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I. Introduction

1 **Q. Please state your names and positions with PGE.**

2 A. My name is Mike Niman. My position at PGE is Manager, Financial Analysis. I provide
3 my qualifications at the end of this testimony.

4 My name is Terri Peschka. I am the General Manager of Power Operations at PGE. I
5 am responsible for managing PGE's net variable power costs (NVPC). My qualifications
6 appear at the end of this testimony.

7 My name is Patrick G. Hager. I am the Manager of Regulatory Affairs at PGE. My
8 qualifications appear at the end of PGE Exhibit 1100.

9 **Q. What is the purpose of your testimony?**

10 A. The purpose of our testimony is to provide the initial General Rate Case (GRC) forecast of
11 PGE's 2011 net variable power costs and compare this estimate with the 2010 Annual
12 Update Tariff (AUT) NVPC as approved by the Commission in Order No. 09-433 (Docket
13 No. UE 208). We discuss updates to the 2010 AUT parameters such as forward curves, as
14 well as modeling changes, which can occur only in GRC proceedings. We also explain why
15 per-unit NVPC have decreased by \$1.63 per MWh from 2010 to 2011.

16 **Q. Are there minimum filing requirements that accompany the GRC and AUT filings?**

17 A. Yes. Order No. 08-505 mandated a list of minimum filing requirements (MFRs) for PGE in
18 future AUT filings and general rate case proceedings. The MFRs define the documents PGE
19 will provide in conjunction with the NVPC portion of PGE's initial (direct case) and update
20 filings of its GRC and/or AUT proceedings. PGE Exhibit 401 contains the list of required
21 documents as approved by Order No. 08-505. The required MFRs are included as part of

1 our electronic work papers, with the remainder of the MFRs to be filed within fifteen days of
2 this filing.

3 **Q. Has producing the MFR documents been helpful to power cost proceedings?**

4 A. Yes. Production of the MFR documentation in conjunction with filings has led to a more
5 transparent process with fewer data requests.

6 **Q. What is your GRC net variable power cost estimate?**

7 A. Our 2011 GRC forecast is \$747.2 million, based on forward curves and contracts as of
8 December 17, 2009.

9 **Q. How do you organize the remainder of your testimony?**

10 A. Our testimony has four sections beyond this introduction:

- 11 • Section II: Monet Model;
- 12 • Section III: Monet Updates and Model Changes;
- 13 • Section IV: Comparison with the 2010 UE 208 NVPC Forecast; and
- 14 • Section V: Qualifications.

II. Monet Model

1 **Q. How did PGE model its NVPC for the 2011 test year?**

2 A. We used our power cost forecasting model, called “MONET” (or Monet).

3 **Q. Please briefly describe Monet.**

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

8 To do this, the model employs the following data inputs:

- 9 • Forecasted retail loads, on an hourly basis;
- 10 • Physical and financial contract and market fuel (coal, natural gas, and oil)
11 commodity and transportation costs;
- 12 • Thermal plants, with forced outage rates and scheduled maintenance outage days,
13 maximum operating capabilities, heat rates, operating constraints, and any
14 variable operating and maintenance costs (although not part of net variable power
15 costs for ratemaking purposes);
- 16 • Hydroelectric plants, with output reflecting current non-power operating
17 constraints (such as fish issues) and peak, annual, seasonal, and hourly maximum
18 usage capabilities;
- 19 • Wind power plants, with peak capacities, annual capacity factors, and monthly
20 and hourly shaping factors;
- 21 • Transmission (wheeling) costs;
- 22 • Physical and financial electric contract purchases and sales; and

- 1 • Forward market curves for gas and electric power purchases and sales.

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

10 **Q. What is the source of the forward curves that PGE inputs to Monet?**

11 A. For this initial filing, we use a single day snapshot of trading curves to obtain forecasts for
12 2011 of natural gas prices at Sumas, Rockies, AECO, and Malin, and monthly on- and off-
13 peak power prices at the Mid-C. The trading curves are supplied by PGE’s Power
14 Operations Group, which purchases and sells wholesale electricity and gas, and validated by
15 our Risk Management group. For our final update filing in November 2010, we will use a
16 five-day average of trading curves.

