BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 180

General Rate Case Filing

PORTLAND GENERAL ELECTRIC COMPANY

Pretrial Brief

March 15, 2006

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 180

In the Matter of the Revised Tariff Schedules for Electric Service in Oregon filed by PORTLAND GENERAL ELECTRIC COMPANY	))))	**PRETRIAL BRIEF OF PORTLAND GENERAL ELECTRIC COMPANY**

I. INTRODUCTION

This case is Portland General Electric Company's ("PGE") request to revise its tariff schedules pursuant to ORS 757.205 and ORS 757.220. PGE proposes revised rates and schedules that meet our customers' needs for reasonable prices and PGE's need for the opportunity to earn a return on invested capital that is commensurate with similar companies, allows it to maintain its credit and to attract capital. This brief is submitted to meet the requirements of OAR 860-013-075.

It has been over five years since PGE's last general rate case, Docket UE 115. Those five years have been eventful for the electric industry. Market electric and natural gas prices have reached and remained at unprecedented levels, wholesale energy markets have changed significantly, some utilities have suffered serious financial damage, and customers have responded to higher prices by decreasing their energy usage. The last five years have been particularly eventful for PGE as well, in some cases in ways we hope are never repeated. PGE has not only survived these interesting times, but has managed those costs within its control while continuing to provide excellent service to its customers.

PGE now looks forward to once again being a publicly traded company. It is anticipated that soon after the filing of this case at least 30% of PGE's stock will be distributed to creditors of Enron Corp. and its affiliated debtors, and PGE stock will begin trading on the New York Stock Exchange. In the 2007 test year used in this case, PGE is what it was in the past; a locally headquartered, stand-alone, publicly traded utility.

The regulatory environment has changed since PGE's last rate case as well. UE 115 was driven by the changing expectations of customers and movement toward restructuring, including the then recently enacted SB 1149. At that time, the movement was away from a regulatory environment that encouraged utilities to build generation. Customers wanted choices in a competitive market, and did not want the utility to make future resource decisions for them. Customers expected PGE to manage power market risk without building new PGE-owned plants.

The outcome of UE 115 affected the market structure, and the presence of competition for electric supply for PGE customers. Some large customers have chosen to obtain their electric supply from competitive suppliers. This docket maintains the current options of large customers, and implements new options for customers to choose an alternate supplier. However, customer and regulatory expectations around restructuring have changed considerably since UE 115, and this docket reflects that change.

One area that has changed significantly is the desire for utilities to build and own generation plants. Through integrated resource planning, a process that includes significant customer input and thorough Commission review, PGE identified a need to add additional generation resources. An aspect of this case is PGE's implementation of that plan through building the Port Westward combined-cycle combustion turbine generating plant discussed below and at length in PGE's testimony.

Customers continue to desire and expect outstanding service from PGE, and PGE has successfully provided it. PGE's customer service is among the top in the nation. PGE's power quality and reliability are also near the top nationwide, service that has become even more important to industrial and residential customers of late.

II. THIS CASE

A. Financial Issues. PGE has delayed requesting rate relief, but cannot continue to experience lagging financial performance without the risk of raising costs in the long term. The projected test year results show that, without a rate increase, PGE will earn a return on equity ("ROE") of 8.42%. That is significantly below PGE's currently authorized ROE, and the ROE of 10.75% requested in this docket to maintain PGE's credit and attract capital.

This case is based on a normalized future test period of calendar year 2007. Based on the expenses in that test year, PGE requests a net overall increase in rates of 8.9%. PGE will seek a schedule in this docket that will allow revised tariff schedules to be implemented on January 1, 2007.

B. Net Variable Power Costs. Nearly half of the requested increase is due to increases in net variable power costs ("NVPC"), or the variable costs to produce and purchase electricity. The largest drivers of increased net variable power costs are the market prices of fuel and power purchased to meet customer load. In UE 115, the Commission implemented a Resource Valuation Mechanism ("RVM"), tariff Schedule 125. Each year the RVM calculates transition charges or credits for those customers opting for an alternate electric supplier, and adjusts PGE's rates to reflect projected power costs for the coming year. PGE presently estimates that the RVM will result in a 4.1% increase in 2007 rates without regard for this filing.[1] PGE proposes in this filing to limit the RVM to those customers choosing direct access or market-based pricing options, and to make certain changes to MONET. These changes, along with a difference in load assumptions, result in a general rate case NVPC estimate of $856,968,000.

