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April 1, 2016

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Filing Center
Public Utility Commission of Oregon
201 High Street, SE Ste. 100
Salem, OR 97301

RE: UE ______In the Matter of Portland General Electric Company's 2017 Annual Power Cost Update Tariff (Schedule 125)

Attention Filing Center:

Enclosed for filing in the above referenced matter please find the following:

Original and five copies of Direct Testimony of:

- **Jay Tinker, Brett Sims (PGE / 100)**
- **Brett Sims, Darrington Outama (PGE / 200)**
- **Scott Russell, Alex Tooman (PGE / 300)**
- **Mike Niman, Terri Peschka and Patrick G. Hager (PGE / 400)**
- **Marc Cody (PGE / 500)**

Electronic copy (email) 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 the Protective Order.

In conjunction with this filing, PGE will also submit on April 1, 2016 an application for affiliated interest transactions. PGE Exhibits 100, 200, and 300 of this filing provide additional detail related to the requirements of OAR 860-027-0040, sections (g) through (j).

PGE's initial forecast of 2017 net variable power costs, excluding PGE's forecast of federal production tax credits, is $499.8 million. PGE's preliminary estimate of base rate impacts is a reduction effective January 1, 2017 of about 1.4%.

Sincerely,

Jay Tinker

Jay Tinker
Director, Rates and Regulatory Affairs

JT/sp
cc: UE 294 Service List

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **PORTLAND GENERAL ELECTRIC COMPANY's 2017 ANNUAL POWER COST UPDATE TARIFF OF DIRECT TESTIMONY** to be served by electronic mail to those parties whose email addresses appear on the attached service list for OPUC Docket No. UE 294.

DATED at Portland, Oregon, this 1st day of April, 2016.

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OPUC DOCKET # UE 294

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BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE XXX
Annual Update Tariff Filing
For Prices Effective January 1, 2017

PORTLAND GENERAL ELECTRIC COMPANY

DIRECT TESTIMONY AND EXHIBITS

April 1, 2016

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE XXX

Policy

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Jay Tinker
Brett Sims

April 1, 2016

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I. Introduction

Q. Please state your names and positions with PGE.

A. My name is Jay Tinker. I am the Director of Rates and Regulatory Affairs at PGE.

My name is Brett Sims. I am the Director of Origination, Structuring, and Resource Strategy at PGE.

Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to introduce: 1) the initial Annual Update Tariff (AUT) forecast of PGE's 2017 Net Variable Power Costs (NVPC); and 2) PGE's proposal to implement a long-term gas hedging program.

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

A. Our initial 2017 NVPC forecast, excluding PGE's forecast of federal production tax credits, is $499.8 million, based on contracts and forward curves as of February 25, 2016. This initial 2017 NVPC forecast represents a reduction of $32.3 million relative to our final 2016 NVPC forecast.

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, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; and cost of wind day-ahead forecast error to align with the April 1 filing;

- October - Update power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; and loads; and
- November - Two update filings: 1) update gas and electric forward curves; final updates to power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; long-term customer opt-outs; and 2) final update of gas and electric forward curves.

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

A. Yes. Commission Order No. 08-505 adopted a list of MFRs for PGE in AUT filings and general rate case (GRC) filings. 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 401 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, 2016). The MFR documents are designated as either "confidential" or "non-confidential".

Q. How is the remainder of your testimony organized?

A. In the next section we provide an overview of PGE's current short-term and mid-term gas hedging strategy and describe PGE's proposal for long-term gas hedging. We then provide our rationale for pursuing long-term gas hedging at this time and describe the benefits to be derived therefrom. Next, we discuss the reason for employing an affiliated-entity structure for the long-term gas hedging transaction. We then summarize our proposal and recommendations for long-term gas hedging, and in the last section, we provide our qualifications.

Q. Is PGE providing other testimony in support of this AUT filing?

A. Yes. PGE is providing the following pieces of testimony:

- PGE Exhibit 200 discusses proposed guidelines for PGE's long-term gas hedging transactions.
- PGE Exhibit 300 elaborates further on long-term gas hedging by describing: 1) the available strategies for implementing a long-term gas hedging program including the potential risks associated with executing a transaction and how we propose to mitigate them; 2) our review of market opportunities and our process for selecting a specific resource and counterparty; 3) the nature of the long-term gas hedging costs we include in this filing; and 4) the timeline to achieve regulatory approval for cost recovery of the planned long-term gas hedging transaction.
- Exhibit 400 provides specific details regarding PGE's 2017 power cost forecast including updates to the MONET model, the 2017 load forecast, and a comparison with the 2016 NVPC forecast.
- Exhibit 500 provides the estimated price impacts from this filing and describes the calculation of Schedule 125 prices.

II. PGE's Current Gas Hedging Strategy

Q. What specifically do you mean by gas hedging?

A. For PGE, a gas hedge is the acquisition of a physical or financial position that reduces or offsets the risk of market price volatility for fuel to operate our gas-fired thermal plants.

Q. Why is gas hedging important?

A. It is important because customers have indicated that they prefer price stability.[1] In addition, the National Association of Regulatory Commissioners (NARUC) adopted a resolution in 2011 stating:[2]

> Public and private policy makers should remove barriers to using a diverse portfolio of natural gas contracting structures and hedging options. Long-term contracts and hedging programs are valuable tools to manage natural gas price risk. Policies, including tax measures and accounting rules that unnecessarily restrict the use or raise the costs of these risk management tools should be avoided.

In fact, the topic of PGE's hedging strategy, in particular our mid-term strategy (MTS), was discussed at length in Docket No. UE 228 and affirmed by Commission Order No. 11-432:

> We conclude that PGE's overall hedging strategy to be prudently designed. Specifically, we find that the MTS is a reasonable approach to addressing the three-year period between the company's short-term hedges and purchases and the company's long-term resource investment, and agree that the appropriate goal is to address PGE's entire NOP [net open position]. ... Based on the testimony and contemporaneous exhibits PGE introduced documenting the design and goals of the MTS, as well as its expectation at the time the MTS was introduced that gas and power market volatility would remain high, we conclude that PGE's MTS is an objectively reasonable strategy. (Page 8).

Q. Please describe PGE's current gas hedging.

A. PGE hedges its forward gas requirements by means of financial fixed-for-float swaps (swaps) out to five years. The current strategy incorporates the execution of swaps on a

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[1] "Integrated Resource Plan Research – Relevant Insights from Residential, General Business, & Key Business Customers", February 2006, slide 69. Also see PGE 2007 Integrated Resource Plan, June 29, 2007. Pages 135–144 and Appendix F. See also PGE Exhibit 400 in Docket No. UE 228, pages 6-7.

[2] NARUC Resolution on Ensuring Stable Natural Gas Markets, http://pubs.naruc.org/pub/5398465D-2354-D714-51B7-81C42A3D7A42.

calendar year, quarterly, or monthly basis at expected average gas requirements. Swaps executed further out (three-to-five years) are limited to calendar year strips due to market liquidity, while quarterly or monthly swaps become more available as you get closer to delivery period. These market liquidity and product availability constraints require PGE to actively manage swaps and fixed-price and physical index gas purchases to match the specific fuel requirements of our gas-fired plants.

The following illustrates an example of a paired swap and physical index purchase combination:

- PGE pays a fixed price to a financial counterparty and the financial counterparty pays a representative market index price to PGE;
- PGE then purchases physical gas from a supplier at the representative market index price.

The net result of these transactions is that PGE pays a fixed price for physical gas.

Q. Does PGE hedge with physical gas purchases?

A. In recent years, financial hedging has largely replaced physical hedging. For shorter term hedges (i.e., day ahead to three months), some physical fixed-price gas is still purchased to offset short term fluctuations in gas consumption.

Q. How long in duration are these hedges?

A. PGE's gas hedges are currently executed for a period out to five years, consisting of one to 24-month purchases (i.e., short-term hedging) and the MTS, which addresses the three year period out to five years.

Q. How long has PGE been pursuing the MTS?

A. PGE has been executing transactions under the MTS since the first year of its implementation in 2007. Transactions executed under the strategy have been included in PGE's AUT filings and general rate cases since 2008. As noted in Section I, above, PGE's current hedging strategy was discussed at length in Docket No. UE 228.

Q. Does PGE keep the Commission Staff (Staff) and other parties updated on its hedging activities and other power supply operations?

A. Yes. PGE holds Quarterly Power Supply Update meetings and has been doing so for many years. Attendees typically include Staff and representatives from both the Industrial Customers of Northwest Utilities (ICNU) and the Citizens' Utility Board (CUB).

Q. Is there a limitation to the MTS as a hedging tool for customers?

A. Yes. As forward gas prices and price discovery continually move with changing market conditions (either up or down), PGE's hedges are also subject to market swings. Consequently, while the MTS provides a benefit of reduced price volatility for customers, the MTS's benefit is of limited duration because those hedges extend only out to five years.

Q. What is the practical effect of these limitations of the MTS for customers?

A. The MTS provides some protection against price volatility but does not provide price protection against structural shifts that impact the longer-term market price for gas.

Q. Can you give an example to illustrate these effects?

A. In Section III, below, we discuss a number of factors that could lead to structural shifts in the market for gas. To the extent that spot market prices increase due to these factors, subsequent MTS hedge prices will also increase and PGE customers will pay higher prices for electricity as these costs flow through the AUT. A longer-term gas hedge, however, would provide protection against structural shifts, with the degree of protection being a function of the amount hedged.

Q. Are there alternative means of hedging that improve upon the MTS?

A. Yes. As discussed in PGE Exhibit 300, our preferred alternative would be for PGE to reach an agreement for cost-of-service gas via acquisition of gas production properties in the form of a non-operating working interest (i.e., direct ownership of natural gas reserves, production assets, and related property and facilities, but not involved in the day-to-day operations of gas production). This type of cost-based price and supply hedge would last significantly longer than five years, provide protection against longer-term structural shifts in market conditions, as well as provide greater diversity among PGE's gas resources.

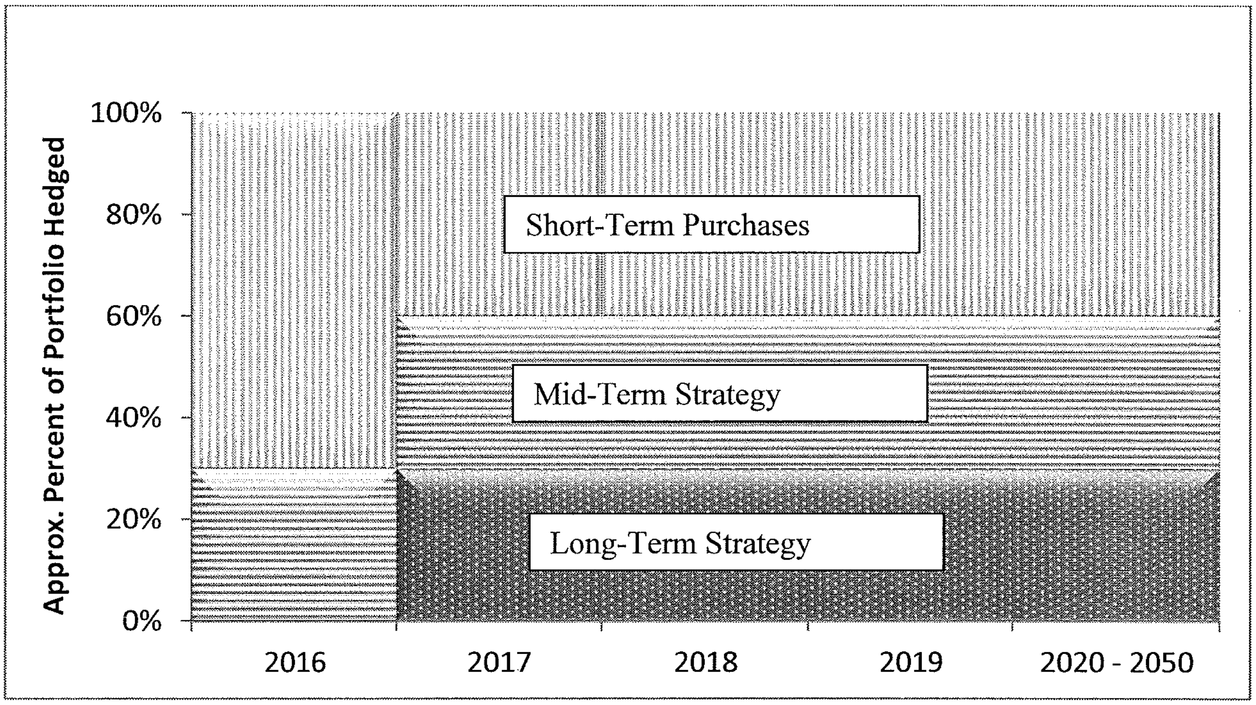
Q. Does long term fuel hedging shift risk from PGE shareholders to customers?

A. No, it does not. Notwithstanding the MTS, structural shifts in market conditions ultimately impact the cost at which PGE procures fuel to operate our natural gas-fired power plants. Those changes in market conditions (higher or lower) then flow to customer prices through the AUT process. In other words, customers today <u>are</u> exposed to the risk that gas prices will be substantially different in the future than they are today.

Q. How would the proposed long-term gas hedging fit into your existing gas hedging strategy?

A. PGE's proposed long-term gas hedging will be layered on to the existing MTS (as depicted in Figure 1, below) and the MTS will continue to provide customers with the shorter-term price stability for which it was designed. Similar to the acquisition of heat rate represented by a new generation facility or a long-term power purchase agreement in relation to energy, the proposed transactions will have the effect of closing part of PGE's price volatility and price level position, but on a longer-term basis.

Figure 1
Integration of Long-Term Gas Strategy



III. Basis for Long-Term Gas Hedging

Q. Why does PGE believe it is important to consider long-term gas hedging now?

A. There are a number of reasons that lead us to this conclusion. The first and foremost is that PGE has significantly increased its reliance on cost-effective gas-fired generation to meet customer energy and capacity requirements. In 2006, gas-fired generation accounted for only 5% of PGE's electric supply portfolio. With the additions of the Port Westward 1 and 2 plants in 2007 and 2014, respectively, plus the addition of the Carty plant in 2016, gas generation will account for over 40% of our energy portfolio in 2017.

Q. What is the significance of this transition?

A. One effect is that given this level of gas-fired generation, a $1 increase in the price of gas would result in approximately a $50 million increase in PGE's power costs (absent effects of hedging). An additional effect is that PGE has moved away from a reliance on the short-term electricity market for energy and the risks associated with electric price volatility and supply reliability, and moved toward a reliance on the market for gas and the risks associated with gas price volatility. While the addition of gas-fired electric generation provides a "heat-rate" hedge, which fixes the rate of converting gas to electricity, it does not provide protection against increases in the cost of fueling the generator. At most times of the year, gas generators set the marginal price for electricity with the price of gas contributing roughly one-half of the total cost of power (the other half are fixed costs of generating capacity and other non-fuel costs).

In response, implementing long-term gas hedges better matches the expected lives of PGE's gas-fired resources, which are expected to remain productive for at least thirty-five years. Consequently, we believe that the appropriate strategy to address a portion of this risk is to engage in long-term gas hedging (see PGE Exhibit 200 for the proposed guideline addressing the portion of PGE's gas requirement to be covered by long-term hedging).

Q. What other reasons lead you to propose long-term gas hedging?

A. A second reason is that gas prices exhibit both short-term volatility due to a number of factors (e.g., weather, supply disruptions, storage and/or transportation availability, where some of this volatility is mitigated by the existing MTS), plus the potential for longer-term structural shifts due to fundamental changes in supply and demand. To mitigate longer-term price variability, PGE proposes to implement a longer-term hedging mechanism that would provide customers with protection from structural shifts in the market at a cost that is at or below the current long-term market price forecast.

Q. Are there likely factors that could lead to structural shifts in the market for gas?

A. Yes. In recent years, gas production has increased at a faster rate than consumption and the resulting commodity price is currently at historic lows in real terms.[3] While this situation is favorable for gas purchasers such as PGE, other factors could affect the demand for natural gas over time to cause upward pressure on gas prices, such as:

- North American exports of liquefied natural gas are forecast to increase the demand for gas by as much as 15%.[4]
- Fuel switching (i.e., coal to natural gas) and new gas-fired generation in the electric power sector are projected to increase aggregate gas demand by 10% to 12% by the mid-2020s.[5]

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[3] Puko, Timothy. "Natural Gas Sinks to 14-Year Low." The Wall Street Journal. December 15, 2015
[4] Wood Mackenzie "North America Gas Long-Term Outlook H2 2015"
[5] Ibid.

- Industrial uses (e.g., agricultural uses, methanol, plastics, chemicals and other refining) are expected to increase gas demand by 5% to 7%.[6]
- Transportation use of natural gas (particularly in the commercial and maritime sectors) is expected to steadily increase over time.[7]

Q. Are these factors reflected in the gas price forecast?

A. Yes. The Wood Mackenzie long-term, gas price forecast (that PGE uses for integrated resource planning), reflects a long-term price increase due to expected structural shifts in the market for gas. If such a gas price increase were to occur, a long-term, cost-of service gas hedge would mitigate the impact for PGE customers. If this increase were not to occur, the larger, non-long-term-hedged portion of PGE's gas position would reflect the benefit of the lower prices.

Q. Are there factors that could also affect supply conditions?

A. Yes. The current, low gas price level has already induced significant declines in new drilling activity for gas and oil. The number of active drilling rigs in early 2016 was down 40% from the number in early 2015, with current numbers being the lowest since 1999. North American natural gas production peaked in late 2015 and has since stalled with recent production efficiency gains through technological advancement offsetting declining production from in-field rig counts. Should current prices and reduced rig counts persist, declining aggregate production and supply is likely to occur.

Q. Why, then, is it important to pursue long-term gas hedging at this time?

A. As noted above, the current spot market price for gas is at historic low levels. This has the effect of lowering revenues and profits of producing companies, such that there is increased

[6] Ibid.
[7] Ibid.

interest among potential sellers for long-term transactions with high-quality, strategic (end-user) purchasers such as PGE.

Q. What if these factors do not materialize as expected?

A. It is possible that prices could continue to decline due to factors such as technological innovation, but with prices (and associated producer profits) already so low, there is little reason to expect significant resources would be applied to this effort. Therefore, even if prices do continue to decline, we do not believe this would be a long-term trend.

Q. Why not a long-term trend?

A. Based on the factors we describe above and the long-term gas price forecast. As noted above (and provided in confidential PGE Exhibit 302C) the long-term gas price forecast that we use in our integrated resource planning, reflects such increases. Ultimately, the future entails uncertainty, and uncertainty is the primary reason that hedging is performed. In fact, historical evidence demonstrates that gas prices experience considerable volatility as well as periodic structural shifts, as shown in Figures 2 and 3, below. Because future gas prices will likely continue to fluctuate due to the factors cited above, or other unforeseen reasons, long-term hedging will help bring stability to gas costs (and electricity prices) for PGE customers.

Q. How have gas prices trended over recent years?

A. Gas prices have been quite volatile, as shown in Figures 2 and 3, below, which reflect monthly spot market prices at the Sumas trading hub.[8]

[8] Figure 3 converts gas cost per-MMBtu to per-MWh (based on output-weighted heat rate) to better reflect the cost to customers. Although PGE purchases gas on a per MMBtu basis, PGE's customers pay for it on a per MWh basis through power costs.

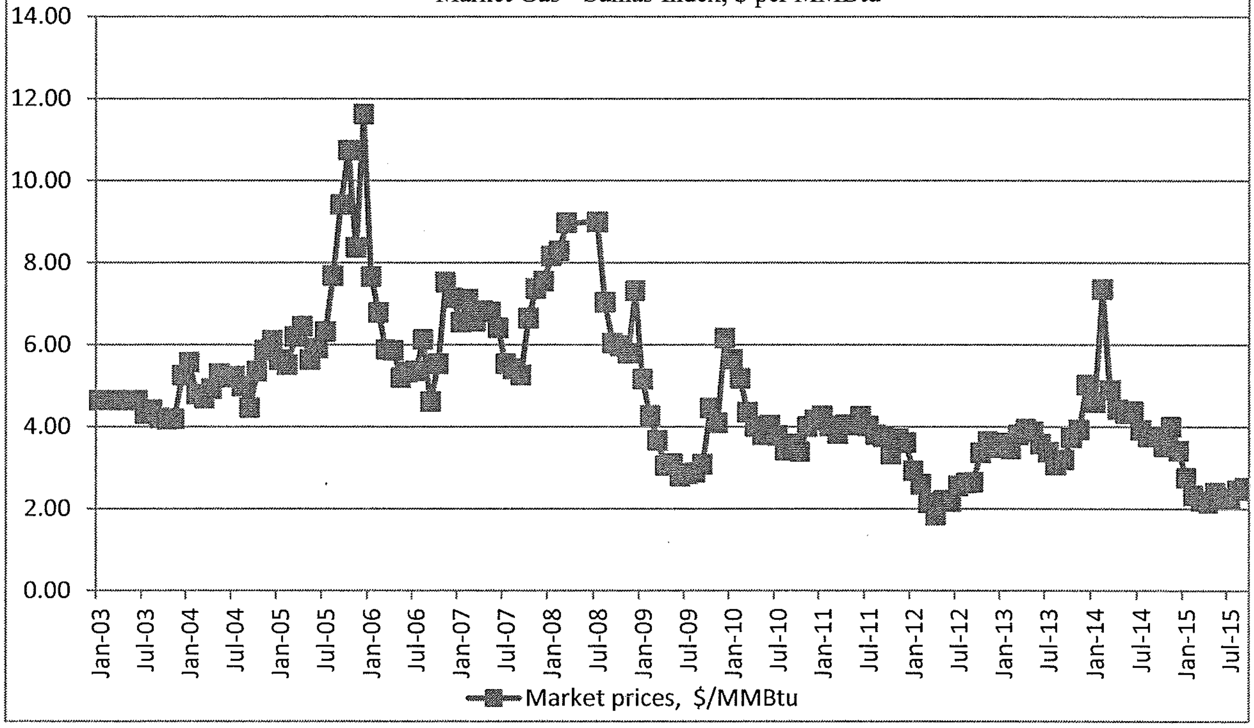


Figure 2
Market Gas - Sumas Index; $ per MMBtu

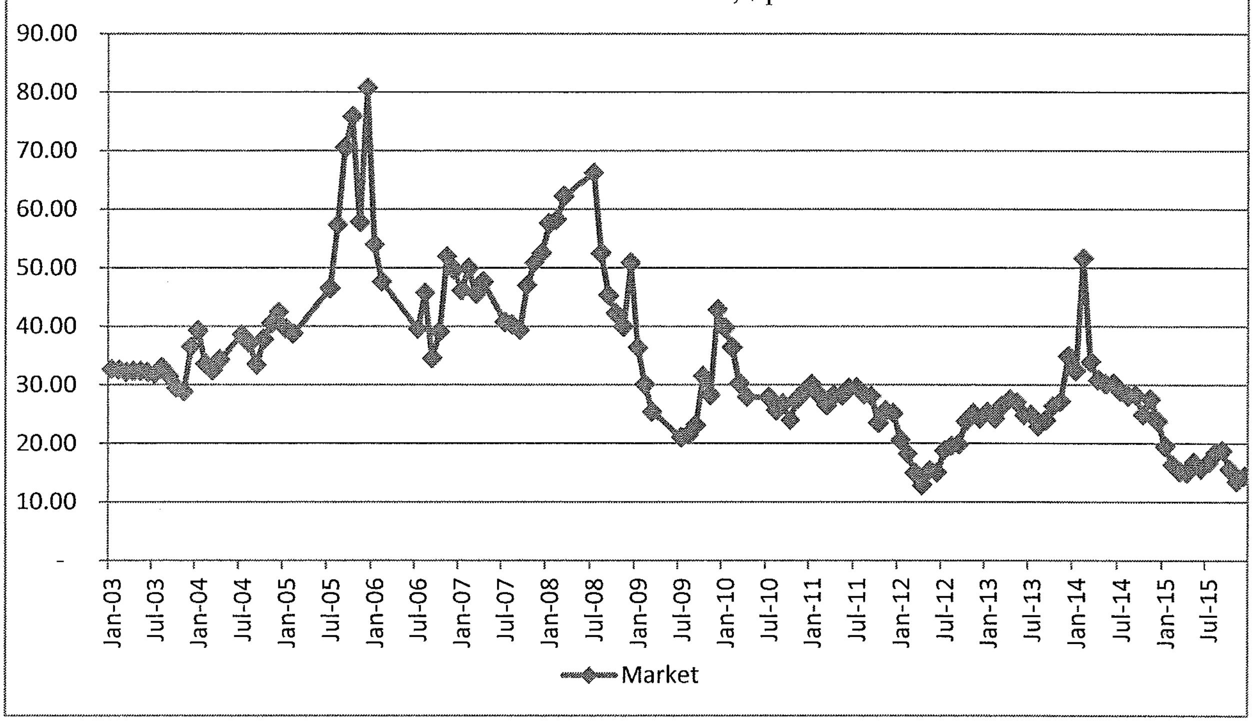


Figure 3
Market Gas - Sumas Index; $ per MWh

IV. Summary of Proposed Long-Term Gas Hedging Activity

Q. In what type of hedging does PGE propose to engage?

A. Based on months of in-depth research, we conclude that a non-operating working interest provides the most long-term benefit to customers in the form of cost-of-service gas. Although we have not entered into a transaction, our goal is to conclude one in time to include its costs in the 2017 AUT. (See PGE Exhibit 300 for a discussion of long-term gas hedging alternatives and a timeline for incorporating a completed transaction in the 2017 AUT).

Q. Has PGE's research included all available strategies for long-term gas hedging?

A. Yes. As discussed in PGE Exhibit 300, PGE is evaluating and will continue to evaluate all available alternatives (including, among others, long-term financial swaps) since our goal is to identify the long-term gas hedge strategy that is in the best interest of our customers.

Q. Are you evaluating a particular region with gas production for your investment?

A. Yes. For the proposed cost-of-service gas, we are currently evaluating producers in the US Rocky Mountain region (US Rockies) with adequate accessibility to processing facilities and interstate pipelines. We are initially focusing on the US Rockies because: 1) PGE purchases gas from the market at hubs located in that region; and 2) PGE maintains long-term gas transportation agreements from this area; and 3) it is a mature, well-understood gas producing region.