17 Using this forecast, we create hourly wholesale prices for electric power. To create
18 hourly prices, we begin with typical price profiles for winter, summer, and off-season, and
19 for weekdays, Saturdays, and Sundays, and use historical hourly price information. Because
20 we model on-peak prices as independent from off-peak prices in a given month, we review
21 price transitions from on-peak to off-peak hours to make sure they are appropriate. We also
22 examine hourly prices for a typical weekday, Saturday, and Sunday for each month in the
23 forecast period to make sure the prices are consistent between hours (e.g., Sunday prices

1 lower than Saturday prices on-peak). Hourly calculations take into account the number of
2 on-peak and off-peak hours in each month of the forecast period to ensure hourly prices are
3 consistent with the monthly prices. The results of this calculation are used directly in
4 Monet.

5 **Q. How does PGE define NVPC?**

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

III. Monet Updates and Model Changes

1 **Q. Does the NVPC section of this proceeding substitute for a 2011 test year AUT filing?**

2 A. Yes. Because this is a GRC proceeding, we include not only the parameter revisions
3 allowed under PGE's AUT (Tariff Schedule 125), but also model changes and updates
4 allowed only in a general rate case. The final NVPC update in this proceeding will be the
5 2011 forecast that we will compare with the 2011 actual NVPC under the provisions of
6 Schedule 126, which implements our Power Cost Adjustment Mechanism (PCAM). PGE
7 discusses its proposed revisions to the PCAM in PGE Exhibits 200 and 1100.

8 **Q. What load forecast do you use in this initial filing?**

9 A. We use the 2011 forecast for cost of service load described in PGE Exhibit 1400. That
10 forecast is approximately 19,944,650 MWh, or 2,277 MWa¹, a decrease of 13 MWa from
11 UE 208 (2010 test year).

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

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

- 14 • April 1 – update thermal plant parameters and forced outage rates; update power,
15 fuel, and transportation/transmission contracts; gas and electric forward curves;
16 planned thermal and hydro maintenance outages; loads; and any errata corrections
17 to our February 16 initial filing;
- 18 • July – update power, fuel, transportation/transmission contracts, and related costs;
19 gas and electric forward curves; planned thermal and hydro maintenance outages;
20 and loads;

¹ This is at the bus-bar and differs from load at the customer meter by line losses.

- 1 • September – update power, fuel, transportation/transmission contracts, and related
2 costs; gas and electric forward curves; planned hydro maintenance outages; and
3 loads; and
- 4 • November – two updates: 1) forward curve updates, final updates of power
5 contracts, fuel contracts, transportation/transmission contracts, long-term opt outs,
6 and related costs; and 2) final gas and electric forward curves.

7 **Q. What updates and model changes do you propose in this docket?**

8 A. In this initial filing, we include nearly all of the typical updates included in an April 1 AUT
9 filing. One exception is the thermal forced outage rates. We plan to file an update that
10 includes forced outages rates based on 2006-2009 data by April 1, 2010, consistent with
11 information that would be used in an AUT filing for 2011. By this date, we will have
12 processed the 2009 data needed to complete the outage rate calculations. In this initial
13 filing, we use the same forced outage rates based on 2005-2008 data as we used in UE 208
14 (2010 AUT). In addition, for some items that we update annually, such as 4-year average
15 calculations for certain long-term contracts or fixed coal cost items, we will update these in
16 our April 1 filing. We will also update several of the items included under Schedule 125 as
17 this docket proceeds. Finally, we made the following additional updates and modeling
18 changes in our initial Monet runs:

- 19 • Inclusion of Biglow Canyon phase 3 net power cost benefits;
- 20 • Updates to reflect the latest Pacific Northwest Coordination Agreement (PNCA)
21 Headwater Benefits study;
- 22 • Updated hydro plant H/K factors;
- 23 • Add Oak Grove Relicensing Update for Harriet Lake Base Flow;

