Portland General Electric Company
Legal Department
121 SW Salmon Street • Portland, Oregon 97204
(503) 464-8926 • Facsimile (503) 464-2200

Douglas C. Tingey
Assistant General Counsel

April 1, 2011

Via Electronic Filing and Messenger
Oregon Public Utility Commission
Attention: Filing Center
550 Capitol Street NE #215
PO Box 2148
Salem OR 97308-2148

Re: In the Matter of PORTLAND GENERAL ELECTRIC COMPANY'S 2012 Annual Power Cost Update Tariff (Schedule 125)

Attention Filing Center:

Enclosed for filing in the above-captioned docket please find the following:

Original and five copies of testimony of:
- **Mike Niman and David Weitzel (PGE/100)**
- **Marc Cody and Rob Macfarlane (PGE/200)**

Three copies on CD of:
- **Work Papers (non-confidential portions only)**

Original and two copies of:
- **Motion for Approval of Protective Order (with proposed Protective Order)**

PGE will submit the confidential exhibits and work papers after entry of a Protective Order. PGE is requesting expedited consideration of its Motion for Approval of Protective Order.

PGE's initial forecast of 2012 NVPC is $724.9 million. At this level of NVPC, PGE projects a base rate reduction effective January 1, 2012 of about 1.1%.

These documents are being filed electronically with the Filing Center. Hard copies will be sent via U.S. Mail. An extra copy of the cover letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided. Thank you in advance for your assistance.

Sincerely,

DOUGLAS C. TINGEY
Assistant General Counsel

DCT:cbm
Enclosures
cc: UE 215 Service List

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE ___

Annual Update Tariff Filing
For Prices Effective January 1, 2012

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits

Portland General Electric

April 1, 2011

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **DIRECT TESTIMONY AND WORK PAPERS (non-confidential portions only) and MOTION FOR PROTECTIVE ORDER OF PORTLAND GENERAL ELECTRIC COMANY** to be served by electronic mail to those parties whose email addresses appear on the attached service list, and by First Class US Mail, postage prepaid and properly addressed, to those parties on the attached service list who have obtained permission to receive hard copy service for OPUC Docket No. UE 215.

Dated at Portland, Oregon, this 1st day of April, 2011.

Patrick G. Hager, Manager, Regulatory Affairs
Portland General Electric Company
121 SW Salmon St., 1WTC0702
Portland, OR 97204
503-464-7580 Telephone
503-464-7651 Fax
pge.opuc.filings@pgn.com

SERVICE LIST –
OPUC DOCKET # UE 215
April 1, 2011

Heather Rode heatherrode@gmail.com (*Waived Paper Service)	Kurt J. Boehm, Attorney BOEHM KURTZ & LOWRY kboehm@bkllawfirm.com (*Waived Paper Service)
Robert Jenks (C) CITIZENS' UTILITY BOARD OF OREGON bob@oregoncub.org (*Waived Paper Service)	Gordon Feighner (C) CITIZENS' UTILITY BOARD OF OREGON gordon@oregoncub.org (*Waived Paper Service)
Kevin Elliott Parks (C) CITIZENS' UTILITY BOARD OF OREGON kevin@oregoncub.org (*Waived Paper Service)	G. Catriona McCracken (C) CITIZENS' UTILITY BOARD OF OREGON catriona@oregoncub.org (*Waived Paper Service)
Raymond Myers (C) CITIZENS' UTILITY BOARD OF OREGON ray@oregoncub.org (*Waived Paper Service)	Benjamin Walters, Chief Deputy City Atty (C) CITY OF PORTLAND bwalters@ci.portland.or.us (*Waived Paper Service)
David Tooze CITY OF PORTLAND – PLANNING & SUSTAINABILITY dtooze@ci.portland.or.us (*Waived Paper Service)	Jess Kincaid, Energy Partnership Coordinator COMMUNITY ACTION PARTNERSHIP OF OREGON jess@caporegon.org (*Waived Paper Service)
S. Bradley Van Cleve (C) DAVISON VAN CLEVE 333 SW Taylor, Suite 400 Portland, OR 97204 mail@dvclaw.com	Stephanie S. Andrus, Assistant AG (C) DEPARTMENT OF JUSTICE 1162 Court Street, NE Salem, OR 97301-4096 stephanie.andrus@state.or.us
Kevin Higgins, Principle (C) ENERGY STRATEGIES, LLC khiggins@energystrat.com (*Waived Paper Service)	Nona Soltero, Corporate Law Department #23C FRED MEYER STORES/KROGER nona.soltero@fredmeyer.com (*Waived Paper Service)
Marcy Putnam, Political Affairs & Communication Representatives IBEW LOCAL 125 17200 NE Sacramento Street Portland, OR 97230 marcy@ibew125.com	Greg Bass SEMPRA ENERGY SOLUTIONS, LLC gbass@semprasolutions.com (*Waived Paper Service)
Lon L. Peters (C) NW ECONOMIC RESEARCH, INC. lon@nw-econ.com (*Waived Paper Service)	Jordan A. White, Senior Counsel PACIFIC POWER & LIGHT jordan.white@pacificorp.com (*Waived Paper Service)
Oregon Dockets PACIFICORP, dba PACIFIC POWER & LIGHT oregondockets@pacificorp.com (*Waived Paper Service)	Judy Johnson (C) OREGON PUBLIC UTILITY COMMISSION PO Box 2148 Salem, OR 97308-2148 judy.johnson@state.or.us

