured on applicable insurance policies of contractors used by the municipality to perform streetlight maintenance work.

c. The municipality and PGE must develop appropriate procedures to maintain accurate records of streetlight and pole ownership, lamp wattages, communications protocols with PGE and related information necessary for accounting, billing and mapping purposes.

d. The OPUC must affirm that any service disturbance or any violation of OPUC safety rules caused by the municipality or an agent of the municipality working on streetlights will not be counted against PGE as a service quality incident for purposes of Service Quality measurements.

e. If in the future, a municipality seeks to convert Option C luminaires on PGE-owned poles back to Option B luminaires and service of such luminaires under Option B is available, the municipality must convert all such Option C luminaires located on PGE-owned poles back to Option B. Prior to reconversion PGE will, at the municipality's cost, determine if the luminaires have been maintained in an acceptable manner and maintenance has not been deferred. If the luminaires have not been properly maintained PGE will charge the municipality the cost of any corrective maintenance required to bring the luminaires up to PGE standards. Prior to reconversion the municipality must provide sufficient notice to PGE to allow it to manage its workforce and modify its records.

7. The Stipulating Parties agree that this Stipulation is in the public interest and will produce rates, terms and conditions in connection with the Critical Account Priority and

Streetlight Service issues addressed herein that are fair, just and reasonable.

8. The Stipulating Parties agree that they will support and cooperate in the filing of a motion or motions to admit into the record of this proceeding all testimony previously submitted in this matter dealing with Critical Account Priority and Streetlight Service issues.

9. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR § 860-14-0085. The Stipulating Parties agree to support this Stipulation throughout this proceeding and in any appeal, provide witnesses to sponsor this Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements and affirming the use of the stipulated facts contained herein. The Stipulating Parties also agree to cooperate in drafting and submitting the explanatory brief or written testimony required by OAR § 860-14-0085(4).

10. If this Stipulation is challenged by any other party to this proceeding, or any other party seeks a resolution of the Critical Account Priority or Streetlight Service issues in this docket that departs from the terms of this Stipulation, the Stipulating Parties agree to cooperate in the cross-examination of witnesses and the presentation of a unified, jointly supported case; provided, however, that the Stipulating Parties agree that each Party reserves the right to cross-examine witnesses and put into the record such evidence as it deems appropriate to respond fully to the issues presented or portion of the Stipulation being challenged, including the right to raise issues that are incorporated in the settlements embodied in this Stipulation. Notwithstanding this reservation of individual rights, the Stipulating Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation.

11. The Stipulating Parties acknowledge that this Stipulation was negotiated as an integrated agreement. If the Commission rejects all or any material part of this Stipulation, or

adds any material condition in approving this Stipulation, each Party reserves the right to withdraw from this Stipulation upon written notice to the Commission and the other Parties within five (5) business days of service of the final order rejecting this Stipulation or adding such material condition.

12. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

13. The Parties agree that this Stipulation represents a compromise in the positions of the Parties. As such, conduct, statements, and documents disclosed in the negotiation of this Stipulation shall not be admissible as evidence in this or any other proceeding. The Stipulating Parties agree that they will not cite this Stipulation, or those portions of any Commission order directly addressing or adopting this Stipulation, as precedent in any other proceeding other than a proceeding to enforce the terms of this Stipulation; provided, however, that the foregoing shall be strictly construed as limited in scope to the existence and content of the settlement embodied in the Stipulation and shall not generally be interpreted as limiting the manner in which any Stipulating Party may reference, cite or otherwise make use of testimony or other evidence accepted into and made a part of the permanent record of this proceeding.

14. By entering into this Stipulation, no Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other Party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

DATED this 31st day of October, 2006.

PORTLAND GENERAL ELECTRIC COMPANY

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LEAGUE OF OREGON CITIES

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CITY OF GRESHAM

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CITY OF PORTLAND

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DATED this day of October, 2006.

PORTLAND GENERAL ELECTRIC
COMPANY

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LEAGUE OF OREGON CITIES

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CITY OF GRESHAM

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CITY OF PORTLAND

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DATED this day of October, 2006.

PORTLAND GENERAL ELECTRIC COMPANY

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LEAGUE OF OREGON CITIES

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CITY OF GRESHAM

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Approved as to Form

David R R

City Attorney's Office

CITY OF PORTLAND

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DATED this 31st day of October, 2006.

PORTLAND GENERAL ELECTRIC
COMPANY

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LEAGUE OF OREGON CITIES

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CITY OF GRESHAM

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CITY OF PORTLAND

Benjamin Walters
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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 180/ UE 181/ UE 184

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision (UE 180), In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Annual Adjustments to Schedule 125 (2007 RVM Filing) (UE 181), In the Matter of PORTLAND GENERAL ELECTRIC COMPANY Request for a General Rate Revision relating to the Port Westward Plant (UE 184).	)	STIPULATION REGARDING SCHEDULE 76R ISSUES

This Stipulation ("Stipulation") is among Portland General Electric Company ("PGE"), Staff of the Public Utility Commission of Oregon ("Staff"), and the Industrial Customers of Northwest Utilities ("ICNU") (together, the "Stipulating Parties").

I. INTRODUCTION

On March 15, 2006, PGE filed Advice No. 06-8 for a general rate revision to increase its retail rates. The filing was based on a projected test year of 2007 and was docketed as UE 180. The advice filing was suspended by the Commission, and on April 4, 2006, the Administrative Law Judge held a Prehearing Conference and established a procedural schedule. On April 24, 2006, PGE filed Advice No. 06-10, to reflect in rates the Port Westward generation plant when it comes into service for customers, currently anticipated to be March 2007. That filing was docketed as UE 184, and was also suspended by the Commission. Dockets UE 180, UE 184 and UE 181 (PGE's 2007 RVM filing), have all been consolidated.

ICNU filed direct and sur-rebuttal testimony regarding various issues related to partial requirements service under Schedule 76R. Staff also filed testimony addressing Schedule 76R. PGE responded to Staff's and ICNU's testimony with its own rebuttal and sur-surrebuttal testimony.