Q. Is PGE considering investments in Canada?

A. PGE currently purchases the majority of its gas from Canada, and Canadian investments may also represent effective long-term, cost-of-service gas hedges. PGE has opted to focus on US Rockies investments for our initial transaction, however, based on PGE's greater familiarity with US business and environmental law with regard to this type of investment.

Q. What amounts do you plan to spend or levels of gas do you expect to acquire?

A. In PGE Exhibit 200, we propose to establish guidelines that will set limits for our gas hedging activities. These limits will include a "Long-Term Benchmark Price" and the maximum amount of gas to procure.

Q. What is the benefit to customers from the proposed long-term hedging?

A. The benefit of the proposed hedging program is to limit electric price variability for customers by reducing gas cost volatility. We do this by obtaining a long-term supply of natural gas on a cost-of-service basis at a time when gas costs are very low.

Q. Why do you refer to your proposal as a program?

A. As discussed in PGE Exhibit 200, we plan to employ a phased-in approach to achieve the maximum allowed purchase commitment as well as make subsequent long-term hedges to maintain that level (if subject to depletion with a non-operating working interest).

Q. Do you have any analyses to demonstrate the possible benefit?

A. Yes. PGE has prepared a back cast analysis of the impacts of long-term hedging on PGE's gas costs based on the following assumptions:

- Market costs as identified in Figure 2, and extended through 2016;
- A fixed gas requirement and portfolio of heat rates based on the 2016 forecasted levels for PGE's plants;
- Hedging implemented at the real levelized cost of gas based on the gas forecast used in PGE's integrated resource planning; and

- Hedging layered in annually to offset resource depletion and maintain the target percent of our gas requirement.

Q. What is the significance of the real, levelized cost of gas?

A. For purposes of the back cast analysis, PGE assumed that each phase of long-term hedges were purchased at a price equal to the present value equivalent of the then-current, long-term market price forecast, or Long-Term Benchmark Price. Consequently, any long-term gas hedge transaction we propose will have to be at or below the current Long-Term Benchmark Price to be considered cost effective. Said differently, PGE will only propose transactions that are priced below the current long-term market forecast on a present value basis. See PGE Exhibit 300 for additional details on the comparison of the "Long-Term Projected Cost" of the gas hedge to the Long-Term Benchmark Price.

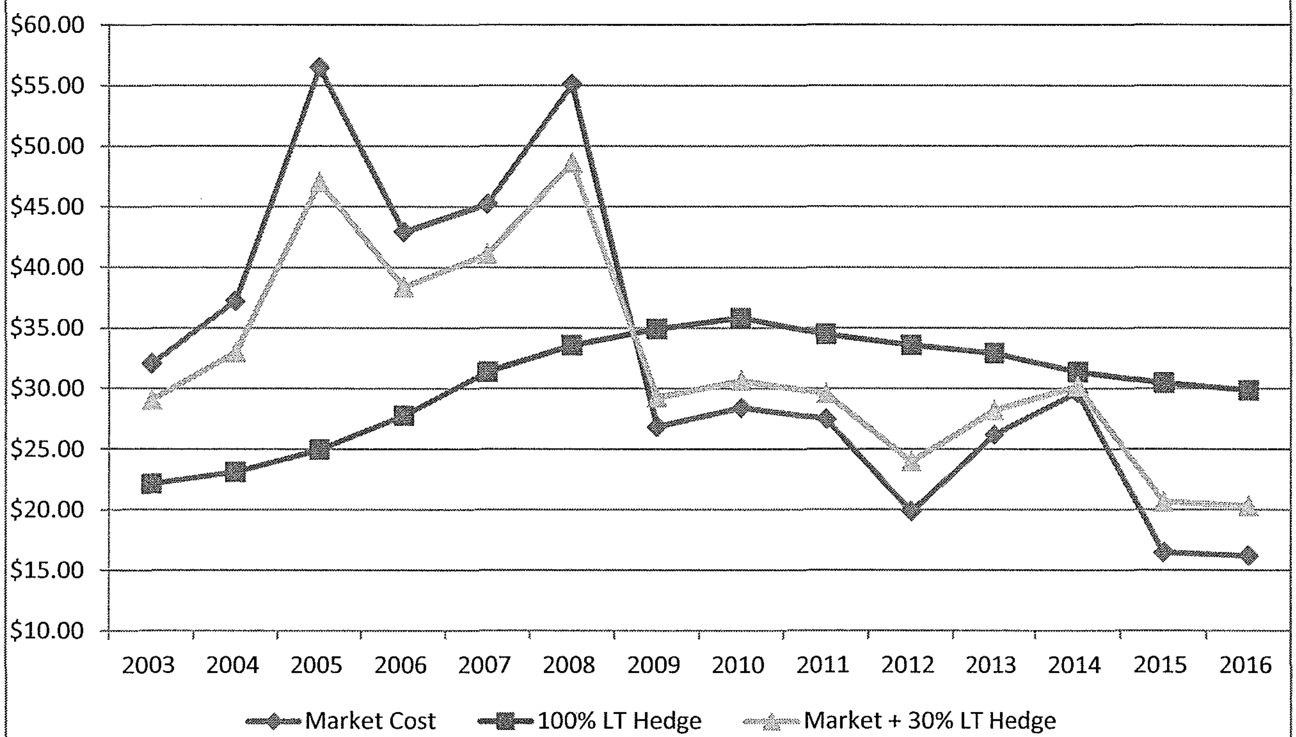
Q. What were the results of the back cast analysis?

A. Figure 4, below, lists three possible scenarios:

- "Market Cost" – All gas purchased at spot market prices.
- "Market + 30% LT Hedge" – 70% of gas purchased at spot market prices and 30% purchased through a long-term gas hedge.
- "100% LT Hedge" – All gas purchased through a long-term gas hedge.

The results of the back cast demonstrate that long-term gas hedging would have resulted in: 1) gas costs that have little variability with 100% of the gas requirement hedged; and 2) diminished gas cost volatility with 30% of the gas requirement hedged (the bases of these percentages are discussed below). As with Figure 3, we converted gas cost per MMBtu to per MWh, since that is the unit upon which electric customers will realize the impacts.

Figure 4
Backcast LT Gas Hedging Example; $ per MWh



Q. What does Figure 4 indicate with regard to customers' costs when comparing hedged gas versus non-hedged gas?

A. If we compare the "Market Cost" line to the "Market + 30% LT Hedge" line, where the average difference between them is approximately $4.50/MWh, this difference would represent approximately 7.0% of the average PGE customer's bill for energy charges. Figure 4 also indicates that when market costs are rising, the hedged costs are less than market. Conversely, when market costs are declining, the hedged costs are higher than market. A fundamental aspect regarding long-term gas hedging, however, is that it is not about "beating" the market. The purpose for hedging is to improve price stability for customers, which Figure 4 demonstrates.

Q. Is PGE proposing to have 100% or 30% of its gas requirement covered by long-term hedging?

A. We are not proposing a 100% long-term gas hedge. We simply include that level in Figure 4 for comparison purposes and to show that gas cost volatility at that level of hedging is as minimal as would be expected. The 30% assumption, however, is used to demonstrate the impacts of a more reasonable target but one large enough to observe actual effects (excluding assumptions about short term hedging or the MTS as discussed in Section II, and illustrated in Figure 1, above).

V. Overview of Affiliated Interest

Q. Does PGE propose to have an affiliated entity participate in this hedging activity?

A. Yes. The use of an affiliate is a desirable enterprise risk management tool, which is employed to provide separation between a parent and its subsidiary, and to limit the parent's liability for the business operations of the subsidiary.

Q. Are you submitting an affiliated interest filing to support this aspect of your proposal?

A. Yes. In conjunction with this filing and our proposal to perform long-term gas hedging with Portland General Gas Supply Company (PGGS), an affiliated entity, PGE is submitting an application for affiliated interest transactions. In effect, PGE Exhibits 100, 200, and 300 of this AUT filing address the requirements of OAR 860-027-0040, sections (g) through (j). In summary, the affiliated interest filing requests approval of three agreements between PGE and PGGS:

- Updated Master Service Agreement (MSA) for PGE to provide PGGS with administrative and general business services in accordance with the terms of the existing MSA. The existing MSA was approved for PGE's other affiliates by Commission Order No. 06-250 in Docket No. UI 248. PGGS will be incorporated into the MSA by Addendum 8.
- Operating Service Agreement (OSA) for PGE to provide PGGS with technical services related specifically to oil and gas properties.
- Purchase Gas Agreement (PGA) for PGE to purchase cost-of-service gas from PGGS.

Q. Do these agreements all conform to the lower-of-cost-or-market rule as stated in OAR 860-027-0048(4)(e)?

A. The MSA and OSA both conform to the rule. Because the PGA's objective is to provide PGE with cost-of-service gas as a long-term hedge against the potential volatility of market purchases, PGE requests a waiver of the lower-of-cost-or-market rule in OAR 860-027-0048(4)(e) for all natural gas purchases under the PGA.

VI. Summary and Conclusions

Q. How would you summarize your proposal?

A. PGE proposes to implement a long-term gas hedging program to provide a stable supply of low-cost gas with which to fuel our fleet of gas-fired thermal plants for years to come. More specifically, a non-operating working interest would provide cost-of-service gas on a long-term basis and provide greater diversity among PGE's gas resources.

We propose to implement the program now because the current environment reflects historically low gas prices, whereas long-term, gas prices are forecast to increase. If higher gas prices are realized, long-term gas hedging would reduce the impact on customer prices, but would do so on a limited and cost-effective basis. In addition, the current low-price environment is engendering increased interest among producers for long-term transactions with qualified purchasers such as PGE.

Finally, the purpose of such long-term gas hedging is not to "beat the market" but rather to reduce the volatility of gas prices that would flow through PGE's power costs to our customer's electric prices.

Q. What specifically do you request the Commission approve?

A. We request that the Commission approve the following:

- Affiliated interest transactions between PGE and PGGS, including the PGA, OSA, and updated MSA.
- A waiver of the lower-of-cost-or-market rule for the Purchase Gas Agreement.
- Proposed guidelines as described in PGE Exhibit 200.
- The long-term gas hedging costs to be included in the AUT per the formulas described in PGE Exhibit 300.

VII. Qualifications

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

A. I received a Bachelor of Science degree in Finance and Economics from Portland State University in 1993 and a Master of Science degree in Economics from Portland State University in 1995. In 1999, I obtained the Chartered Financial Analyst (CFA) designation. I have worked in the Rates and Regulatory Affairs department at PGE since 1996.

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

A. I received a Bachelor of Arts degree in Business and Economics from Linfield College in 1990 and a Master of Business Administration degree from George Fox University in 2001. I have been the Director of Origination, Structuring, and Resource Strategy at PGE since 2005. Previously, I was a manager and senior analyst with the Origination and Structuring group at PGE. I have also held other managerial positions at a variety of banking and energy companies prior to working at PGE.

Q. Does this complete your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE XXX

Proposed Guidelines

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony of

Brett Sims
Darrington Outama

April 1, 2016

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I. Introduction

Q. Please state your names and positions with PGE.

A. My name is Brett Sims. I am the Director of Origination, Structuring, and Resource Strategy at PGE. My qualifications appear at the end of PGE Exhibit 100.

My name is Darrington Outama. I am the Manager of Origination and Structuring at PGE. My qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to introduce proposed guidelines for PGE's long-term gas hedging. We believe Commission approval of these guidelines is important to: 1) establish appropriate consideration and limits for PGE's long-term gas hedging; and 2) allow PGE to execute additional hedging within the guidelines.

Q. How is your testimony organized?

A. In the next section, we explain the basis for the guidelines and why they are appropriate. We then describe the proposed guidelines in detail. In the last section, we provide Mr. Outama's qualifications.

II. Basis for Guidelines

Q. Why are you proposing guidelines for your long-term gas hedging?

A. The reason for guidelines is to establish a framework around which prudence can be measured for the proposed long-term gas hedging strategy and specific transactions pursuant to that strategy.

Q. Would operating within approved guidelines establish prudence?

A. Effectively, yes. If PGE proposes a transaction within approved guidelines (and with appropriate documentation), the presumption is that the transaction is prudent subject to Commission determination that new circumstances or evidence demonstrates otherwise. This premise is no different than that related to PGE's mid-term strategy (MTS – as discussed in PGE Exhibit 100), for which the Commission concluded "PGE's overall hedging strategy to be prudently designed" and that "PGE's MTS is an objectively reasonable strategy." (Commission Order No. 11-432, Page 8.) This does not mean that every transaction completed as part of the MTS is automatically prudent because PGE would still have to demonstrate prudence based on the information available at the time we execute specific transactions.

III. Proposed Guidelines

Q. What guidelines do you propose for PGE's long-term gas hedging program?

A. We propose four guidelines that we believe are appropriate for our long-term gas hedging program.

Guidelines 1 and 2 relate to any of the long-term gas hedging alternatives as discussed in PGE Exhibit 300:

1) Establish that the "Long-Term Projected Cost" must be at or below the comparable "Long-Term Benchmark Price".
2) Establish a maximum gas purchase commitment.

Guidelines 3 and 4 relate only to the non-operating working interest form of long-term gas hedging as discussed in PGE Exhibit 300:

3) Enter into transactions for properties that contain "Proved Reserves" or "Probable Reserves". Proved reserves are those quantities of gas, which can be estimated with reasonable certainty to be economically producible from known reservoirs and under existing economic conditions, operating methods, and government regulations. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.[1]
4) Establish limits within which the unit cost of the long-term gas is incorporated into PGE's annual power cost update (i.e., AUT filing).

We discuss each guideline in detail below and welcome suggestions for others that we may have overlooked but that may also be meaningful.

[1] Netherland, Sewell, and Associates, Inc. at http://netherlandsewell.com/resources.html

Q. Please describe your first guideline regarding cost-effectiveness.

A. This guideline establishes the cost-effectiveness of the hedge at the time the hedge is executed[2] and would specify that the original Long-Term Projected Cost of gas per MMBtu, purchased as part of our long-term gas hedging, is at or below the current Long-Term Benchmark Price.

Q. What is the exact calculation for this guideline?

A. PGE would compare the real, levelized cost of the proposed gas hedge (i.e., the Long-Term Projected Cost) to the equivalent real, levelized forecast cost of gas used in PGE's integrated resource planning (i.e., the Long-Term Benchmark Price). If the Long-Term Projected Cost of the investment or contract is at or below the comparable current Long-Term Benchmark Price, then the proposed transaction would be deemed cost effective. This calculation plus other calculations related to cost recovery of long-term gas hedging are described in detail in PGE Exhibit 300. PGE Confidential Exhibit 302C provides the current gas price forecast by year and corresponding Long-Term Benchmark Price (real, levelized).

Q. Please describe your second guideline regarding the long-term gas purchase commitment.

A. This guideline is intended to establish the appropriate range of long-term gas hedging activity and can be stated as either a total dollar amount, total MMBtu amount, or as a percent of average annual gas burn. PGE proposes that a range of 15% to 30% of projected annual average gas burn be the appropriate range for this guideline. This recommendation is significant enough to reduce customers' exposure to price volatility and yet allow for

[2] In this context, executed represents the point at which PGE commits to a long-term gas hedging transaction (subsequent to Commission approval) that will result in gas being produced and expenses being recorded to PGE's actual power costs.

customers to still benefit if gas prices were to decline. This range also corresponds to PGE's MTS which we limit to 10% to 30% of PGE's open position.

Q. What methodology did you use to evaluate this guideline?

A. We extended PGE's MTS model, which is a 5-year net variable power cost model, to a 30 year stochastic model. This model was further customized to only measure PGE's gas thermal portfolio's volatility as a function of movement of power and gas prevailing prices. Similar to the MTS results, these price simulations created a distribution of potential net variable power costs for the portfolio as is (i.e., without any hedges). We further characterize this starting risk position using its mean expected value, standard deviation around that mean, and its 5th and 95th percentile. From this starting position, we monitored these risk characteristics while simulating an incremental quantity of hedges executed in 5% to 10% increments of total gas requirement. Each increment's resulting portfolio risk characteristics was then recorded.

Q. How did you determine the proposed range?

A. We determined this range of recommended percentage by balancing the stated desire to mitigate customers' prices from going higher, if natural gas prices were to increase, with the desire for customers to also benefit, if natural gas prices were to decline further from current levels. The analysis revealed a linear relationship between the amount of hedges executed and the reduction of the portfolio risk profile. In essence, for every incremental quantity of hedge simulated, a proportionate amount of risk was reduced. The method used to determine the range introduced additional considerations which bounded our recommended range: materiality of the risk reduction and ratio of benefits versus the cost of hedging, available transport capability from the basin being considered, and a nationwide review of similar hedging programs to calibrate the recommendation.

Q. Is the methodology being reviewed externally?

A. Yes. PGE has engaged a third party consultant to assess and examine the approach. Their results and any recommendations made will be available prior to full execution of any transaction.

Q. What is your plan to implement the second guideline?

A. We propose that PGE implement a phased-in approach to achieve the maximum purchase commitment, as allowed by the second guideline. We also propose that PGE be allowed to make subsequent investments to maintain the allowed level of gas hedging, if needed to offset the depletion associated with prior investments in non-operating working interests. To do so, each year PGE will evaluate:

- Our long-term gas hedging position against the limits of the second guideline; and
- All viable alternatives for additional long-term gas hedging including, among others, long-term financial swaps.

PGE would only execute a least-cost, least-risk, long-term gas hedging transaction to the extent it is cost-effective and within the effective limits of the second guideline.

Q. If your long-term gas hedging program is approved, does PGE intend to burn its newly acquired fuel supply in its gas plants?

A. PGE will make the least-cost decision between burn, store, or sell on an ongoing basis. For example, if it is cost effective to sell PGE's gas in the market, and purchase replacement gas from the market, PGE will do so. If it is cost effective to transport PGE's gas to burn at our plants, PGE will do so. Either activity will attain the value of the hedge.

Q. Please describe your third guideline related to investing only in production projects with "Proved Reserves" or "Probable Reserves".

A. In order to minimize the potential for dry-hole risk, PGE plans to only acquire gas projects with a combination of: 1) existing production wells with proved reserves, plus 2) the possibility of future potential production with probable reserves. In the industry, "proved" refers to gas reserves that can be commercially recovered with a 90% certainty that actual production volumes will meet or exceed estimates over a given period of time, while "probable" refers to gas reserves that can be commercially recovered with a 50% certainty that actual production volumes will equal or exceed proved plus probable estimates over a given period of time.[3]

Q. Other than the dry-hole risk mentioned above, how do you plan to address production volume risk?

A. Volume risk occurs if a non-operating working interest produces more or less gas than originally projected. Such variances could be based on either short-term production variability or long-term systematic conditions. We plan to address this risk for customers by means of the fourth guideline, which proposes limits within which the unit cost of the long-term gas is incorporated into PGE's annual AUT filing. As described in PGE Exhibit 300, PGE will calculate an annual "Comparison Rate" based on the forecasted costs of the long-term gas and the original projected volume. The rate to be included in the AUT modeling would then be limited to ±10% of the Comparison Rate. Within the ±10% bands, customers would absorb the costs or benefits associated with under or over production, respectively.

[3] Netherland, Sewell, and Associates, Inc. at http://netherlandsewell.com/resources.html

Outside the ±10% bands, PGE would absorb the costs or benefits associated with under or over production.

Q. Will PGE propose updates to the guidelines if circumstances change?

A. Yes. PGE will continue to monitor the market and conditions. If changed circumstances warrant changes in the guidelines, or if the fourth guideline does not reasonably conform to the specifics of a proposed transaction, PGE will recommend changes to stakeholders and the Commission.

Q. Do you propose any reporting requirements?

A. Yes. We propose that PGE submit annual reports on the previous year's long-term gas hedging activity and perform reassessments of the overall program every five years.

Q. Please describe your proposed reporting requirements in more detail.

A. In order to provide the Commission with detailed information regarding PGE's long-term gas hedging activities and demonstrate that we are operating within the established guidelines, we plan to submit annual reports that would provide:

- Gas cost per MMBtu – PGE will calculate this by dividing the total cost of the gas by the total volume produced. The cost of the gas produced will be based on Portland General Gas Supply Company's (PGGS's)[4] total revenue requirement as described in PGE Exhibit 300. We will then provide appropriate comparisons to originally modeled and updated costs also described in PGE Exhibit 300.
- Amount of purchase commitment – PGE will provide the aggregate actual investment in comparison to the maximum gas purchase commitment as specified by the second guideline.

[4] PGGS is PGE's affiliated entity as described in Section V of PGE Exhibit 100.

Q. What would the five-year reassessment evaluate?

A. We envision that the five-year reassessment would evaluate how the guidelines have been met over time and how each of those results has been trending. We also envision that the results of the reassessment will be submitted as part of a docketed proceeding, in order to allow other parties the opportunity to comment. We would then expect a Commission decision that will indicate one of the following: 1) reauthorize PGE's long-term gas hedging as currently operating; 2) reauthorize PGE's long-term gas hedging program but with modifications to the program or additional conditions/guidelines; or 3) decline to authorize any additional long-term gas hedging agreements or transactions while continuing to permit recovery of cost-of-service natural gas under prior transactions.

IV. Qualifications

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

A. I received a Bachelor of Science degree in Accounting and Finance from University of Washington in 1996. I have over 18 years of experience with PGE working in accounting, financial planning, risk management, and structuring and origination. I currently manage Origination, Structuring and Fundamental Analysis. Previously, I was a senior analyst in the three departments I worked in. I have been involved in originating and pricing of custom products, asset acquisitions, as well as ad hoc project management including the 2012 Request for Proposals on behalf of PGE's customers.

Q. Does this complete your testimony?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE XXX

Structure of Proposed Long-Term Gas Hedge

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Scott Russell
Alex Tooman

April 1, 2016

Table of Contents

I. Introduction

Q. Please state your names and positions with PGE.

A. My name is Scott Russell. I am a Specialist with the Structuring and Origination Department at PGE.

My name is Alex Tooman. I am a Project Manager with Regulatory Affairs at PGE.

Our qualifications appear at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to describe the proposed structure to implement PGE's long-term gas hedging initiative.

Q. How is your testimony organized?

A. In the next section we discuss the available strategies for implementing a long-term gas hedging program including the potential risks associated with executing a transaction and how we propose to mitigate them. We then describe our review of market opportunities and our process for selecting a specific resource and counterparty. Next, we discuss: 1) the nature of the costs we plan to include in PGE's April 1, annual power cost update filing; and 2) the timeline to achieve regulatory approval for cost recovery of the planned transaction. In the final section, we provide our qualifications.

II. Long-Term Gas Hedging Alternatives

Q. What are the current alternatives for long-term gas hedging?

A. There are effectively three long-term gas hedging alternatives: financial fixed-for-float swaps, physical prepay agreements, and non-operating working interests. We discuss them in detail below.

A. Financial Fixed-For-Float Swap

Q. What is a financial fixed-for-float swap?

A. Financial fixed-for-float swaps are simply financial hedging agreements to fix the price of PGE's purchased gas at a pre-determined level and are typical of the ones we currently employ for short- and mid-term gas hedging as described in PGE Exhibit 100, Section II. PGE would not own any facilities or mineral rights and would not take delivery of physical gas.

Q. Who are typical counterparties and how long do these agreements last?

A. Banks and other financial entities are the typical counterparties for these agreements. As noted in PGE Exhibit 100, between our short-term gas hedging and MTS, we currently transact these agreements for up to five years. Longer-term swaps, however, may be available on a very limited, bi-lateral basis depending on market conditions. For example, a small number of participants will periodically offer swaps for terms up to 10 or 15 years. However, market availability for these longer-term financial instruments has varied considerably over time, resulting in extended periods of time where offers/sellers have been unavailable. Similar to swaps transacted under the MTS, price is fluid and reflective of the then-current market conditions.

Q. Are there risks involved with the fixed-for-float swap?

A. Yes. The primary risk associated with fixed-for-float swaps is counterparty performance and credit risk because they are not backed by a title interest in physical gas or other tangible assets; rather the performance of the contract is solely backed by the buyer's contract enforcement (legal rights) and confidence (credit risk assessment) in the capability of the seller. In this case, sellers (typically banks and merchants) are making a financial guarantee that they will be willing and able to make payments as gas prices change over time.

Q. How do you mitigate counterparty risk?

A. The primary method is to transact with financially sound counterparties that are likely to have the wherewithal to perform over the term of the contract. We make this determination based on their corporate and credit profiles. Counterparty performance risk can also be addressed through the posting of collateral or by requiring performance bonds, insurance or related risk management instruments. Additionally, changes in exposure to counterparty performance risk over time due to market price changes are typically addressed through "margining" requirements. Margining provisions require the posting of collateral as changes in market prices affect the value of the contract between the parties.

Q. How significant are margin requirements?

A. Margin requirements can be quite large. For example, if the market price of gas were to move by $1.00 on a 15-year fixed-for-float contract for 20,000 MMBtu[1] of gas, then approximately $110 million of collateral (with corresponding financing costs) would be required to fulfill the margin requirements.

[1] 20,000 MMBtu represents approximately 13% of PGE's average daily gas requirement.

B. Physical Prepay Agreement (PPA)

Q. Please describe physical prepay agreements.

A. Physical prepay agreements involve upfront cash payments for set quantities of physical gas to be delivered in the future.

Q. Is there any ownership aspect to such agreements?

A. No. PGE would own no mineral rights or production assets.

Q. Who are typical counterparties and how long do these agreements last?

A. Typical counterparties for prepay transactions are banks. Agreements can last up to 30 years and as with swaps beyond 5 years, market depth and liquidity are very limited.

Q. Are there risks involved with pre-pay agreements?

A. Yes. The risks and risk mitigation strategies associated with pre-pay agreements are similar to those with fixed-for-float swaps except that counterparty performance and credit risk is more severe due to the pre-payment aspect. In other words, if the counterparty experiences financial difficulties and is not able to perform according to the agreement, PGE's prepayment would be unsecured and likely unrecoverable. Based on this greater risk, we do not recommend that PGE pursue a long-term prepay agreement.