- 1 • Inclusion of mercury control chemical costs at the Boardman plant;
- 2 • Reclassification of certain operating costs to net variable power cost including the
- 3 cost of:
 - 4 ○ Broker fees related with PGE’s activities in the gas and electric markets;
 - 5 ○ Credit facilities and margin interest associated with collateral deposits;
 - 6 ○ Ammonia for NO_x control at Coyote and Port Westward; and
 - 7 ○ Lime at Colstrip 3 and 4 for SO₂ control;
- 8 • Updated Colstrip 3 and 4 to “non-cycling” from “cycling;”
- 9 • Improve the modeling of the Coyote Springs auxiliary boiler economics in the
- 10 dispatch logic;
- 11 • Inclusion of a peak/super-peak energy contract; and
- 12 • Inclusion of WECC-proposed operating reserves.

13 PGE will include the following updates in its April 1 filing:

- 14 • Coyote Springs Turbine Upgrade; and
- 15 • Pelton/Round Butte generation for the addition of the Selective Water Withdrawal
- 16 (SWW) facility.

17 PGE also proposes one additional change to simplify the modeling in Monet:

- 18 • Relax the requirement to freeze thermal plant variable O&M costs.

19 **Q. What is the impact of these updates and modeling changes on NVPC relative to the**
20 **final 2010 AUT forecast?**

21 A. The updates and changes in this initial filing decrease NVPC by approximately \$36.9
22 million. However, several of the items in Monet including broker fees, collateral costs,
23 ammonia costs, and lime costs, are reclassifications of operating expenses to NVPC, rather

1 than changes to our modeling. Aside from these reclassifications, updates and modeling
2 changes decrease NVPC by approximately \$42.0 million.

A. Biglow Canyon Phase 3

3 **Q. Did you include any Biglow Canyon (Biglow) phase 3 costs in the 2011 GRC NVPC?**

4 A. Yes. We include costs for BPA tariff integration, royalty payments, an imbalance premium,
5 and a day-ahead forecast error estimate, which total \$5.9 million. We also include Biglow
6 Canyon phase 3 in our operating reserve calculations. Additionally, we include the BPA
7 Transmission Credit of \$2.8 million associated with Biglow Canyon phase 3.

8 **Q. What impact does Biglow Canyon phase 3 have on 2011 power costs?**

9 A. Biglow Canyon phase 3 reduces 2011 NVPC by approximately \$22.3 million. This is the
10 result of lower net market purchases (\$24.9 million), lower wheeling costs (\$2.8 million),
11 and lower WECC incremental reserves cost (\$0.5 million). As we noted above, variable
12 costs for Biglow Canyon phase 3 are approximately \$5.9 million. PGE's confidential work
13 papers include the Monet output files with and without Biglow Canyon phase 3.

B. Pacific Northwest Coordination Agreement Study Update

14 **Q. Please describe the updates you made based on the new Pacific Northwest**
15 **Coordination Agreement (PNCA) study.**

16 A. Under the PNCA, the Northwest Power Pool conducts a 70-year regulation study called the
17 Headwater Benefits Study (Study), based on a regulation model whose objective function is
18 to maximize the firm energy load-carrying capability of the Northwest system as a whole.
19 This model considers the loads and thermal resources of regional entities, as well as hydro
20 resources. The model produces a simulated regulation of 70 water years under historical

1 stream flows, which we then use, with a set of adjustments, to develop the average hydro
2 energy inputs to Monet. For this filing, we updated from the 2006-07 Study to the 2008-09
3 Study to establish base average expected outputs for our hydro resources. We then adjusted
4 these base figures using essentially the same adjustment steps used to develop our UE 208
5 hydro inputs to Monet (such as removing PGE Hydro maintenance, changing to continuous
6 mode, and adjusting for end-of-study reservoir content).