As a result of those settlement discussions, the Stipulating Parties have agreed to the terms set forth below to settle all issues raised in this proceeding involving Schedule 76R. The Stipulating Parties submit this Stipulation to the Oregon Public Utility Commission (the "Commission") and request that the Commission adopt an order in this docket implementing the following provisions.

II. TERMS OF STIPULATION

1. This Stipulation is entered to settle all issues raised in this docket regarding Schedule 76R.

2. Attached as Exhibit "A" to this Stipulation are revised tariff sheets for Schedule 76R. The attached revised Schedule 76R provides additional service and pricing options for partial requirements customers. The Stipulating Parties request that the Commission adopt and approve this revised Schedule 76R.

3. The Stipulating Parties agree that this Stipulation is in the public interest and will result in rates that are fair, just and reasonable.

4. This Stipulation does not limit a Stipulating Party's ability to propose to the Commission changes to Schedule 76R at any time after the schedule becomes effective.

5. The Stipulating Parties agree that this Stipulation represents a compromise in the positions of the parties. As such, conduct, statements, and documents disclosed in the negotiation of this Stipulation shall not be admissible as evidence in this or any other proceeding.

6. If this Stipulation is challenged by any other party to this proceeding, or any other party seeks a change in Schedule 76R (the economic replacement power tariff) that departs from the terms of this Stipulation, the Stipulating Parties reserve the right to cross-examine witnesses and put in such evidence as they deem appropriate to respond fully to the issues presented, including the right to raise issues that are incorporated in the settlements embodied in this Stipulation. Notwithstanding this reservation of rights, the Stipulating Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation.

7. If the Commission rejects all or any material part of this Stipulation, or adds any material condition to any final order which is not contemplated by this Stipulation, each Party reserves the right to withdraw from this Stipulation upon written notice to the Commission and the other Parties within five (5) business days of service of the final order that rejects this Stipulation or adds such material condition.

8. This Stipulation will be offered into the record in this proceeding as evidence pursuant to OAR § 860-14-0085. The Stipulating Parties agree to support this Stipulation throughout this proceeding and in any appeal, provide witnesses to sponsor this Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained herein. The Stipulating Parties also agree to cooperate in drafting and submitting the explanatory brief or written testimony required by OAR § 860-14-0085(4).

9. By entering into this Stipulation, no Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other Party in arriving at the terms of this Stipulation. Except as provided in this Stipulation, no Party shall

be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding.

10. This Stipulation may be signed in any number of counterparts, each of which will be an original for all purposes, but all of which taken together will constitute one and the same agreement.

DATED this 9th day of November, 2006.

PORTLAND GENERAL ELECTRIC COMPANY

STAFF OF THE PUBLIC UTILITY
COMMISSION OF OREGON

INDUSTRIAL CUSTOMERS OF
NORTHWEST UTILITIES

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____
PORTLAND GENERAL ELECTRIC COMPANY

____
STAFF OF THE PUBLIC UTILITY
COMMISSION OF OREGON

____
INDUSTRIAL CUSTOMERS OF
NORTHWEST UTILITIES

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DATED this 9th day of November, 2006.

____
PORTLAND GENERAL ELECTRIC COMPANY

____
STAFF OF THE PUBLIC UTILITY
COMMISSION OF OREGON

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____
INDUSTRIAL CUSTOMERS OF
NORTHWEST UTILITIES

SCHEDULE 76R
PARTIAL REQUIREMENTS
ECONOMIC REPLACEMENT POWER RIDER

PURPOSE

To provide Customers served on Schedule 75 with the option of purchasing Energy from the Company to replace some, or all, of the Customer's on-site generation when the Customer deems it is more economically beneficial than self generating.

AVAILABLE

In all territory served by the Company.

APPLICABLE

To Large Nonresidential Customers served on Schedule 75.

MONTHY RATE

The following charges are in addition to applicable charges under Schedule 75:

Transmission and Related Services Charge
per kW of Daily Economic Replacement Power (ERP)
On-Peak Demand per day $0.026

Daily ERP Demand Charge

	Delivery Voltage	
	Secondary and Primary	Subtransmission
per kW of Daily ERP Demand during On-Peak hours per day*	$0.095	$0.050

System Usage Charge
per kWh of ERP 0.178 ¢

Transaction Fee
per Energy Needs Forecast (ENF) $50.00

Energy Charge**
per kWh of ERP See below for ERP Pricing

* Peak hours (also called heavy load hours "HLH") are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. Off-peak hours (also called light load hours "LLH") are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all day Sunday.

** See Schedule 100 for applicable adjustments.

SCHEDULE 76R (Continued)

ENERGY NEEDS FORECAST (ENF) AND ECONOMIC REPLACEMENT POWER (ERP)

Economic Replacement Power (ERP) is Electricity supplied by the Company to meet an Energy Needs Forecast (ENF). The ENF specifies the amount of Electricity in mWh for each hour that ERP is requested to serve some or all of the Customer's load normally supplied by the Customer's generation (amounts in excess of the Baseline Energy under Schedule 75) pursuant to the requirements of the applicable ERP Supply Option.

Each ENF will be based on the Customer's expected Energy requirements and the Customer will use best efforts to conform Actual Energy usage to the ENF and utilize Energy imbalances to the minimum extent reasonably possible.

The ENF will specify the expected ERP needed by hour. The Customer will deliver the ENF to the Company in accordance with Company procedures. The Company will inform the Customer as to the availability of ERP at the time of the ENF request. The Company can choose to provide all or a portion of the ENF and will inform the Customer of any such adjustment to the submitted ENF. Customer acceptance of such modification of the ENF by the Company will be confirmed within 15 minutes of the proposed ENF revision by the Company. If the Company does not inform the Customer that it is modifying the submitted ENF within 30 minutes of receipt of the ENF, the ENF will be deemed accepted by the Company.

The Customer may utilize only one of the ERP supply options on any day.

ERP Supply Options

Each request for ERP will originate from the requesting Customer and requires an ENF from the customer. At the time of an ENF submittal, Customer must designate which of the available ERP pricing options the ENF applies to for purposes of pricing and price quotes. Customer is solely responsible for the accuracy of an ENF and the acceptance or rejection of a price quote.