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1 Since Schedule 125 will continue in force at least until resolution of this rate case, PGE will comply with that tariff and make an RVM filing within a few weeks of the filing of this case.

C. Other Costs. Cost changes in the areas of Fixed Power Costs, Administrative and General expenses, Transmission and Distribution, Customer Service, Compensation, Trojan Decommissioning and all other areas of the company have not been addressed in a ratemaking proceeding for about five years. There are five main drivers of the revenue requirement change since UE 115:

- Operations and Maintenance and Administrative and General costs are approximately $49 million higher;
- Non-income based taxes (property taxes, payroll taxes, franchise fees) are approximately $11 million higher;
- Pre-tax return requirements are approximately $10 million lower;
- Depreciation and amortization is approximately $5 million lower; and
- Revenue growth reduces PGE's need for a price increase by approximately $20 million.

In total, cost changes in all these areas result in a requested increase of 1.7% in this docket. The submitted testimony addresses each general area, test year costs, and historical costs since 2002. As shown in the testimony, PGE has managed its costs very well, but higher rates are necessary at this time.

D. Generating Resources. Another major element of this docket is the Port Westward generation plant PGE expects to be in service in early 2007. Port Westward is a "G-class" combined cycle combustion turbine. When completed it will be among the most efficient, if not the most efficient, gas fired generation plant in the northwest. PGE requests that the Commission decide in this case the cost changes associated with Port Westward and allow PGE to file compliance tariffs affecting the revenue requirement change when the plant begins commercial operation. If that date is significantly different from PGE's forecast of March 1, 2007, however, it may be necessary to re-forecast the plants effect on NVPC.

Because Port Westward will at times generate power at prices less than prevailing market prices, the dispatch of Port Westward will decrease net variable power costs. The ratebase addition of the plant and operating costs will, of course, increase costs. The net effect is an increase of about 2.9% commencing when Port Westward becomes operational.

This case also contains an increase in hydro generation related costs, primarily as a result of hydro relicensing capital costs and expenses. PGE's new hydro licenses will require capital expenditures of about $370 million between now and 2020, as well as increased O&M. A portion of those costs are in the test year in this case.

E. Advanced Metering Infrastructure. One other large potential investment is discussed in the testimony in this case. PGE proposes to implement an Advanced Metering Infrastructure ("AMI") system. AMI enables the automated collection of meter data through a fixed network. An AMI system would allow PGE to reduce operational costs in the long-term, provide additional services to customers, bill more accurately, and offer additional demand response programs. Such a system is a large capital investment – PGE anticipates about $141 million over a three year period. The submitted testimony contains PGE's analysis showing that an AMI system would provide a net present value of benefits over the next twenty years of $4 million to $20 million.

PGE has not included the costs and benefits of implementing AMI in the base rate request in this case. Whether PGE should implement AMI at this time is a policy decision and PGE seeks the Commission's determination as to whether PGE should do so. If the Commission approves the program, as well as the "cost smoothing" deferral PGE proposes, implementing AMI would increase the 2007 revenue requirement by $3.7 million.

F. Power Cost Tariffs. PGE is proposing two significant tariff revisions dealing with power costs. As the Commission is aware, net variable power costs for PGE have, for several years, varied significantly from those assumed in ratemaking. One major driver of this variation has been hydro generation variation.

There have been several dockets dealing with this issue, most recently UE 165 in which Staff and PGE stipulated to a temporary hydro adjustment mechanism. The Commission rejected the Stipulation, but offered PGE the opportunity to file a revised hydro adjustment mechanism. For a number of reasons, among them that PGE, Staff, the Citizens' Utility Board ("CUB"), and the Industrial Customers of Northwest Utilities ("ICNU") had been working together on potential approaches to this issue, PGE declined to file a revised mechanism and notified the Commission that PGE would propose a broader adjustment mechanism in this docket.