Randall J. Falkenberg (C) RFI CONSULTING, INC. PMB 362 8343 Roswell Road Sandy Springs, GA 30350 consultrfi@aol.com	Gregory M. Adams RICHARDSON & O'LEARY, PLLC greg@richardsonandoleary.com (*Waived Paper Service)
Peter J. Richardson (C) RICHARDSON & O'LEARY, PLLC peter@richardsonandoleary.com (*Waived Paper Service)	James Benya THE INTERNATIONAL DARK SKY ASSOCIATION jbenya@benyalighting.com (*Waived Paper Service)
Leo Smith THE INTERNATIONAL DARK SKY ASSOCIATION leo@smith.net (*Waived Paper Service)	

UE ___ / PGE / 100
Niman – Weitzel

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Power Costs

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Mike Niman
David Weitzel

April 1, 2011

Table of Contents

I. Introduction

Q. Please state your names and positions with PGE.

A. My name is Mike Niman. My position at PGE is Manager, Financial Analysis.

My name is David Weitzel. I am a project manager in the Regulatory Affairs department at PGE.

Our qualifications are included at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to provide the initial Annual Update Tariff (AUT) forecast of PGE's 2012 net variable power costs (NVPC). We then compare this estimate with the 2011 General Rate Case (GRC) NVPC as approved by the Commission in Order No. 10-410 (UE 215). We also discuss updates to 2012 AUT parameters and explain why per unit NVPC have decreased by approximately $0.94 per MWh from 2011 to 2012.

Q. What is your AUT net variable power cost estimate?

A. Our 2012 AUT forecast is $724.9 million, based on contracts and forward curves on February 17, 2011.

Q. What schedule in this docket do you propose for NVPC updates?

A. We propose the following schedule for the power cost updates:

- July - update power, fuel, and transportation/transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; and loads;
- September - update power, fuel, and transportation/transmission contracts, and related costs; gas and electric forward curves; planned hydro maintenance outages; and loads; and

- November - two updates: 1) forward curve updates, final updates of power contracts, fuel contracts, transportation/transmission contracts, long-term opt-outs, and related costs; and 2) final gas and electric forward curves.

Q. Will the final AUT forecast update serve as the basis for the 2012 Power Cost Adjustment Mechanism established by Order No. 07-015?

A. Yes, with one modification. In the UE 201 (2007 PCAM) Stipulation, parties supported a change in the language of Schedule 126 to clarify that adjustments to forecasted NVPC are made to reflect the impact of customer direct access enrollments under Schedules 515 through 594 that take place after the final Monet power cost run is filed in mid-November. If there is a change in the enrollments, a new Monet run reflecting those changes will form the baseline unit net variable power cost for the PCAM calculations.

Q. Are there Minimum Filing Requirements (MFRs) associated with the AUT?

A. Yes. Order No. 08-505 mandated a list of minimum filing requirements (MFRs) for PGE in AUT filings and GRC proceedings. The MFRs define the documents PGE will provide in conjunction with the NVPC portion of PGE's initial (direct case) and update filings of its GRC and/or AUT proceedings. PGE Exhibit 101 contains the list of required documents as approved by Order No. 08-505. The required MFRs are included as part of our electronic work papers, with the remainder of the MFRs to be filed within fifteen days of this filing (i.e. April 15, 2011).[1]

Q. How is the remainder of your testimony organized?

A. After this introduction, we have five sections:

- Section II: Monet Model;

[1] Per the UE 198 Stipulation, most of the MFRs will be filed on or before April 15, 2011. The summary MFRs are filed with the testimony.

- Section III: Monet Updates and Input Changes;
- Section IV: Load Forecast;
- Section V: Comparison with 2011 UE 215 NVPC Forecast; and
- Section VI: Qualifications.

II. Monet Model

Q. How did PGE forecast its NVPC for 2012?

A. As in previous dockets, we used our power cost forecasting model, called "MONET" (or Monet).

Q. Please briefly describe Monet.

A. We built this model in the mid-1990s and have since incorporated several refinements. In brief, Monet models the hourly dispatch of our generating units. Using data inputs, such as forecasted load and forward electric and gas curves, the model minimizes power costs by economically dispatching plants and making market purchases and sales. To do this, the model employs the following data inputs:

- Forecasted retail loads, on an hourly basis;
- Physical and financial contract and market fuel (coal, natural gas, and oil) commodity and transportation costs;
- Thermal plants, with forced outage rates and scheduled maintenance outage days, maximum operating capabilities, heat rates, operating constraints, and any variable operating and maintenance costs (although not part of net variable power costs for ratemaking purposes);
- Hydroelectric plants, with output reflecting current non-power operating constraints (such as fish issues) and peak, annual, seasonal, and hourly maximum usage capabilities;
- Wind power plants, with peak capacities, annual capacity factors, and monthly and hourly shaping factors;
- Transmission (wheeling) costs;

- Physical and financial electric contract purchases and sales; and
- Forward market curves for gas and electric power purchases and sales.

Using these data inputs, Monet simulates the dispatch of PGE resources to meet customer loads based on the principle of economic dispatch. Generally, any plant is dispatched when it is available and its dispatch cost is below the market electric price. Any plant can also be operating in one of various stages – maximum availability, ramping up to its maximum availability, starting up, shutting down, or off-line. Given thermal output, expected hydro and wind generation, and contract purchases and sales, Monet fills any resulting gap between total resource output and PGE's retail load with hypothetical market purchases (or sales) priced at the forward market price curve.