ENF Options for ERP

Short Notice ENF: The Customer must provide the ENF to the Company a minimum of 90 minutes prior to the first hour that Short-Notice ERP is requested.

Daily ENF: At the Customer's option, between 0600 and 0615 of a Pre-Schedule Day, the customer will communicate with PGE in an agreed-to manner the customer's interest in purchasing ERP power for delivery the next day or days (as required by the daily day-ahead pre-scheduling protocols of Western Electricity Coordinating Council ("WECC")). Customer will at this time provide the Company with the Energy Needs Forecast (ENF) for HLH or LLH or both for the day or days of delivery. The ENF may differentiate between HLH and LLH hours but will be a flat (constant) MW amount for the each HLH or LLH or both.

Monthly ENF: Not less than 7 business days prior to the last trading day for the upcoming quote month, the customer may submit an ENF for the next month. The ENF may be differentiated into HLH or LLH for the entire month.

SCHEDULE 76R (Continued)

ENF AND ERP (Continued)
ERP Supply Options (Continued)
ENF Options for ERP (Continued)

The Daily ENF pre-scheduling protocols will conform to the standard practices, applicable definitions, requirements and schedules of the WECC. Pre-Schedule Day means the trading day immediately preceding the day of delivery consistent with WECC practices for Saturday, Sunday, Monday or holiday deliveries.

ERP Pricing

The following ERP Energy Charges are applied to the applicable hourly ENF and summed for the hours for the monthly billing:

Short-Notice ERP: The Short Notice ERP Energy Charge will be an Hourly Rate consisting of the Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index) plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.236¢ per kWh for wheeling, plus losses. If prices are not reported for a particular hour or hours, the average of the immediately preceding and following reported hours' prices within on- or off-peak periods, as applicable, will determine the price for the non-reported period. Prices reported with no transaction volume or as survey-based will be considered reported.

Daily ERP: The Daily ERP Energy Charge will be determined in accordance with a commodity energy price quote from the Company accepted by the Customer plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.236¢ per kWh for wheeling, plus losses. Customer will communicate with PGE between hour 0615 and 0625 to receive the PGE commodity energy price quote based on the customer's submitted ENF for the day of delivery. Customer will state acceptance of quote within 5 minutes of receipt of quote from the Company. The quote may incorporate reasonable premiums to reflect the additional cost of ENF amounts that are in nonstandard block sizes (i.e., other than multiples of 25 MW) and such premium will not be separately stated. The methods to communicate and the times to receive information and quotes may be adjusted with mutual written agreement of the parties. Failure to accept a quote in the stated time is deemed to mean the quote is rejected and the transaction will not take place.

Monthly ERP: The Monthly ERP Energy Charge will be determined in accordance with a price quote accepted by the Customer plus a 5% adder, which will not be less than 0.15¢ per kWh, plus 0.236¢ per kWh for wheeling, plus losses. At customer request and based on the submitted Monthly ENF, the Company will provide a price quote for the next full calendar month for the ENF commodity energy only amount specified by the customer at the time of the request. The Company will respond to the request with a quote within 4 hours or as otherwise mutually agreed to. Customer will accept or reject the quote within 30 minutes. Customer communication regarding a price quote will be in the manner agreed to by the Company and the Customer. The quote may incorporate reasonable premiums to reflect the additional cost of ENF amounts that are in nonstandard block sizes (i.e., other than multiples of 25 MW) and such premium will not be separately stated.

SCHEDULE 76R (Continued)

ENF AND ERP (Continued)
ERP Supply Options (Continued)
ERP Pricing Continued)

The methods to communicate and the times to receive information and quotes may be adjusted with mutual written agreement of the parties. Failure to accept a quote in the stated time is deemed to mean the quote is rejected and the transaction will not take place.

On-peak hours (Heavy Load Hours, HLH) are between 6:00 a.m. and 10:00 p.m. PPT (hours ending 0700 through 2200), Monday through Saturday. Off-peak hours (Light Load Hours, LLH) are between 10:00 p.m. and 6:00 a.m. Monday through Saturday and all hours Sunday.

Losses will be included by multiplying the ERP Charge by the following adjustment factors:

Subtransmission Delivery Voltage	1.0337
Primary Delivery Voltage	1.0488
Secondary Delivery Voltage	1.0834

ACTUAL ENERGY USAGE

Actual Energy usage during times when ERP deliveries are occurring will be the amount of Energy above the Customer's Schedule 75 Baseline Energy.

IMBALANCE ENERGY SETTLEMENT

Imbalance Settlement Amounts are bill credits or charges resulting from hourly Imbalance Energy multiplied by the applicable hourly Settlement Price and summed for all hours in the billing period. Imbalance Energy is the kWh amount determined hourly as the deviation between Actual Energy for such hour and the ENF for such hour (i.e., Imbalance Energy = Actual Energy less ENF).

For any Imbalance Energy in any hour up to 7.5% of the hourly ENF (positive or negative amount), the Imbalance Settlement Amount for the hour is:

- For positive Imbalance Energy (where Customer receives more ERP than the ENF), the Imbalance Energy multiplied by the Settlement Price of the Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index), plus 0.236¢ per kWh for wheeling, plus losses.
- For negative Imbalance Energy (where Customer receives less ERP than the ENF), the Imbalance Energy is multiplied by the Settlement Price of the DJ-Mid-C Hourly Index plus 0.236¢ per kWh for wheeling, plus losses.

SCHEDULE 76R (Continued)

IMBALANCE ENERGY SETTLEMENT (Continued)

For any Imbalance Energy in any hour in excess of 7.5% of the hourly ENF (positive or negative amount), the Imbalance Settlement Amount for the hour is:

- For positive excess Imbalance Energy, the excess Imbalance Energy multiplied by the Settlement Price, which is the Dow Jones Mid-Columbia Hourly Price Index (DJ-Mid-C Hourly Index), plus 10%, plus 0.236¢ per kWh for wheeling, plus losses.
- For negative excess Imbalance Energy, the excess Energy Imbalance is multiplied by the Settlement Price of the DJ-Mid-C Hourly Index, less 10%, plus 0.236¢ per kWh for wheeling, plus losses.

The Imbalance Settlement Amount may be a credit or charge in any hour.