PGE has done so, and proposes two tariffs to deal with the variability of power costs. While the discussions with Staff, CUB and ICNU did not result in definitive agreement on the specifics of how power cost variances should be reflected in PGE's rates, the work to date has resulted in significant understanding of the concerns and desires of the various parties. PGE proposes these two tariff schedules as a reasonable approach to the considerable financial and cost of service effects of variation in power costs:

<u>Annual Adjustment</u>. PGE proposes an Annual Update, tariff Schedule 125. This adjustment is similar to, but narrower than the current RVM. Under this schedule, PGE will

revise service prices annually on January 1 through an automatic adjustment clause to reflect a forecast of NVPC developed using the MONET model updated with certain defined inputs of current and projected information for the coming year. The tariff contains both the input parameters and the process. As set forth in the testimony of Pamela G. Lesh and Michael A. Niman (PGE 400), this Annual Update resolves many of the aspects of the RVM proceedings that have caused disagreement in past dockets.

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

Together, these two mechanisms are a reasonable and appropriate ratemaking approach to the variability of net variable power costs.

Short-Term Transition Adjustment. PGE also proposes Schedule 128, a Short-Term Transition Adjustment to accomplish the results of the ongoing valuation required under OAR 860-038-0140 for customers choosing direct access. This valuation is currently done through the RVM process. Schedule 128 is offered as a separate adjustment that will continue to make the valuation similar to that done in the RVM process. Schedule 128 also provides for the posting of transition adjustments to facilitate a monthly election window. In UM 1206 PGE agreed to propose a monthly, balance of year, election window for customers to choose direct access, and it has proposed tariffs to implement that in this case. Schedule 128 will govern the transition adjustments for those windows.

G. Other Key Proposals. PGE makes several other proposals in this docket including:

- A decrease of about $10 million in the annual customer contribution to the Nuclear Decommissioning Trust (NDT), and return of $20 million from this fund;
- Inclusion of the results of PGE's most recent depreciation study, which generally lowers PGE's depreciation expense;
- Changes to PGE's direct access program, based on experience to date, including termination of the Part B Short Term Resource Notice under Schedule 125, and addition of monthly opportunities for customers to choose direct access of market-based pricing for the balance of a given year;
- A new pricing option under which our larger-load customers can place 50% of their load on an Energy Service Supplier (ESS) and the remainder on a PGE cost of service rate;
- A new Schedule 89 (and 589 for direct access) for business customers whose loads exceed 1,000 kW to better reflect cost differences for these larger customers and a re-opening of Schedule 38, time-of-day service, for mid-size seasonal customers who may benefit from its pricing structure;
- New options under Schedule 483 by which PGE can offer customers choosing this long-term opt-out from PGE's cost of service resources market-based prices for the three or five years; and
- A two-year notice requirement for self-generating customers to place load presently

met with their own generation back on cost of service, comparable to the notice required of customers choosing a five-year opt-out from PGE's cost of service resources.

Each of these proposals is explained in the testimony submitted herewith.

III. TESTIMONY

PGE's testimony and exhibits demonstrate that the Commission should approve this Application. The rates and tariffs proposed will result in rates that are just and reasonable. PGE is introducing thirteen pieces of testimony sponsored by the following witnesses:

EXHIBIT NO.	TITLE	WITNESSES
100	Policy	James J. Piro and Pamela G. Lesh
200	Revenue Requirement	L. Alex Tooman and Jay Tinker
300	Fixed Power Costs	Stephen Quennoz and Stephen Schue
400	Power Cost Framework	Pamela G. Lesh and Michael A. Niman
500	Administrative and General	James J. Piro and L. Alex Tooman
600	Transmission and Distribution	Stephen Hawke
700	Customer Service	Stephen Hawke
800	Advanced Metering Infrastructure	Stephen Hawke, Bruce Carpenter and L. Alex Tooman
900	Compensation	Arleen Barnett and Joyce Bell
1000	Trojan Decommissioning	Stephen Quennoz and Steven B. Nichols
1100	Cost of Capital	Patrick G. Hager and William J. Valach
1200	Load Forecast	Ham T. Nguyen
1300	Pricing	Doug Kuns and Marc Cody

IV. SUMMARY OF TESTIMONY

Exhibit 100. James J. Piro and Pamela G. Lesh present the opening testimony. They describe PGE's strategic direction and goals, which serve as the context for this rate case filing. They also present and discuss PGE's key proposals and the objectives that guided their development.