7 **Q. What impact do these PNCA-related changes have on your 2011 NVPC forecast?**

8 A. The net impact of updating the PNCA study is a decrease in NVPC of \$1.7 million.

C. Hydro Plant Performance

9 **Q. How do the hydro plant performance factor updates affect the Monet forecast?**

10 A. The primary updates are to the H/K factors, which translate hydro flows into electricity
11 generation. The H/K factors for North Fork, Faraday and River Mill were updated to correct
12 for a consistent overstatement of the factors based on 9 recent years of actual flow and
13 generation data. We updated the North Fork factor from 10.18 kW/cfs⁽²⁾ to 8.64 kW/cfs,
14 resulting in a NVPC increase of approximately \$1.8 million. We updated the Faraday factor
15 from 10.00 kW/cfs to 7.68 kW/cfs, resulting in a NVPC increase of approximately \$2.6
16 million. We updated the River Mill factor from 5.60 kW/cfs to 4.90 kW/cfs, resulting in a
17 NVPC increase of approximately \$0.8 million.

D. Oak Grove Update for Harriet Lake Base Flow

18 **Q. Please describe this update.**

² cfs = cubic feet per second

1 A. This update models the hydro generation lost at Oak Grove due to a new base flow
2 requirement at Harriet Lake as part of the Clackamas Relicensing Agreement. Under the
3 Relicensing Agreement, PGE will be required to provide a base flow from Harriet Lake
4 year-round, reducing the flow available to the Oak Grove powerhouse for generation. The
5 base flow requirement was calculated net of existing spill due to high flow conditions. This
6 incremental spill was then used to estimate the lost generation at Oak Grove. The new base
7 flow requirement is expected to begin in September 2011, following a scheduled outage.

8 **Q. How does this requirement affect the 2011 NVPC forecast?**

9 A. The net impact of updating Oak Grove for the Harriet Lake base flow requirement is an
10 increase in NVPC of \$0.8 million.

E. Boardman Mercury Control Chemicals

11 **Q. What is the basis for your estimate of Boardman mercury control chemicals?**

12 A. During 2010, PGE will install additional mercury suppressant equipment at the Boardman
13 plant. This suppressant system, which will be fully functional in 2011, utilizes brominated,
14 activated carbon to limit mercury emissions to levels required by the Department of
15 Environmental Quality.

16 **Q. What is the annual cost of these emission control chemicals and is it included in
17 NVPC?**

18 A. PGE forecasts the cost of the chemicals to be approximately \$1.9 million. It is appropriate
19 to include these costs in NVPC because chemical cost varies directly with the plant's
20 operation, and when incurred will be accounted for as a fuel cost in FERC account 501.

F. Operating Expense Reclassifications

1. Broker Fees

Q. Why is PGE including broker fees in its forecast of NVPC?

A. Broker fees are a direct result of PGE’s participation in the wholesale power markets. The power markets have evolved over time from bilateral trades between and among electric utilities (a predominantly physical market without independent parties) to one that now incorporates many independent parties and is predominantly financial. While this evolution has brought benefits such as more counterparties and additional liquidity, it has also brought with it more explicit fees. Rather than transacting just once with a physical deal and incurring one fee, a financial deal requires two transactions and typically three fees. In the first transaction, PGE enters into the financial arrangement (e.g., “fixed” for “floating” swap) where PGE typically incurs an over-the-counter (OTC) broker fee and a clearing broker fee. In the second transaction, which typically occurs closer to the execution date, PGE enters into a physical transaction (e.g., an index purchase) and incurs just an OTC broker fee.

The amount of fees PGE incurs in a given year is also subject to market conditions that affect the volume of transactions PGE enters into. Factors that come into play include available generation, loads, market liquidity, and hydro conditions.

Q. How has PGE included broker fees in its forecast?

A. PGE has forecast 2011 broker fees using historical actuals as a basis and escalating at 2.5%, the standard rate of inflation in Monet, for expected increases in fee rates. The result is an increase to NVPC of approximately \$0.7 million.