Q. How does PGE define NVPC?

A. NVPC include wholesale (physical and financial) power purchases and sales ("purchased power" and "sales for resale"), fuel costs, and other costs that generally change as power output changes. PGE records its net variable power costs to FERC accounts 447, 501, 547, 555, and 565. Based on prior Commission decisions, we include some fixed power costs, such as excise taxes and transportation charges, because they relate to fuel used to produce electricity. We "amortize" these fuel-related costs even though, for purposes of FERC accounting, they appear in a balance sheet account (FERC 151). We also exclude some variable power costs, such as variable operation and maintenance costs (O&M), because they are already included elsewhere in PGE's accounting. However, variable O&M is used to determine the economic dispatch of our thermal plants. The "net" in NVPC refers to net of forecasted wholesale sales of electricity, natural gas, fuel and associated financial instruments.

Q. Do the MFRs provide even more detailed information regarding the inputs to Monet?

A. Yes. The MFRs provide detailed work papers supporting the inputs used to develop this initial forecast of 2012 NVPC.

III. Monet Updates and Input Changes

Q. What updates are allowed under PGE's Schedule 125, Annual Power Cost Update (AUT) Tariff?

A. Schedule 125 states that the following updates are allowed in AUT filings:

- Forced Outage Rates based on a four-year rolling average;
- Projected planned plant outages;
- Forward market prices for both gas and electricity;
- Projected loads;
- Contracts for the purchase or sale of power and fuel;
- Changes in hedges, options, and other financial instruments used to serve retail load; and
- Transportation contracts and other fixed transportation costs.

Q. Which of these updates do you include in this initial filing?

A. We include all of the updates listed and address significant items below.

Q. With regard to estimated BPA imbalance charges related to wind integration, the Stipulation resolving NVPC issues in UE 215 stated that PGE would, "re-evaluate its modeling in the next AUT case." Has PGE updated its approach for estimating the Biglow Canyon BPA imbalance charge in this filing?

A. Yes, PGE has updated its modeling of imbalance energy for this filing. Although a modeling change is not typically allowed in an AUT proceeding, we include this change in order to honor the agreement reached in the Stipulation referenced above.

Q. How did PGE estimate the imbalance charge previously?

A. The imbalance charge was previously estimated based on actual hourly wind data from 1998 provided by an outside consultant. This procedure was employed in UE 197, UE 208, and UE 215.

Q. Please describe the method used by PGE in this filing to estimate the BPA imbalance charge.

A. PGE's intention with this change is to incorporate actual operating experience into the estimation of the imbalance charge. For this filing, PGE estimates the energy subject to BPA imbalance charges as a function of the installed capacity at Biglow Canyon. The actual average monthly imbalance energy is determined by reviewing BPA invoices. This amount is compared with the actual installed capacity at Biglow Canyon during that month in order to determine the historical relationship between the two values. This relationship is used in Monet to estimate the imbalance energy for 2012. The estimated imbalance energy is priced at the Mid-Columbia flat price to determine the estimated imbalance charge. [2]

Q. What is the impact of this change on NVPC?

A. This change decreases NVPC by approximately $350,000 in this filing.

Q. What do you recommend for future filings?

A. PGE recommends that parties continue to review the optimal method for estimating imbalance charges. PGE is currently in the process of working with a third-party consultant to refine the process used for estimating generation at Biglow Canyon. The method adopted for estimating imbalance charges should ultimately be aligned with that used for estimating generation.

Q. How was the 2012 Boardman coal commodity cost determined for this initial filing?

[2] For additional details on the calculation, please see the MFRs provided in Volume 7 – Wind Power Inputs on April 15, 2011.

A. The cost of coal at Boardman for 2012 is currently estimated with an indicative price obtained by PGE's Power Operations group. PGE has issued an RFP and is in the process of evaluating bids to procure coal for 2012. We expect to complete our review and execute a contract by the end of summer. Consequently, we will update the coal cost in a future filing.

IV. Load Forecast

Q. Please summarize PGE's forecast for its 2012 retail load.

A. Table 1 below summarizes actual and forecast deliveries to various customer groups from 2009 through 2012 in million kWh at average weather conditions.

Table 1
Retail Energy Deliveries: 2009–2012
(cycle month energy in million kWh, average weather)

	2009 Actual *	2010 Actual *	(UE 215) 2011 Forecast	(UE__) 2012 Forecast
Residential	7,747	7,555	7,608	7,622
General Service	7,432	7,264	7,320	7,403
Industrial	3,901	3,991	3,826	4,036
Lighting	111	110	112	112
Total Retail	19,191	18,920	18,866	19,174

* The 2009 and 2010 actual loads are weather-adjusted.
Numbers may not total due to rounding.

Q. Does this 2012 forecast include all loads?

A. Yes. The forecast includes both PGE cost-of-service loads and deliveries of energy to customers under Schedules 485/489.

Q. Does PGE's cost-of-service load forecast assume that certain long-term opt-out customers return to a cost-of-service rate in 2012?

A. No, not for 2012. PGE's load forecast typically accounts for long-term opt-out customers who are either in the final year of a 3-year term or are on a 5-year term and have given notice that they intend to return to cost-of-service. However, PGE currently has no 3-year opt-out customers or 5-year opt-out customers that have given notice. Thus, the 2012 cost-of-service load forecast assumes no increase in load to serve opt-out customers returning to a cost-of-service rate.