These witnesses also introduce the other pieces of testimony filed in this docket.

Exhibit 200. L. Alex Tooman and Jay Tinker summarize the overall revenue requirement of $1,644,624,000 before inclusion of Port Westward, and $1,689,536,000 after inclusion of Port Westward. Messrs. Tooman and Tinker explain that PGE is using a 2007 test year, and compare the request with the 2002 test year used in UE 115, and also 2004 actual expenses.

This testimony also presents, and uses for test year purposes, PGE's request for new depreciation rates. The new depreciation study is before the Commission in Docket 1233, and would decrease depreciation expense in the test year by about $13 million.

Messrs. Tooman and Tinker explain the taxes and fees assessed on PGE. Their testimony also presents PGE's forecasted capital expenditures. Messrs. Tooman and Tinker also testify to PGE's rate base. The average 2007 rate base is $1,748,061,000 before inclusion of Port Westward, and $2,027,208,000 after inclusion of Port Westward. They discuss the costs associated with Port Westward, and PGE's request to have them reflected in rates when the plant is operational. This testimony also discusses accounting changes and PGE's request for rate treatment of some deferred accounts.

Exhibit 300. Stephen Quennoz and Stephen Schue address PGE's long-term power supply resources, and the associated costs. There have been several changes in PGE's owned and

contractual hydro facilities since 2002, and they are discussed in this testimony.

Forecasted 2007 costs for power operations and plant-related O&M expenses are almost $81 million, including Port Westward. These witnesses discuss the management of thermal plant-related costs, which PGE has held to a rate increase less than inflation since 2002. There has been a larger increase in hydro related costs, primarily as a result of hydro relicensing capital costs and expenses. PGE's new hydro licenses will require capital expenditures of about $370 million between now and 2020. A small portion of those costs are in the test year in this case. The witnesses explain the relicensing process, the requirements of the new licenses, and why the investments are cost-effective.

Mr. Quennoz and Mr. Schue also discuss in detail the decision to build Port Westward. They discuss the process used in evaluating the various options that led to the decision to build Port Westward, and the decision to procure a "G-class" turbine. These witnesses also set forth the process used in selecting a contractor to build the plant, and the associated costs. They also testify that the plant is currently within budget and on schedule to be on-line March 1, 2007.

Exhibit 400. PGE's net variable power costs ("NVPC") are presented by Pamela G. Lesh and Michael A. Niman. Rates increase 4.1% from 2006 to recover NVPC using the RVM methodology. The primary causes of the increase are increases in projected electric and natural gas prices. The testimony also states that PGE will file a 2007 RVM as required by its existing tariff, and propose schedules in that docket and this one that will allow resolution of PGE's proposed changes to direct access in time for the September Schedule 483 elections.

This testimony also proposes an ongoing methodology for reflecting power costs in PGE's cost of service rates. The framework uses three common regulatory tools – a general rate case, a forward-looking automatic adjustment clause, and a retrospective automatic adjustment clause – to achieve the goal of reasonably reflecting in rates the actual costs of providing service, and to allocate the risks of variance between forecast costs used in setting rates and the actual costs experienced in providing service. The testimony explains the reasoning behind the proposal, the methodologies and allocations, and the process and timing proposed.

Exhibit 500. James J. Piro and L. Alex Tooman address PGE's administrative and general expenses. Test year A&G expenses are $109.8 million. This represents an average annual increase of 2.9% since 2002. In general, inflation is the primary reason for the increased costs. In addition, benefit costs and pension costs have increased at a rate much higher than overall inflation. Additional regulatory requirements in the accounting and finance areas, and some new functions, such as investor relations, also increase A&G costs. The witnesses describe these costs and the steps PGE takes to control costs.