Q. Is the inclusion of broker fees allowed under the current Schedule 125 and Schedule 126?

1 A. Yes. Schedules 125 and 126 allow for the inclusion of the “cost[s] of...hedges, options, and
2 other financial instruments used to serve retail load.”

3 **Q. Will broker fees be included in future AUT and PCAM filings?**

4 A. Yes. The factors described above are many of the same dynamic attributes that PGE already
5 updates in its AUT filings, which are subject to the PCAM.

6 **Q. Where were broker fees previously recorded?**

7 A. PGE previously recorded and recovered broker fees as power operations O&M.

8 **Q. Have you included these broker fees anywhere else in this rate case aside from NVPC?**

9 A. No.

2. *Collateral Deposits*

10 **Q. What costs has PGE included related to collateral deposits?**

11 A. PGE has included the cost of certain revolving credit facilities fees and net margin interest³.
12 The revolving credit facilities fees are included for only the portion of PGE’s credit facilities
13 used to support power operations. PGE discusses collateral deposits in more detail in PGE
14 Exhibit 1100.

15 **Q. What is the effect of including costs associated with collateral deposits in this forecast?**

16 A. The result is an increase to NVPC of approximately \$2.6 million comprised of a \$2.0 million
17 increase for revolver fees and a \$0.6 million increase for net margin interest.

18 **Q. Will costs associated with collateral deposits be included in future AUT and PCAM
19 filings?**

20 A. Yes. PGE will include an updated forecast of collateral deposits and associated net interest
21 costs in future AUT and PCAM filings.

³ Depending on market conditions, PGE can find itself in a position of being a net recipient or net depositor of collateral. Therefore, it is possible that PGE could be either a net recipient or net payer of margin interest.

1 **Q. Is the inclusion of collateral deposit costs allowed under the current Schedule 125 and**
2 **Schedule 126?**

3 A. Yes. Schedules 125 and 126 allow for the inclusion of the “cost[s] of...hedges, options, and
4 other financial instruments used to serve retail load.”

3. *Ammonia*

5 **Q. What is the basis for your calculation of ammonia costs for Port Westward and Coyote**
6 **Springs?**

7 A. Port Westward and Coyote Springs use ammonia to reduce oxides of nitrogen (NOx)
8 emissions to levels that comply with state and federal requirements. In our Monet forecast,
9 we multiply a forecasted ammonia price by an average ammonia feed rate for each of the
10 plants. The average feed rate is based on PGE’s historical experience with ammonia
11 consumption and the fuel heat input to the plants.

12 **Q. Did you use this same approach for ammonia in UE 197, the last general rate case?**

13 A. Not precisely. In UE 197, although the method to calculate the cost was very similar, we
14 included these costs in O&M expenses rather than NVPC. We have subsequently
15 determined that it is more appropriate to classify these costs as NVPC because they vary
16 with gas use by the plant and when incurred are accounted for as a fuel cost in FERC
17 account 501.

18 **Q. Are ammonia costs for Coyote Springs expected to decrease in the future?**

19 A. Yes. During the 2011 major maintenance outage, an upgrade to the dry low NOx
20 combustion system will reduce the NOx output that has to be catalyzed by the ammonia,
21 which in turn will result in significantly reduced consumption of ammonia.

22 **Q. What is the NVPC effect of the ammonia costs?**

1 A. The ammonia costs, which have been reclassified from O&M to NVPC, total approximately
2 \$0.5 million, comprised of \$0.4 million for Port Westward and \$0.1 million for Coyote
3 Springs.

4 **Q. Have you included ammonia costs anywhere else in this case aside from NVPC?**

5 A. No.

4. *Lime*

6 **Q. What is the basis for your calculation of lime costs for Colstrip Units 3 and 4?**

7 A. Colstrip Units 3 and 4 use lime to reduce sulfur dioxide emissions to levels that comply with
8 state and federal requirements. In our Monet forecast, we unitize the Colstrip forecast for
9 total lime costs based on tons of coal burned, and then multiply by the amount of coal
10 consumed on a monthly basis.