DAILY ERP DEMAND

Daily ERP Demand is the highest 30 minute Demand occurring during the days that the Company supplies ERP to the Customer less the sum of the Customer's Schedule 75 Baseline Demand and any Unscheduled Demand. Daily ERP Demand will not be less than zero. Daily ERP Demand will be billed for each day in the month that the Company supplies ERP to the Customer.

If the sum of the Customer's Unscheduled and Schedule 75 Baseline Demand exceeds their Daily ERP Demand, no additional Daily Demand charges are applied to the service under this schedule for the applicable Billing Period.

UNSCHEDULED DEMAND

Unscheduled Demand is the difference in the highest 30 minute monthly Demand and the Customer's Baseline occurring when the Customer did not receive ERP.

ADJUSTMENTS

Service under this rider is subject to all adjustments as summarized in Schedule 100, except for: 1) any power cost adjustment recovery based on costs incurred while the Customer is taking Service under this schedule, and 2) Schedule 128.

SPECIAL CONDITIONS

1. Prior to receiving service under this schedule, the Customer and the Company must enter into a written agreement governing the terms and conditions of service.

2. Service under this schedule applies only to prescheduled ERP supplied by the Company pursuant to this schedule and the corresponding agreement. All other Energy supplied will be made under the terms of Schedule 75. All notice provisions of this schedule and agreement must be complied with for delivery of Energy. The Customer is required to maintain Schedule 75 service unless otherwise agreed to by the Company.

SCHEDULE 76R (Concluded)

SPECIAL CONDITIONS (Continued)

3. All charges and requirements of Schedule 75 will apply except as provided for under this schedule.

4. ERP supplied will not be resold.

5. The Company may interrupt ERP due to transmission constraints.

6. The Customer must notify the Company's Merchant Power Operations, at a specified phone number, as soon as practical of otherwise unplanned load deviations greater than five MW that are expected to last one hour or longer.

7. If Customer is unable to use or accept delivery of ERP due to circumstances beyond its control, the difference between Actual Energy and the ENF shall be treated as Imbalance Energy.

8. Upon mutual agreement between the Company and Customer, the otherwise applicable Schedule 75 monthly Basic and Facility Capacity Charges will be replaced by a flat monthly Basic and Facility Capacity Charge billed under this schedule. The flat monthly Basic and Facility Capacity Charge will be set to maximize the economic value of sales under this schedule.

9. The Company is not responsible for providing market information to Customer.

10. The Company has no obligation to provide the Customer with ERP except as explicitly agreed to by both parties.

11. Each day of flow will begin at the hour ending 0100 and end at the 2400 hour under Pacific Prevailing Time (Pacific Standard Time or Pacific Daylight Time).

Portland General Electric
UE 180: General Rate Case
Commission Authorized Revenue Requirement
Twelve Months Ending December 31, 2007
(000)

PGE'S REVENUE REQUIREMENT REQUEST PER FILED RESULTS:		**$25,064**
STIPULATED ADJUSTMENTS:		
All Other Taxes	($2,339)	
FIT and SIT Deduction	($3,655)	
Administrative & General and Operations & Maintenance Adjustment	($6,761)	
Incentive Adjustment	($4,657)	
Wages & Salary	($3,770)	
Adjustment to Other Revenues	($41)	
Capital Expenditures Adjustment	($831)	
System Losses	$0	
Membership Adjustment	($85)	
Tenant Improvements	$0	
Weatherization Adjustment	($71)	
Customer Service & Information Expense Adjustment	($1,626)	
Beaver 8 Generating Facility	($1,310)	
UM 1233 Stipulated Depreciation Adjustment	($5,688)	
PGE's Updated NVPC/Revenues	$12,445	(including Coal Loss Adjustment)
Revenue Senstive Adjustments and Rounding	($468)	
TOTAL STIPULATED ADJUSTMENTS:		**($18,857)**
COMMISSION ADJUSTMENTS ON CONTESTED ISSSUES:		
Net Variable Power Cost Adjustment	($4,745)	
Extrinsic Value	$0	
Ancillary Services	($1,468)	
Capacity Contract	($1,427)	
RATE OF RETURN:		
Change to Capital Structure (50/50)	(7,349)	
Change to Cost of Debt (6.49%)	(2,732)	
Change to Cost of Equity (10.10%)	(10,059)	
TOTAL ADJUSTMENTS ON CONTESTED ISSUES:		**($27,779)**
TOTAL COMMISSION AUTHORIZED REVENUE REQUIREMENT:		**($21,572)**

Portland General Electric
UE 184: Port Westward
Commission Authorized Revenue Requirement
Twelve Months Ending December 31, 2007
(000)

PGE'S REVENUE REQUIREMENT REQUEST PER FILED RESULTS:		**$44,911**
STIPULATED ADJUSTMENTS:		
FIT and SIT Deduction	($584)	
UM 1233 Stipulated Depreciation Adjustment	($1,932)	
PGE's Updated NVPC/Revenues	$4,905	
Revenue Senstive Adjustments and Rounding	$6	
TOTAL STIPULATED ADJUSTMENTS:		**$2,395**
COMMISSION ADJUSTMENTS ON CONTESTED ISSSUES:		
Annualized Dispatch Benefit	($1,984)	
RATE OF RETURN:		
Change to Capital Structure (50/50)	(1,174)	
Change to Cost of Debt (6.49%)	(436)	
Change to Cost of Equity (10.10%)	(1,607)	
TOTAL ADJUSTMENTS ON CONTESTED ISSUES:		**($5,201)**
TOTAL COMMISSION AUTHORIZED REVENUE REQUIREMENT:		**$42,105**

Portland General Electric
UE 180 / UE 184
Revenue Requirement Model
Twelve Months Ending December 31, 2007
($000)