Q. If customers select a long-term opt-out program for 2012, will PGE adjust the load forecast?

A. Yes. PGE will adjust the 2012 cost-of-service load forecast accordingly, as specified in Schedule 125.

Q. How does the initial 2012 load forecast differ from the final UE 215 forecast?

A. Table 1 shows PGE's historical weather-adjusted retail energy deliveries for 2009 and 2010, the final UE 215 forecast for 2011, and our current forecast for 2012. In UE 215, we projected total deliveries of 18,866 million kWh for 2011. We currently project 19,174 million kWh for 2012 under average weather conditions. Our 2012 load forecast is 1.6% higher than the forecast for 2011 used to set rates in UE 215.

Q. Was the 2012 forecast developed using the same model that was used in UE 215?

A. Yes. The model specification remains the same as previous filings. Inputs to the model were updated reflecting actual loads through January. However, economic and employment data were not available from the state in a timely manner. As a result, the model parameters were not re-estimated for this initial filing. The load forecast will be updated (including parameter estimation) in the June filing as indicated in Section I above. PGE Exhibit 1400 in Docket UE 215 (specifically pages 6–10) explains the estimation procedures in detail.

Q. What load do you use in your 2012 test year power cost forecast?

A. The load listed in Table 1 represents total system load on a cycle month-basis at the customer meter as used to calculate rates. The load used to generate power costs in Monet is the cost-of-service load on a calendar month-basis. Table 2 below reconciles the total system load in Table 1 with the cost-of-service load on a calendar month-basis.

Table 2
Total System Load on Cycle Month at Meter
to Cost-of-Service Load on Calendar Month at Meter: 2012
(million kWh)

Total System Load (cycle month)	19,174
Add: Cycle to Calendar Month Difference	22
Total System Load (calendar month)	19,196
Less: Schedules 485/489	(545)
Cost-of-Service Meter Load	18,651

Numbers may not total due to rounding.

Q. What is the corresponding initial cost-of-service busbar load forecast for 2012?

A. With the addition of line losses to Table 2, the initial busbar load forecast for 2012 is 20,052,127 MWh (or 20,052.1 million kWh), or 2,283 MWa. This load is the basis for the hourly Monet load input data.

V. Comparison with 2011 UE 215 NVPC Forecast

Q. Please restate your initial 2012 NVPC forecast.

A. The initial forecast is $724.9 million.

Q. How does the 2012 forecast compare with the UE 215, 2011 forecast approved in Commission Order No. 10-410?

A. Based on PGE's final updated Monet run for the 2011 test year, the forecast was $728.1 million, or $37.09 per MWh. The 2012 forecast is $724.9 million, or $36.15 per MWh[3], approximately $0.94 per MWh lower.

Q. What are the primary factors that explain the decrease in NVPC forecast for 2012 versus the NVPC forecast for 2011 in UE 215?

A. As Table 3 demonstrates, multiple factors contribute to the approximate $3.2 million decrease:

Table 3
Factors in Power Cost Differences 2012 vs. 2011 ($ Million)

Element	Effect
Hydro Cost and Performance	$15
Coal Cost and Performance	-4
Gas Cost and Performance	8
Wind Cost and Performance	0
Contract and Market Purchases	-59
Market Purchases for Cost of Service Load Increase	14
Transmission	6
Higher Market Price	16
Total	-$3

Numbers may not total due to rounding.

Reduced contract costs for 2012 and more market purchases to account for a lesser quantity of contract MWh contribute to lower overall power costs. PGE expects less hydro production in 2012 largely as a result of the expiration of both the Rocky Reach and Priest Rapids Displacement contracts in 2011. This lower hydro production necessitates additional

[3] These calculations are based on bus-bar cost-of-service load and include the fact that the 2012 cost-of-service load forecast is 41.6 MWa higher (2,282.8 – 2,241.2) than the 2011 cost-of-service load forecast.

market purchases which, combined with higher market price and additional purchases to meet increased load, partially offset the power cost decrease.

VI. Qualifications

Q. Mr. Niman, please describe your qualifications.

A. I received a Bachelor of Science degree in Mechanical Engineering from Carnegie-Mellon University and a Master of Science degree in Mechanical Engineering from the California Institute of Technology. I am a registered Professional Mechanical Engineer in the state of Oregon.

I have been employed at PGE since 1979 in a variety of positions including: Power Operations Engineer, Mechanical Engineer, Power Analyst, Senior Resource Planner, and Project Manager before entering into my current position as Manager, Financial Analysis in 1999. I am responsible for the economic evaluation and analysis of power supply including power cost forecasting, new resource development, least-cost planning, and avoided cost estimates. The Financial Analysis group supports the Power Operations, Business Decision Support, and Rates & Regulatory Affairs groups within PGE.

Q. Mr. Weitzel, please state your educational background and experience.

A. I received a PhD in Economics from the University of Washington in 1980 with a field in econometrics. In 1997, I obtained the Chartered Financial Analyst (CFA) designation. I have worked in the Rates and Regulatory Affairs department since 2009.

My forecasting work includes two projects for the Electric Power Research Institute; for one project I estimated the effects of time-of-use pricing on residential electricity demand and for a second project I estimated models to forecast industrial demand for energy. For Puget Power, I created statistical models to forecast energy savings from residential conservation programs. As a member of the GTE (and later Verizon) Demand Analysis and Forecasting Group, I was responsible for research design and for forecasting demand for

telecommunication services. Also at Verizon, I participated in the development of statistical testing protocols to assess parity of service provision in local telecommunications markets. With Insightful Corporation, I developed models to forecast demand for consumer goods. Miscellaneous projects include forecasting the price of oil tanker services, forecasting water demand, and models to predict credit problems.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
101	List of MFRs per OPUC Order No. 08-505
102C	April 1 Initial Filing Monet Output Files and Assumptions Summary

ORDER NO. 08-505

Minimum Filing Requirements
July 7, 2008

General

The Minimum Filing Requirements (MFRs) define the documents to be provided by PGE in conjunction with the Net Variable Power Cost (NVPC) portion of the Company's initial (direct case) and update filings of its General Rate Case (GRC) and/or Annual Update Tariff (AUT) proceedings.