11 **Q. Did you use this same approach for lime in UE 197, the last general rate case?**

12 A. No. In UE 197, PGE estimated lime costs for Colstrip and included them as O&M expenses
13 rather than NVPC. We have subsequently determined that it is more appropriate to classify
14 these costs as NVPC because they vary with coal consumption, and when incurred are
15 accounted for as a fuel cost in FERC account 501.

16 **Q. What is the NVPC effect of the lime costs?**

17 A. The lime costs, which have been reclassified from O&M to NVPC, total approximately \$1.3
18 million.

19 **Q. Have you included these lime costs anywhere else in this case aside from NVPC?**

20 A. No.

G. Colstrip Cycling

1 **Q. Please describe the effect of switching Colstrip Units 3 and 4 from cycling to non-**
2 **cycling.**

3 A. Recent iterations of Monet have produced results where Colstrip Units 3 and 4 cycle on and
4 off on an hourly basis, which does not reflect the plant’s actual operation. This cycling logic
5 is appropriate for a simple-cycle combustion turbine such as Beaver Unit 8, but not a coal
6 plant. Switching Colstrip’s designation from cycling to non-cycling will make Monet more
7 consistent with the actual operation of this base load coal plant. Doing so also makes the
8 treatment of Colstrip and Boardman consistent in Monet. There is no NVPC change
9 associated with this modeling change at this time.

H. Coyote Auxiliary Boiler

10 **Q. Why did you change the dispatch modeling of the Coyote Springs auxiliary boiler?**

11 A. Until this update, Monet was cycling the plant off without considering the cost of operating
12 the auxiliary boiler during times when PGE is required to maintain operation of the auxiliary
13 boiler in order to serve PGE’s steam customers. Although the costs for the auxiliary boiler
14 were captured in Monet, they were not accounted for in the economic dispatch decision of
15 the plant.

16 **Q. What is the result of altering the dispatch modeling for the Coyote Springs auxiliary**
17 **boiler?**

18 A. The dispatch decision now accounts for the costs to maintain operation of the auxiliary
19 boiler to serve steam customers when Coyote is not generating power, and thus, the dispatch
20 of the Coyote plant and the corresponding auxiliary boiler dispatch are more economical.

1 **Q. How does this change affect NVPC?**

2 A. This change in dispatch logic results in a small NVPC decrease of approximately \$0.1
3 million.

I. Peak/Super-Peak Energy Contract

4 **Q. Please describe the inclusion of a peak/super-peak energy contract.**

5 A. Each year, PGE conducts a planning process to ensure that it has adequate resources to
6 cover a 1-in-5 load excursion event during the summer months, which have high and
7 particularly volatile prices as the entire western grid peaks. The analysis consists of a
8 comparison between available dispatchable thermal generation, forecasted hydro generation,
9 forecasted wind generation, existing long-term power contracts and the peak forecasted
10 loads under the 1-in-5 planning scenario. As part of this analysis, PGE's traders are asked to
11 make a market assessment of the amount of energy PGE can reliably acquire in the
12 prescheduled and real-time markets. This assessed volume typically represents half of the
13 500 MW to 700 MW necessary to cover a 1-in-5 planning event, as compared to a 1-in-2
14 load profile. Because PGE can only rely on the short-term market to cover a limited amount
15 of the 1-in-5 load, PGE typically fills the remaining deficit by entering into a summer peak-
16 shaping transaction for firm generation. The simplest and most cost effective product
17 available in the market is an on-peak for super-peak exchange of physical power, where
18 PGE supplies on-peak power and buys super-peak power at a ratio of 1 to 2. This ratio
19 ensures that the transaction is energy neutral on a daily basis, better matches energy supply
20 with demand and, similarly, avoids the drawback of further market purchases where PGE
21 would have to sell excess power in shoulder hours.