C. Non-Operating Working Interest

Q. What is a non-operating working interest?

A. Under a working interest, PGE through its affiliate Portland General Gas Supply Company (PGGS – as described in Section V of PGE Exhibit 100), would have direct ownership of natural gas reserves along with related wells, production assets, property, and facilities, and would enter into a joint operating agreement with the seller. We would also have ownership voting and auditing rights, be responsible for our share of costs, and take delivery of our share of physical gas. Under a non-operating working interest, however, PGE and PGGS would not be involved in the day-to-day operations of the gas production.

Q. What specifically would you own?

A. PGGS would own an undivided, percentage interest in the underlying mineral rights, leasehold property and production assets (which may include: above and below ground pipes, casings, pumps, compressors, collection systems and related infrastructure).

Q. What types of counterparties exist for these types of transactions and how long do these agreements last?

A. The typical counterparties are gas and oil producers. Because the principal governing operating agreement is for operation of natural gas producing wells, the joint operating agreement effectively lasts as long as gas is being produced, which can be up to 30 years or longer depending on the richness of the geologic formation.

Q. What are the primary characteristics of such an agreement?

A. PGGS would own surface and subsurface production assets and mineral rights and would, therefore, be responsible for its proportional share of costs in exchange for receiving its proportional share of gas and associated liquids. As noted above, PGGS would not be an operator under this structure, which means that we would not be directly involved with the day-to-day management and operation of the property. (See PGE Exhibit 301 for a diagram of a non-operating working interest.)

Q. What are the specific risks associated with non-operating working interests?

A. The first is the risk that the amount of gas produced does not match estimates. Specifically, if the volume of gas produced is less than projected, then the unit cost per MMBtu will be higher than anticipated. Conversely, if more gas is produced than expected, the cost per unit of gas delivered would decline below initial estimates. These outcomes result from spreading fixed costs over a higher or lower quantity of produced gas versus original projections.

Q. How will this be treated?

A. As described in Section IV below, the originally projected cost and volume of gas will be incorporated into PGE's power cost forecast for 2017. To the extent that actual costs and/or gas volumes are different, they will be reflected in PGE's 2017 actual power costs and will flow through our power cost adjustment mechanism (PCAM). The PCAM, in turn, has both power cost deadbands and earnings deadbands, which given their respective sizes, means that a positive power cost variance[2] and earnings shortfall will have to be significant before any collections would occur (i.e., the authorized PCAM is structured to produce infrequent refunds and collections). Consequently, risk of intra-year variances in projected gas volumes would generally be borne by PGE.

Q. Please provide an example.

A. Assume that PGE has a positive annual variance in its PCAM of $10 million due to lower than average hydro conditions (excluding any effects of long-term gas hedging). According to the PCAM structure, this variance is subject to a $30 million deadband. This means that the power cost variance is zero, no earnings review is necessary, and there is no collection of this amount from customers. Assume now that the annual variance is $5 million higher due to the impact of lower than expected production volume associated with a long-term gas hedge. If so, the $15 million annual variance is still within the $30 million deadband and PGE would absorb the additional cost as intra-year volume risk.

[2] A positive power cost variance is where actual power costs exceed forecasted power costs. A negative power cost variance is where forecasted power costs exceed actual power costs.

As an additional example, assume the original annual variance is $32 million and the impact of lower than expected production volume is still $5 million. This would produce a power cost variance of $6.3 million (i.e., (37 million - $30 million) * 90%). The $6.3 million power cost variance would then be subject to an earnings review, which means it would be collected from customers only to the extent that PGE's regulated adjusted return on equity (ROE) would be no higher than the currently authorized ROE minus 100 basis points. If PGE were within the earnings deadband, there would be no collection of the $6.3 million power cost variance.

Q. How would inter-year volume risk be treated?

A. Under existing treatment, PGE updates its power cost forecast each year, along with all specified components, as part of the annual AUT filing. Our proposal, as described in Section IV below, would include floor and ceiling bands within which the cost of the long-term gas (as largely affected by production volume) would be included in the AUT forecast. Actual power costs and the approved baseline forecast will still flow through the PCAM as currently structured.

Q. Are there any other ways to mitigate the production risk?

A. Yes. The best way to reduce production risk is to invest in properties located in mature, predictable basins with a history of low production variability. To this end, PGE has partnered with an independent, expert reservoir engineering firm to assist in identifying properties appropriate for PGE's long-term hedging program.

Q. Are there environmental risks associated with the proposed natural gas production?

A. Yes. There are environmental risks and potential liabilities primarily associated with potential or past releases of liquids or gases into the environment (air, water, or soil). These releases can occur during operational activities, material handling, disposal processes or due to poor housekeeping, maintenance, or structural integrity of wells or above-ground system components. Additional risks and liabilities are based on the failure of existing programs and procedures to maintain compliance with applicable environmental regulations.

The first and best option to reduce environmental risks is to invest in properties with a lower environmental risk profile. Environmental risk profile would consider both the likelihood of having significant releases to the environment as well as the sensitivity of features that may be impacted in the event of a release. Properties located in close proximity to towns, sources of water supply, designated ecological habitat etc. would generally have higher environmental risk than properties located further from these sensitive features. The risk profile will also consider both the condition of the physical assets (wells and above ground components) and the counterparty/operator's means, methods, and procedures for handling, transport and disposal in order to assess the likelihood of significant releases occurring. Environmental risk will be significantly reduced by partnering with an operator that has a proven record with respect to asset maintenance, spill prevention, and environmental responsibility, on a property with assets in good physical condition. Due diligence activities will be performed to assess the level of environmental risk associated with potential operating partners and their assets. Due diligence will begin with a high level review of some general information including the following:

- Location and well logs of existing wells, gathering systems, and/or aboveground facilities to be purchased. Primary information needed is specific location (i.e., latitude and longitude), date of well completion, well depth, general construction information.

- Location and general depth of planned future wells to be drilled for future drilling programs.
- Operating company environmental programs including: 1) maintenance policies and procedures, 2) compliance auditing policies and procedures, and 3) spill prevention.
- Surface and mineral lease agreements for existing and planned wells and associated infrastructure.
- Well construction and integrity testing policies and procedures.
- Identification of any known environmental issues associated with the existing wells or areas planned for future wells.
- Waste disposal methods and locations associated with existing wells and planned future wells.
- Company environmental record (e.g., fines, violations, regulation compliance history).
- Company safety record over the past three years.
- Company health and safety program.
- Other items identified by Legal and Environmental advisors during the due diligence process.

Q. How would you use this information?

A. Upon receiving information, PGE and advisors can identify potential issues such as nearby known environmental cleanup sites, wetlands, surface water bodies, designated ecological areas or protected habitat, land use rules, land ownership (public vs. private), population density, geologic and hydrologic conditions, current groundwater use, and compare environmental compliance programs and procedures to general industry standards. Information related to the construction of wells and above ground facilities will allow PGE to assess the general age and construction methods used. Information regarding the operator's policies and procedures will allow an assessment of their general level of care and resources dedicated to environmental and safety compliance and risk mitigation. Information related to previous fines, violations and safety scoring will provide an indication of an operator's track record to date. This high level assessment could be used to rank multiple transactions, if applicable.

After the high level assessment phase, PGE and consultants would perform a more detailed review of all pertinent information including items that may not have previously been requested. This work can be performed: 1) prior to a site inspection to aid in scoping the site reconnaissance, 2) during and following the site inspection, if the inspection results in observations that warrant additional document review, or 3) a combination of both. As a next step, a physical inspection of the property would be performed that would include inspecting the property, wellheads, gathering lines, tanks, any disposal sites, mud pits, etc. This would be an opportunity to look at the physical condition of the assets and also look for nearby sensitive receptors, confirm location of nearest residences, water supply wells, and surrounding land use. This also would provide an opportunity to observe the operator, to give us an understanding of how they perform their activities, as well as conduct interviews with workers and local regulators, if deemed necessary. Following site inspection, an analysis of findings would be conducted to identify: any data gaps, specific areas of concern, recommendations to proceed, and follow-up tasks as needed. These activities would be performed by an expert consultant with PGE review.

Q. What type of follow-up activity would PGE preform?

A. Follow up activities can vary depending on the results of the initial due diligence effort; however a common follow-up task involves a more detailed review of agency or owner/operator records and collecting environmental samples (i.e., groundwater, soil etc.) from areas of concern to establish baseline conditions prior to acquiring an interest. The need for any sampling would be identified and scoped during the tasks described above. If the sampling scope is simple and minimally invasive, it can be performed as a modification to the site inspection described above. If the needed sampling requires the use of drill rigs or other specialized equipment, or is intricate in scope the work is usually performed on a second visit after the scope can be carefully planned.

Information obtained during the environmental due diligence process would enable the transacting parties to make educated business decisions regarding the allocation of environmental liabilities. The information would also influence how contractual provisions are drafted to address known and potential environmental liabilities. The kinds of provisions could include indemnifications, representations and warranties, covenants, or conditions precedent to closing.

Q. Is there insurance available to address some of the environmental risk?

A. Yes, we list the typical policies below. We would require that the counterparty demonstrate they carry adequate levels of this insurance. We would also plan to have PGGS carry stand-alone coverage to address the operator's allocations of insurance limits and their deductibles.

- General/Excess Liability – covers third-party claims for bodily injury or property damage and would act as a backstop where coverage for the operator is inadequate or where the operator's limits have been exhausted.

- Control of Well – covers expenses incurred in regaining control of a well in the event of a "blowout".
- Pollution Legal Liability – covers legacy environmental claims falling under various environmental laws.

Q. How will environmental costs be reflected in your proposal?

A. We plan to include prudent environmental costs as part of the cost-of-service rate that PGGS will charge PGE for gas. In Section IV, below, we describe how the cost-of-service rate will be developed.

Q. Is PGE equally considering all the available strategies or are you focusing on one particular type of agreement?

A. With the exception of a long-term prepay agreement, PGE is evaluating all available strategies since our goal is to identify the long-term gas hedge strategy that is in the best interest of our customers. Based on our research and evaluations conducted to date, a non-operating working interest appears to provide the best long-term value for PGE's customers. In addition, a non-operating working interest would provide greater diversity within our gas resource portfolio by introducing a cost-of-service alternative.

As mentioned in PGE Exhibit 200, if PGE were to make subsequent investments to offset the depletion associated with prior investments in non-operating working interests, we would continue to evaluate all viable alternatives.

III. Efforts to Select a Counterparty

Q. Please describe PGE's market outreach and research to-date.

A. In November 2014, PGE began a research effort to understand the risks and rewards associated with hedging natural gas beyond our current mid-term strategy (MTS – see PGE Exhibit 100 for more detail on PGE's current gas hedging). As part of that effort, PGE engaged consultants and other experts to assess strategic options for implementing a long-term hedging program as well as the potential benefits and challenges of each. In addition, PGE has met with various market participants including, banks, legal advisors, producers, marketers, and end users in an effort to better understand the unique aspects of such transactions and the value proposition associated with long-term gas hedging.

Q. With how many market participants have you had discussions?

A. In order to get a complete representation of the market, PGE identified the top 25 US Rockies-basin producers that account for approximately 90% of current production in the region. Additionally, the team identified several smaller, privately held producers with the potential to be a good strategic partner for PGE. To-date, we have met with and/or corresponded with over 40 producers in the US Rockies. Additionally, PGE has met with several banks and marketing companies that have presented PGE with contract or financial hedging alternatives.

Q. Did you, at any time, employ request-for-proposals as part of this process?

A. Although we did not issue formal request for proposals, we conducted multiple, concurrent, bi-lateral discussions with the 40+ producers (identified above) regarding PGE's needs. We gave each of these producers detailed information about our requirements and expectations, and provided each producer an opportunity to propose structures and terms and conditions that would meet those requirements and expectations.

Q. Please describe the meetings and correspondence with producers in more detail.

A. In each case we provided them with a fact-sheet describing PGE, our regulatory process, gas purchasing / hedging needs, and PGE's preference for a long-term strategic partner. We then asked candidates to provide feedback on whether or not they wanted to continue discussions with PGE and if so, to provide an indicative term sheet that would provide a starting point for continued commercial discussions.

Q. Did you conduct a similar process with other non-producing market participants?

A. Yes. PGE maintains strong commercial relationships with banks and marketers that regularly participate in energy markets through our ongoing MTS and short-term hedging programs. This allows us to closely follow financial hedge product offerings and market availability with respect to price and term. For the current outreach effort, we met with or spoke to five major banks that offer long-term financial hedges for natural gas. Our inquiries led to offers for financial hedge products with terms ranging from seven to fifteen years.

Q. How is PGE evaluating potential resource opportunities?

A. In order to ensure that any executed transactions best meet the objectives of the proposed long-term gas hedging program, PGE has implemented a thorough process for evaluating, ranking, and selecting preferred resources and counterparties. PGE's scoring and selection criteria include the following elements:

- Price
- Resource characteristics

- Counterparty credit and performance
- Non-price terms and conditions
- Quantity
- Environmental considerations

In addition, and as previously mentioned, PGE has widely engaged potential sellers and market participants to help ensure that credible and potentially interested counterparties and resources are considered.

Q. Have you identified a specific counterparty and prepared an agreement to implement long-term gas hedging?

A. As a result of our search process we are continuing discussions with all parties that have expressed interest. While several proposals show promise, we do not yet have a fully negotiated deal. If negotiations are successful and the transaction meets the proposed guidelines outlined in PGE Exhibit 200, we plan to seek approval of the associated costs in PGE's annual power cost update (i.e., our 2017 AUT filing), as discussed in Section IV, below. If PGE cannot identify a cost-effective transaction that meets the long-term gas hedging program objectives this year, we will withdraw our proposal from the 2017 AUT. At that time, we will reevaluate prevailing conditions to determine whether to pursue a similar transaction for inclusion in the 2018 AUT.

IV. Regulatory Process and Timeline

Overview

Q. What specifically have you included in the current AUT filing?

A. Because we have not completed an agreement prior to the AUT filing, we incorporated a pro forma transaction in the initial AUT modeling. We believe the pro forma input is reasonable because it is based on the following criteria:

- The rate per MMBtu is based on indicative prices we have gathered from the research and market outreach described in Section III, above. If PGE completes a transaction, the final rate we would include in the 2017 AUT would be at or below this amount.
- The projected volume will be set at 20,000 MMBtu, which represents approximately 13% of PGE's average daily requirement and is within the second proposed guideline.

Q. Do you plan to provide updates during the AUT to reflect an actual transaction?

A. Yes. We plan to provide updates during the course of the 2017 AUT process corresponding to the proposed schedule we list in Table 2, below. Specifically, we will provide updates with supporting work papers at the times we submit the term sheet and definitive agreements. We will also incorporate the associated modeling parameters in the scheduled MONET runs.

Q. Does the AUT allow the type of transaction you are proposing for long-term gas hedging?

A. Yes. Schedule 125 specifies that certain updates "will be made in each of the Annual Power Cost Update filings" (page 125-1). These updates include:

- Contracts for the purchase or sale of power and fuel.
- Changes in hedges, options, and other financial instruments used to serve retail load.

Because we propose that certain calculations be performed for including long-term gas hedging costs in the annual AUT filings, we describe those in detail below.

Calculations

Q. If you complete an agreement, how exactly does PGE propose to include the long-term gas in customer prices?

A. As described in PGE Exhibit 200, the first step would be to compare the "Long-Term Projected Cost" of the investment to the current "Long-Term Benchmark Price". If the Long-Term Projected Cost of the investment is at or below the current Long-Term Benchmark Price (at the time the hedge is executed), then the proposed transaction would be deemed to be cost effective. More specifically, the Long-Term Projected Cost of the investment is equal to the real, levelized cost of the proposed gas hedge based on PGGS's annual projected revenue requirements (described below) and annual projected production volumes over the life of the transaction. The Long-Term Benchmark Price is equal to the real, levelized forecast cost of gas as used in PGE's integrated resource planning. PGE Confidential Exhibit 302C provides the current gas price forecast by year and corresponding Long-Term Benchmark Price (real, levelized).

Q. After determining cost-effectiveness, what are the subsequent steps you envision with respect to cost recovery for long-term gas hedging?

A. Table 1, below summarizes the proposed calculations we would use in relation to long-term gas hedging. PGE Exhibit 303 provides example calculations for each step in Table 1 and also provides the derivation of the terms used. We also describe each step in more detail below.

Table 1
Proposed Calculations for Long-Term Gas Hedging

Step 1 – Determine overall cost effectiveness
Long-Term Projected Cost of the transaction ≤ Long-Term Benchmark Price
Step 2 – Include 2017 projected cost of service rate in 2017 AUT along with projected production volume
Step 3 – Include costs in subsequent AUTs
If Forecast Rate > Comparison Rate
AUT to include lesser of the Forecast Rate or the Comparison Rate plus 10%, along with forecasted production volume
If Forecast Rate < Comparison Rate
AUT to include greater of the Forecast Rate or the Comparison Rate less 10%, along with forecasted production volume

Q. How will you calculate the cost-of-service rate of your long-term hedging proposal?

A. We will do so by calculating PGGS's annual revenue requirement and dividing that by the annual production volume to derive the cost per MMBtu.

Q. Please explain PGGS's revenue requirement in more detail.

A. PGGS's revenue requirement will consist of the elements listed in PGE Exhibit 304 and will be calculated in the same manner as PGE's revenue requirement. The primary elements of PGGS's revenue requirement consist of: operating costs, capital costs (including return on equity), rate base, and credits for other revenue (if any). PGE Exhibit 304 also lists the basis for which each component will be updated to reflect: 1) changes to statutory or regulatory requirements associated with gas production, 2) most recent estimates of inflation rates,[3] 3) our most current forecast of prudent costs, and 4) Commission decisions in PGE's most recent general rate case.

Q. Will you provide detailed revenue requirements to support your proposed transaction and requests for cost recovery?

[3] Based on Global Insight forecasts.

A. Yes. We will provide detailed projected revenue requirements and projected production volumes, by year, over the life of the transaction. For 2017, we will use the original cost and volume projections for inclusion in the AUT modeling. The original cost projection represents the first year of the annual projected revenue requirements used to derive the real, levelized cost of the proposed gas hedge. For subsequent AUTs, we plan to update the costs, as described above, to create forecast revenue requirements. The forecast revenue requirements will then be divided by the most current forecast of production volume to determine the "Forecast Rate". We will also divide the annual forecast revenue requirement by the originally projected production volume for that year to determine the "Comparison Rate". If the forecast production volume exceeds the originally projected production volume, the Forecast Rate will be less than the Comparison Rate. Conversely, if the forecast production volume is below the originally projected production volume, the Forecast Rate will be greater than the Comparison Rate.

Q. What is the purpose the "Comparison Rate"?

A. We introduce the Comparison Rate to address the issue of volume risk identified in Section II, above. In short, the Comparison Rate provides a basis to determine floor and ceiling rates for inclusion in the AUT along with the most current forecast of production volume. The ceiling represents the maximum rate to include for cost recovery: costs up to the ceiling rate would be absorbed by customers and costs over the ceiling rate would be absorbed by PGE. The floor represents the minimum rate to include for cost recovery; benefits down to the floor rate would flow to customers and benefits under the floor rate would flow to PGE.

Q. Assuming Commission approval, please describe how the bands would be calculated and applied.

A. Each year after 2017, PGE will compare the current year's Forecast Rate to the Comparison Rate and make the following determinations (PGE Exhibit 303 demonstrates application of the floor and ceiling bands with examples of moderate and major over/under production):

- If the Forecast Rate is greater than the Comparison Rate (due to under-production), PGE will incorporate the lesser of the Forecast Rate or the Comparison Rate plus 10% of the Comparison Rate in the AUT modeling (along with the forecast production volume).
- If the Forecast Rate is less than the Comparison Rate (due to over-production), then PGE will incorporate the greater of the Forecast Rate or the Comparison Rate less 10% of the Comparison Rate in the AUT modeling (along with the forecast production volume).

Q. Why do you believe the floor and ceiling bands are appropriate?

A. The ceiling creates a band with which to limit the negative effects of under-production for customers and the floor creates a band with which to share the benefits of over-production. In other words, the ceiling and floor bands are used to allocate the volume risk between, and align the interests of, PGE and customers.

Q. How will the actual costs be reflected in PGE's books?

A. PGE will record the actual costs from PGGS in the appropriate power cost account(s). These power costs will then be included in the annual calculations that PGE submits as part of our PCAM as authorized by Commission Order No. 07-015 (Docket UE 180) and established in PGE Schedule 126.

Timeline

Q. How do you plan to incorporate the completed agreement in the AUT proceeding?

A. We plan to do so by proposing the following schedule at the AUT's Prehearing Conference. In addition, we expect that there will be no significant changes between the July 5 and July 22 drafts of the definitive agreement between PGGS and the counterparty.

Table 2
Draft AUT Schedule

Date	Filing / Submission
April 1	PGE files 2017 AUT
June 3*	PGE submits term sheet between PGGS and counterparty for long-term gas hedging
June 20	Parties file opening testimony
July 5*	PGE submits draft definitive agreement between PGGS and counterparty for long-term gas hedging
July 11	PGE files reply testimony
July 15	MONET update
July 22*	PGE submits: 1) final definitive agreement between PGGS and counterparty for long-term gas hedging; and 2) final Purchase Gas Agreement between PGGS and PGE
August 1	Parties file rebuttal testimony
August 15	PGE files surrebuttal testimony PGGS
August 31	Hearing
September 14, 28	Briefs
September 30	MONET update
October 31	Commission decision
November 4, 15	MONET updates

*(if PGE is able to identify an appropriate transaction and negotiate mutually agreeable terms and conditions)

Q. How will the timing of a Commission decision in October affect your ability to finalize the agreement on long-term gas hedging?

A. In PGE Exhibit 100, Section VI, Messrs. Tinker and Sims identify the specific items for which we request Commission approval. Absent that approval, the transaction will not go forward. Consequently, one of our primary criteria is that the selected counterparty agrees to a condition precedent that the transaction must meet PGE's regulatory requirements. Typically, transactions of this type close within significantly shorter periods of time. With the proposed schedule, we believe there is sufficient information and time to allow Parties to thoroughly review PGE's proposal.

V. Qualifications

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

A. I received a Bachelor of Science degree in Economics from Oregon State University in 2004 and a Master of Science degree in Economics from Oregon State University in 2006. I have been with PGE from 2009 to present in various financial structuring and business development roles. Prior to joining PGE, I worked for TransCanada as a business analyst specializing in rate design, tariff management, and business development in the US Pipelines West division.

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

A. I received a Bachelor of Science degree in Accounting and Finance from the Ohio State University. I received a Master of Arts degree in Economics and a Ph.D. in Economics from the University of Tennessee. I have held managerial accounting positions in a variety of industries and have taught economics at the undergraduate level for the University of Tennessee, Tennessee Wesleyan College, Western Oregon University, and Linfield College. Finally, I have worked for PGE in the Rates and Regulatory Affairs department since 1996.