The term "Supporting Documents and Work Papers" as used here means the documents used by the persons doing the NVPC forecasting at PGE to develop the final inputs to Monet and the final modeling in Monet for each filing. This may include such items such as contracts, emails, white papers, studies, PGE computer programs, Excel spreadsheets, Word documents, pdf and text files. This will not include intermediate developmental versions of documents that are not used to support the final filing. Documents will be provided electronically where practical.

In cases where systems change or are replaced in the future, such as BookRunner, the MFRs will continue to provide substantially the same information as provided in PGE's 2009 GRC (UE-198).

PGE will take reasonable steps to ensure that the MFRs can be made available to CUB and ICNU at the time of the filing, rather than these parties having to wait for the OPUC to approve the protective order in the case.

Delivery Timing

In either an AUT year (April 1 initial filing) or a GRC year (Feb. 28 initial filing), at a minimum the following portion of the Direct Case Filing MFRs will be delivered with the initial filing:

- Summary Documents (Items 1-6)
- Modeling Enhancements and New Item Inputs (Item 14) – not applicable in AUT year
- Miscellaneous Item 15d - re: Testimony and Exhibits provided on the CD

The remainder of the Direct Case Filing MFRs will be delivered with the initial filing if practical, or no later than fifteen days after the filing (e.g. March 15 in a GRC year, April 15 in an AUT year).

For all update filings, Update Filing MFRs will be delivered with the update filing with the following exception. For the April 1 GRC Update Filing in a GRC year, the delivery of Item 23 will be made with the filing if practical, or no later than fifteen days after the filing (e.g. April 15).

Direct Case Filing

Applicability

- Applies to GRC Initial Filing (e.g. February 28) in a GRC year
- Applies to AUT Initial Filing (i.e. April 1) in a non-GRC year

Summary Documents

1. Monet model for the final step
2. Hourly Diagnostic Reports for the final step
3. Step Log showing NVPC effects of modeling enhancements, modeling changes, addition of new items or removal of items from the prior year rate proceeding (GRC or AUT), and other major updates that PGE believes the parties would want to see identified separately, such as updating the hydro study.
4. Output/Assumptions Summary Report comparable to that provided for the 2009 GRC
5. Executable files, any other files needed to run Monet, and installation instructions
6. Identification of the operating system PGE uses to operate Monet

Supporting Documents and Work Papers for the Following

7. Forward Curve Inputs. Consists of:
    a. Electric curve extract from Trading Floor curve file
    b. Gas curve extract from Trading Floor curve file
    c. Canadian/US Foreign exchange rate (F/X Curve) from Risk Management
    d. Model run for hourly shaping of monthly on/off-peak electric curve (Lydia Program)
    e. Oil forward curve
8. Load Inputs. Consists of:
    a. Monthly load forecast from Load Forecast Group
    b. Hourly load forecast from Load Forecast Group
    c. Copy of the loss study used by Load Forecast Group to develop busbar load forecast
9. Thermal Plant Inputs
    a. Capacities
    b. Heat Rates
    c. Variable O&M
        This includes any other cost or savings components modeled as part of Variable O&M, such as incremental transmission losses, SO_2 emission allowances (emission allowance $/ton price forecast, plant emission factors lb/MMBtu), etc.
    d. Forced outage rates
    e. Maintenance outage schedules and derations
    f. Minimum capacities
    g. Operating constraints
    h. Minimum up times
    i. Minimum down times
    j. Plant testing requirements
    k. Oil usage volumes
    l. Coal commodity costs
    m. Coal transportation costs
    n. Coal fixed fuel costs classified as NVPC items
        Includes items such as: Colstrip Fixed Coal Cost and the following Boardman costs: Rail Car Mileage Tax, Coal Sampling, Rail Car Lease, Rail Car Maintenance, Trainset Storage Fee, and Coal Car Depreciation
10. Hydro Inputs
    a. Monthly energy for all Hydro Resources
        This will include the results of PGE's most current study using the Pacific Northwest Coordination Agreement (PNCA) Headwater Benefit Study. Note that this program is not the property of PGE and should be obtained from the Northwest Power Pool. Provide the PGE version of the PNCA model inputs, so that if the Parties obtain the PNCA model, they would have the inputs needed to reproduce PGE's study.
    b. Description of logic for hourly shaping where applicable
    c. Usable capacities where applicable
    d. Operating constraints modeled
    e. Hydro maintenance derations.
    f. Hydro forced outage rates (not currently modeled)
    g. Hydro plant H/K factors
    h. Spreadsheet demonstrating how the hydro energy final output from the PNCA study is adjusted to arrive at the monthly energy output on the PwrAEOut sheet
11. Electric and Gas Contract Inputs
    a. Copy of contract for each long-term (5-year or greater term) or non-standard power contract modeled in Monet.
        For some contracts, this may consist of a term sheet rather than a full contract, depending on what was deemed reasonably necessary by the power modelers to model the contract in Monet.
    b. BookRunner extracts for the test year of:
        Electric Physical Contracts
        Electric Financial Contracts
        Gas Physical Contracts