		2007 Per application Includes Power Costs (1)	Commission Authorized Adjustments (2)	2007 Adjusted (3)	Revenue Req without Port Westward 1/1/2007 (4)	Results at Reasonable Return Inc. Pwr Costs (5)
	SUMMARY SHEET					
1	**Operating Revenues**					
2	Retail Sales	$1,619,953	($90,146)	$1,529,807	(21,572)	$1,508,235
3	Wholesale Sales	0	0	0	0	0
4	Other Revenues	17,728	1,472	19,200	0	19,200
5	**Total Operating Revenues**	$1,637,681	($88,674)	$1,549,007	($21,572)	$1,527,435
6	**Operating Expenses**					
7	Net Variable Power Costs	$856,968	($80,941)	$776,027	$0	$776,027
8	Production	71,970	0	71,970	0	71,970
9	Other Power Supply (Trojan)	218	0	218	0	218
10	Transmission	10,279	(34)	10,245	0	10,245
11	Distribution	60,336	(1,623)	58,713	0	58,713
12	Customer Accounting	0	0	0	0	0
13	Customer Service & Info	60,015	(1,644)	58,371	0	58,371
14	Uncollectibles	8,586	(478)	8,108	(114)	7,994
15	Administrative and General	109,785	(12,876)	96,909	0	96,909
16	**Total Operation & Maintenance**	$1,178,157	($97,596)	$1,080,561	($114)	$1,080,447
17	Depreciation	$154,384	($6,346)	$148,038	$0	$148,038
18	Amortization	18,848	0	18,848	0	18,848
19	Taxes Other than Income	47,497	(2,267)	45,230	0	45,230
20	Income Taxes	58,698	5,805	64,503	(8,229)	56,274
21	Miscellaneous Revenue and Expense(Franch. Fees)	37,907	(2,109)	35,797	(505)	35,293
22	**Total Operating Expenses**	$1,495,490	($102,513)	$1,392,977	($8,848)	$1,384,129
23	**Net Operating Revenues**	$142,191	$13,839	$156,030	(12,724)	$143,306
24	**Average Rate Base**					
25	Electric Plant in Service	$4,316,780	($13,084)	$4,303,696	$0	$4,303,696
26	Less: Accumulated Depreciation & Amortization	(2,463,112)	0	(2,463,112)	0	(2,463,112)
27	Accumulated Deferred Income Taxes	(205,677)	0	(205,677)	0	(205,677)
28	Accumulated Deferred Inv. Tax Credit	(5,005)	0	(5,005)	0	(5,005)
29	**Net Utility Plant**	$1,642,986	($13,084)	$1,629,902	$0	$1,629,902
30	Plant Held for Future Use	$0	$0	$0	$0	$0
31	Acquisition Adjustments	0	0	0	0	0
32	Working Capital	77,765	(5,332)	72,433	(460)	71,973
33	Fuel Stock	0	0	0	0	0
34	Materials & Supplies	50,177	0	50,177	0	50,177
35	Customer Advances for Construction	0	0	0	0	0
36	Weatherization Loans	0	0	0	0	0
37	Misc Deferred Credits	(28,082)	0	(28,082)	0	(28,082)
38	Misc. Deferred Debits	4,689	0	4,689	0	4,689
39	Misc. Rate Base Additions/(Deductions)	0	0	0	0	0
40	**Total Average Rate Base**	$1,747,535	($18,416)	$1,729,119	($460)	$1,728,659
41	**Rate of Return**	8.14%		9.02%		**8.29%**
42	**Implied Return on Equity**	9.27%		11.57%		10.10%

Portland General Electric
UE 180 / UE 184
Income Tax Calculation On Revenue Requirement
Twelve Months Ending December 31, 2007
($000)

		Income Tax Calculations	2007 Per Company Filing (1)	Commission Authorized Adjustments (2)	2007 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1		Book Revenues	$1,637,681	($88,674)	$1,549,007	($21,572)	$1,527,435
2		Book Expenses Other than Depreciation	1,282,409	(101,972)	1,180,436	(619)	1,179,817
3		State Tax Depreciation	154,384	(6,346)	148,038	0	148,038
4		Interest	51,150	4,873	56,023	(15)	56,008
5	Less:	Schedule M Differences	(38,410)	0	(38,410)	0	(38,410)
6		State Taxable Income	$188,148	$14,771	$202,919	($20,938)	$181,981
7		Production Deduction	($4,017)	$0	($4,017)	$0	($4,017)
8		Total State Taxable Income	$184,131	$14,771	$198,902	($20,938)	$177,964
9		State Income Tax @ 6.617%	$12,184	$977	$13,161	($1,385)	$11,776
10		State Tax Credits	(166)	0	(166)	0	(166)
11		Net State Income Tax	$12,018	$977	$12,995	($1,385)	$11,610
12		Additional Tax Depreciation	0	0	0	0	0
13	Plus:	Other Schedule M Differences	0	0	0	0	0
14		Federal Taxable Income	$172,113	$13,794	$185,907	($19,553)	$166,354
15		Federal Tax @ 35%	$60,240	$4,828	$65,068	($6,844)	$58,224
16		Federal Tax Credits	0	0	0	0	0
17		Current Federal Tax	$60,240	$4,828	$65,068	($6,844)	$58,224
18		ITC Adjustment					
19		Deferral	0	0	0	0	0
20		Restoration	1,461	0	1,461	0	1,461
21		Total ITC Adjustment	($1,461)	$0	($1,461)	$0	($1,461)
22		Provision for Deferred Taxes	($12,099)	$0	($12,099)	$0	($12,099)
23		Total Income Tax	$58,698	$5,805	$64,503	($8,229)	$56,274

Portland General Electric
UE 180
Adjustments Before Port Westward
Twelve Months Ending December 31, 2007
($000)