Q. Does this complete your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
301	Diagram of Non-Operating Working Interest within the Natural Gas Value Chain
302C	Gas price forecast
303	Example Detail for AUTs
304	Elements of PGGS's Revenue Requirement

Producer Business Models:

Natural Gas Value Chain

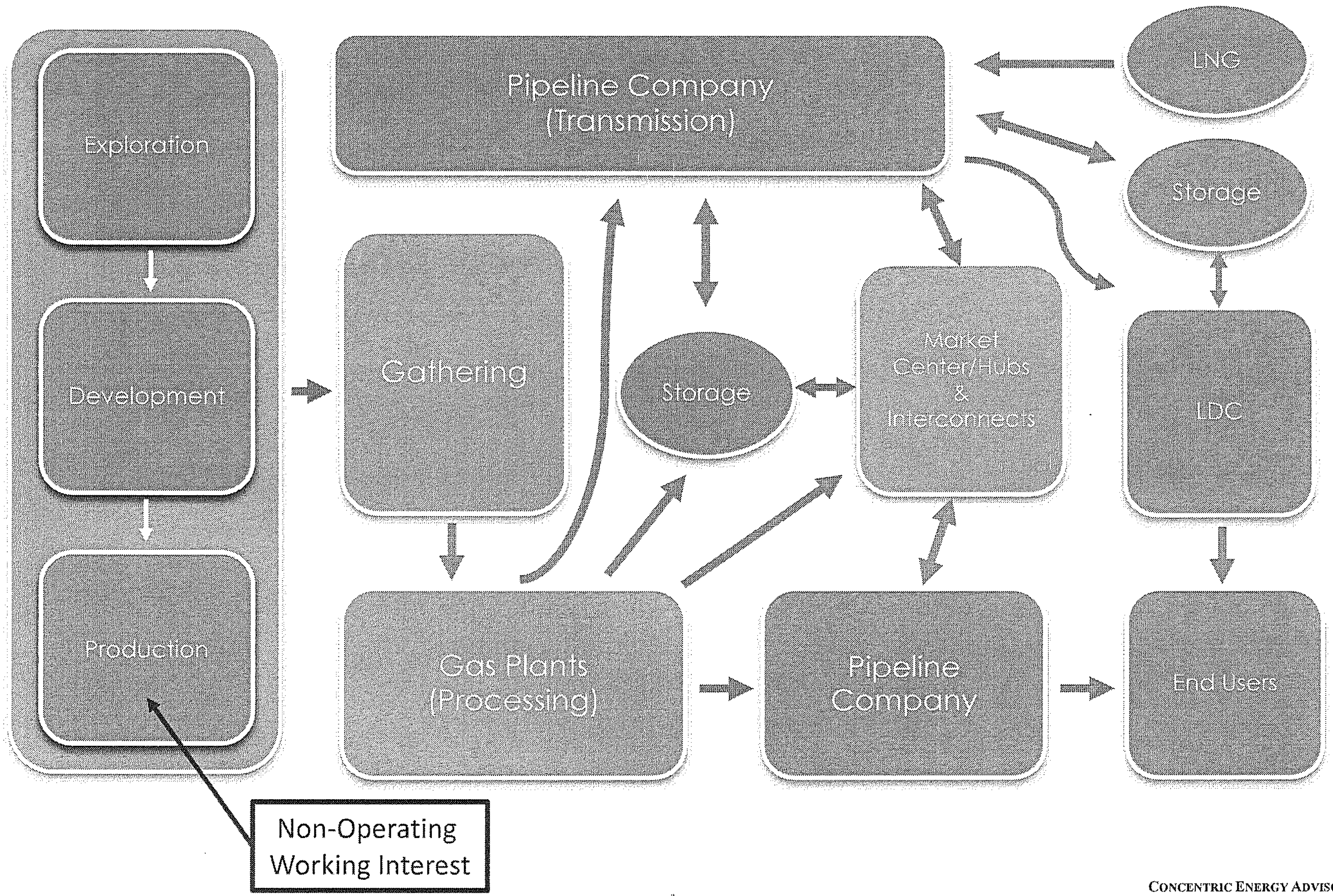

Exhibit 302C

Confidential

Exhibit 303
Example Detail for AUTs
For Demonstration Purposes Only

Original Projections

Year	Annual Revenue Requirements* (a)	Volume Dth (b)	Original Projected Rate (c) = (a)/(b)	Real Levelized (d)	Comments
2017	$ 30,000,000	6,000,000	$ 5.00		
2018	$ 29,000,000	5,900,000	$ 4.92		
2019	$ 28,000,000	5,800,000	$ 4.83		
2020	$ 27,000,000	5,700,000	$ 4.74		
2021	$ 26,000,000	5,600,000	$ 4.64		
...	...	...	...		
2046	$ 1,000,000	3,100,000	$ 0.32		
				$ 3.90	LT Projected Cost ≤ Current LT Benchmark Price

Annual Forecasts

Year	Annual Revenue Requirements* (e)	Volume Dth (f)	Forecast Rate (g) = (e)/(f)	Projected Volume (c) (h) = (b)	Comparison Rate (i) = (e)/(h)	Comments
2017	$ 30,000,000	6,000,000	$ 5.00	6,000,000	$ 5.00	Forecast = Original Projection for first year
2018	$ 29,100,000	5,800,000	$ 5.02	5,900,000	$ 4.93	
2019	$ 28,500,000	5,000,000	$ 5.70	5,800,000	$ 4.91	
2020	$ 26,900,000	5,850,000	$ 4.60	5,700,000	$ 4.72	
2021	$ 26,300,000	6,300,000	$ 4.17	5,600,000	$ 4.70	

To Include in AUT Based on Formula

Year	Forecast Rate (j) = (g)	Comparison Rate (k) = (i)	(j) ≤ or ≥ (k) (l)	Rate in AUT (m)	Comments
2017	$ 5.00	$ 5.00	(j) = (k)	$ 5.00	Forecast = Original Projection for first year
2018	$ 5.02	$ 4.93	(j) > (k)	$ 5.02	IF ((k * 1.1) < j, k * 1.1, j)
2019	$ 5.70	$ 4.91	(j) > (k)	$ 5.41	IF ((k * 1.1) < j, k * 1.1, j)
2020	$ 4.60	$ 4.72	(j) < (k)	$ 4.60	IF ((k * 0.9) > j, k * 0.9, j)
2021	$ 4.17	$ 4.70	(j) < (k)	$ 4.23	IF ((k * 0.9) > j, k * 0.9, j)

PGE Exhibit 304
Elements of Portland General Gas Supply's Revenue Requirement

Element	Additional Description	Basis for Update
Other Revenue	Revenue credits from sales of non-gas hydrocarbons (if any)	Annual forecast of sales
Operating Expenses		
Operations and Maintenance	O&M costs including delivery costs, normal environmental costs, and charges from PGE through the Operating Service Agreement	Annual forecast of prudent costs including inflation and changes to statutory/regulatory requirements
Administrative and General	A&G costs including charges from PGE through the Master Service Agreement	Annual forecast of prudent costs including inflation and changes to statutory/regulatory requirements
Lease Operating Costs		Annual forecast of prudent costs including inflation and changes to statutory/regulatory requirements
Royalties		Annual forecast of prudent costs
Gas Production Costs	Gathering Fees, Separating Fees, Processing Fees, Transportation Fees, and Water Disposal Costs	Annual forecast of prudent costs including inflation and changes to statutory/regulatory requirements
Capital Costs		
Depletion	Reduction of gas reserves	Annual forecast of prudent costs
Depreciation	Depreciation of plant assets including decommissioning/reclamation costs	Annual forecast of prudent costs
Taxes Other Than Income	Property taxes, production taxes, etc.	Annual forecast of prudent costs
Income Taxes	State and federal including deferred taxes	As calculated
Cost of Capital	PGE's weighted average cost	PGE's most recent general rate case
Rate Base		
Plant in Service	Gross plant	Annual forecast of prudent costs
Accum. Depreciation		Annual forecast of prudent costs
Accum. Deferred Taxes		Annual forecast of prudent costs
Working Cash	Based on PGE's Working Cash rate	PGE's most recent general rate case

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE XXX

Power Costs

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Michael Niman
Terri Peschka
Patrick G. Hager

April 1, 2016

Power Costs

Table of Contents

I. Introduction

Q. Please state your names and positions with Portland General Electric (PGE).

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

My name is Terri Peschka. My position at PGE is General Manager, Power Operations.

My name is Patrick G. Hager. My position at PGE is Manager, Regulatory Affairs.

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 2017 Net Variable Power Costs (NVPC). We discuss several of the updates included in this initial forecast for 2017, as well as provide an update on PGE's efforts to comply with the Commission's directions in Order No. 15-356 (Docket No. UE 294). We also compare our initial forecast with PGE's final 2016 NVPC forecast and explain why the per unit expected NVPC have decreased by approximately $1.80 per MWh.

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

A. Our initial 2017 NVPC forecast, excluding PGE's forecast of federal production tax credits (PTC), is $499.8 million, based on contracts and forward curves as of February 25, 2016. This initial 2017 NVPC forecast represents a reduction of $32.3 million relative to our final 2016 NVPC forecast.

Q. Have you proposed a schedule in this docket for NVPC updates?

A. Yes. As described in PGE Exhibit 100, we propose the following schedule for the power cost updates:

- July - Update power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned thermal and hydro maintenance outages; and cost of wind day-ahead forecast error to align with the April 1 filing;

- October - Update power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; gas and electric forward curves; planned hydro maintenance outages; and loads; and
- November - Two update filings: 1) update gas and electric forward curves; final updates to power, fuel, emissions control chemicals, transportation, transmission contracts, and related costs; long-term customer opt-outs; and 2) final update of gas and electric forward curves.

Q. How is the remainder of your testimony organized?

A. After this introduction, we have five sections:

- Section II: MONET Model;
- Section III: MONET Updates;
- Section IV: 2017 Load Forecast;
- Section V: Comparison with 2016 NVPC Forecast; and
- Section VI: Qualifications.

II. MONET Model

Q. How did PGE forecast its NVPC for 2017?

A. As in prior dockets, we used our power cost forecasting model, called "MONET" (the Multi-area Optimization Network Energy Transaction model).

Q. Please briefly describe MONET.

A. We built this model in the mid-1990s and have since incorporated several refinements. Using data inputs, such as an hourly load forecast 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:

- Retail load forecast, 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, emissions control chemicals, and any variable operating and maintenance costs (although not part of net variable power costs for ratemaking purposes, except as discussed below);
- 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. Thermal plants 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 Federal Energy Regulatory Commission (FERC) accounts 447, 501, 547, 555, and 565. As in the 2016 NVPC proceeding, we include certain variable chemical costs. We exclude some variable power costs, such as certain 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. Based on prior Commission decisions, certain fixed costs, such as excise taxes and transportation charges, are included in MONET. For the purposes of FERC accounting, these items are included with fuel costs in a balance sheet account for inventory (FERC 151); this inventory is then expensed to NVPC as fuel is consumed. The "net" in NVPC refers to net of forecasted wholesale sales of electricity, natural gas, fuel and associated financial instruments.

Q. Do the minimum filing requirements (MFRs) provide more detailed information regarding the inputs to MONET?

A. Yes. The MFRs provide detailed work papers supporting the inputs used to develop our initial forecast of 2017 NVPC. Commission Order No. 08-505 adopted a list of MFRs for PGE in AUT filings and general rate case (GRC) filings. PGE Exhibit 401 contains the list of required documents under Order No. 08-505.

III. MONET Updates

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;
- Wind energy forecast based on a five-year rolling average;
- Costs associated with wind integration;
- Forward market prices for both gas and electricity;
- Projected loads;
- Contracts for the purchase or sale of power and fuel;
- Emission control chemical costs;
- Thermal plant variable operation and maintenance, including the cost of transmission losses, for dispatch purposes;
- Changes in hedges, options, and other financial instruments used to serve retail load;
- Transportation contracts and other fixed transportation costs; and
- Reciprocating engine lubrication oil 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. We also include a forecast of federal PTCs consistent with the provisions of Oregon Senate Bill 1547, Section 18b.

A. Long-Term Gas Hedging

Q. What is a long-term gas hedge?

A. For PGE, a gas hedge is the purchase of a physical or financial position that is intended to reduce or offset the risk of market price volatility for fuel to operate our gas-fired thermal plants. By long term, we refer to commitments that are over five years in duration.

Q. Has PGE developed a proposal for long-term gas hedging?

A. Yes. PGE is currently negotiating with potential counterparties to develop and complete an agreement whereby we would acquire a long-term gas hedge. Although these negotiations are not yet complete, we believe that we have enough information (regarding the type of transaction that we will provide) to include a 'pro forma' transaction in this filing.

Q. Has PGE provided additional testimony in support of the proposed long-term gas hedge?

A. Yes. PGE provided three sets of additional testimony:

- PGE Exhibit 100, Policy – provides an overview of PGE's current and proposed hedging strategy; provides justification for pursuing long-term gas hedging at this time; and discusses the reason for employing an affiliated entity structure for the transaction.
- PGE Exhibit 200, Guidelines – enumerates proposed guidelines for long-term gas hedging and explains why they are appropriate.
- PGE Exhibit 300, Structure of Proposed Long-Term Gas Hedge – provides detail regarding:
    - PGE's review of market opportunities and our process for selecting a specific resource and counterparty;

- The available strategies for implementing a long-term gas hedging program including the potential risks associated with executing a transaction and how we propose to mitigate them;
- The nature of the costs we include in this filing;
- The timeline to achieve regulatory approval for cost recovery of the planned transaction.

Q. What, specifically, has PGE included in MONET regarding the proposed long-term gas hedge?

A. For this filing, PGE has incorporated a pro forma long-term gas hedge into the MONET modeling that reflects the following components:

- The rate per MMBtu is based on indicative prices PGE has gathered from our research and market outreach. The details of this component are discussed in PGE Exhibits 200 and 300.
- The projected volume is set at 20,000 MMBtu per day. The details of this component are discussed in PGE Exhibit 200.

Q. What effect does the inclusion of the pro forma transaction have on PGE's initial 2017 NVPC forecast?

A. Due to the higher year one indicative price (when measured against PGE's forecast of natural gas prices in 2017), including the pro forma transaction increases PGE's 2017 NVPC forecast by approximately $19.8 million. However, as described in PGE Exhibit 300, any completed agreement would need to have a long-term projected cost that is at or below the long-term benchmark price (measured on a real, levelized basis) used in PGE's integrated resource planning.

B. California Trading Margins

Q. The stipulation resolving NVPC issues in Docket No. UE 294 stated that PGE would "propose a method for forecasting California trading margins in its next Annual Power Cost Update filing". Please summarize the California trading margin issue raised in Docket No. UE 294.

A. In Docket No. UE 294, ICNU argued that PGE's NVPC forecast was overstated because PGE did not account for benefits realized as a result of PGE's ability to utilize its firm transmission access to sell and purchase power at the California-Oregon Border (COB) market. ICNU argued that customers are currently paying the cost associated with transmission access to the COB market and should therefore receive the economic benefits. ICNU proposed to reflect in MONET the benefits of PGE's access to markets other than the Mid-Columbia (Mid-C) market, primarily COB, by imputing a value derived using quantities and prices from historical sales and purchases.

Q. Has PGE addressed this issue in its initial filing in this proceeding?

A. Yes. PGE has included modeling in MONET that seeks to estimate (under normal conditions) the net power cost benefits that could be attained by PGE utilizing its firm transmission access to sell or purchase power at the COB market (i.e., California trading margins).

Q. How does PGE propose to forecast California trading margins in the 2017 NVPC forecast?

A. PGE proposes to include a pro forma contract in MONET, recognizing PGE's ability to purchase at Mid-C and sell at COB and vice versa (depending on prevailing forward price curves). The pro forma contract's value will be the result of a modeled on- and off-peak purchase or sale in each month of the year.

To value the pro forma contract, we will use forward curve prices for the Mid-C and COB trading hubs to forecast the price margin. We will forecast the pro forma contract quantity based on an analysis of historical trading volumes.

Q. Please describe PGE's method to forecast COB prices in the 2017 NVPC forecast.

A. We propose using PGE's forward curve methodology, which we have used for the creation of PGE's forward price curves in past AUT and GRC proceedings. Price curves for both natural gas and power are generated by the term power and gas trading desks. While previously not used in MONET, PGE's power desk does generate a COB forward price curve that is developed and validated in a manner consistent with PGE's Mid-C forward price curve. Similar to Mid-C, the COB forward price curve is a monthly time series of on- and off-peak prices.

Q. Please describe PGE's method to forecast the pro forma contract quantity under normal conditions in the 2017 NVPC forecast.

A. Similar to other variables modeled in MONET (e.g., wind generation and forced outage rates) we propose a rolling-average of historical data. In the case of COB trading quantities, we propose a rolling three-year average of actual trading data (measured as monthly on- and off-peak purchases and sales) from PGE's trading data information system, but with one adjustment and one constraint.

Q. Please describe PGE's adjustment to the historical trading data.

A. In the three-year average, PGE has removed real-time (i.e., intra-hour) transactions in the fourth quarter of each historical year. We removed these trades because beginning

October 1, 2017, we plan to participate in the Western Energy Imbalance Market (EIM).[1] Since the EIM optimizes generator dispatch every 5 minutes, we anticipate offering our resources to the EIM, instead of separately seeking to make real-time trades at COB.

Q. Does PGE's adjustment significantly change the historical trading data results?

A. No. In this initial filing, PGE relies on trading data from 2013 – 2015. Table 1 shows the historical trading data, less real-time transactions in the fourth quarter of each year.

Table 1
Historical Sales and Purchases (GWh)

Sales	2015	2014	2013
COB	1,845	1,214	1,130
Less Q4 Real-Time	34	29	49
Total	1,811	1,186	1,081

Purchases	2015	2014	2013
COB	166	208	263
Less Q4 Real-Time	10	14	18
Total	156	194	245

Q. Please describe PGE's constraint on the historical trading data.

A. We will compare the forecast of quantity resulting from the historical data against known transmission path de-rates in the forecast year. If the quantity exceeds our merchant operations' firm transmission rights due to a known path de-rate, we will reduce our forecast to reflect the temporary path rating.

Q. Is PGE's method intended to estimate results under normal conditions?

A. Yes. The basic principle of MONET is to produce a final test year forecast of NVPC that reflects a baseline (or deterministic) forecast of all variables, including sales from (and

[1] The Western EIM is a voluntary, balancing energy market operated by the California Independent System Operator (CAISO) that optimizes generator dispatch within and between Balancing Authority Areas every 5 minutes.

purchases for) PGE's resource portfolio under normal conditions (e.g., plant operations, water and wind flows, and weather).

Q. Is PGE forecasting a margin for purchases <u>and</u> sales in each month of the forecast year?

A. No. PGE's method will forecast a margin for <u>either</u> a purchase <u>or</u> sale in the on- and off-peak period of each month of the forecast year. For example, if the January 2017 COB price is greater than the Mid-C price in the on- and off-peak periods, PGE will assume a purchase at Mid-C and a sale to COB in both periods (i.e., there is no economic reason for MONET to purchase from COB if the COB price is greater than Mid-C).

Q. Will PGE adjust its margin forecast if PGE enters into a firm commitment to sell or purchase power at the COB trading hub prior to the first NVPC update in November?

A. Yes. While liquidity for year-ahead forward physical transactions at COB is limited, PGE will reduce the benefit of the pro forma contract by any margin monetized through any transactions PGE enters into prior to the first NVPC update in November that would settle in the AUT period. As a result, customers will receive the margin through either the pro forma contract's imputed value or the margins realized via the forward transaction.

Q. What effect does this proposed method have on PGE's initial 2017 NVPC forecast?

A. PGE's proposed method results in a forecast of approximately 1.4 million MWh sold, 0 MWh purchased, and an annual average trading margin of approximately $3.60/MWh, which reduces NVPC by $4.9 million.

C. BPA Variable Energy Resource Balancing Service (VERBS) Election

Q. Can you please briefly explain BPA's VERBS and committed scheduling?

A. Yes. Currently, PGE's owned wind resources (Biglow Canyon and Tucannon River Wind Farms) are part of BPA's Balancing Authority Area (BAA). Under its transmission tariff, BPA offers VERBS to customers with variable energy resources (VERs), such as wind, within BPA's BAA. VERBS provide capacity reserves for regulating, following, and imbalance:

- Regulating reserves are held for the moment-to-moment differences between generation and load.
- Following reserves are held for the larger differences that occur over longer periods of time within the hour.
- Imbalance reserves are held for differences between scheduled and actual generation for the hour.

BPA's provision of capacity reserves to VERBS customers is a function of the committed scheduling option made by a VERBS customer. For example, PGE presently pays the VERBS rate aligned with 30/15 committed scheduling. Under the 30/15 committed scheduling option, PGE makes four wind schedule changes per hour.[2] BPA has also offered 30/60 and 40/15 committed scheduling options in the past. Both of these options are more expensive than the 30/15 committed scheduling option, because BPA is responsible for more of the intra-hour variability of a customer's resource placed on the BPA BAA.

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[2] PGE submits a schedule 30 minutes prior to each 15-minute schedule interval for the forecast of each plant's output. The forecast is based on BPA's persistence forecast, which is the one-minute average of generation from 31 to 30 minutes before each scheduling period. For example, PGE would submit a schedule for Biglow Canyon at 2:30 p.m. for generation that will occur from 3:00 p.m. to 3:15 p.m. The schedule is based on a forecast that is derived by taking the average of Biglow Canyon's generation from 2:29 p.m. to 2:30 p.m.

Q. What VERBS rate does PGE use in its initial 2017 NVPC forecast?

A. From January 1, 2017 through September 30, 2017, we use the BPA VERBS Base Service rate for 30/15 committed scheduling in our initial 2017 NVPC forecast. From October 1, 2017 through December 31, 2017, we continue to use the BPA VERBS Base Service rate for 30/15 committed scheduling.

Q. Is it PGE's intent to keep its owned wind resources in BPA's BAA after October 1, 2017?

A. No. It is our intent to pseudo-tie (i.e., dynamically transfer) our owned wind resources out of BPA's BAA (i.e., fully self-integrate) effective October 1, 2017. We have expressed this intent publicly, beginning with BPA's Generation Inputs Workshop held on January 21, 2016. On November 11, 2015, we made the necessary formal requests to BPA to enable the dynamic transfer of both resources out of the BPA BAA.

Q. If it is not PGE's intent to keep its owned wind resources in BPA's BAA, why does this initial filing contain a VERBS rate after October 1, 2017?

A. BPA does not maintain a published process (including an established schedule) for pseudo-tieing generating resources out of its BAA. Therefore, at the time of this initial filing, PGE does not have a reasonable level of confidence in BPA's ability to meet PGE's requested pseudo-tie date of October 1, 2017.

Q. Will BPA commit to meeting PGE's request to pseudo-tie generating resources out of BPA's BAA by October 1, 2017?

A. No, not at this time. BPA has indicated in public workshops that the process to switch a resource from one BAA to another BAA can take considerable time. Due to the uncertainty in its schedule, BPA has been noncommittal in completing PGE's request to pseudo-tie by

October 1, 2017. Consistent with this position, BPA established a Mock Election process for VERBS elections in its rate case period beginning October 1, 2017 and ending September 30, 2019 (i.e., the BP-18 rate period). In this Mock Election, BPA directed customers to submit by March 15, 2016 two elections: a preferred non-binding election of VERBS and a "back-up" election in the event that BPA cannot accommodate a customer's preferred election.

Q. What elections did PGE submit?

A. PGE submitted a preferred election to pseudo-tie our owned wind resources out of BPA's Balancing Authority Area by October 1, 2017. Our "back-up" election was 30/15 committed scheduling.

Q. Has BPA <u>officially</u> offered VERBS election options for the October 1, 2017 – September 30, 2019 rate period?

A. No. All discussions to-date are non-binding. Presently, PGE would anticipate binding election decisions for the BP-18 rate period to be due by April 1, 2017. BPA will continue to hold workshops throughout the summer, which will determine the types of VERBS elections to be offered by BPA.

Q. What effect does PGE's committed scheduling election have on PGE's initial 2017 NVPC forecast?

A. PGE's election results in no change to PGE's NVPC forecast (i.e., $0 effect), because we modeled PGE's use of 30/15 committed scheduling in PGE's 2016 NVPC forecast.

Q. Does PGE plan to revisit its VERBS rate assumption during this proceeding?

A. Yes. Given the uncertainty in BPA's ability to complete PGE's pseudo-tie request by October 1, 2017, PGE will reassess our VERBS rate assumption prior to each scheduled update in the AUT process. In the event that PGE can attain a reasonable level of confidence in BPA's ability to meet PGE's requested pseudo-tie date of October 1, 2017, we can assume full self-integration beginning October 1, 2017.

Q. What actions is PGE taking to attain a reasonable level of confidence in BPA's ability to complete a pseudo-tie by October 1, 2017?

A. In addition to our actions described above, we are advocating for inclusion in three seasonal studies/reviews that must be completed before a pseudo-tie is established. These studies/reviews, listed in sequential order, include:

1) BPA's Dynamic Transfer Capability Study (typically completed in the spring)
2) WECC's Remedial Action Scheme Review (typically completed in the fall)
3) BPA's Local Integration Test (typically completed in the fall)

Given the seasonal nature of these studies/reviews, PGE has limited opportunities to be part of the needed work prior to October 1, 2017.

D. Western Energy Imbalance Market (EIM)

Q. Please describe the Western EIM.

A. The Western EIM is a voluntary, balancing energy market operated by the California Independent System Operator (CAISO) that optimizes generator dispatch within and between Balancing Authority Areas (BAAs) every 5 minutes. The Western EIM's operations began November 1, 2014. PacifiCorp and Nevada Energy are active participants in the CAISO-operated market. Puget Sound Energy and Arizona Public Service have announced planned market entries in 2016.

Q. When will PGE begin participating in the Western EIM?

A. PGE is preparing for a market entry date of October 1, 2017. This date is identified in the Implementation Agreement filed by CAISO on November 20, 2015 at the Federal Energy Regulatory Commission (FERC). FERC accepted the Implementation Agreement between CAISO and PGE on January 20, 2016.

Q. How does the Western EIM operate?

A. In general, the Western EIM can facilitate sub-hourly optimization of load-resource balancing across a wide-area footprint. In this market, a market operator (i.e., CAISO) receives load-resource plans from each market participant for each market scheduling interval. Along with this load-resource plan, each participant also submits the dispatchable range and associated price curve for each resource it can make available to the market operator for dispatch within each market interval. Using this information, the market operator re-dispatches the resources made available to it while respecting available transmission flows and individual resource economics.

Q. How will PGE's participation in the Western EIM benefit customers?

A. We expect the Western EIM to produce several benefits, including sub-hourly dispatch savings, flexible reserve savings, and reliability benefits. In order to estimate the benefits associated with sub-hourly dispatch and flexible reserves, PGE engaged Energy + Environmental Economics (E3). E3's study (as well as PGE's complementary qualitative analysis) is provided in PGE Exhibit 402.[3]

[3] PGE evaluated reliability benefits as part of the analysis that accompanied the E3 study.

Q. Please describe the first benefit, sub-hourly dispatch savings.

A. We expect the primary economic benefit to come from sub-hourly dispatch savings resulting from PGE's ability to export and import in near real time with other Western EIM participants to respond to intra-hour imbalances. In E3's study, EIM participation relieves PGE of the need to start up and run its most expensive gas generators. Additionally, modeled results show that PGE can reduce the number of yearly starts for units 1-7 of its Beaver plant. Gross sub-hourly dispatch savings in the 2020 base scenario of E3's study were estimated to be approximately $2.7 million (2015 $).[4] The E3 study also assessed key sensitivities such as higher natural gas prices and higher renewable penetration levels. Under both sensitivities, the E3 study identified the long-term value of the EIM as sub-hourly dispatch savings increased considerably.[5]

Q. Please describe the second benefit, flexible reserve savings.

A. In the Western EIM, there can be a reduction of flexible reserve requirements. The EIM calculates the flexible reserve requirement for each period for each BA as a stand-alone entity, then calculates the flexible reserve requirement for the entire EIM/ISO footprint. The difference between these two values is allocated back to each participating BA proportional to their flexible reserve requirements for that period without diversity. In the E3 study, this lower flexible reserve requirement provided additional dispatch flexibility and led to greater sub-hourly dispatch savings. PGE's portion of gross savings due to modeled flexible reserve reductions in the 2020 base scenario of E3's study was estimated to be approximately $800 thousand (2015 $).

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[4] PGE will also incur transaction costs in the Western EIM. In its study of the Western EIM, PGE estimated transaction costs to range from $400 thousand to $500 thousand per year.

[5] Under a high gas price scenario, EIM savings increased from $2.7 million to $5.8 million. Under a high renewables scenario, EIM savings increased from $2.7 million to $6.1 million.

Q. Please describe the third benefit, the reliability benefits from Western EIM participation.

A. In 2013, a FERC Staff Report addressed the reliability value an EIM can provide.[6] The Staff Report stated that "while an EIM would not be a replacement for capacity adequacy, a larger pool of resources under an EIM footprint could provide more ramping capability and respond to variations and imbalances more quickly."

The 2013 FERC Staff Report also points out that an EIM could provide reliability benefits through enhanced situational awareness. While the models utilized to run the security constrained economic dispatch (SCED) are not reliability tools themselves, FERC argues that an "EIM could provide proactive solutions to potential reliability issues through automated redispatch every 5 minutes using SCED." By proactively signaling resources to respond to system imbalances, an EIM can potentially correct issues before they would need to be resolved by the reliability coordinator.