Gas Financial Contracts
F/X Hedge Contracts

c. Copy of each firm gas transportation or storage contract modeled in Monet
d. List of the PURPA QF contracts modeled in Monet
e. List of the long-term (5-year or greater term) or non-standard contracts modeled in MONET that were not included in PGE's most recent GRC or AUT.
f. Gas transportation input spreadsheet or its successor/equivalent
g. Website snapshots input to the gas transportation spreadsheet
h. Other Supporting Documents and Work Papers for contracts modeled in Monet, including any items showing on the Monet Cost and/or Energy Output reports not covered above. Could include structured contracts, option contracts, etc.
i. Coal contracts: Covered above under Thermal Plant Inputs
j. Amortizations of regulatory assets or liabilities modeled in the Contracts section of Monet

12. Wheeling Inputs
    a. Supporting Documents and Work Papers for all wheeling items modeled in Monet
13. Wind Power Inputs. Includes but not limited to:
    a. Monthly energy
    b. Hourly energy
    c. Maintenance
    d. Forced outage rates
    e. Integration costs, royalties, other costs and elements modeled
14. Modeling Enhancements and New Item Inputs
    a. Supporting Documents and Work Papers for all modeling enhancements and new items modeled in Monet.
    b. Includes modeling or logic changes, changes to the methodology used to compute data inputs or other type of enhancement to the Monet model.
    c. Modeling revisions, refinements, clean-ups etc. that do not affect NVPC under any conditions will not be considered to be modeling enhancements.
15. Miscellaneous
    a. Line Item Adjustments to Monet such as OPUC orders, settlement stipulations, others
    b. Identification of all transactions modeled in Monet that do not produce energy
    c. Items in Monet not covered elsewhere above
    d. For all testimony and exhibits provided on the CD in pdf format, provide the testimony in searchable pdf format, and provide any exhibits created in Excel in the original Excel format when available to PGE.

Historical Operating Data

16. Hourly extract of data from PGE's Power Scheduling and Accounting System showing actual hourly energy values for the most recent Four-Year Calendar Period of the following:
    a. Generation from each coal, gas, hydro and wind generating plant modeled in Monet. Note that Colstrip Units 3 and 4 generation is aggregated in PGE's system, and the Mid-C contract generation is similarly aggregated.
    b. Long-term (>5 years) electric contract purchases, sales and exchanges modeled in Monet.
17. Table showing the actual monthly generation of each PGE coal, gas, hydro and wind generating plant modeled in MONET, from the period 1998 through the last calendar year.
18. Monthly compilations of actual NVPC produced by PGE for the most recent calendar year.

Update Filings

19. Monet model for the final step
20. Hourly Diagnostic Reports for the final step
21. Step Log showing effect on NVPC of each update step since the last filing
22. Output/Assumptions Summary Report comparable to that provided for the 2009 GRC
23. For each Monet update step:
    a. Text description of update, including identification and location of input changes within Monet.
    b. Excel file containing Monet standard output reports (PwrCsOut, PwrAEOut, PwrEnOut) and PC Input sheets.
    c. Supporting Documents and Work Papers for the update step
24. For all testimony and exhibits provided on the CD in pdf format, provide the testimony in searchable pdf format, and provide any exhibits created in Excel in the original Excel format when available to PGE.

UE ___ / PGE / 200
Cody – Macfarlane

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Marc Cody
Robert Macfarlane

April 1, 2011

Pricing

Table of Contents

I. Introduction and Summary

Q. Please state your name and position.

A. My name is Marc Cody. I am a Senior Analyst in the Pricing and Tariffs Department. My qualifications are listed in Section IV.

My name is Robert Macfarlane. I am an Analyst in the Pricing and Tariffs Department. My qualifications are also listed in Section IV.

Q. What is the purpose of your testimony?

A. This testimony describes the following:

- The estimated price impacts from this filing anticipated to occur on January 1, 2012.
- The calculation of Schedule 125 prices. PGE Exhibit 201 contains a draft of Schedule 125.

PGE will file the final Schedule 125 prices incorporating the final updates to Net Variable Power Costs (NVPC) on November 15.

II. Estimated Rate Impacts

Q. What are the base rate impacts of the proposed $19.5 million reduction in Schedule 125 prices?

A. Table 1 below summarizes the COS base rate impacts for 2012 for selected Schedules. These estimates are preliminary and subject to change due to among other items, market electric and gas prices.

Table 1
Estimated Base Rate Impacts

Schedule	Rate Impact
Sch 7 Residential	-1.0%
Sch 32 Small Non-residential 30 kW or less	-1.0%
Sch 83 Non-residential 31-200 kW	-1.2%
Sch 85 Secondary 201-1,000 kW	-1.3%
Sch 85 Primary 201-1,000 kW	-1.3%
Sch 89 Secondary Over 1,000 kW	-1.3%
Sch 89 Primary Over 1,000 kW	-1.4%
Sch 89 Subtransmission Over 1,000 kW	-1.4%
Overall	-1.1%

Q. What other price changes do you expect to occur on January 1, 2012?

A. We anticipate several changes on January 1, 2012. First, we anticipate changes to Schedule 105 Regulatory Adjustments to capture the amortization of miscellaneous deferrals. Second, we anticipate changes to Schedule 122 Renewable Resources Automatic Adjustment Clause. We currently project a zero price for this schedule in 2012. Third, we anticipate changes to the system usage charge for Schedules 85 and 89 (as well as their direct access equivalents) based on changes in the Schedule 129 Long-term Transition Adjustment starting in 2012. Finally, we expect that the Regional Power Act Exchange Credit (Schedule 102) will be revised to reflect a prospective settlement amongst multiple regional parties resulting in an approximate 1% decrease for residential customers. Updated estimates of these price changes will be provided later in this proceeding.