Exhibit 600. Stephen Hawke testifies regarding PGE's transmission and distribution system. He explains how PGE maintains its system, and the operational and capital costs necessary to do so. Mr. Hawke explains that PGE's transmission and distribution system has grown significantly since 2002. The number of PGE customers served by the system has increased 8% since 2002, and labor and materials costs have increased significantly during this time. As Mr. Hawke explains, test year O&M expenses for transmission and distribution are an increase of about $21 million over 2002 expenses, and capital expenditures have increased about $16 million in the same time.

Exhibit 700. Mr. Hawke also addresses PGE's Customer Service functions and costs. The areas covered by the Customer Service testimony are responsible for most interactions with

retail customers. Customer Service costs in the 2007 test year are about $68 million. This represents an increase at an average annual rate of 5.7% since 2002. The testimony explains the major drivers of the cost increases and the steps PGE has taken to minimize costs while providing the service our customers expect and demand.

Exhibit 800. Stephen Hawke, Bruce Carpenter and L. Alex Tooman explain PGE's proposed Advanced Metering Infrastructure system. As discussed above, an AMI system is projected to generate cost savings, allow PGE to provide additional services to customers, and enable additional demand response programs. This testimony sets forth the costs and benefits of the system, and presents the proposal as a stand-alone issue. The testimony also contains a proposal by PGE to mitigate the rate impact of deploying the system by deferring the revenue requirement associated with the capital costs together with the O&M savings until the end of 2009.

Exhibit 900. Arleen Barnett, PGE's Vice President, Administration, and Joyce Bell, Director of Compensation, testify on compensation and human resource issues. The focus of their testimony is total compensation and PGE's practice of setting each total compensation component to the market median. Total compensation in the 2007 test year is $256.6 million, an increase of 5.4% per year on average since 2002. A large driver of that increase is the rising cost of health and dental benefits.

The witnesses also discuss the particular challenges PGE faces in this area. For example, PGE has a larger portion of workers ages 45 through 64 than other utilities and the population in general. We expect significantly more retirements in the coming years than have occurred historically. At the same time, a tight labor market for replacement employees with the necessary skills has made attracting and retaining employees more difficult and costly.

Exhibit 1000. Costs associated with Trojan decommissioning are addressed by Stephen Quennoz and Steven B. Nichols. These witnesses explain that PGE has consistently completed decommissioning projects safely and under budget. PGE has been so successful at this that it has garnered international acclaim. As a result, Mr. Quennoz and Mr. Nichols make two proposals on behalf of PGE: one, to decrease the annual contribution to the Nuclear Decommissioning Trust ("NDT") by almost $10 million, and extend contributions through 2024; and two, to return $20 million from the NDT that is currently surplus due to cost savings. Both of these proposals provide significant rate benefits to customers.

Exhibit 1100: Patrick G. Hager and William J. Valach present PGE's testimony on cost of capital. The witnesses discuss PGE's cost of long term debt, and the financial markets between 2001 and 2005 during which some of this debt was issued. PGE's long-term debt for 2007 has an effective interest rate of 6.69%.

The witnesses also address PGE's equity costs. Three specific risks currently have a significant impact on PGE: the wholesale power environment, hydro generation variation, and regulatory risks. These risks have changed in scope and magnitude since 2002, and impact the return on equity that is appropriate for PGE. Relying on the Discounted Cash Flow and Risk Positioning models, the witnesses recommend a 10.75% return on equity. The analysis of the ROE covers single and multi-stage DCF's and risk positioning analyses with both corporate bonds and treasury bonds.

The testimony also addresses capital structure. The witnesses calculated PGE's capital structure using the forecasted income statement and balance sheet for 2007, with expected financings through 2007. PGE's capital structure has changed significantly since 2002. PGE's projected common equity component of capital structure is 55.96%. The witnesses explain why PGE intends to maintain that equity ratio.