	Commission Authorized Adjustments	All Other Taxes (S-1)	FIT & SIT Adjustment (S-2)	A&G and O&M Adjustment (S-3)	Power Cost Adjustment (S-4)	Incentive Adjustment (S-5)	Wages & Salary Adjustment (S-6)	Coal Loss Adjustment (S-7)	Other Revenues Adjustment (S-8)	Capital Expenditures Adjustment (S-9)	Extrinsic Value Adjustment (S-10)
1	**Operating Revenues**										
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
3	Wholesale Sales	0	0	0	0	0	0	0	0	0	0
4	Other Revenues	0	0	0	0	0	0	0	40	0	0
5	**Total Operating Revenues**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$40**	**$0**	**$0**
6	**Operating Expenses**										
7	Net Variable Power Costs	$0	$0	$0	($4,598)	$0	$0	$0	$0	$0	$0
8	Production	0	0	0	0	0	0	0	0	0	0
9	Other Power Supply (Trojan)	0	0	0	0	0	0	0	0	0	0
10	Transmission	0	0	(34)	0	0	0	0	0	0	0
11	Distribution	0	0	(1,623)	0	0	0	0	0	0	0
12	Customer Accounting	0	0	0	0	0	0	0	0	0	0
13	Customer Service & Info	0	0	0	0	0	0	0	0	0	0
14	Uncollectibles	0	0	0	0	0	0	0	0	0	0
15	Administrative and General	0	0	(4,894)	0	(4,366)	(3,534)	0	0	0	0
16	**Total Operation & Maintenance**	**$0**	**$0**	**($6,551)**	**($4,598)**	**($4,366)**	**($3,534)**	**$0**	**$0**	**$0**	**$0**
17	Depreciation	0	0	0	0	0	0	0		0	0
18	Amortization	0	0	0	0	0	0	0	0	0	0
19	Taxes Other than Income	(2,267)	0	0	0	0	0	0	0	0	0
20	Income Taxes	892	(2,148)	2,577	1,809	1,734	1,403	0	16	89	0
21	Miscellaneous Revenue and Expense										
22	**Total Operating Expenses**	($1,375)	($2,148)	($3,974)	($2,789)	($2,632)	($2,131)	$0	$16	$89	$0
23	**Net Operating Revenues**	**$1,375**	**$2,148**	**$3,974**	**$2,789**	**$2,632**	**$2,131**	**$0**	**$24**	**($89)**	**$0**
24	**Average Rate Base**										
25	Electric Plant in Service	0	0	0	0	(1,271)	(1,029)	0		(7,000)	0
26	Accumulated Depreciation & Amortization	0	0	0	0	0	0	0	0	0	0
27	Accumulated Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0
28	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0	0	0	0
29	**Net Utility Plant**	$0	$0	$0	$0	($1,271)	($1,029)	$0	$0	($7,000)	$0
30	Plant Held for Future Use	0	0	0	0	0	0	0	0	0	0
31	Acquisition Adjustments	0	0	0	0	0	0	0	0	0	0
32	Working Capital	(72)	(112)	(207)	(145)	(137)	(111)	0	1	5	0
33	Fuel Stock	0	0	0	0	0	0	0	0	0	0
34	Materials & Supplies	0	0	0	0	0	0	0	0	0	0
35	Customer Advances for Construction	0	0	0	0	0	0	0	0	0	0
36	Weatherization Loans	0	0	0	0	0	0	0	0	0	0
37	Prepayments	0	0	0	0	0	0	0	0	0	0
38	Misc. Deferred Debits	0	0	0	0	0	0	0	0	0	0
39	Misc. Rate Base Additions/(Deductions)	0	0	0	0	0	0	0	0	0	0
40	**Total Average Rate Base**	**($72)**	**($112)**	**($207)**	**($145)**	**($1,408)**	**($1,140)**	**$0**	**$1**	**($6,995)**	**$0**
41	**Revenue Requirement Effect**	**($2,339)**	**($3,655)**	**($6,761)**	**($4,745)**	**($4,657)**	**($3,770)**	**$0**	**($41)**	**($831)**	**$0**

Portland General Electric
UE 180
Adjustments Before Port Westward
Twelve Months Ending December 31, 2007
($000)

	Commission Authorized Adjustments	System Losses Adjustment (S-11)	Membership Adjustment (S-12)	Tenant Improvements Adjustment (S-13)	Weatherization Services Adjustment (S-14)	Customer Info and Advertising Adjustment (S-15)	Ancillary Services Adjustment (S-16)	Beaver 8 Generating Facility (S-17)(PGE-1)	UM 1233 Stipulated Depreciation (S-18)(PGE-4)	Capacity Contract (I-1)	Update NVPC/Rev (PGE-5)	Total Adjustments (Base Rates)
1	**Operating Revenues**											
2	Retail Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	($90,146)	($90,146)
3	Wholesale Sales	0	0	0	0	0	0	0	0	0	0	$0
4	Other Revenues	0	0	0	0	0	1,432	0	0	0	0	$1,472
5	**Total Operating Revenues**	**$0**	**$0**	**$0**	**$0**	**$0**	**$1,432**	**$0**	**$0**	**$0**	**($90,146)**	**($88,674)**
6	**Operating Expenses**											
7	Net Variable Power Costs	0	$0	$0	$0	$0	$0	$0	$0	($1,384)	($74,959)	($80,941)
8	Production	0	0	0	0	0	0	0	0	0	0	$0
9	Other Power Supply (Trojan)	0	0	0	0	0	0	0	0	0	0	$0
10	Transmission	0	0	0	0	0	0	0	0	0	0	($34)
11	Distribution	0	0	0	0	0	0	0	0	0	0	($1,623)
12	Customer Accounting	0	0	0	0	0	0	0	0	0	0	$0
13	Customer Service & Info	0	0	0	(69)	(1,575)	0	0	0	0	0	($1,644)
14	Uncollectibles	0	0	0	0	0	0	0	0	0	(478)	($478)
15	Administrative and General	0	(82)	0	0	0	0	0	0	0	0	($12,876)
16	**Total Operation & Maintenance**	**$0**	**($82)**	**$0**	**($69)**	**($1,575)**	**$0**	**$0**	**$0**	**($1,384)**	**($75,437)**	**($97,596)**
17	Depreciation	0	0	0	0	0	0	(497)	(5,849)	0	0	($6,346)
18	Amortization	0	0	0	0	0	0	0	0	0	0	$0
19	Taxes Other than Income	0	0	0	0	0	0	0	0	0	0	($2,267)
20	Income Taxes	0	32	0	27	619	563	281	2,264	545	(4,898)	$5,805
21	Miscellaneous Revenue and Expense										(2,109)	($2,109)
22	**Total Operating Expenses**	$0	($50)	$0	($42)	($956)	$563	($216)	($3,585)	($839)	($82,444)	($102,513)
23	**Net Operating Revenues**	**$0**	**$50**	**$0**	**$42**	**$956**	**$869**	**$216**	**$3,585**	**$839**	**($7,702)**	**$13,839**
24	**Average Rate Base**											
25	Electric Plant in Service	0	0	0	0	0	0	(6,709)	2,925	0	0	($13,084)
26	Accumulated Depreciation & Amortization	0	0	0	0	0	0	0	0	0	0	$0
27	Accumulated Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	$0
28	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0	0	0	0	$0
29	**Net Utility Plant**	$0	$0	$0	$0	$0	$0	($6,709)	$2,925	$0	$0	($13,084)
30	Plant Held for Future Use	0	0	0	0	0	0	0	0	0	0	$0
31	Acquisition Adjustments	0	0	0	0	0	0	0	0	0	0	$0
32	Working Capital	0	(3)	0	(2)	(50)	29	(11)	(186)	(44)	(4,287)	($5,332)
33	Fuel Stock	0	0	0	0	0	0	0	0	0	0	$0
34	Materials & Supplies	0	0	0	0	0	0	0	0	0	0	$0
35	Customer Advances for Construction	0	0	0	0	0	0	0	0	0	0	$0
36	Weatherization Loans	0	0	0	0	0	0	0	0	0	0	$0
37	Prepayments	0	0	0	0	0	0	0	0	0	0	$0
38	Misc. Deferred Debits	0	0	0	0	0	0	0	0	0	0	$0
39	Misc. Rate Base Additions/(Deductions)	0	0	0	0		0	0	0	0	0	$0
40	**Total Average Rate Base**	**$0**	**($3)**	**$0**	**($2)**	**($50)**	**$29**	**($6,720)**	**$2,739**	**($44)**	**($4,287)**	**($18,416)**
41	**Revenue Requirement Effect**	**$0**	**($85)**	**$0**	**($71)**	**($1,626)**	**($1,468)**	**($1,310)**	**($5,688)**	**($1,427)**	**$12,445**	**($26,029)**