III. Calculation of Schedule 125 Prices

Q. Please describe how you calculated the Schedule 125 amount.

A. We determined the Schedule 125 amount by comparing the projection of 2012 NVPC to the amount of NVPC that is recovered through the combination of our current energy prices adjusted to exclude fixed generation cost recovery, multiplied by the 2012 load forecast by schedule (the resulting revenues we reference as NVPC revenues). The difference between 2012 NVPC and NVPC revenues constitutes the Change in NVPC. This amount, either positive or negative, is multiplied by 1.0338 to account for revenue sensitive costs such as uncollectibles and franchise fees. Page 1 of PGE Exhibit 202 provides a summary of the Schedule 125 amount of $19.5 million and how it is spread to the respective schedules. Also included on page 1 are the proposed Schedule 125 prices.

Q. Please provide a more detailed description of how you calculate the NVPC revenues.

A. Page 2 of PGE Exhibit 202 demonstrates the calculation. We start with the tariff energy prices for each schedule and remove the portion of these energy prices that recovers the UE 215 fixed generation costs. We then multiply these prices by the respective energy billing determinant to calculate the amount of NVPC projected to be recovered for the 2012 test period. For 2012, we project NVPC revenues of $743.7 million. This amount is carried over to Page 1 of PGE Exhibit 202 in order to calculate the Schedule 125 amount.

Q. Please describe how you allocate the Schedule 125 amount to each rate schedule and how you calculate the Schedule 125 price.

A. We allocate and price the Schedule 125 amount consistent with Special Condition 1 of Schedule 125 which states the following:

> Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy based on the basis of an equal percent of

generation revenue applied on a cents per kWh basis to each applicable rate schedule.

Q. Where is the calculation of the basis of the Schedule 125 allocations, the 2012 Base Generation Revenues?

A. We present this calculation, which is simply the 2012 projected energy billing determinants times the tariff energy price, on page 2 of PGE Exhibit 202.

IV. Qualifications of Witnesses

Q. Mr. Cody, please state your educational background and qualifications.

A. I received a Bachelor of Arts degree and a Master of Science degree from Portland State University. Both degrees were in Economics. The Master of Science degree has a concentration in econometrics and industrial organization.

Since joining PGE in 1996, I have worked as an analyst in the Rates and Regulatory Affairs Department. My duties at PGE have focused on cost of capital estimation, marginal cost of service, rate spread and rate design.

Q. Mr. Macfarlane, please state your educational background and qualifications.

A. I received a Bachelor of Arts business degree from Portland State University with a focus in finance.

Since joining PGE in 2008, I have worked as an analyst in the Rates and Regulatory Affairs Department. My duties at PGE have focused on pricing and regulatory issues.

From 2004 to 2008, I was a consultant with Bates Private Capital in Lake Oswego, OR where I developed, prepared, and reviewed financial analyses used in investor vs. broker litigation.

Q. Does this complete your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
201	Schedule 125
202	Calculation of Schedule 125 Prices

SCHEDULE 125 (Continued)

FILING AND EFFECTIVE DATE

On or before April 1st of each calendar year, the Company will file estimates of the adjustments to its NVPC to be effective on January 1st of the following calendar year.

On or before October 1st of each calendar year, the Company will file updated estimates with final planned maintenance outages, final load forecast, updated projections of gas and electric prices, power, and fuel contracts.

On November 15th, the Company will file the final estimate of NVPC and will calculate and file the final change in NVPC to be effective on the next January 1st with: 1) projected market electric and fuel prices based on the average of the Company's internally generated projections made during the period November 1st through November 7th, 2) load reductions from the October update resulting from additional participation in the Company's Long-Term Cost of Service Opt-out that occurs in September, 3) new market power and fuel contracts entered into since the previous updates, and 4) the final planned maintenance outages and load forecast from the October 1st filing.

RATE ADJUSTMENT

The rate adjustment will be based on the Adjusted NVPC less the NVPC revenues that would occur at the NVPC prices determined in the Company's most recent general rate case applied to forecast loads used to determine changes in Net Variable Power Costs. NVPC prices are defined as the price component that recovers the level of NVPC from the Company's most recent general rate case contained in each Schedule's Cost of Service energy prices.

ADJUSTMENT RATES

Schedule		Part A ¢ per kWh
7		(0.113)
15		(0.090)
32		(0.105)
38	Large Nonresidential	(0.100)
47		(0.115)
49		(0.114)
75		
	Secondary	(0.095) (1)
	Primary	(0.092) (1)
	Subtransmission	(0.090) (1)
83		(0.103)

(1) Applicable only to the Baseline and Scheduled Maintenance Energy.

SCHEDULE 125 (Concluded)

ADJUSTMENT RATES (Continued)

Schedule		Part A ¢ per kWh
85		
	Secondary	(0.098)
	Primary	(0.095)
87		
	Secondary	(0.095)
	Primary	(0.092)
	Subtransmission	(0.090)
89		
	Secondary	(0.095)
	Primary	(0.092)
	Subtransmission	(0.090)
91		(0.090)
92		(0.092)
93		(0.089)
94		(0.092)

SPECIAL CONDITIONS

1. Costs recovered through this schedule will be allocated to each schedule using the applicable schedule's forecasted energy on the basis of an equal percent of generation revenue applied on a cents per kWh basis to each applicable rate schedule.