Finally, Messrs. Hager and Valach discuss the upcoming distribution of PGE common stock which will separate PGE from Enron. It is expected that in April 2006 Enron creditors will receive at least 30% of PGE's common stock. We expect PGE's stock to begin trading on the New York Stock Exchange in April 2006.

Exhibit 1200: Ham T. Nguyen presents PGE's load forecast. He forecasts that total retail loads will increase 2.3% from the 2005 weather-adjusted level. Only a small, 0.9% increase, is forecast for residential loads. Commercial and industrial loads are forecast to increase at higher rates, 2.8% and 4.0% respectively. Even with these forecast increases, the 2007 load forecast is below the 2002 test year forecast used in PGE's last general rate case.

Exhibit 1300. Doug Kuns and Marc Cody testify on pricing. They detail the tariff building blocks used to develop rates, the revenue requirement process, and marginal costs.

PGE has designed the rates based on cost causation. The proposed rate change, excluding power cost related changes handled through the RVM process and before inclusion of Port Westward, is 1.7% overall.

This testimony also discusses several tariff changes proposed in this case. In the proposed rates, the Annual Cost of Service tariff Energy Charge is based on the cost of meeting each schedule's energy requirements. This differs from the approach taken in UE 115 that included a transition adjustment to the market determined Energy Charge. PGE proposes to apply transition adjustments only to those customers who choose an Energy Charge other than cost of service or direct access. PGE also proposes to replace the current Resource Valuation Mechanism with the Annual Update which separates the annual update of power costs from the transition adjustment.

This testimony also includes the Power Cost Variance Mechanism to be applied to all customers except those that have opted to leave cost of service for a period of more than one year. This tariff proposal is addressed in more detail in PGE 400.

The testimony also describes other proposed tariff changes, and also minor modifications to PGE's Rules and Regulations and some Schedule 300 charges.

V. REQUEST FOR APPROVALS

PGE requests that the Commission issue an order:

(1) Approving the requested rate changes;

(2) Approving the proposed tariffs and rules;

(3) Ordering PGE to file revised rates at the time Port Westward becomes operational, reflecting the capital costs, O&M expenses and dispatch benefits of the plant; and

(4) Deciding that it is prudent at this time for PGE to implement an automated metering infrastructure, and implementation of a deferral for certain associated costs.

Dated: this 15th day of March, 2006.

Respectfully submitted,

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Exhibit 1

Case Summary

($000)

	Before Port Westward	Including Port Westward
Total Revenue Requirement	$1,644,624	$1,689,536
Change in Revenues Requested		
RVM Power Costs	$72,748	$72,748
Other Costs	$25,147	$69,784
Total Change in Revenues Requested	$97,895	$142,532
Total Change net of RPA & Other	$85,123	$129,760
Percent Change in Base Revenues Requested		
RVM Power Costs	4.7%	4.7%
Other Costs	1.6%	4.5%
Total Change in Revenues Requested	6.3%	9.2%
Percent Change in Total Revenues Requested (with supplemental adjustments)		
RVM Power Costs	4.1%	4.1%
Other Costs	1.7%	4.8%
Total Change net of RPA & Other	5.8%	8.9%
Test Period	2007	2007
Requested Rate of Return on Capital (Rate Base)	8.97%	8.97%
Requested Rate of Return on Common Equity	10.75%	10.75%
Proposed Rate Base	$1,748,061	$2,027,208
Results of Operation		
A. Before Price Change		
Utility Operating Income	$141,956	$155,280
Average Rate Base	$1,747,526	$2,026,251
Rate of Return on Capital	8.12%	7.66%
Rate of Return on Common Equity	9.24%	8.42%
B. After Price Change		
Utility Operating Income	$156,740	$181,769
Average Rate Base	$1,748,061	$2,027,208
Rate of Return on Capital	8.97%	8.97%
Rate of Return on Common Equity	10.75%	10.75%
Net Effect of Proposed Price Change		
A. Residential Customers	5.7%	8.5%
B. Small Non-residential Customers	7.9%	10.6%
C. Large Non-residential Customers	5.4%	8.8%
D. Lighting & Signal Customers	10.6%	12.0%
Note: Changes in Revenues are on a cycle basis for Cost of Service Customers		