Q. Are there costs associated with PGE's Western EIM participation?

A. Yes. There are two general categories of costs related to PGE's participation in the Western EIM: start-up costs and ongoing O&M costs.

Q. Please describe PGE's start-up costs.

A. Prior to participating in the Western EIM, PGE must implement several key capital projects that collectively fall under a project plan known as Energy Market Readiness. Examples of these projects include:

1. *Bid-to-Bill Software*: PGE will implement software solution(s) that address all aspects of integrating into an EIM. This software includes advanced functionality for portfolio optimization, unit commitment, tagging and scheduling.

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[6] FERC Staff. *Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market.* February 26, 2013. https://www.caiso.com/Documents/QualitativeAssessment-PotentialReliabilityBenefits-WesternEnergyImbalanceMarket.pdf

2. *Generation and Transmission Outage Management Reporting*: PGE will align processes and software applications to effectively manage and communicate planned and unplanned outages to the market operator (i.e., CAISO).

3. *Full Network Model and Energy Management System Upgrades*: The development and maintenance of an accurate full network model and energy management system is a requirement to participate in the EIM. In this project, PGE will upgrade its software used in the System Control Center to ensure transmission and generation assets are modeled accurately and real-time data is exchanged between PGE and the CAISO in order to bid generation resources into the Western EIM.

We presently estimate our start-up costs to be approximately $11 million in capital, which would represent a revenue requirement of approximately $3.5 million in year one of the project's book life.[7] We also estimate incurring start-up O&M costs of $1.9 million by October 1, 2017.

Q. Please describe PGE's ongoing O&M costs.

A. PGE's ongoing O&M consists of nine new positions (i.e., incremental labor FTEs) needed to support PGE's participation in the market, annual fees related to IT systems and support, and variable fees paid to CAISO (i.e., EIM transaction costs). PGE Confidential Exhibit 403C provides a detailed list of our projections for ongoing O&M costs. PGE's estimate of ongoing O&M costs in 2017 is $870 thousand. On an annual basis, our estimate of ongoing O&M cost is $2.3 million.

Q. Have you included EIM benefits and costs in this case?

A. No. Due to the uncertainty surrounding the level of benefits that will be achieved and the costs that will be incurred, particularly in the early stages of PGE's participation in the EIM, we propose to set benefits equal to zero in our 2017 forecast.

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[7] Capital estimate of $11 million includes loadings and allowance for funds used during construction. PGE's revenue requirement calculation assumes a book depreciation life of 5 years, and a tax depreciation life of 3 years. PGE's financial and tax parameters are consistent with parameters approved through Commission Order No. 15-356 in Docket No. UE 294.

Q. How will actual benefits be passed back to customers?

A. We propose to pass back any net benefits that result from our EIM participation in the final quarter of 2017 via the PCAM. Net benefits will be the result of actual gross benefits less our EIM costs in 2017 (i.e., our revenue requirement for ongoing O&M in 2017 and actual EIM capital costs).

Q. Other than the uncertainty you cited above, why is setting benefits equal to zero a reasonable method for the purpose of establishing EIM's impact on NVPC in 2017?

A. We have identified two reasons.

1) We believe it is appropriate to match the benefits that customers will begin to receive from the Western EIM with the costs to PGE of providing those benefits.
2) PGE's proposed approach is consistent with Commission Order No. 14-331 in Docket No. UE 287, which recognized the reasonableness of a stipulation to reflect no net EIM costs or benefits in PacifiCorp's net power cost forecast for the fourth quarter of 2015.

Q. What effect does this proposed method have on PGE's initial 2017 NVPC forecast?

A. PGE's proposed method results in no change to PGE's NVPC forecast (i.e., $0 effect).

E. Boardman Rail Transportation Contracts

Q. Can you please briefly describe PGE's rail transportation contract(s) used to transport coal to the Boardman plant?

A. PGE currently transports coal to its Boardman plant under separate transportation contracts with BNSF Railway Company (BNSF) and Union Pacific Railroad Company (UP). Under these contracts PGE pays a dollar per ton rate for coal deliveries from mines in the

Wyoming Powder River Basin to the Boardman plant.[8] These contracts were effective beginning January 1, 2014 and expire on December 31, 2020.

Q. Do the rail transportation contracts contain minimum delivery volume requirements?

A. Yes. The BNSF and UP contracts contain minimum delivery volume requirements through 2019, but the requirements lessen after certain time periods have passed. PGE's confidential MFRs describe the minimum delivery volume requirements in detail.

Q. What happens if PGE fails to meet its minimum delivery volume requirements?

A. PGE is required to pay a shortfall tonnage rate (shortfall rate) as compensation for any undelivered BNSF and UP rail traffic volume. PGE's confidential MFRs describe the shortfall rate rules and calculations in detail.

Q. Has PGE modeled minimum delivery volume requirements and shortfall rates in MONET in the past?

A. No, not explicitly. Table 2 lists our forecast for Boardman dispatch (measured as a capacity factor) and the corresponding implied burn (measured in tons) associated with the dispatch.

Table 2
Forecast Boardman Dispatch and Coal Burn

Test Year	Dispatch (Capacity Factor)	Coal Burn (Tons)
2013	80.0%	2.3 million
2014	67.9%	2.0 million
2015	71.6%	2.1 million
2016	34.4%	0.894 million

In previous years, PGE has not explicitly modeled minimum delivery volume requirements, because our forecast for Boardman dispatch levels has been high enough to burn (on a modeled basis) the minimum delivery volume requirements. However, our forecast of

[8] The BNSF contract is for transportation of coal from mines in the Wyoming Powder River Basin to Spokane, WA. The UP contract is for transportation of coal from Spokane, WA, to Boardman, OR.

Boardman's dispatch level in 2016 was considerably lower than prior years, resulting in a forecast of coal burn near our minimum delivery volume requirements.

Q. What is PGE's forecast for Boardman plant operations in 2017?

A. In this initial filing, we forecast an initial, base case Boardman dispatch of 14.2%[9] with a coal burn level of less than 0.500 million tons, prior to any consideration of minimum delivery volume requirements and shortfall rates. Due to the historically low natural gas prices (which largely establish electric prices in the power market), Boardman is effectively displaced by lower cost resources in all months except for January and December.

Q. Does Boardman's displacement result in lower power costs?

A. Yes. By dispatching PGE's portfolio of resources only when it is economic to do so, MONET minimizes power costs. Presently, the results of Boardman displacement indicate that the plant's variable power costs would effectively be greater than our forecast for electric power prices in all months of the forecast year except for January and December.

Q. Does Boardman's displacement result in lower power costs if PGE accounts for the contractual minimum delivery volume requirements and shortfall rates?

A. Yes, but the power cost benefit is partially offset by the power cost implications of accounting for the shortfall rate. Our forecast for Boardman's dispatch increases to 45.2% (from 14.2%) with a coal burn level of 1.3 million tons.

Q. Rather than paying a shortfall rate, could PGE accept the minimum contract volume and add coal to its inventory?

A. Yes, but only to an extent. When we reach the upper range of previous inventory levels, we hit operational limits, and potentially safety limits as well. For example, coal purchased

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[9] 567,742 MWh / 8760 hours / 456 MW = 14.2%

from the Wyoming Powder River Basin contains large amounts of moisture and volatiles. If Boardman is not dispatched and coal inventory levels rise, trapped moisture and humidity can increase the chance of spontaneous combustion. This chance increases as more coal dust is present, which occurs when moisture from the coal evaporates and the coal placed in inventory degrades from large chunks to dust.

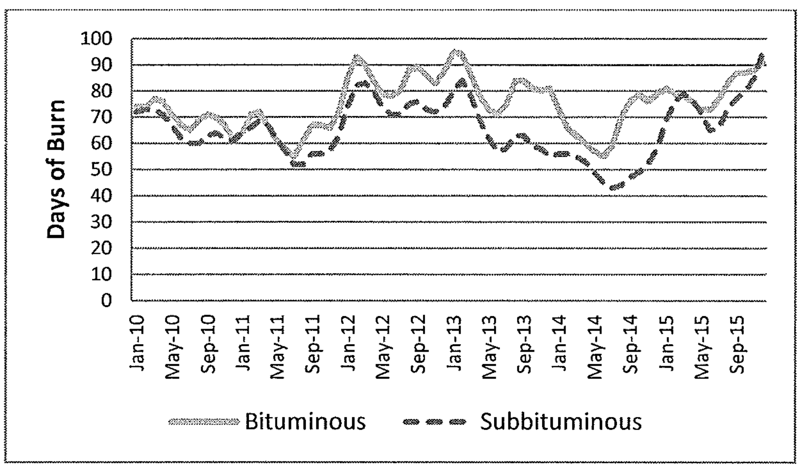
Q. What level of coal inventory has PGE maintained in the past at Boardman?

A. During the past six years (i.e., 2010 – 2015), our coal inventory has fluctuated from 28 to 120 days of coal burn, averaging 82 days.

Q. How has PGE's level of coal inventory compared to industry levels?

A. Our level of coal inventory is similar to industry levels. Figure 1 displays U.S. coal inventory reported by the Energy Information Administration.

Figure 1: U.S. Coal Inventory Measured in Average Days of Burn for Bituminous and Subbituminous Coal[10]



If we were to plot Boardman data on Figure 1, our level of coal inventory from 2010 to 2015 would exhibit a similar shape, but a larger range, relative to U.S. data.

[10] https://www.eia.gov/electricity/monthly/update/fossil_fuel_stocks.cfm#tabs_stocks2-1

Q. Why does PGE's level of coal inventory exhibit a larger range but similar shape relative to industry levels?

A. Consistent with contractual terms, PGE makes coal commitments and nominations in the year prior to delivery. Therefore, market fluctuations (e.g., falling natural gas prices or increased rail traffic) in the delivery year will lead to increases or decreases in a plant's coal inventory. This pattern was clearly shown in the U.S. coal inventory data we presented in Figure 1. However, the significant mine-to-plant distance for the Boardman plant (i.e., over 1,000 miles) can worsen the impacts of market fluctuations and lead to a larger range of inventory levels.[11]

For example, by February 2014, the coal inventory level at the Boardman plant fell to approximately 30 days. While PGE nominated and purchased less coal to reduce its coal inventory level from a peak of 116 days in mid-2012, higher rail traffic over the 1,000 plus miles of rail led to delayed coal deliveries.

Q. How is PGE presently managing its coal inventory level at Boardman and the risk of shortfall tons?

A. We are identifying the least-cost alternative for managing coal inventory from 2016 through the end of 2017. Our longer-term, two-year look is targeting an inventory level of approximately 500,000 tons (i.e., 60-days) by year-end 2017. PGE is monitoring Boardman operations every business day, and we continually elect the less costly of two options.

- **Option 1:** Reduce the Boardman dispatch cost by the shortfall rate, thereby increasing plant dispatch and coal burn.
- **Option 2:** Pay the shortfall rate and reduce tonnage delivered to the Boardman site.

[11] It is also important to note that Figure 1 displays an industry average, rather than individual plant statistics. Averaging will reduce the peaks and troughs in the curve.

Additionally, PGE is taking the minimum required tons per the rail transport contracts.

Q. Why is PGE targeting an inventory level of 500,000 tons (i.e., 60-days)?

A. We are balancing the risks associated with too much (or too little) coal. A 60-day level is slightly less than the average of historical industry levels for subbituminous coal[12] (see Figure 1 above), and positions PGE to more easily mitigate safety and operational risks if low power prices continue to displace the Boardman plant in 2017 and beyond. In addition, with a 60-day level, we also mitigate the risk of PGE forgoing economic dispatch opportunities for lack of coal.

Q. How is PGE modeling shortfall rates associated with contractual minimum volume requirements in this filing (i.e., the 2017 test year)?

A. To minimize power costs, we are modeling the business options described above (i.e., reduce the Boardman dispatch cost by the shortfall rate or opt to pay the shortfall rate and reduce coal deliveries). In MONET we first calculate the number of dispatch months necessary to minimize the amount of shortfall shipping at a macro month level. We then rank the months that are most economic to run (i.e., the least "out-of-the money"). For these identified months, we reduce the variable O&M in MONET by the shortfall rate to encourage Boardman to dispatch more. If shortfall tons remain after Boardman's increased dispatch, MONET uses the shortfall rate(s) to calculate a cost for cancelling delivery of the remaining shortfall tons.

[12] Coal units using subbituminous coal are largely located in the western United States.

Q. What effect do these contract terms have on PGE's initial 2017 NVPC forecast?

A. Accounting for these contract terms initially increases PGE's initial 2017 NVPC forecast by approximately \$8.0 million. However, after we update Boardman dispatch costs to re-optimize and mitigate shortfall charges, the cost impact is reduced to \$1.2 million.

F. Federal Production Tax Credits

Q. Has PGE included a forecast of the federal production tax credits (PTC) it receives due to electricity production from owned variable energy resources?

A. Yes. We are including a forecast of the PTC for PGE's owned wind resources, consistent with the provisions of Oregon Senate Bill 1547, Section 18b,[13] which reads:

> Each public utility that makes sales of electricity shall forecast on an annual basis the projected state and federal production tax credits received by the public utility due to variable renewable electricity production, and the Public Utility Commission shall allow those forecasts to be included in rates through any variable power cost forecasting process established by the commission.

Q. What, specifically, has PGE included in MONET?

A. We have included the following components:

1. **PTC for Calendar Year 2017**: We assume a PTC of \$23 per MWh, matching the current published U.S. Internal Revenue Service (IRS) rate provided in Internal Revenue Bulletin: 2015-20.
2. **Quantity**: We use our calculated five-year wind averages for each owned wind resource as the production forecast for calendar year 2017.
3. **Gross-Up Factor**: In order to convert a net income result into a gross revenue result, we multiply the PTC by the gross-up factor (i.e., 1.658) approved by Commission Order No. 15-356 in Docket No. UE 294.

[13] Senate Bill 1547 was signed into law by the governor on March 11, 2016.

Q. Will PGE make any updates to its PTC forecast during the AUT proceeding?

A. Possibly. The IRS provides an annual update to the PTC, applying an inflation adjustment factor as reported in the Federal Register. The IRS typically publishes this update towards the end of May of each year. If the IRS changes the current published PTC, PGE will update MONET to reflect the change.

Q. Other than the components included in its NVPC forecast, will PGE make any other changes to account for the price impacts of its 2017 PTC forecast?

A. Yes. We will re-categorize the fixed and variable components of the generation revenue requirement approved by Commission Order No. 15-356 in Docket No. UE 294. There will be no net change in the generation revenue requirement, but we will remove the credit from fixed costs and apply the credit to variable costs. This re-categorization will increase fixed costs but variable costs will decrease by the same amount.

Q. What effect does the forecast of federal production tax credits have on the variable cost portion of PGE's generation revenue requirement?

A. Table 3 shows the change in generation revenue requirement, which is the result of price and quantity changes from 2016 to 2017. The variable cost portion of PGE's generation revenue requirement increases by $5.3 million in 2017 (i.e., PTC benefit decreases from $81.5 million to $76.2 million).

Table 3
Change in Generation Revenue Requirement due to PTCs

	2016	2017
PTC	$24/MWh	$23/MWh
Quantity	2,047,929 MWh	1,999,245 MWh
Gross-Up Factor	1.658	1.658
Generation Revenue Requirement	($81.5 million)	($76.2 million)

IV. 2017 Load Forecast

Q. Please summarize PGE's forecast for its 2017 retail load.

A. Table 4 below summarizes actual and forecast deliveries to various customer groups from 2015 through 2017 in thousand MWh at average weather conditions. The 2017 forecasted deliveries of 19,453 thousand MWh is 0.5 percent higher than the forecasted 2016 deliveries due to growth in energy deliveries to the industrial customer class. Energy deliveries to the residential and general service customer classes are comparable or slightly lower than forecasted 2016 due to the additional day in 2016 leap year, which is equivalent to 0.3 percent growth on a full-year basis.

Table 4
Retail Energy Deliveries: 2015–2017
(cycle month energy in thousand MWh, weather-adjusted)(3)

	2015 Actual (1)	2016 Forecast(2)	2017 Forecast
Residential	7,567	7,626	7,622
General Service	7,426	7,483	7,456
Industrial	4,574	4,175	4,310
Lighting	84	74	65
Total Retail	19,651	19,359	19,453

(1) 2015 actual loads are weather-adjusted according to UE 294 weather methodology

(2) 2016 contains two months weather-adjusted actuals and remainder of year updated forecast

(3) Numbers may not total due to rounding.

Q. Does this 2017 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 2017?

A. No. PGE does not assume that certain long-term opt-out customers return to cost of service in 2017. PGE assumes all long-term opt-out customers remain on direct access. PGE does assume that short-term (1-year) opt-out customers return to cost-of-service in 2017.

Q. If customers select a long-term opt-out program for 2017, will PGE adjust the load forecast?

A. Yes. PGE will adjust the 2017 cost-of-service load forecast accordingly, as specified in Schedule 125.

Q. Was the 2017 forecast developed using the same model used in Docket No. UE 294?

A. Yes. The same forecast models used in Docket No. UE 294 were updated with recent actuals through January 2016, the March 2016 (most recent) economic forecasts from the Oregon Office of Economic Analysis, and rolling 15-year average weather for 2001 - 2015.

Q. What load do you use in your 2017 test year power cost forecast?

A. The load listed in Table 4 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 5 below reconciles the total system load in Table 4 with the cost-of-service load on a calendar month-basis.

Table 5
Total System Load on Cycle Month at Meter
to Cost-of-Service Load on Calendar Month at Meter: 2017
(thousand MWh)

Total System Load (cycle month)	19,453
Add: Cycle to Calendar Month Difference	10
Total System Load (calendar month)	19,462
Less: Schedules 485/489	(1,652)
Cost-of-Service Meter Load	17,811

Numbers may not total due to rounding.

Q. What is the corresponding initial cost-of-service bus bar load forecast for 2017?

A. With the addition of line losses to Table 5, the initial bus bar load forecast for 2017 is 18,971.5 thousand MWh, or 2,166 MWa. This load is the basis for the hourly MONET load input data.

V. Comparison with 2016 NVPC Forecast

Q. Please restate your initial 2017 NVPC forecast.

A. The initial forecast, excluding PGE's forecast of PTCs, is $499.8 million.

Q. How does the 2017 forecast compare with the 2016 forecast utilized to develop power costs in Docket No. UE 294 and approved in Commission Order No. 15-356?

A. Based on PGE's final updated MONET run for the 2016 test year, the forecast was $532.1 million, or $28.14 per MWh. The initial 2017 forecast is $499.8 million, or $26.34 per MWh, which is approximately $1.80 per MWh less than the final forecast for 2016.

Q. What are the primary factors that explain the decrease in NVPC forecast for 2017 versus the NVPC forecast for 2016 in Docket No. UE 294?

A. Table 6 shows changes in NVPC by factor (excluding PGE's forecast of PTCs) between 2017 and 2016.

Table 6
Forecast Power Cost Difference 2017 vs. 2016
($ Million)

Factor	**$ Effect***
Hydro Cost and Performance	-0.1
Coal Cost and Performance	6.8
Gas Cost and Performance	-2.9
Wind Cost and Performance	-2.6
Contract and Market Purchases	-39.1
Market Purchases for Load Change	0.4
Transmission	5.0
Total	-32.3

* Numbers may not total due to rounding

Increased market purchases along with lower contract costs contribute substantially to lower overall forecast power costs in this initial filing. This overall decrease is partially offset by slightly higher net resource (i.e., hydro, coal, gas, and wind) costs and an increase in transmission costs. The increase in transmission costs is largely attributable to including the fixed transmission costs for the Carty Generating Station in each month of the forecast year.[14]

[14] In PGE's 2016 NVPC forecast, fixed transmission costs for the Carty Generating Station did not begin until May 2016.

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. Ms. Peschka, please state your educational background and experience.

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

Q. Mr. Hager, please describe your qualifications.

A. I received a Bachelor of Science degree in Economics from Santa Clara University in 1975 and a Master of Arts degree in Economics from the University of California at Davis in 1978. In 1995, I passed the examination for the Certified Rate of Return Analyst (CRRA). In 2000, I obtained the Chartered Financial Analyst (CFA) designation.

I have taught several introductory and intermediate classes in economics at the University of California at Davis and at California State University Sacramento. In addition, I taught intermediate finance classes at Portland State University. Between 1996 and 2004, I served on the Board of Directors for the Society of Utility and Regulatory Financial Analysts. Between 2002 and 2007, I served on the Advantis Credit Union Audit Committee and I now serve on the Board of Directors.

I have been employed at PGE since 1984, beginning as a business analyst. I have worked in a variety of positions at PGE since 1984, including power supply. My current position is Manager, Regulatory Affairs.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
401	List of MFRs per OPUC Order No. 08-505
402	Comparative Analysis of Northwest and Western EIM Intra-Hour Energy Market Options
403C	Ongoing O&M for EIM

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.

<u>Historical Operating Data</u>

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.

PGE

Comparative Analysis of Western EIM and NWPP MC Intra-Hour Energy Market Options

November 6, 2015

Table of Contents

I Executive Summary

As PGE and other utilities have added large quantities of variable energy resources (VERs) to the regional resource mix, it has become increasingly apparent that pooling generating resources regionally and trading closer to real time are valuable tools utilities can use to continue providing reliable, cost-effective energy to customers in the region.

PGE is working on several fronts to develop an integrated solution to enhance operational efficiency, integrate renewable resources, and optimize its generation portfolio. While PGE believes that it can obtain benefits through participating in an energy imbalance market (EIM), PGE has already taken incremental actions to enhance operational efficiency, including efficiencies relating to managing VERs. To achieve this integrated solution, PGE has undertaken the following initiatives:

- **Technology Improvements** in the tools utilized by PGE's Power Operations and Balancing Authority (BA) functions to optimize PGE's generation portfolio and eliminate manual communications.
- **Variable Energy Resource Integration:** PGE has implemented 15-minute wind scheduling and is continuing to evaluate VER integration options.
- **Sub-Hourly Market Participation**: PGE has fully analyzed the sub-hourly market options available and is prepared to participate in an EIM.

This report focuses on the next phase of PGE's integrated approach, sub-hourly market participation. In this phase, PGE explored its two opportunities for participation in a sub-hourly market, the Western EIM and the Northwest Power Pool (NWPP) Market Assessment and Coordination Committee (MC) initiative. The Western EIM expands the California Independent System Operator's (California ISO, or CAISO) existing real-time market to cover participating Balancing Authority Areas (BAAs) in the Western Interconnection in order to provide a responsive foundation for matching changes in supply and demand through a 5- and 15-minute market. The NWPP MC sub-hourly market remains under development, but, as of the writing of this report, was focused on an incremental approach that began with a 15-minute Centralized Clearing Energy Dispatch (CCED) program as an initial step that could lead to a potential 5-minute Security-Constrained Economic Dispatch (SCED) energy market.

In December 2014, the Public Utility Commission of Oregon (OPUC) issued an Order requiring that PGE analyze and report back on the relative impacts of joining the Western EIM. This report focuses on the qualitative analysis required by the OPUC, while an economic comparison between the two available options, conducted by Energy + Environmental Economics (E3), can be found in Appendix B, "PGE EIM Comparative Study: Economic Analysis Report."

As described in the remainder of this report, PGE's analysis indicates that the Western EIM is the best path forward for PGE's customers. While initially there was substantial value in the NWPP MC footprint, the reduced resource footprint available among participants in the NWPP MC initiative shifted the economic value for PGE's customers to favor moving to join the Western EIM. PGE will continue to work with NWPP partners on regional reliability initiatives and continues to look for value for PGE customers through the NWPP Reserve Sharing Group.

1 Introduction

In 2013, PGE began work on a series of projects to modernize systems, facilitate the integration of VERs, and prepare PGE to enter a sub-hourly market. These projects include upgrades to PGE's Power Operations and BA systems, elimination of redundant systems, enhanced communications, and operational efficiency improvements. This portfolio of programs is described in more detail in Appendix A. Ultimately, these projects allowed PGE to move to 15-minute wind scheduling in October 2015 and have prepared PGE to join an EIM in October 2017.

In its order acknowledging PGE's 2013 IRP, the OPUC directed PGE to analyze and report back on the impacts of joining the Western EIM. The Commission Order had four requirements, which have been reordered to facilitate the flow of the analysis:

Requirement 1: Estimate the benefits of going to 5-minute dispatch.[1]

Requirement 2: Estimate the diversity benefits of joining an EIM.

Requirement 3: Evaluate the potential reliability benefits of participating in an EIM.

Requirement 4: Estimate the potential benefits of deferring or eliminating the need for new generation or other flexible resources.

PGE was also required to create a steering committee, including representatives of OPUC staff, stakeholders, and industry experts, to oversee the study. Consistent with the OPUC Order, PGE established three committees to oversee and offer insight on the study. These committees consisted of a stakeholder advisory committee, a technical review committee, and a modeling team comprised of utility and market operator partners. Figure 1 lists the members of each committee.

[1] Modeling results in this report are based on 10-minute dispatch, with accompanying narrative discussing 5-minute dispatch.

Figure 1. Committee Members

EIM Comparative Study with E3

Utility/Market Operator Partners

Modeling Team

Clint Kalich	Avista
Scott Kinney	Avista
Jared Ellsworth	Idaho Power
Ron Schellberg	Idaho Power
Casey Johnston	Northwestern Energy
Ray Bush	Northwestern Energy
Bruce McAllister	PacifiCorp
Jim Price	CAISO

Advisory Committee EIMSAC

John Crider	OPUC
Cameron Yourkowski	Renewables Northwest
Bob Jenks	CUB
Scott Downey	Peak Reliability
Michael Goggin	American Wind Energy Assoc.
Maury Galbraith	Western Interstate Electric Board
Mark Rothleder	California ISO
Carl Monroe	Southwest Power Pool
Scott Kinney	Avista Corp.
Jim Shetler	BANC (Balancing Authority of Northern California)
Rachel Dibble	BPA
Tess Park	Idaho Power Company
Joe Lawlor	PG&E
Steve Beuning	Xcel Energy

Technical Review Committee TRC

Michael Milligan	National Renewable Energy Laboratory (NREL)
Brendan Kirby	Consultant to NREL
Bart McManus	BPA
John Ollis	Northwest Power and Conservation Council
Ron Shelburg	Idaho Power Company
Ted Brekken	Oregon State University
Eduardo Cotilla-Sanchez	Oregon State University

The committees met on multiple occasions throughout the study process and provided PGE with timely guidance on many issues, including:

Stakeholder Advisory Committee: Commented on matters technical in nature and advised PGE's internal modeling team on foundational study elements such as study structure and key assumptions.