PORTLAND GENERAL ELECTRIC
Calculation of Schedule 125 Prices

Schedules	2012 Calendar COS Energy MWH	2012 Base Generation Revenues	Generation Allocation	2012 Base NVPC Revenues	Sch 125 Allocation	2012 NVPC Revenues	2012 Sch 125 Rate mills/kWh	2012 Sch 125 Revenues
Schedule 7	7,620,181	$519,604	44.29%	$329,480	($8,617)	$320,863	(1.13)	($8,611)
Schedule 15	23,372	$1,274	0.11%	$808	($21)	$786	(0.90)	($21)
Schedule 32	1,521,928	$96,734	8.25%	$61,288	($1,604)	$59,684	(1.05)	($1,598)
Schedule 38	33,454	$2,017	0.17%	$1,280	($33)	$1,246	(1.00)	($33)
Schedule 47	22,777	$1,573	0.13%	$995	($26)	$969	(1.15)	($26)
Schedule 49	66,626	$4,593	0.39%	$2,914	($76)	$2,837	(1.14)	($76)
Schedule 83-S	2,839,386	$176,894	15.08%	$112,042	($2,934)	$109,109	(1.03)	($2,925)
Schedule 85-S	2,279,005	$134,628	11.48%	$85,242	($2,233)	$83,009	(0.98)	($2,233)
Schedule 89-S	544,832	$31,327	2.67%	$19,875	($520)	$19,355	(0.95)	($518)
Schedule 85-P	301,504	$17,231	1.47%	$10,911	($286)	$10,625	(0.95)	($286)
Schedule 89-P	2,772,683	$153,255	13.06%	$97,219	($2,542)	$94,677	(0.92)	($2,551)
Schedule 89-T	513,510	$27,977	2.38%	$17,750	($464)	$17,286	(0.90)	($462)
Schedule 91	106,968	$5,832	0.50%	$3,696	($97)	$3,599	(0.90)	($96)
Schedule 92/94	4,621	$255	0.02%	$162	($4)	$158	(0.92)	($4)
Schedule 93	574	$31	0.00%	$20	($1)	$19	(0.89)	($1)
TOTAL	18,651,421	$1,173,224	100%	$743,680	($19,457)	$724,223		($19,442)
			Sch 125 TARGET ===>		($19,457)			

2012 NVPC	$724,860	
2012 NVPC Revenues	$743,680	(page 2 of Exhibit 202)
Change in NVPC	($18,821)	
Revenue Senstitive Adj. 3.38%	($636)	
Sch 125 Revenue Requirement	($19,457)	

PORTLAND GENERAL ELECTRIC
Calculation of Generation and NVPC Revenues

Schedule	2012 Calendar MWh	Energy Price	2012 Base Energy Revenues	UE 215 Rate Design Energy Price	Generation Energy Price	2012 Base Generation Revenues	UE 215 Fixed Gen. Price	NVPC Price	2012 NVPC Revenues
Sch 7									
Block 1	6,008,064	67.78	$407,227	1.42	66.36	$398,695	24.95	41.41	$248,794
Block 2	1,612,117	75.00	$120,909	0.00	75.00	$120,909	24.95	50.05	$80,686
Sch 15	23,372	54.52	$1,274		54.52	$1,274	19.97	34.55	$808
Sch 32	1,521,928	63.56	$96,734		63.56	$96,734	23.29	40.27	$61,288
Sch 38									
On-peak	17,279	66.33	$1,146		66.33	$1,146	22.03	44.30	$765
Off-peak	16,176	53.83	$871		53.83	$871	22.03	31.80	$514
Sch 47	22,777	69.07	$1,573		69.07	$1,573	25.39	43.68	$995
Sch 49	66,626	68.94	$4,593		68.94	$4,593	25.21	43.73	$2,914
Sch 83-S	2,839,386	62.30	$176,894		62.30	$176,894	22.84	39.46	$112,042
Sch 85-S									
On-peak	1,467,083	61.77	$90,622		61.77	$90,622	21.67	40.10	$58,830
Off-peak	811,922	54.20	$44,006		54.20	$44,006	21.67	32.53	$26,412
Sch 85-P									
On-peak	192,346	59.89	$11,520		59.89	$11,520	20.96	38.93	$7,488
Off-peak	109,158	52.32	$5,711		52.32	$5,711	20.96	31.36	$3,423
Sch 89-S									
On-peak	351,104	60.19	$21,133		60.19	$21,133	21.02	39.17	$13,753
Off-peak	193,728	52.62	$10,194		52.62	$10,194	21.02	31.60	$6,122
Sch 89-P									
On-peak	1,638,370	58.37	$95,632		58.37	$95,632	20.21	38.16	$62,520
Off-peak	1,134,313	50.80	$57,623		50.80	$57,623	20.21	30.59	$34,699
Sch 89-T									
On-peak	300,716	57.58	$17,315		57.58	$17,315	19.90	37.68	$11,331
Off-peak	213,192	50.01	$10,662		50.01	$10,662	19.90	30.11	$6,419
Sch 91	106,968	54.52	$5,832		54.52	$5,832	19.97	34.55	$3,696
Sch 92	4,621	55.26	$255		55.26	$255	20.24	35.02	$162
Sch 93	574	53.67	$31		53.67	$31	19.65	34.02	$20
Totals	18,651,818		$1,181,756			$1,173,224			$743,680

Note: See Attachment B page 52 of PGE UE 215 compliance work papers for source of fixed generation prices.