Portland General Electric
UE 180 / UE 184
Revenue Requirement Model
Twelve Months Ending December 31, 2007
($000)

	SUMMARY SHEET	Company's Request Port Westward (6)	Results with Port Westward Change (7)	Commission Authorized Adjustments Port Westward (8)	Adjusted for Port Westward Change (9)	Revenue Req with Port Westward 3/1/2007 (10)	Results with Port Westward (11)
1	**Operating Revenues**						
2	Retail Sales	$0	$1,508,235	$0	$1,508,235	$42,105	$1,550,340
3	Wholesale Sales	0	0	0	$0	0	0
4	Other Revenues	0	19,200	0	$19,200	0	19,200
5	**Total Operating Revenues**	$0	$1,527,435	$0	$1,527,435	$42,105	$1,569,540
6	**Operating Expenses**						
7	Net Variable Power Costs	($11,746)	$764,281	$2,831	$767,112	$0	$767,112
8	Production	8,440	80,410	0	80,410	0	80,410
9	Other Power Supply (Trojan)	0	218	0	218	0	218
10	Transmission	0	10,245	0	10,245	0	10,245
11	Distribution	0	58,713	0	58,713	0	58,713
12	Customer Accounting	0	0	0	0	0	0
13	Customer Service & Info	0	58,371	0	58,371	0	58,371
14	Uncollectibles	0	7,994	0	7,994	223	8,217
15	Administrative and General	315	97,224	0	97,224	0	97,224
16	**Total Operation & Maintenance**	($2,991)	$1,077,456	$2,831	$1,080,287	$223	$1,080,510
17	Depreciation	$10,667	$158,705	($1,988)	$156,717	$0	$156,717
18	Amortization	0	18,848	0	18,848	0	18,848
19	Taxes Other than Income	0	45,230	0	45,230	0	45,230
20	Income Taxes	**(6,217)**	50,057	(687)	49,370	16,062	65,432
21	Miscellaneous Revenue and Expense(Franch. Fees)	0	35,293	0	35,293	985	36,278
22	**Total Operating Expenses**	$1,459	$1,385,588	$156	$1,385,744	$17,270	$1,403,014
23	**Net Operating Revenues**	($1,459)	$141,847	($156)	$141,691	$24,835	$166,525
24	**Average Rate Base**						
25	Electric Plant in Service	$285,205	$4,588,901	$994	$4,589,895	$0	$4,589,895
26	Less: Accumulated Depreciation & Amortization	(5,333)	(2,468,445)	0	(2,468,445)	0	(2,468,445)
27	Accumulated Deferred Income Taxes	(1,758)	(207,435)	0	(207,435)	0	(207,435)
28	Accumulated Deferred Inv. Tax Credit	0	(5,005)	0	(5,005)	0	(5,005)
29	**Net Utility Plant**	$278,114	$1,908,016	$994	$1,909,010	$0	$1,909,010
30	Plant Held for Future Use	$0	$0	$0	$0	$0	$0
31	Acquisition Adjustments	0	0	0	0	0	0
32	Working Capital	76	72,049	8	72,057	898	72,955
33	Fuel Stock	0	0	0	0	0	0
34	Materials & Supplies	0	50,177	0	50,177	0	50,177
35	Customer Advances for Construction	0	0	0	0	0	0
36	Weatherization Loans	0	0	0	0	0	0
37	Misc Deferred Credits	0	(28,082)	0	(28,082)	0	(28,082)
38	Misc. Deferred Debits	0	4,689	0	4,689	0	4,689
39	Misc. Rate Base Additions/(Deductions)	0	0	0	0	0	0
40	**Total Average Rate Base**	$278,190	$2,006,849	$1,002	$2,007,851	$898	$2,008,749
41	**Rate of Return**		7.07%		7.06%		**8.29%**
42	**Implied Return on Equity**		7.66%		7.63%		10.10%

Portland General Electric
UE 180 / UE 184
Income Tax Calculation On Revenue Requirement
Twelve Months Ending December 31, 2007
($000)