Technical Review Committee: Offered expertise in, and recommendations on, modeling techniques, model inputs, and feasibility of the modeling approach.

Utility/Market Operator Modeling Team: Reviewed input and output data for accuracy and robustness.

As PGE explained in comments submitted in its 2013 IRP proceeding, PGE believed that an analysis of joining the Western EIM was most useful when compared to joining the NWPP MC Initiative.[2] Therefore, PGE selected E3, an experienced energy market modeling consulting firm, to conduct a benefits study on each of the two market alternatives. That study is attached to this report as Appendix B.

[2] *See* PGE's Supplemental Comments, Docket LC 56 (November 7, 2014).

1.1 Background

Traditionally in the Northwest, utilities have traded within bilateral term, daily, and hourly markets to optimally position themselves for hourly operations each day. To manage intra-hour variability, individual utilities have used generation assets (either utility-owned or contracted) to follow variation in load on a minute-to-minute basis. With 55 percent of the region's generating capacity consisting of hydroelectric generation, Northwest system operators have been able to leverage those resources' inherent flexibility to integrate VERs as stand-alone BAs. However, as BAs seek to reliably operate the grid with higher levels of VERs, utilities and other stakeholders are identifying and evaluating mechanisms to improve and supplement the coordination opportunities of existing bilateral markets.

An intra-hour market, such as an EIM, is one solution. An EIM is a balancing energy market that optimizes generator dispatch within and between participating BAs at an established interval (e.g., 5 or 15 minutes). Key elements of an EIM include:

- **A voluntary, within-hour, energy-only market platform.** This platform allows participants to voluntarily offer resources within the market footprint.
- **Security constrained via a state estimator model of the footprint.** This tool dispatches the lowest-cost, voluntarily offered, resources to serve the combined loads of all EIM participants within the physical limitations of the transmission grid.
- **A market operator to optimize energy dispatch across a wide area.** The market operator provides centralized clearing of energy bids and offers and does not have a financial interest in any market transaction.
- **"As-available" transmission system capability.** The EIM only uses the transmission system capability available in real-time after recognizing all flows resulting from scheduled uses and inadvertent interchange – that is, the difference between system operating limits and actual real-time flows.

In evaluating an EIM, it is important to understand what an EIM is *not* designed to do.

- **An EIM is not an energy- or capacity-supply mechanism, and it does not replace the current, bilateral contractual business structure.** While an EIM optimizes the deployment of resources already committed at the start of the operating hour, it is not designed to resolve supply deficits. In other words, participation in an EIM will not lead to a reduction in contingency or regulating reserves; rather, participation in an EIM allows for a reduction in flexible reserve requirements due to the "diversity benefit" of the EIM. This is discussed in more detail in Section 4 (see Requirement 4 discussion) of this report.
- **An EIM does not perform Transmission Service Provider functions, and is not a regional transmission organization (RTO) or an independent system operator (ISO) with centralized planning, day-ahead markets, congestion management, etc.** An EIM does not involve any change in operational control over the transmission system or the sale of transmission services.

The following section provides a high-level overview of the Western EIM and the NWPP MC CCED/SCED.

2 Overview of Western EIM and NWPP MC CCED/SCED

2.1 Western EIM

The Western EIM[3] expands the CAISO's existing real-time market to cover participating BAAs in the Western Interconnection to provide a responsive foundation for matching changes in supply and demand. The Western EIM takes advantage of the existing CAISO real-time market by adding new procedures to accommodate the voluntary participation of BAs without disrupting the ISO's current market structure. Pricing of energy in the Western EIM is based on Locational Marginal Pricing (LMP) for specific market zones established by the CAISO. The Western EIM clears both generation and load using a SCED algorithm.

While Western EIM participants are included in the CAISO's 15-minute and 5-minute markets, they do not participate in the CAISO's day-ahead market, ancillary services markets, or the California Resource Adequacy construct. Each participating BA remains responsible for maintaining reliability, including: meeting operating reserve and capacity requirements; scheduling interchange transactions and performing curtailment of the transmission facilities under its operational control; and manually dispatching resources for reliability.

A BA's participation in the Western EIM is voluntary and termination of participation in the Western EIM is not subject to an exit fee. Accordingly, a participating BA that wishes to cease participating in the EIM need only provide CAISO with at least six months' advance written notice. Although there is no exit fee, the participating BA remains responsible for charges and financial obligations incurred during the term of its participation.

2.2 NWPP MC CCED/SCED

As of the writing of this report, the NWPP MC sub-hourly market remains under development. To date, the MC has focused on an incremental approach that would use a 15-minute CCED program as an initial step that could lead to a potential future 5-minute SCED energy market. Additionally, the NWPP MC has proposed developing a Regulating Reserve Sharing Group (RRSG). These initiatives are part of a phased approach to solving current and future challenges while limiting implementation risks and maximizing the potential for sustainable, long-term gains for all NWPP MC CCED/SCED members.

The proposed 15-minute CCED and RRSG programs are not intended to replace or disrupt the region's bilateral market activities; rather, these initiatives are meant to complement the existing market framework. Each participating BA would remain responsible for: maintaining reliability, including meeting operating reserve and capacity requirements; scheduling interchange transactions, and

[3] The description of the Western EIM is taken from *Cal. Indep. Sys. Operator Corp*, 147 FERC ¶ 61,231, at PP 7-23 (June 19, 2014).

performing curtailment of the transmission facilities under its operational control; and manually dispatching resources for reliability.

The proposed NWPP MC 15-minute CCED would arrange for voluntary sales and purchases of energy at the central Market Zone for each 15-minute delivery interval. The NWPP MC CCED would not directly manage load-resource balance or clear imbalance energy; rather, it would effectively give BAs the opportunity to acquire or provide displacement energy in a more automated and efficient manner than currently available. Once the CCED is up and running, the NWPP MC would evaluate the costs and benefits of expanding the market into a full SCED. The NWPP MC has completed substantial design work for the SCED in order to scope and prepare for this progression. The SCED is designed around 5-minute dispatch cycles in which the SCED calculates locational pricing and issues dispatch instructions for participating resources. As envisioned, the SCED would meet the key elements outlined in Section 1.1 of this report.

3 EIM Preparation Activities, Start-Up and Ongoing Costs

With the growth of its portfolio of renewable energy resources and its move to BPA's 15-minute wind integration program in October 2015, PGE identified the need to upgrade its Power Operations infrastructure to better manage variability and meet the requirements of sub-hourly scheduling and dispatch. To prepare for intra-hour operation, PGE launched several projects in 2013 designed to move the company through three upgrade phases:

Technology Improvements – In this phase, PGE modernized tools used by Power Operations and the BA to optimize the generation portfolio, eliminate manual communications, standardize the decision-making process, and create an auditable system of record of dispatch decisions and plant operations. Projects in this phase included consolidation of the plant information (PI) data from PGE's generating facilities, upgrades to plant telemetry, the addition of automatic generation control (AGC) at PGE's thermal plants, upgrades to generation and interchange meters, addition of an outage management tool, and the implementation of a portfolio optimization system called GenOps.

VER Integration – In this phase, PGE moved another step towards VER self-integration, and prepared to determine the level of VER Balancing Service PGE would require for the upcoming BPA rate case period (October 2015 thru September 2017). Projects in this phase included individual plant studies to determine the wear-and-tear costs of cycling PGE's plants to balance load and VER output. The data from these studies became an input into the GenOps optimization model to ensure the most efficient dispatch of PGE's generation units.

Sub-Hourly Market Participation – In this phase, PGE is preparing to participate in an EIM. The projects in this phase include the implementation of a bid-to-bill system that will enable an automated interface with the market for bidding and settlements.

Under an EIM or SCED scenario, PGE will incur incremental, one-time implementation costs to implement the bid-to-bill system. PGE also estimates that in both cases it will incur equivalent ongoing costs for software maintenance and hosting fees, and labor costs. PGE's cost analysis focuses on the difference in market costs (both start-up and ongoing) between the Western EIM and the NWPP SCED to determine which market option is most cost effective.

Participant start-up charges for the Western EIM are based on an allocation of the total start-up costs for the EIM of $19.6 million. The allocation is based on the entrant's proportionate share of the total Western Electricity Coordinating Council (WECC) Net Energy for load service, excluding the CAISO. Start-up costs may include any customization requested by the participant. PGE's start-up costs for joining the Western EIM would be approximately $645,000.

The ongoing costs for the Western EIM are assessed to EIM participants as the EIM administrative charge. This charge consists of an EIM market services charge and an EIM systems operation charge. The EIM market services charge is allocated to gross instructed imbalance energy while the EIM system operations charge is allocated to gross real-time energy flow. While ongoing costs are not as easily quantified, PGE estimates that Western EIM ongoing costs would be $400,000-500,000 each year.[4]

Participant start-up charges for the NWPP SCED are not publicly available, but PGE's best estimate based on participation in NWPP MC market scoping activity in 2013-2015 was that a NWPP MC-built SCED program would be significantly more costly than the Western EIM, assuming the SCED program would be facilitated by a new entity using a to-be-developed market platform. Similarly, ongoing cost estimates are not publically available for the NWPP MC SCED; however, PGE estimates that these charges would be greater than the Western EIM given the same assumptions above.

4 Comparative Analysis

This section, in conjunction with the E3 report, addresses the requirements established in the OPUC Order on the relative impacts of joining the Western EIM. The Commission Order had four requirements:

Requirement 1: Estimate the benefits of going to 5-minute dispatch.

Requirement 2: Estimate the diversity benefits of joining an EIM.

Requirement 3: Evaluate the potential reliability benefits of participating in an EIM.

Requirement 4: Estimate the potential benefits of deferring or eliminating the need for new generation or other flexible resources.

[4] Proposed Western EIM administrative charge modifications were accepted by FERC in *Cal. Indep. Sys. Operator Corp*, 153 FERC ¶ 61,087, at PP 59-61 (October 26, 2015). PGE's estimates are based on the previous design of the charge, as that was the prevailing cost methodology at the time of PGE's decision.

Req. 1: Estimate the benefits of going to 5-minute dispatch

PGE engaged E3 to compare the potential economic benefits of PGE's participation in either the Western EIM or a NWPP MC SCED that was assumed to have identical functional features as the Western EIM, but with a footprint comprised of a collection of NWPP MC BAAs.[5] The analysis uses production simulation modeling in PLEXOS[6] to estimate PGE's benefit of participating in the EIM or SCED by comparing PGE's real-time generation costs as an EIM or SCED participant, as well as any EIM or SCED energy revenues and purchase costs, against a Business-As-Usual (BAU) scenario in which PGE does not participate in either regional real-time market.

As described in the table below, and more extensively in the E3 Study attached as Appendix B, under the Base Case simulated for the year 2020, the analysis estimates that Western EIM participation would produce $2.7 million in annual savings from sub-hourly dispatch, and higher dispatch cost savings of up to $6.1 million in alternative sensitivity cases such as higher natural gas prices or higher regional renewable buildout.

By comparison, estimated savings in the NWPP MC resulted in $4.6 million of annual sub-hourly dispatch cost savings for PGE in the Base Case, and up to $7.2 million in the high renewable resource sensitivity. Table 1 below summarizes these results for each scenario. The results represent gross benefits, and are not net of participation costs.

Table 1. Annual Savings to PGE from Participation in Western EIM or NWPP SCED (2015 $million)

Scenario	Western EIM Savings	NWPP SCED Savings
Sub-hourly Dispatch Savings only		
Base Case	$2.7	$4.6
High Gas Price	$5.8	$6.4
Alt. Transmission Transfer[7]	$3.0	N/A
High RPS Case	**$6.1**	**$7.2**

While the base case shows higher benefits under the NWPP MC SCED scenario, the gap between the Western EIM and NWPP MC SCED scenarios narrows considerably under key sensitivities such as higher natural gas prices or higher renewable generation. Furthermore, the present number of expected footprint participants in the NWPP MC SCED is now lower than the number of footprint participants modeled in PGE's SCED scenario. After completion of PGE's study, Idaho Power Company announced in a Sept. 24, 2015, press release its withdrawal from the NWPP MC efforts.

[5] For this analysis, the participants in the Western EIM are assumed to be: CAISO, PacifiCorp, NV Energy, and Puget Sound Energy. For the NWPP MC, the participants are assumed to be: Avista Corp., British Columbia Hydro, BPA, Idaho Power Co., Grant County PUD, Douglas County PUD, Chelan County PUD, NorthWestern Energy, Sacramento Municipal Utilities District, Seattle City Light, Tacoma Power, and Western Area Power Administration-Upper Missouri.
[6] PLEXOS is an integrated gas and electricity operational model capable of modelling the integrated power system with a sub-hourly dispatch.
[7] This scenario looks at benefits under a scenario with increased transmission transfer capability from PGE to the CAISO.

Ultimately, the reduced resource footprint available among participants in the NWPP MC Initiative shifted the economic value to favor PGE joining the Western EIM. Additionally, the timeline to enter the Western EIM is well established and would most likely allow a significantly shorter timeline to market participation than the eventual SCED market envisioned by the NWPP.

Req. 2: Estimate the diversity benefits of joining an EIM

In Requirement 1, PGE quantified the sub-hourly dispatch benefits of joining the Western EIM and NWPP MC SCED. In addition, E3's study quantifies the diversity benefit of combining PGE's load and VER variability with that of the other participants in the Western EIM or NWPP MC SCED. The study estimates this diversity benefit by reducing the flexible reserve requirements for participating zones to reflect the pooling of VER and load forecast error and variability across the Western EIM or NWPP MC SCED footprint as a whole. The simulation model is then run an additional time to reflect overall cost savings to PGE. This results in the following forecasted flexible reserve pooling benefits, reflecting the overall diversity across market participants.

Table 2 shows the diversity benefit PGE would realize from including PGE's load and VERs in either of the markets analyzed in this study. The first row summarizes the sub-hourly dispatch benefits only (quantified for Requirement 1) of joining the Western EIM or NWPP SCED in the Base Scenario. The bottom row shows the total savings—including sub-hourly dispatch benefits as well as flexible reserve pooling to reflect diversity of the footprint.

Table 2. PGE's diversity benefit from Western-EIM and NWPP-SCED

Scenario	Western EIM Savings	NWPP SCED Savings
Sub-hourly Dispatch Savings only		
Base Scenario	\$2.7	\$4.6
Dispatch and Reserve savings		
Base Scenario with Reserve Pooling	\$3.5	\$5.3

The difference between the two rows represents the incremental savings, beyond sub-hourly dispatch savings, that could be provided from overall system diversity and flexible reserve pooling. Incremental diversity savings for PGE from the Western EIM is estimated to be \$800,000, while the savings from NWPP MC SCED are estimated at \$700,000. The pooling of PGE's load and renewables with that of either footprint results in a similar magnitude of diversity in most hours. As a result, the diversity-driven generation cost savings to PGE is very similar for participation in either footprint.

Req. 3: Evaluate the potential reliability benefits of participating in the EIM

Two of the recognized benefits of joining an EIM are greater diversity and enhanced reliability. Joining an EIM provides resource-sufficient BAs access to a wider footprint that includes more load and more generating resources. As noted by the National Renewable Energy Laboratory (NREL), a larger operating footprint enhances reliability by increasing the ability of the system to respond to variability for two reasons:

1. Pooling of variable loads and wind generation increases diversity, which reduces overall per-unit variability; and
2. A broader resource mix increases ramping capability linearly.[8]

In other words, by including pooling resources and obligations across time zones, climate regions, and loads, these two factors provide a feedback loop in which "aggregation provides an increased ability to manage variability, which itself is reduced with aggregation."[9]

In 2013, a Federal Energy Regulatory Commission (FERC) Staff Report addressed the reliability value an EIM can provide. The Staff Report stated that "while an EIM would not be a replacement for capacity adequacy, a larger pool of resources under an EIM footprint could provide more ramping capability and respond to variations and imbalances more quickly."[10] Additionally, spreading the ramping requirements over a broader generation portfolio reduces the cycling burden of any single unit.

Moreover, the larger and more diverse the EIM dispatch footprint, the more resources become available to meet fluctuations in load or generation. As the 2013 FERC Staff Report points out:

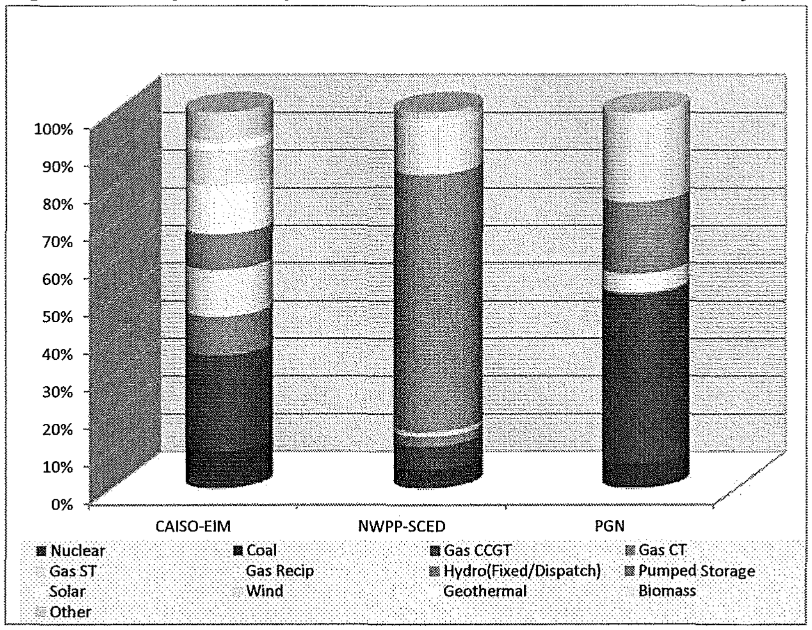
> As the geographic area that SCED dispatches is increased, there is a greater diversity of options available to manage operational limits . . . [B]y providing a diversity of redispatch options from across the EIM footprint, an EIM would reduce the risk of any balancing authority being short of supply to respond to imbalances.[11]

Lastly, the 2013 FERC Staff Report points out that an EIM could provide reliability benefits through enhanced situational awareness. While the models utilized to run the SCED dispatch are not reliability tools themselves, FERC argues that an "EIM could provide proactive solutions to potential reliability issues through automated redispatch every 5 minutes using SCED." By proactively signaling resources to respond to system imbalances, an EIM can potentially correct issues before they would need to be resolved by the reliability coordinator.[12]

Figure 2 provides a footprint comparison of the generating resources that comprise the Western EIM and the NWPP MC. Generally, the resource mix of the NWPP MC is 55 percent hydroelectric generation, whereas the Western EIM and PGE footprints are dominated by thermal generation.

[8] National Renewable Energy Laboratory. *Operating Reserve Reductions from Proposed Energy Imbalance Market with Wind and Solar Generation in the Western Interconnection*, at 25. May, 2012. : http://www.nrel.gov/docs/fy12osti/54660.pdf.
[9] Id. at 26.
[10] FERC Staff. *Qualitative Assessment of Potential Reliability Benefits from a Western Energy Imbalance Market.* February 26, 2013. https://www.caiso.com/Documents/QualitativeAssessment-PotentialReliabilityBenefits-WesternEnergyImbalanceMarket.pdf (2013 FERC Staff Report).
[11] 2013 FERC Staff Report at 18 (internal citation omitted).
[12] *Id.* at 12-13.

Figure 2. Footprint Comparison of Generation Resource Capacity[13]



In the NWPP MC, hydroelectric generation represents the majority of available flexible resources, with some thermal generating units also capable of adding flexibility. The ability to optimize hydropower, thermal, and other renewable resources across the NWPP MC footprint would offer the flexible capacity needed to support the increased penetration of VERs. Having access to additional flexible, low-carbon hydropower through the NWPP MC SCED would offer an opportunity for PGE to collaborate with other regional partners in meeting renewable integration and carbon reduction goals.

Generation in the Western EIM is primarily fueled by natural gas (58 percent), followed by 24 percent renewable resources, 13 percent large hydroelectric, 4 percent nuclear units and 1 percent oil and coal. However, the Western EIM's share of renewables is growing due to recent advances in solar technology and increasing state renewable portfolio standards. California legislation (SB 350), passed in September 2015, raises the California Renewable Portfolio Standard (RPS) to 50 percent by December 31, 2030. In a 50 percent RPS scenario, overgeneration[14] is likely to become an issue within California. A 2014 E3 study suggests that in a 50 percent RPS scenario, overgeneration will occur in more than 20 percent of all hours, amounting to 9 percent of RPS energy. As a result, the report recommends increasing regional

[13] Generation resource capacity derived from Energy Exemplar's Plexos database.

[14] Overgeneration occurs when "must-run" generation – non-dispatchable renewables, nuclear power, combined heat and power, run-of-the-river hydroelectricity and thermal generation that is needed for grid stability—exceeds loads. When these generators cannot be ramped up and down like conventional fossil-fired power plants, they may produce more energy than required by the system at certain times of the day.

coordination as a key tool for facilitating the integration of more renewable resources into the bulk power system at a lower cost.[15] An EIM is one tool to accomplish this regional coordination.

For PGE, joining the Western EIM would provide access to a more sizeable and diverse resource mix, along with a growing renewables portfolio. While the hydroelectric generation that dominates the NWPP MC footprint is recognized for its flexibility, the total size and generation diversity of the Western EIM footprint offsets this advantage.

PGE's own generating capacity consists of thermal generating units, hydroelectric and renewables.

Ultimately, participation in either the Western EIM or NWPP MC would provide reliability benefits for PGE in terms of expanded footprint and greater diversity. While PGE has chosen to join the Western EIM, the company is continuing to work with NWPP members on initiatives to improve regional reliability. PGE has benefited from data-sharing tools implemented in the NWPP MC Phases 3 and 4, including the Regional Flow Forecast (RFF) tool, the Regional Resource Monitoring and Deliverability (RMD) tool, the Area Control Error (ACE) Diversity Interchange (ADI) program, and the Reliability Based Control (RBC) program.

Req. 4: Estimate the potential benefits of deferring or eliminating the need for new generation or other flexible resources

As described in the E3 report (Appendix B), EIM participation does not alleviate the responsibilities of BAs to carry adequate reserves. Within an EIM, the BA remains responsible for meeting its peak load and demonstrating resource sufficiency. While EIM participation will not reduce planning reserves or impact resource additions, the EIM will reduce operating reserve-carrying requirements due to the "diversity benefit" of the EIM.

Previous E3 studies have referenced "reserve reduction" as a benefit of EIM participation. However, these studies do not define specifically what this reserve reduction is. As described below, while EIM participation may allow a "release" of some flexible reserves for other dispatch uses, resource sufficiency requirements mandate that each BA enter each hour having scheduled enough energy and flexible ramping capability to fully meet the BA's load-resource balance.

Currently, PGE carries three types of operating reserves[16]: contingency reserves, regulating reserves, and flexible reserves.

- **Contingency Reserves** are the capacity resources deployed by the BA to meet the Disturbance

[15] Energy and Environmental Economics. *Investigating a Higher Renewables Portfolio Standard in California.* January 2014. *https://www.ethree.com/documents/E3_Final_RPS_Report_2014_01_06_ExecutiveSummary.pdf.*

[16] NERC defines Operating Reserves as follows: "That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve." *See* Glossary of Terms Used in NERC Reliability Standards (updated Sept. 29, 2015). *http://www.nerc.com/pa/Stand/Pages/default.aspx.*

Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements.[17]

- **Regulating Reserves** are the amount of reserve responsive to AGC. Regulating reserves respond rapidly to system operator requests for up and down movements and are used to track the moment-to-moment fluctuations in system load and to correct for unintended fluctuations in generator output.[18]
- **Flexible Reserves**[19] provide a bridge between regulating reserves and net system load variations within each hour.

PGE's entrance into the Western EIM will not reduce its NERC required **contingency reserve** obligations. PGE also expects to continue to carry the same amount of **regulating reserve** in an EIM that it carries today.

The reserves most impacted by EIM participation are **flexible reserves** that are used within the hour to meet changes in load or variable generation output. In an intra-hour market construct, flexible capacity reserves can be pooled across the entire market footprint.

In the Western EIM, there is a reduction of flexible capacity reserves that is incorporated into the resource sufficiency evaluation that occurs 60 minutes prior to the operating hour (T-60). The Western EIM calculates the flexible reserve requirement for each period for each BA as a stand-alone entity, then calculates the flexible reserve requirement for the entire EIM/ISO footprint. The difference between these two values is allocated back to each participating BA proportional to their flexible reserve requirements for that period without diversity.[20]

While the Western EIM provides a flexible reserve pooling benefit, this calculation occurs hourly and is based on the prevailing system conditions at the time of calculation. Because this calculation does not produce a predictable reduction that can be utilized for long-term planning, the reserve pooling benefit will not impact day-ahead or long-term planning. Therefore, Western EIM flexible reserve pooling will not directly result in the deferral or elimination of flexible generation needs for any EIM entity. However, due to the more accurate resource scheduling made possible by the EIM, PGE may be able to deploy some resources that are currently used for hourly flexible reserves through the market (or receive lower-cost imbalance energy from another EIM participant), holding only those regulating and flexible reserves needed to cover variability within the 15- or 5-minute dispatch interval.

The E3 study includes a benefit calculation to quantify the diversity benefit of pooling reserves within Western EIM footprint and the NWPP MC SCED footprint. As noted earlier, the E3 study found that the

[17] *Id.* (NERC definition of Contingency Reserve).
[18] *Id.* (NERC definition of Regulating Reserve).
[19] PGE utilizes flexible reserves in excess of the NERC minimum required to meet contingency reserve obligations to reliability balance fluctuations in supply and demand within the operating hour. Flexible reserves are synonymous with load following reserves; while historically, changes in load drove the need for intra-hour flexibility, today, fluctuations in both load and variable energy resources require a BA to hold flexible reserves. This report uses the term "flexible reserve" to reflect this new paradigm.
[20] Section 10.3.2.1 of the western EIM *Business Practice Manual*.

estimated savings associated with reduced reserves are relatively small $800,000 for the Western EIM, $700,000 for the NWPP MC SCED – relative to the base scenario. While the E3 study provides a method to quantify the financial benefit of flexible reserve pooling, it does not address the long-term assessment of flexible capacity reserve demand for PGE or the need for additional generation, given that PGE will continue to operate as a separate BA and remain responsible for meeting its reliability and load service obligations.