22 **Q. What is the NVPC effect of this contract?**

1 A. PGE forecasts that this contract will increase NVPC by approximately \$0.6 million.

2 **Q. What is the premium associated with this type of contract and why is it justified?**

3 A. Based on PGE's experience during 2007 through 2009, this type of contract carries a
4 premium of approximately 10%. This premium has two components: 1) the premium value
5 of energy delivered during the highest hourly load period and 2) a risk premium to
6 compensate the seller of super-peak energy for the risks of entering into a forward sales
7 agreement months in advance of actual delivery.

8 As mentioned above, PGE's experience has been that it can reliably acquire
9 approximately half of the energy deficit during the period in question. The remaining deficit
10 can either be filled by an on-peak for super-peak exchange as described above, or PGE can
11 reserve its own shapeable generation resources for load excursions and purchase larger
12 portions of block energy. The latter approach is less economically efficient than the
13 peak/super-peak exchanges that PGE enters into.

14 **Q. Will peak/super-peak contracts be included in future AUT and PCAM filings?**

15 A. Yes. PGE will include an updated forecast of these contract costs in future AUT and PCAM
16 filings.

J. WECC Operating Reserves

17 **Q. Please describe the implementation of the new standard on WECC Contingency**
18 **Reserve Requirements.**

19 A. In April 2008, WECC proposed new standards for operating reserves, which NERC
20 approved on October 29, 2008. The proposed standards are currently awaiting approval by
21 FERC. The proposed standards are for operating reserves of 3% of control area load and 3%
22 of generation, which would replace the current requirement for total operating reserves equal

1 to 7% of thermal generation and 5% of hydro and wind generation. FERC has not indicated
2 when they will issue a decision. The overall effect of the change is an increase in operating
3 reserve requirements for PGE, resulting in a \$0.7 million increase to NVPC. Should FERC
4 not approve the proposed standards by October 1, 2010, PGE will adjust our NVPC forecast.

5 **Q. Do you provide further information regarding these model enhancements, new items
6 and major updates?**

7 A. Yes. We provide further explanation and support for these in the MFRs included with our
8 Work Papers.

K. Pending Update: Coyote Springs Turbine Upgrade

9 **Q. Please describe this pending upgrade.**

10 A. In 2011, during the plant's scheduled maintenance outage, PGE plans to upgrade various
11 components at Coyote Springs including a new compressor, turbine rotor, casings, and dry
12 low NOx combustion system. These upgrades are expected to increase the generation
13 capacity of the plant and potentially improve the heat rate. PGE will incorporate projections
14 of the operating benefits, and related costs, in its April 1 filing.

L. Pending Update: Pelton/Round Butte Generation for the

Addition of the SWW Facility

15 **Q. Please describe this pending update.**

16 A. This update will model the hydro generation lost at Round Butte under normal operating
17 conditions due to a reduction in head caused by the SWW facility. PGE will incorporate
18 projections of this cost in its April 1 filing. However, we have included supporting
19 documentation for this change in the MFRs filed with this case.

M. Dynamic Variable O&M for Thermal Plants

1 **Q. What is your proposed modeling change to variable O&M in Monet?**

2 A. This change would relax the current requirement that the thermal plant variable O&M costs
3 as modeled in Monet be frozen at the April 1 update filing in a general rate case year and
4 remain frozen until the next general rate case. Instead, certain dynamically modeled
5 adjustments in Monet would be permitted, including:

- 6 • Annual escalation for general inflation;
- 7 • Dynamically modeled transmission loss costs or savings, which depend on
8 burner-tip fuel prices, which are frequently updated. This currently affects only
9 Port Westward and Colstrip;
- 10 • The market price of SO₂ emission allowances. This currently affects only
11 Boardman and Colstrip;
- 12 • Updates to the Montana Producer's Tax or Wholesale Energy Transaction Tax.
13 This affects only Colstrip; and
- 14 • Updates to the plant emission factors for SO₂, which can change when we have a
15 new coal commodity contract. This practically affects only Boardman.