		Income Tax Calculations	Impact of Port Westward (6)	Results with Port Westward Change (7)	Commission Authorized Adjust Port Westward (8)	Adjusted for Port Westward Change (9)	Revenue Req with Port Westward 3/1/2007 (10)	Results at Reasonable Return (11)
1		Book Revenues	$0	$1,527,435	$0	$1,527,435	$42,105	$1,569,540
2		Book Expenses Other than Depreciation	7,676	1,187,493	2,831	1,190,324	1,208	$1,191,532
3		State Tax Depreciation	0	148,038	(1,988)	146,050		$146,050
4		Interest	8,141	64,149	905	65,054	29	$65,083
5	Less:	Schedule M Differences	8,947	(29,463)	0	(29,463)	0	($29,463)
6		State Taxable Income	($24,764)	$157,217	($1,748)	$155,469	$40,860	$196,329
7		Production Deduction	$0	($4,017)	$0	($4,017)	$0	($4,017)
8		Total State Taxable Income	($24,764)	$153,200	($1,748)	$151,452	$40,860	$192,312
9		State Income Tax @ 6.617%	($1,639)	$10,137	($116)	$10,021	$2,704	$12,725
10		State Tax Credits	0	(166)	0	(166)	0	(166)
11		Net State Income Tax	($1,639)	$9,971	($116)	$9,855	$2,704	$12,559
12		Additional Tax Depreciation	0	0	0	0	0	0
13	Plus:	Other Schedule M Differences	0	0	0	0	0	0
14		Federal Taxable Income	($23,125)	$143,229	($1,632)	$141,597	$38,156	$179,753
15		Federal Tax @ 35%	($8,094)	$50,130	($571)	$49,559	$13,358	$62,917
16		Federal Tax Credits	0	0	0	0	0	0
17		Current Federal Tax	($8,094)	$50,130	($571)	$49,559	$13,358	$62,917
18		ITC Adjustment						
19		Deferral	0	0	0	0	0	0
20		Restoration	0	1,461	0	1,461	0	0
21		Total ITC Adjustment	$0	($1,461)	$0	($1,461)	$0	$0
22		Provision for Deferred Taxes	$3,516	($8,583)	$0	($8,583)	$0	$3,516
23		Total Income Tax	($6,217)	$50,057	($687)	$49,370	$16,062	$65,432

ORDER NO. 07-015

Portland General Electric
UE 184
Port Westward Adjustments
($000)

	Commission Authorized Adjustments	FIT & SIT Adjustment (S-PW-1)	Life Estimate Adjustment (S-PW-2)	PGE's Updated NVPC/Rev (S-PW-3)	Annualized Dispatch Benefit (ICNU-PW-1)	Total Adjustments (Base Rates)
1	**Operating Revenues**					
2	Retail Sales	$0	$0	$0	$0	$0
3	Wholesale Sales	0	0	0	0	$0
4	Other Revenues	0	0	0	0	$0
5	**Total Operating Revenues**	**$0**	**$0**	**$0**	**$0**	**$0**
6	**Operating Expenses**					
7	Net Variable Power Costs	$0	$0	$4,753	($1,922)	$2,831
8	Production	0	0	0	0	$0
9	Other Power Supply (Trojan)	0	0	0	0	$0
10	Transmission	0	0	0	0	$0
11	Distribution	0	0	0	0	$0
12	Customer Accounting	0	0	0	0	$0
13	Customer Service & Info	0	0	0	0	$0
14	Collectibles	0	0	0	0	$0
15	Administrative and General	0	0	0	0	$0
16	**Total Operation & Maintenance**	**$0**	**$0**	**$4,753**	**($1,922)**	**$2,831**
17	Depreciation	0	(1,988)	0	0	($1,988)
18	Amortization	0	0	0	0	$0
19	Taxes Other than Income	0	0	0	0	$0
20	Income Taxes	(343)	770	(1,870)	756	($687)
21	Miscellaneous Revenue and Expense					$0
22	**Total Operating Expenses**	($343)	($1,218)	$2,883	($1,166)	$156
23	**Net Operating Revenues**	**$343**	**$1,218**	**($2,883)**	**$1,166**	**($156)**
24	**Average Rate Base**					
25	Electric Plant in Service	0	994	0	0	$994
26	Accumulated Depreciation & Amortization	0	0	0	0	$0
27	Accumulated Deferred Income Taxes	0	0	0	0	$0
28	Accumulated Deferred Inv. Tax Credit	0	0	0	0	$0
29	**Net Utility Plant**	$0	$994	$0	$0	$994
30	Plant Held for Future Use	0	0	0	0	$0
31	Acquisition Adjustments	0	0	0	0	$0
32	Working Capital	(18)	(63)	150	(61)	$8
33	Fuel Stock	0	0	0	0	$0
34	Materials & Supplies	0	0	0	0	$0
35	Customer Advances for Construction	0	0	0	0	$0
36	Weatherization Loans	0	0	0	0	$0
37	Prepayments	0	0	0	0	$0
38	Misc. Deferred Debits	0	0	0	0	$0
39	Misc. Rate Base Additions/(Deductions)	0	0	0	0	$0
40	**Total Average Rate Base**	**($18)**	**$931**	**$150**	**($61)**	**$1,002**
41	**Revenue Requirement Effect**	**($584)**	**($1,932)**	**$4,905**	**($1,984)**	**$405**

Portland General Electric
UE 180 / UE 184
Commission Authorized
Cost of Capital

REVENUE SENSITIVE COSTS	
Revenues	1.00000
Operating Revenue Deductions	
Uncollectible Accounts	0.00530
Taxes Other - Franchise	0.02340
- Other	
- Resource supplier	
State Taxable Income	0.9713
State Income Tax	0.06427
Federal Taxable Income	0.90703
Federal Income Tax @ 35%	0.31746
ITC	
Current FIT	0.31746
Other	
Total Excise Taxes	0.38173
Total Revenue Sensitive Costs	0.41043
Utility Operating Income	0.58957
Net-to-Gross Factor	1.696155

Commission Authorized Cost of Capital

COST OF CAPITAL	% of CAPITAL	COST	WEIGHTED COST
Long Term Debt	50.00%	6.48%	3.24%
Preferred Stock	0.00%	0.00%	0.00%
Common Equity	50.00%	10.10%	5.05%
Total	100.00%		8.29%