Appendix A – PGE's Intra-Hour Market Readiness

PGE Projects Launched for Intra-Hour Market Readiness Under the Dynamic Dispatch Program

The objective and benefits from each of the individual projects are described below.

PI (Plant Information) Consolidation

- Objective: Install an interface server at each of PGE's generating facilities to consolidate the generation data into a central enterprise PI server.
- Benefits: Establishes a consistent, reliable method of retaining plant data and creates a central repository of data that is easily extracted for operations and analytical work.

AGC Equipment Install

- Objective: Install AGC telemetering equipment at Beaver, Boardman, Coyote and Port Westward, which allows them to receive remote set point signals from PGE's Energy Management System (EMS).
- Benefits: Allows these plants to be remotely controlled to provide load following and increase the dispatch efficiency of plants to meet load and provide flexible reserves. In the next phase, PGE will install AGC on the Tucannon River and Biglow Canyon wind facilities.

Meter Replacement Project

- Objective: To replace current analog meters at generation and intertie locations within the PGE BA.
- Benefits: Increases situational awareness within the PGE system, reduces meter outages/failures, improves accuracy of settlements, and elevates our meter inventory to current industry standards that are compatible with Western EIM standards of providing revenue-quality 5-minute data.

Outage Management Tool Project

- Objective: Refine current and develop new business practices for the declaration, approval and recording of long-term and short-term generation and transmission outages. Implement software designed to capture long-term and short-term generation and transmission outage information for reporting to the necessary reliability and market entities in a manner consistent with the FERC Code of Conduct.
- Benefit: Elimination of redundant entries into a variety of systems by multiple personnel within the outage communication chain. Possible reduction in number of systems used to capture generation and transmission outage information. Streamlines and automates processes associated with the periodic reporting of generation and transmission availability to reliability and market entities.

GenOps System Optimization

- Objective: Implement an automated sub-hourly optimization tool to be used by PGE's Power Operations, BA, and generation plant operators to optimize the PGE system for reliability requirements, system constraints, and economic dispatch within the PGE generation portfolio on a sub-hourly basis.
- Benefits: Increases efficiency and coordination of generating portfolio dispatch.

Cycling Costs Studies

- Objective: Identifies the wear-and-tear costs related to cycling plants to balance load and VERs, provides comparison of PGE plant operating costs vs. similar plants, determines costs for hot, warm, and cold starts, as well as ramping. Studies[1] were conducted by Intertek APTECH, an engineering consulting firm with more than 130 years' experience[2] in this field.
- Benefits: Provides supporting documentation of increased variable Operations and Maintenance (O&M), refines inputs to PGE's wind integration study optimization model, and informs operations with improved dispatch logic for PGE's GenOps system.

Bid2Bill Project

- Objective: Implement a software solution to assist in the compilation of intra-hour bids and base schedules for submittal to an intra-hour market operator, and assist in the processing of intra-hour market settlement statements.
- Benefits: Simplifies and streamlines the bidding and settlement processes associated with an intra-hour market.

Reliability and Performance Monitoring (RPM) Project

- Objective: Implement predictive analytics to monitor for early indication of equipment faults on an increased number of plant assets, and performance analytics to monitor the operational efficiency of the plants.
- Benefits: Maintains best-in-class plant availability; decreases the risk of unplanned plant outages; and maximizes economic dispatch of our generation assets. Increases planning and scheduling for repair activities, which, in turn, decreases the risk of employee injury and need for maintenance while increasing detection of operational performance degradation.

Wind Asset Management Improvement Project

- Objective: Identify and implement strategies to improve the overall yearly generation performance and integration of PGE's wind fleet and identify and adopt best practices for wind asset

[1] Internal proprietary analysis done on behalf of PGE to examine the comparative costs of increased cycling on PGE Generation Portfolio.
[2] http://www.intertek.com/about/history/

management.

- Benefits: Trained operators who have the knowledge, tools and confidence to integrate wind into PGE's system. Maximization of wind capture and production at the plant.

NWPP MC Reliability Programs

While PGE is focusing market efforts on the Western EIM going forward, PGE continues to support the following reliability and infrastructure efforts through the NWPP.

Regional Flow Forecasting Tool

- Objective: Provide better visibility for real time and forecasted flows on defined transmission paths to enhance reliability.
- Benefits: Users see a graphical map display of Pacific Northwest flowgates for current operating hour (real time) and can navigate to view future hours. Colors are used to indicate when flows approach or exceed system operating limits. Users can also drill down into specific flowgate displays illustrating history and trending values aligned against system operating limits.

Resource Monitoring and Deliverability (RMD) tool:

- Objective: Shows a BA their specific operating hour obligations compared to their operating hour resources in megawatt quantities, and then provides a summary-level resource-sufficiency measure for that operating hour.
- Benefit: Provides a common process that BAs can use to monitor and test resource sufficiency; provides BAs with a forward-looking 2-hour window into their resource sufficiency; assesses expected system topology, such as forecasted load, generation, and interchange schedules; provides an aggregated view of other regional BAs.

Area Control Error (ACE) Diversity Interchange (ADI)

- Objective: The ADI program leverages existing infrastructure to allow automated, momentary sharing of regulation among regional BAs. ADI is currently being used by several BA entities throughout WECC as an operational efficiency tool.
- Benefits: Reduces generator movement and improved Control Performance Standard (CPS) scores.

Reliability Based Control (RBC)

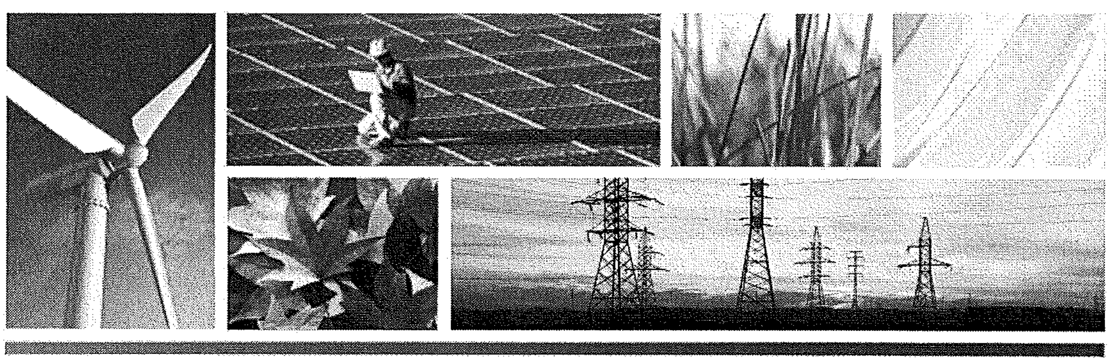
- Objective: As of July 1, 2016, PGE's BA will be required to begin using the BA ACE Limit (BAAL) known as RBC for the WECC pilot field trial. This is the replacement standard for the existing Control Performance Standard (CPS 2). PGE has been participating in the RBC pilot program, and has remained compliant with the more stringent CPS 2 standards. The new RBC standard will allow an entity's ACE values to deviate from zero and remain compliant as long as the error is helping system frequency.

- Benefits: This program will allow for less generator movement as the generators will not be required to respond to smaller frequency and load deviations, and leverage the Bulk Electric Systems (BES) current flexibility to reduce cycling cost associated with the wear-and-tear on system generators. One perceived benefit is that it will reduce an entity's burden for maintaining the appropriate amount of flexible reserves, but the entity will be required to respond to peak RC requests to follow tight control. BAs will still be required to carry the same amount of reserves at all times as they do today.

PGE

PGE EIM Comparative Study: Economic Analysis Report

November 2015



Energy+Environmental Economics

November 6, 2015

PGE EIM Comparative Study: Economic Analysis Report

November 2015

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Table of Contents

Acronyms

BA	Balancing Authority
BAA	Balancing Authority Area
BAU	Business-as-usual
CAISO	California Independent System Operator
ISO	Independent System Operator
DA	Day-ahead
EIM	Energy Imbalance Market
FERC	Federal Energy Regulatory Commission
HA	Hour-ahead
IC	Internal Combustion
LMP	Locational Marginal Price
NVE	NV Energy
NWPP	Northwest Power Pool
PAC	PacifiCorp
PGE	Portland General Electric
PNNL	Pacific Northwest National Laboratory
SCED	Security Constrained Economic Dispatch
WECC	Western Electric Coordinating Council

Executive Summary

Over the past year, Portland General Electric (PGE) has been exploring potential opportunities to improve real-time coordination with other utilities in the Western Interconnection, in an effort to increase operational efficiency and create cost savings for PGE customers. Two opportunities PGE has considered are participation in the energy imbalance market (EIM) operated by the California Independent System Operator (CAISO), and an effort to increase market coordination on a sub-hourly level together with other utilities in the Northwest Power Pool (NWPP). As part of its assessment of opportunities for regional coordination, PGE engaged Energy & Environmental Economics, Inc. (E3), to analyze the potential economic benefits of PGE's participation in either the CAISO EIM, or in a NWPP security constrained economic dispatch (SCED) assumed to have identical functional features as the EIM, but with a footprint comprised of a collection of NWPP Balancing Authority Areas (BAAs). This report describes the results of our study.

The analysis uses production simulation modeling in PLEXOS to estimate PGE's benefits resulting from participating in the EIM or SCED by comparing PGE's real-time generation costs as an EIM or SCED participant, as well as any revenues or costs from transactions with other EIM or SCED participants, against those of a business-as-usual (BAU) case in which PGE does not participate in either regional real-time market. To focus on the incremental impact of PGE participation, the BAU case includes operations of a "current EIM" consisting of the four BAAs that were participating or had announced plans to participate in the EIM at the start of this study.[1] For the NWPP SCED, the BAU case reflects operations of both the existing EIM, as well as an assumed "current SCED" composed of selected NWPP members. The BAAs assumed to be current participants in the EIM or SCED for the BAU Cases are listed in the table below.

Table 1: BAA Participants in EIM or SCED in BAU Case

Current EIM participants for BAU Case	Current NWPP participants for BAU case
CAISO	Avista Corporation (AVA)
PacifiCorp East (PACE)	British Columbia Hydro (BCH)
PacifiCorp West (PACW)	Bonneville Power Administration (BPA)
NV Energy (NVE)	Idaho Power (IPC)
Puget Sound Energy (PSE)	Grant County PUD & Douglas County PUD & Chelan County PUD (collectively, MIDC)
	Northwest Energy (NWMT)
	Sacramento Municipal Utilities District (SMUD)
	Seattle City Light (SCL)
	Tacoma Power (TPWR)
	Western Area Power Administration – Upper Great Plains West Region (WAUW)

In addition, the Base Scenario assumes that PGE has transitioned to full self-integration of the real-time output of its wind resources, dynamically scheduling the actual wind output from BPA to PGE in real time. The analysis includes a separate section to estimate the variable operating costs of PGE transitioning from (a) current practice, in which BPA integrates PGE's wind and schedules to

[1] While this study was ongoing, APS also announced plans to begin participation in the EIM in 2016, but was excluded from the EIM for the purposes of this study.

PGE in flat hourly blocks, to (b) 30/15 scheduling in which BPA schedules PGE's wind output in 15 minute intervals based on output 30 minutes ahead of real time, and finally to (c) full self-integration by PGE of its wind output in real time.

Under the Base Scenario simulated for the year 2020, the analysis estimates that EIM participation would produce $2.7 million in annual sub-hourly dispatch cost savings for PGE. Under alternative scenarios with higher gas prices or higher renewable buildout in the region, EIM participation created $6.1 million in total sub-hourly dispatch cost savings to PGE. The study also indicates that pooling of flexibility reserves among EIM participants could provide an incremental $0.8 million in savings to PGE in the Base Scenario, for a total $3.5 million annually.

By comparison, we estimated annual sub-hourly dispatch cost savings of $4.6 million for PGE participation in a NWPP SCED in the Base Scenario, and up to $7.2 million in the high renewable resource sensitivity. Pooling of flexibility reserves among NWPP SCED participants could also yield an additional $0.7 million in savings to PGE in the Base Scenario. The table below summarizes the results for each scenario. The results represent gross benefits, and are not net of potential participation costs.

Table 2. Annual Savings to PGE from Participation in CAISO EIM or NWPP SCED (2015$ million)

Scenario	CAISO EIM Savings	NWPP SCED Savings
Sub-hourly Dispatch Savings Only		
Base Scenario	$2.7	$4.6
High Gas Price	$5.8	$6.4
Alt. Transmission Transfer	$3.0	N/A
High RPS Case	$6.1	$7.2
Dispatch and Reserve Pooling Savings		
Base Scenario with Reserve Pooling	$3.5	$5.3

Overall, this study estimates that participation in either the CAISO EIM or NWPP SCED would produce modest positive savings for PGE, and that savings from participation in either footprint would be larger either in the presence of higher gas prices or larger renewable resource buildout. Savings in the NWPP SCED reflect the presence of hydro resources providing low-cost flexibility in that footprint, as well as robust transmission transfer capability among those potential participants, especially through connections with the BPA footprint.[2]

Base Scenario savings to PGE are positive and modest due to a combination of factors. The Base Scenario uses a gas forecast provided to PGE by Wood MacKenzie,[3] which shows average fuel prices for PGE area generators of $3.5/MMBTU for 2020 (in 2015 dollars), a lower level than modeled in many previous studies. This resulted in relatively lower economic savings from

[2] An alternative transmission transfer scenario was developed for the CAISO EIM, in which real time transfer capability from PacifiCorp East (PACE) to PacifiCorp West (PACW) was increased from 200 MW to 400 MW, further supporting the idea that greater transmission capability can increase potential participation benefits.
[3] Based on monthly 2020 forwards from Wood Mackenzie North America Natural Gas Long-Term View Q2 2015 for Western area trading hubs.

operational improvements in generator dispatch efficiency. Additionally, PGE's generator portfolio mix modeled for 2020 includes flexible hydro resources and internal combustion (IC) gas units that can respond quickly to changes in sub-hourly needs, as well as a number of efficient and low-cost gas combined cycle resources. Also, the model's Base Scenario sets California's renewable build to meet a 33% RPS target. Recently approved legislation[4] raises that state's renewable portfolio target to 40% by 2024 and 50% by 2030, in addition to renewable distributed generation resources. These developments may provide increasing opportunities to purchase energy from California in real time at a low cost over time.

In addition to savings to PGE customers, we also estimate that PGE participation in the EIM would produce incremental savings of $2.7 to $3.7 million for the current EIM participants, and PGE participation in the NWPP SCED would create $2.7 to $3.2 million in incremental savings for the current SCED participants.

The focus of this analysis is to provide consistent, conservative estimates of operational cost savings to PGE for evaluation of participation in the EIM or the SCED. The study does not quantify potential benefits from improved dispatch in the hour-ahead (HA) market or day-ahead (DA) market, which may develop over time as information produced by the EIM or SCED informs more efficient DA and HA trading. The study also does not quantify any potential reliability benefits from EIM or SCED participation, which are difficult to quantify but may be substantial if participation ultimately assists participants in avoiding a major

[4] See California Legislature, 2015:
https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350.

outage. The study also does not quantify potential cost impact on generator maintenance cost as a result of reduced ramping of thermal units.

EIM and SCED market discussion

The EIM is a balancing energy market that optimizes generator dispatch within and between Balancing Authority Areas (BAAs) every 15 and 5 minutes.[5] The EIM can create real-time dispatch cost savings for EIM participants by: (1) using software tools to identify sub-hourly transactions that produce an optimized dispatch and minimize production costs, while respecting reliability limits; (2) bringing this optimized dispatch down to a 5-minute interval level; (3) incorporating optimized real-time unit commitment of quick-start generation.

Additionally, by allowing BAs to pool load and generation resources on a sub-hourly basis, the EIM can enable participants to reduce the number of units they individually need to commit for providing flexibility reserves within the hour. In December 2011, the CAISO implemented a flexible ramping constraint in the five-minute market optimization to maintain sufficient upward flexibility in the system within the hour.[6] Each generator that is chosen to resolve a constraint is compensated at the marginal generator unit's shadow price, which reflects the opportunity cost for production. The CAISO's calculation of flexible ramping constraints for EIM participants is adjusted downward to reflect diversity of net

[5] For more information regarding the EIM, see https://www.caiso.com/informed/Pages/EIMOverview/Default.aspx.
[6] See CAISO, 2014, Flexible Ramping Constraint Penalty Price In the Fifteen Minute Market. Available at: http://www.caiso.com/Documents/TechnicalBulletin-FlexibleRampingConstraintPenaltyPrice-FifteenMinuteMarket.pdf. The CAISO is in the process of introducing a flexible ramping product, which would allow economic bids to be submitted to procure upward and downward ramping capability.

loads for all participants, subject to transmission constraints. The CAISO determines flexible ramp constraint requirements for each EIM participant based on the aggregate load, wind, and solar resource forecasts and expected variability. By establishing the requirements based on the aggregate load and resource profiles, the benefits of diversity can be reflected in the EIM flexibility reserve requirements. The flexible ramping constraint in the EIM also compensates resources for their contribution to meeting the flexibility constraint. While pooling of flex reserves can reduce variable dispatch and generator commitment costs over time as operators accumulate greater experience with the EIM or SCED, participation in the EIM does not reduce the physical generation capacity that a BA needs to serve peak loads and provide system flexibility. Long-term capacity decisions are beyond the scope of this report and are more appropriately examined using other analytical approaches and modeling tools.

The NWPP has explored a number of initiatives to improve coordination among BAs in the Northwest region, including a "Security Constrained Economic Dispatch", or "SCED" with similar optimized dispatch as the EIM, as well as a centrally cleared economic dispatch (CCED) market intended to enhance trading volume and automation at the 15-minute level. In this study, PGE seeks to compare benefits from regional coordination between different market footprints with similar market functionality, so the study assumes that a NWPP SCED operates for its participants with identical functionality as the CAISO EIM.

Modeling Approach

This study analyzes the impact of PGE participation in the EIM or SCED using the PLEXOS production cost modeling software to simulate sub-hourly operations in the Western Interconnection for the year 2020. Energy Exemplar provided technical support to this study and implemented the sub-hourly production simulation runs in PLEXOS. Savings were identified in two categories: *sub-hourly dispatch benefits*, realizing the efficiency of optimized combined 15- and 5-minute dispatch and real-time unit commitment between PGE and the current EIM or SCED footprint; and *flexibility reserve pooling*, reflecting the diversity of load, wind and solar variability and uncertainty across PGE and the footprint of current EIM or SCED participants.

As a starting point, this study used the PLEXOS database developed by Pacific Northwest National Laboratory (PNNL) for the Western Electricity Coordinating Council's (WECC) Variable Generation Subcommittee (VGS) study from 2012-13[7] and revised as part of the NWPP Phase 1 EIM study from 2013.[8] Similar to those two studies, this analysis used a three-stage simulation process, including DA, HA, and real-time simulations stages to represent the different time horizons of actual power system operations. The DA and HA stages are simulated on an hourly basis.

[7] See WECC, 2013, Balancing Authority Cooperation Concepts to Reduce Variable Generation Integration Costs in the Western Interconnection: Intra-Hour Scheduling. Available at: http://energyexemplar.com/wp-content/uploads/publications/Balancing%20Authority%20Cooperation%20Concepts%20-%20Intra-Hour%20Scheduling.pdf.
[8] See Samaan, NA, et al., 2013, Analysis of Benefits of an Energy Imbalance Market in the NWPP. Available at: http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-22877.pdf.

This database approach was also refined in E3's 2014 analysis of EIM benefits for Puget Sound Energy (PSE).[9] For this PGE study, we have applied subsequent updates to reflect PSE's participation in the EIM in the base case, and to reflect input data provided by PGE staff and a technical review committee composed of experts from other utilities in the Northwest to improve the current representation of the regional system.

Sub-hourly dispatch savings are quantified by (1) running a real-time BAU case that holds energy transfers between non-participating BAs (including PGE) equal to the scheduled levels from the HA simulation but allowing EIM and SCED participants to transact with other participating BAs in the same real-time market, subject to transmission transfer limits; and (2) running EIM and SCED cases (starting from the same HA simulation as the BAU case) that each allow PGE to transact power within the hour with other EIM or SCED participants. The increased flexibility in the EIM and SCED cases produces a reduction in real time production costs for the region, which represents the total societal EIM- or SCED-wide savings as a result of PGE participation. Benefits are then divided between PGE and the current EIM or SCED participants based on the change in their generation cost and their net purchases and sales in real time.

Savings from flexibility reserve pooling are assessed by analyzing the coincidence of sub-hourly load, wind, and solar generation for each of the EIM or SCED members. Within the model, BAs not participating in the EIM or SCED are required to maintain flexibility reserves to meet 95% of the upward and

[9] See E3, 2014, Benefits Analysis of Puget Sound Energy's Participation in the ISO Energy Imbalance Market. Available at: https://www.caiso.com/Documents/PugetSound-ISO_EnergyImbalanceMarket-BenefitsAnalysis.pdf.

downward deviations of their individual BAA's real-time net load compared to their HA forecast. EIM and SCED participants are instead allowed to collectively meet a joint flexibility reserve requirement, which due to load and resource diversity is lower than the sum of individual BAA reserve requirements would be without EIM or SCED participation. PGE's participation in the EIM or SCED with flexibility reserve pooling can result in a lower level of flexibility reserves that PGE needs to hold on committed generators in the hour-ahead case on average, as well as an incremental reduction in flexibility reserve requirements for the current EIM or SCED participants.

Scenario Description

The Base Scenario of this analysis uses gas prices provided to PGE by Wood MacKenzie, which are $3.5/MMBtu on average for 2020 (in 2015 dollars). The Base Scenario also includes renewable resource development to meet current RPS targets for 2020. This includes a 33% RPS for California, a 20% RPS for PGE, and an average 15% renewable share for other NWPP SCED participants.[10] The base case also assumes that PGE fully self-integrates its wind resources, a transition away from its current operational practice in which BPA balances PGE's wind generation and transfers a flat quantity of power to PGE each hour. We also analyzed alternative scenarios which model a high gas price using $4.6/MMBTU gas prices for PGE (30% higher than in the Base Scenario), and a

[10] After reflecting other BAA loads, the Base Scenario renewables represented a 14% share of total in the PGE BAA. After reflecting imports from other BAAs, the model includes 30% renewable share of CAISO BAA load in the Base Scenario and 38% renewable share of CA BAA loads in the High RPS case (excluding behind-the-meter renewables).

higher renewable penetration of 25% RPS for PGE, 40% RPS for California, and 20% RPS for the other NWPP SCED participants.

<u>Summary of results</u>

The scenarios analyzed through this conservative approach resulted in modest positive sub-hourly dispatch cost savings in 2020 for PGE of $2.7 million in the EIM and $4.6 million in the NWPP SCED. PGE participation also provides incremental savings to other EIM or SCED participants. Pooling of flexibility reserves would provide an additional $0.8 million savings in the EIM and $0.7 million in the SCED. Over time, factors such as higher RPS or higher gas prices could result in large benefits for PGE participation in either footprint.

1 Introduction

Portland General Electric (PGE) engaged E3 to analyze the potential economic benefits of PGE's participation in either the CAISO EIM, or in a NWPP security constrained economic dispatch (SCED) assumed to have identical functional features as the EIM, but with a footprint comprised of a collection of NWPP Balancing Authority Areas (BAAs). As part of this analysis, E3 also assessed the production cost impact to PGE of transitioning to assume a larger degree of responsibility for balancing its wind located in BPA—first through use of a 30/15 schedule with BPA and then as full self-integration of the wind by dynamically scheduling the actual wind output from BPA to PGE in real time.

The study seeks to identify changes in dispatch and costs in the two real-time markets (CAISO EIM and NWPP SCED) and to compare how the different footprints of actual or potential members impact savings for PGE. The study also uses a parametric sensitivity analysis to test the robustness of savings results. Sensitivity scenarios include changing gas prices and the penetration level of intermittent renewable resources.

1.1 Context for Study

Utilities throughout the WECC have been increasingly interested in exploring a wider range of opportunities for improved coordination between neighboring BAAs. This has included the

+ CAISO EIM, which allows for a voluntary 5-minute market. The EIM began operating in November 2014 with PacifiCorp and CAISO as initial members. NV Energy announced their intentions to participate beginning in 2015, and Puget Sound Energy and Arizona Public Service have announced participation to begin in 2016.
+ Northwest Power Pool investigation of a SCED for real time sub-hourly transactions, similar to an EIM, as well as other opportunities to promote more active and liquid 15-minute trading in the region.

A number of studies have highlighted the benefits of improved regional coordination, particularly in a context of higher intermittent renewable resources on the system, which add to the flexibility needs required of each BA to address the higher variability and forecast error that results from adding those resources. PGE engaged E3 to conduct a comparative study of the impact and potential savings from PGE participation in either the EIM or a NWPP SCED. E3, working with Energy Exemplar, analyzed PGE participation using a three-stage zonal production simulation model of the Western Interconnection in PLEXOS. This study was done in close coordination with Energy Exemplar, PGE staff, and additional outside utilities, a technical review committee and advisory committees who assisted in refining the key assumptions of the study and the data inputs for both base cases and sensitivities. This report summarizes the results of that analysis.

1.2 Structure of this Report

The remainder of this report is comprised of the following sections:

+ **Section 2** describes the key study assumptions and methods used in this analysis.
+ **Section 3** presents the results of our analysis of PGE transitioning from wind integration status quo to using BPA's 30/15 wind scheduling option, and ultimately to full self-integration. For the purpose of this study, full self-integration becomes the Base Scenario in the EIM and SCED analyses discussed in subsequent sections.
+ **Section 4** presents the results of our analysis of PGE participation in the CAISO EIM.
+ **Section 5** presents the results of our analysis of PGE participation in a NWPP SCED.
+ **Section 6** compares the EIM and SCED results from Sections 4 and 5 and concludes the study.