16 **Q. Why do you want to make this modeling change?**

17 A. The reason is to simplify the modeling and arrive at more accurate dispatch decisions in
18 Monet. Currently, there is an inordinate amount of modeling effort and complexity to freeze
19 the variable O&M in Monet between general rate cases considering the relatively immaterial
20 effect on NVPC. Variable O&M is not included in NVPC but is used in the dispatch
21 decision. This will require a change to Schedule 125, which is reflected in PGE Exhibit
22 1501.

IV. Comparison with 2010 UE 208 NVPC Forecast

1 **Q. Please restate your initial 2011 GRC NVPC forecast.**

2 A. The initial forecast is \$747.2 million including Biglow Canyon phase 3. Without Biglow
3 Canyon phase 3, the forecast is \$769.5 million.

4 **Q. How does the 2011 GRC forecast compare with the UE 208 2010 forecast approved in**
5 **Commission Order No. 09-433?**

6 A. Based on PGE’s final updated Monet run for the 2010 test year, the forecast is \$784.1
7 million, or \$39.09 per MWh. The 2011 forecast is \$747.2 million, or \$37.46 per MWh.⁴

8 **Q. What are the primary factors that explain the decrease in the 2011 forecast compared**
9 **to the 2010 forecast?**

10 A. As Table 1 shows, the approximate \$36.9 million decrease is due to several factors.

Table 1
Factors in Power Cost Differences (\$Million)

Element	Effect
Hydro Cost and Performance	\$14
Coal Cost and Performance	17
Gas Cost and Performance	10
Wind Cost and Performance	-18
Contract and Market Purchases	-51
Fewer Market Purchases for Cost of Service Load Decrease	-6
Other (Net)	-4
Total	-\$37

11 We expect less hydro production in 2011 due to the expiration of certain contracts,
12 decreased share of output at Priest Rapids and Wanapum, and, as described above, changes
13 to the H/K factors. This reduced output is offset by more costly market purchases.
14 Coal-generated output is reduced in part due to more maintenance days at Colstrip Unit 3

⁴ These calculations are based on bus-bar cost of service load and include the fact that the 2011 load forecast is 13 MWa lower.

1 and Boardman, while costs increase due to higher fixed and transportation costs at Colstrip
2 as well as higher coal costs at Colstrip and Boardman. The cost of gas-generated production
3 increases due to higher gas commodity costs. The addition of Biglow Canyon phase 3
4 yields greater output and lower costs per MWh for wind generation. Contract costs and
5 volumes⁵ for 2011 are lower than 2010, with the volume made up for by even lower-cost
6 market purchases. Fewer market purchases are necessary due to a 13 MWa decrease in
7 cost-of-service loads from 2010 to 2011.

⁵ Contract volumes will increase over the course of the year as PGE fills its open power position.

V. Qualifications

1 **Q. Mr. Niman, please describe your qualifications.**

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

6 I have been employed at PGE since 1979 in a variety of positions including: Power
7 Operations Engineer, Mechanical Engineer, Power Analyst, Senior Resource Planner, and
8 Project Manager before entering into my current position as Manager, Financial Analysis in
9 1999. I am responsible for the economic evaluation and analysis of power supply including
10 power cost forecasting, new resource development, least-cost planning, and avoided cost
11 estimates. The Financial Analysis group supports the Power Operations, Business Decision
12 Support, and Rates & Regulatory Affairs groups within PGE.

13 **Q. Ms. Peschka, please state your educational background and experience.**

14 A. I received a Bachelor of Arts degree in Finance from Portland State University. I have been
15 employed at PGE since 1999 in the following positions: Risk Management Analyst,
16 Manager of Risk Management Reporting & Controls, and my current position General
17 Manager of Power Operations. Before joining PGE, I worked at PacifiCorp from 1980 –
18 1999 in various retail, wholesale, planning and mergers and acquisition positions. In my
19 current position, I am responsible for managing the Power Operations group that coordinates
20 the NVPC portfolio over the next five years.

21 **Q. Does this conclude your testimony?**

22 A. Yes.

List of Exhibits

<u>PGE Exhibit</u>	<u>Description</u>
401	Order No. 08-505: Excerpt pertaining to MFRs