2 Study Assumptions and Approach

2.1 Overview of Approach

The CAISO EIM allows participating Western BAs to voluntarily participate in CAISO's real-time energy market. EIM software dispatches generation across participating BAAs every 15 and 5 minutes to solve imbalances, as well as committing quick-start generation every 15 minutes using security constrained unit commitment (SCUC). An important distinction between the EIM and a Regional Transmission Organization is that in the EIM, each participating BA participating remains responsible for meeting its own operating reserve and planning reserve requirements, and the EIM does not replace participating BAs' existing operational practices for unit commitment and scheduling in advance of real-time.

This study quantifies the benefit of sub-hourly dispatch capability using a three-stage simulation process in PLEXOS consistent with the approach developed for the WECC Variable Generation Subcommittee (VGS) and refined in PNNL's Phase 1 Report for the NWPP MC Initiative. This methodology is described in detail in Section 2.4 below.

This study is designed to measure two principal types of benefits:

1. **Sub-hourly dispatch benefits**. Today, each BA in the Western Interconnection outside of the EIM typically dispatches its own internal generating resources to meet imbalances within the hour, while holding real-time exchange with neighboring BAs fixed to the hour-ahead schedule. The EIM can net energy imbalance across participating BAs and economically dispatch generating resources across the entire EIM footprint to manage the imbalance, resulting in operational cost savings. PGE's participation in an EIM enables incremental dispatch efficiency improvements relative to an EIM without PGE.

2. **Flexible reserve pooling**. BAs hold flexibility reserves to balance discrepancies between forecasted and actual net load within the hour. Load following flexibility reserves (referred to in this report as simply "flexibility reserves") provide ramping capability to meet changes in net load between a 5-minute and hourly timescale.[11] By pooling load, wind, and solar output across the EIM footprint, the EIM allows participants to benefit from greater geographic diversity of forecast error and variability by reducing the quantity of flexibility reserves they require. PGE's participation in the EIM or SCED has the potential to bring added load and resource diversity by broadening the real-time market footprint. This potential efficiency gained, through the creation of regional reserve sharing, can result in additional reserve savings.

[11] Regulating reserves address the need for resources to respond to changes inside of each 5 minute interval. Since the EIM operates with 5-minute intervals, it does not directly affect regulating reserve requirements. To be concise, all references to *flexibility reserve* in this report are related to load following reserves; *regulating reserves*, where referenced, are explicitly described by name.

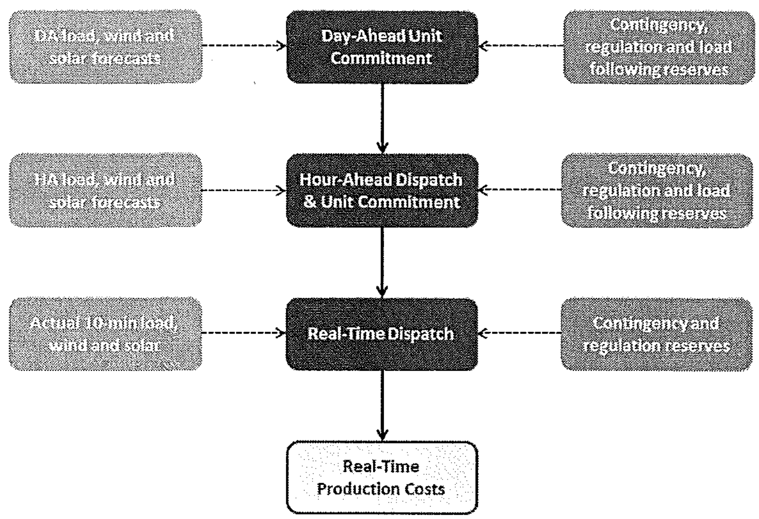
While the reserve diversity produced from pooling of flex reserves can reduce variable dispatch and generator commitment costs, especially over time as operators accumulate greater experience with the EIM or SCED, participation in the EIM does not reduce the physical generation capacity that a BA needs to serve peak loads and provide system flexibility. Long-term capacity decisions are beyond the scope of this report and are more appropriately examined using other analytical approaches and modeling tools.

2.2 Sub-hourly Dispatch Benefits Methodology

2.2.1 PRODUCTION COST MODELING

This study used PLEXOS, a sub-hourly production cost model, to estimate sub-hourly dispatch benefits in 2020. PLEXOS, like other production cost models, simulates bulk power system operations by minimizing the variable cost of operating the system subject to a number of constraints. PLEXOS includes a three-stage sequential simulation process to model DA, HA, and real-time operations, as shown in Figure 1 below.

Figure 1. PLEXOS Three-Stage Sequential Simulation Process



The primary purpose of the DA simulation is to generate daily unit commitment schedules for long-start units, while the HA simulation determines the HA dispatch as well as hourly interchange schedules between BAs. During the real-time simulation, the "actual" load, wind, and solar data are used to generate dispatch, and flexibility reserves are "released" so that the capacity reserved from the HA simulation is allowed to serve real-time imbalances. The DA, HA, and real-time sequential simulation approach allows PLEXOS to differentiate operations for BAs participating or not participating in the EIM or SCED. When a BA is not participating in a real-time market, then: (a) interchange is unconstrained during the DA and HA simulations; and (b) during the real-time simulation, the HA interchange schedule is locked down, resulting in the BA managing its imbalances with its own generation.

In contrast, during the real-time simulation, BAs participating in the EIM or SCED can re-dispatch generation and exchange power with the rest of the SCED or EIM footprint during each of the 10-minute intervals, subject to transmission transfer limitations, which are discussed in Section 2.3.2 below.

While the CAISO EIM operates down to a 5-minute level in actual practice, the most validated sub-hourly WECC dataset available for this analysis includes 10-minute intervals. Using the 10-minute intervals is a practical but conservative compromise of modeling 15-minute optimization with higher EIM transfer capability and modeling 5-minute optimization with potentially more limited EIM transfer capability across paths limited by dynamic transfer limitations across the California-Oregon Intertie (COI) and BPA network. In the final stage, the RT simulation for this study is run with 10-minute intervals, using actual wind, load, and solar output for each interval. While actual EIM operations are on a 5-minute basis, a complete and validated PLEXOS dataset for 5-minute simulation was not available at the time of this study. This study's use of 10-minute time step in the real-time stage (to make use of the WECC VGS dataset) produces EIM and NWPP SCED benefits results that we expect may be conservatively low, as the 10-minute time step reduces the amount of variation within the hour to a small extent, slightly moderating the need for operational flexibility that an EIM or SCED could provide. Overall, however, we expect the 10-minute time step to capture the majority of the real-time dispatch efficiency savings.

2.2.2 BAU SIMULATION

In the BAU case, PGE does not participate in either the EIM or SCED, and must resolve its real-time imbalances with internal generation only. PGE's real-time import and exports are held fixed to the hour-ahead schedule.

Real-time sub-hourly interchanges are simulated among BAAs that are assumed to be existing participants in either the CAISO EIM or NWPP SCED, reflecting the operational efficiencies realized by the CAISO EIM and NWPP SCED before including PGE participation. In other words, the CAISO EIM and NWPP SCED are already assumed to be fully operating without PGE's participation. As a result, savings and efficiencies associated with sub hourly dispatch for each alternative are included in the system cost. These costs serve as the "control" case to compare against the cases with PGE participation.

The BAU case includes operations of a "current EIM" consisting of the four BAAs that were participating or had announced plans to participate in the EIM at the start of this study.[12] For the NWPP SCED, the BAU case reflects operations of both the existing EIM, as well as an assumed "current SCED" composed of selected NWPP members. The BAAs assumed to be current participants in the EIM or SCED for the BAU Cases are listed in the table below.

[12] At the outset of this study, these four BAAs had already begun participation or had announced plans to participate in the EIM over the next two years. While this study was ongoing, APS also announced plans to begin participation in the EIM in 2016, but was excluded from the EIM for purposes of this study.

Table 3: BAA Participants in EIM or SCED in BAU Case

Current EIM participants for BAU Case	Current NWPP participants for BAU case
CAISO	Avista Corporation (AVA)
PacifiCorp East (PACE)	British Columbia Hydro (BCH)
PacifiCorp West (PACW)	Bonneville Power Administration (BPA)
NV Energy (NVE)	Idaho Power (IPC)
Puget Sound Energy (PSE)	Grant County PUD & Douglas County PUD & Chelan County PUD (collectively, MIDC)
	Northwest Energy (NWMT)
	Sacramento Municipal Utilities District (SMUD)
	Seattle City Light (SCL)
	Tacoma Power (TPWR)
	Western Area Power Administration – Upper Great Plains West Region (WAUW)

2.2.3 PGE EIM AND PGE SCED SIMULATIONS

The PGE EIM and PGE SCED cases simulate real-time dispatch with PGE participating in either the CAISO EIM or the NWPP SCED. In each of these cases, intra-hour interchange between PGE and existing EIM or SCED participants is allowed up to the assumed transmission transfer limits.

2.3 Key Modeling Assumptions

Four key modeling assumptions are important for understanding the results of this study: (1) sub-hourly dispatch; (2) real-time transmission capability; (3) hurdle rates; and (4) flexibility reserves.

2.3.1 SUB-HOURLY DISPATCH

In existing operational practice, BAs in the Western Interconnection exchange energy primarily on an hourly basis using hourly or multi-hour schedules, or standardized energy products which include On-Peak, Off-Peak, and Flat energy blocks. These products require long lead times between scheduling the transaction and actual dispatch.[13] Within the hour, each BA resolves imbalances by dispatching generating resources inside its BAA, without the assistance of other BAs. By contrast, the EIM optimizes dispatch of available generating resources in real time across all of the participating BAAs using 15-minute unit commitment and 5-minute dispatch. These sub-hourly processes increase the efficiency of resolving imbalances.

2.3.2 REAL-TIME TRANSMISSION TRANSFER CAPABILITY

Previous studies have indicated that transmission can constrain EIM benefits by limiting the amount of power that can be transferred in real time between participants. This study's transmission topology was built on that of E3's PSE EIM study from 2014 and was updated with the help of public data on transmission transfer capability and input from Technical Review Committee (TRC) members who engaged transmission experts within their organizations representing several BAs in the Northwest.

As this study looks at the benefits of PGE joining the CAISO EIM or a NWPP SCED, two different real-time market footprints were created. PGE's BAA has direct connections with three other BAAs: CAISO and PACW, which are in the

[13] The CAISO EIM and AESO are the exceptions.

CAISO EIM, and BPA, which is in the NWPP SCED footprint. PGE has rights along the COI to CAISO of 296 MW southbound and 450 MW northbound. The transfer capability between PGE and PACW is 448 MW in both directions. BPA's BAA surrounds PGE and thus has a large transfer capability of 4,093 MW in both directions. This robust transfer capability with BPA is important for NWPP EIM savings, as BPA shares significant transmission with most of the other BAs in the NWPP SCED footprint. Zonal depictions of the CAISO EIM and NWPP SCED footprints modelled in this study are shown in Figure 2 and Figure 3.

Figure 2. Real-time Transfer Capabilities across the CAISO EIM with PGE Footprint

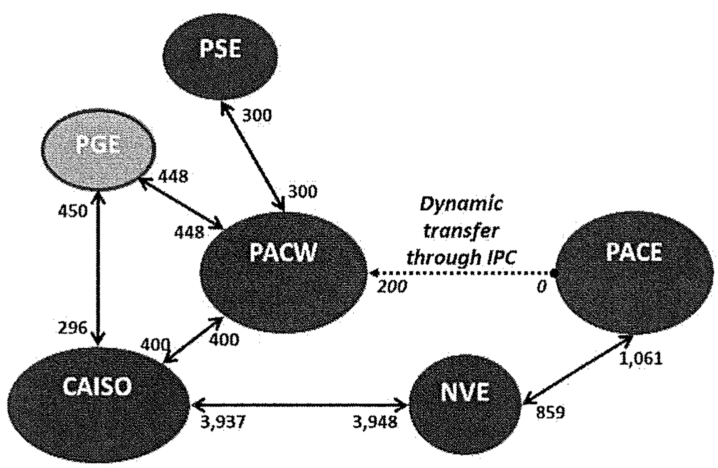
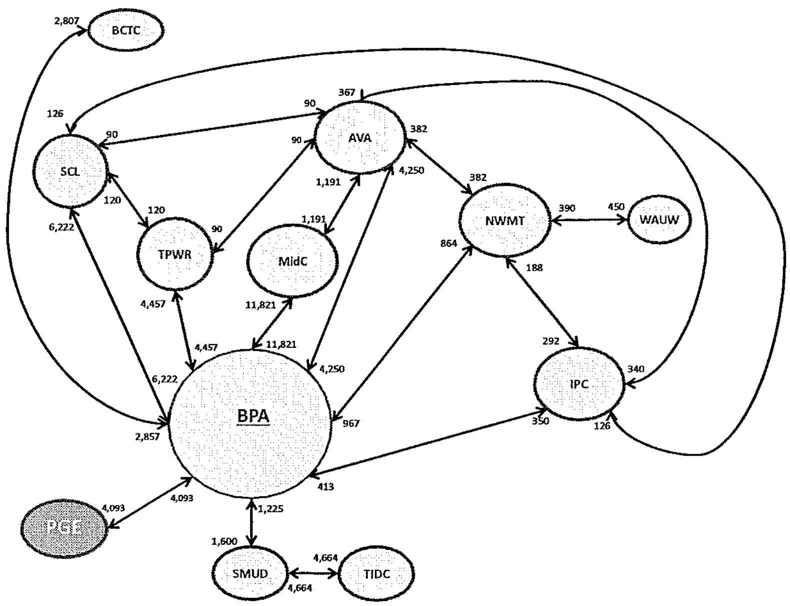


Figure 3. Real-time Transfer Capabilities across a NWPP SCED with PGE Footprint



2.3.3 HURDLE RATES

Within the Western Interconnection's bilateral markets, there are a number of impediments to efficient trade of energy across BAA boundaries. These include:

+ The need, in many cases, for market participants to pay for the fixed costs of the existing transmission system by redirecting or acquiring additional point-to-point transmission service in order to schedule transactions from one BAA to another;
+ The current tariff practice of requiring short-term transactions to provide real power losses for each transmission provider system that is utilized, in some cases resulting in multiple or "pancaked" loss requirements that are added to the fixed costs described above; and
+ Inefficiencies related to having illiquid bulk power and transmission service markets and imperfect information, such DA block trading products, minimum transaction quantities of 25 MW, and the bilateral nature of transaction origination and clearing.

These real-world barriers to trade are reflected in production cost simulations as "hurdle rates", which are applied as $/MWh price adders to energy transfers on interfaces between BAAs. Hurdle rates are applied in the DA and HA cases to inhibit power flow over transmission paths that cross BAA boundaries, to represent these inherent inefficiencies and reduce economic energy exchange between BAAs.

The EIM or SCED eliminates the barriers listed above during real-time operations by performing security-constrained economic dispatch across the entire EIM footprint, allowing more efficient (i.e., lower cost) dispatch. Our production simulations in PLEXOS capture this effect by removing hurdle rates in real time.

Intra-hour exchanges among participants in the EIM and SCED are allowed during the real-time simulation cases. The simulation does not allow incremental intra-hour exchanges (beyond the HA schedule) between BAAs that are non-participants in an EIM or SCED or between the two real-time markets. The absence of hurdle rates in real time in this analysis is consistent with the FERC-approved CAISO tariff amendment associated with the EIM.

In the DA and HA simulations, hurdle rates are maintained between all BAAs, including between EIM participants.[14] We believe this is a conservative assumption regarding the expected adaptation of DA and HA markets based on information identified by the EIM. In reality, we would expect that BAs may adjust their DA and HA scheduled transactions more efficiently over time based on learning the dynamics of the real-time market results. This learning does not imply a shift away from DA and HA scheduling, but rather a more efficient and better informed selection of scheduling levels for any hour based on learning from real-time market participation. To the extent it can be realized, this opportunity for learning and improved DA and HA efficiency is a non-quantified benefit that would be additional to those quantified in this report.

In addition to the hurdle rates described above, charges for CO_2 import fees related to AB32 are still applied to energy transfers from BAs outside of California to California BAs. These charges are applied in all cases, including real-time.

[14] This approach—to maintain hurdle rates for the DA and HA simulation and remove them in the real-time simulation run—is consistent with the methodology used by PNNL in the NWPP's MC Phase I EIM Benefit study. PGE's Technical Review Committee also reviewed and discussed this approach.

For interties among the current EIM participants, hurdle rates were applied to the DA and HA cases, but removed during the real-time case runs for both the BAU and EIM cases.

BAs hold flex capacity in reserve to balance differences between forecasted and actual net load within the operating hour; these within-hour reserves are in addition to the spinning and supplemental reserves carried against generation or transmission system contingencies.[15] Regulating reserves automatically respond to control signals or changes in system frequency on a time scale of a few cycles up to every 5 minutes. For the purposes of this study, distinct load following reserves (referred to in this report simply as "flexibility reserves") provide ramping capability to meet changes in net load and variable energy resources between a 10-minute (as modeled in this study) and hourly timescale. Higher penetrations of wind and solar increase the quantity of both regulating and flexibility reserves needed to accommodate the uncertainty and variability inherent in these resources, while maintaining acceptable BA control performance.

2.3.4 POOLING OF FLEXIBILITY RESERVE REQUIREMENTS

By pooling load and resource variability across space and time, total variability of the combined net load for participants in the EIM or SCED footprint can be reduced, decreasing the amount of flexibility reserves required to ensure reliable operations. This reduces operating costs by:

[15] This study assumes that contingency reserves would be unaffected by an EIM, and that PGE would continue to participate in its existing regional reserve sharing agreement for contingency reserves.

- requiring fewer thermal generators to be inefficiently committed and operated, and
- decreasing flex reserve requirements placed on hydro resources, enabling them to more efficiently generate energy at times most valuable to their systems.

Units that provide regulating reserves must respond faster than the EIM's 5-minute dispatch interval, so EIM participants are assumed here to receive no regulating reserve diversity savings as a result of participating in the EIM.

While there is currently no uniformly defined requirement for BAs to carry flexibility reserves, all BAs must maintain Area Control Error (ACE) within acceptable NERC-defined limits, which necessitates that BAs hold reserves on generators to respond to within-hour changes in load and variable resource output. These reserve needs will grow under higher renewable penetration scenarios.

Additionally, in December 2014, the CAISO implemented a flexible ramping constraint in the five-minute market optimization to maintain sufficient upward flexibility in the system within the hour.[16] Generators that are chosen to resolve a constraint are compensated at the generation shadow price, which reflects the marginal unit's opportunity cost. Furthermore, the CAISO is in the process of

[16] See CAISO, 2014, Flexible Ramping Constraint Penalty Price In the Fifteen Minute Market. Available at: http://www.caiso.com/Documents/TechnicalBulletin-FlexibleRampingConstraintPenaltyPrice-FifteenMinuteMarket.pdf.
See also CAISO, 2014, Flexible Ramping Products Revised Straw Proposal. Available at: http://www.caiso.com/Documents/RevisedStrawProposal_FlexibleRampingProduct_includingFMM-EIM.pdf.

introducing a flexible ramping product, which would allow economic bids to be submitted to procure upward and downward ramping capability.

The CAISO's calculation of flexible ramping constraints for EIM participants is adjusted to reflect diversity of net loads for all participants, subject to transmission constraints. The CAISO determines flexible ramp constraint requirements for the CAISO and each EIM participant based on the aggregate load, wind, and solar resource forecasts and expected variability. By establishing the requirements based on the aggregate load and resource profiles, the benefits of diversity can be reflected in the EIM flexibility reserve requirements. The flexible ramping constraint in the EIM also compensates resources for their contribution to meeting the flexibility constraint.

2.3.4.1 Reserves in BAU Case

In the BAU case, the simulation cases calculated flex reserve requirements for PGE as a standalone entity, assuming that PGE needs to respond to intra-hour variations and forecast errors of its own load and variable resources, including wind resources located in the BPA footprint that PGE is assumed to self-integrate in the Base Scenarios. Reserves in the BAU case for the current EIM and SCED participants (which do not include PGE) are reduced to reflect diversity across each footprint.

2.3.4.2 Reserves in PGE EIM & SCED Case (no flex reserve pooling)

In the EIM and SCED cases without flex reserve pooling, reserves requirements were kept identical to those in their respective BAU cases.

2.3.4.3 Reserves in PGE EIM & SCED Cases (with flex reserve pooling)

In the EIM and SCED cases with flex reserve pooling, reserves requirements for PGE and the existing EIM or SCED participants were reduced to reflect the diversity in load shapes and outputs of wind and solar resources, across the expanded EIM or SCED footprint which includes PGE. The reduction in reserve requirements is applied proportionally for each participant.

2.4 Detailed Scenario Assumptions

2.4.1 INPUT DATA

The initial dataset used for this study is the database used in E3's *Benefits Assessment of Puget Sound Energy Participation in the ISO EIM*[17], which applied PSE- and CAISO-specific updates to the database originally developed for the NWPP Phase 1 EIM analysis. The NWPP database was built on the Transmission Expansion Planning Policy Committee (TEPPC) 2020 PC0 database,[18] with numerous modeling updates to improve the representation of BAAs in the Northwest.[19]

[17] See E3, 2014, Benefits Assessment of Puget Sound Energy Participation in the ISO EIM. Available at: http://pse.com/aboutpse/EnergySupply/Documents/PSE-ISO_EIM_Report_wb.pdf.
[18] It is based on PNNL's Base Case (1.86a) for the NWPP, which itself was modified from a data set and had been developed for use with the PLEXOS sub-hourly model for PNNL's 2012 study for the WECC Variable Generation Subcommittee (VGS).
[19] For a detailed discussion of the updates the NWPP Analytical Team made to improve upon the TEPPC PC0 case, see Section 2 of Samaan et al., 2013, Analysis of Benefits of an Energy Imbalance Market in the NWPP. Available at: http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-22877.pdf.

This study for PGE further refined the study database used in the PSE EIM analysis. These refinements are described below in more detail. Utilizing this database allowed this study to reflect the best available information compiled to represent BAAs in the Northwest.

This study made the following key updates to the case:

+ **Topology updates.** The 2014 PSE EIM study was used as a starting point. From this starting point, modifications were made to the zonal topology using information obtained through Open Access Same-Time Information System (OASIS), Northern Tier Transmission Group (NTTG), and the WECC Path Rating Catalog. Additional information was also gathered from discussions PGE arranged with transmission experts representing several BAs in the Northwest.
+ **Gas prices.** To maintain consistency with PGE's Integrated Resource Plan, gas prices were based on monthly 2020 forwards from Wood Mackenzie North America Natural Gas Long-Term View Q2 2015. These data were translated from hub prices to BA- or plant-specific burner tip prices using the mapping of pipelines, variable transport fees, and other adjustments outlined in the NWPP Phase 1 assessment.
+ **Hydro optimization window.** In practice, PGE plans its dispatch of flexible hydro units up to a week in advance to optimize the value of its reservoirs. This flexibility of hydro generation is prominent in the Northwest. Yet modelling hydro as such in PLEXOS runs the risk of unrealistically optimizing hydro dispatch with perfect foresight over a very long time horizon, without reflection of forecast error in identifying when the hydro will most be needed. Therefore, to balance dispatchable hydro units and maintain flexibility, while preventing perfect foresight, dispatchable hydro units for this study are optimized

with a 24-hour optimization window. In this study, hydro modeling is handled through a series of interactions between simulation stages: monthly hydro energy budgets, which are database inputs, are allocated to each day using PLEXOS's monthly MT simulation based on anticipated load, wind, and solar across the month. Then, the DA and HA simulation stage first optimizes the hydro for each hour based on a DA and HA forecast of hourly load, wind and solar, constrained by the daily generation budget. The RT simulation is permitted to update the hourly hydro schedule across the day to respond to real-time needs within each of the six 10-minute sub-hourly intervals each hour but must maintain the same daily hydro energy total.

+ **Renewable generation updates in California**. In addition to the select generator updates that were made in the CAISO footprint in the PSE EIM study, this analysis has also updated the CAISO renewable resource mix to reflect a higher expected share of solar PV in the 2020 renewable resource portfolio and lower share of wind resources, based on current and planned additions for meeting the state's 33% RPS target by 2020. The resource mix was also adjusted to include additional rooftop PV solar in the CAISO, which was not reflected in the original TEPPC model.

+ **Generation updates in PGE**. PGE recommended a number of changes be made to its generator fleet, many of which were small adjustments to capacity, heat rate, and other operating characteristics. The most notable changes include: (1) splitting up Colstrip Generating Station's four coal-fired units among AVA, NWMT, PACW, PGE, and PSE to reflect ownership and allow for real-time dispatch; (2) adding 210 MW of incremental wind capacity to reflect PGE's 2020 RPS goals; (3) adding PGE's new Port Westward Unit 2, a 220 MW fleet of 12 highly flexible natural gas-fired internal combustion engines; (4) adding the 440 MW combined cycle gas turbine at Carty Generating Station, which is scheduled to come online in 2016; (5) restructuring the generators at

PGE's Beaver facility to better represent the Beaver Combined Cycle Station (units 1-7) and the standalone combustion turbine Beaver Unit 8; (6) removing the Marion Covanta municipal solid waste burning facility since PGE does not control that unit's dispatch; and (7) moving shares of Rock Island and Rocky Reach Hydro Projects to CHPD and shares of Wells Dam to DOPD to reflect expiring contracts.

2.4.2 PGE WIND GENERATION ASSUMPTIONS

Because all of PGE's wind generators are physically located in BPA's BAA, special considerations for these generation profiles and flexibility reserves must be made. Three scheduling regimes were modeled in this study in which the flexibility reserves burden and associated costs between BPA and PGE vary.

+ **BPA Integrates PGE's Wind (using 30/60 schedule).** Under this regime, which is in implementation as of the writing of this report, PGE participates in BPA's Variable Energy Resource Balancing Service (VERBS) under the 30/60 Committed Scheduling. In exchange for fixed and variable payments, BPA sends PGE a generation quantity for each 60-minute schedule period that is based on wind output 30 minutes prior to that period and that includes linear 20-minute border interpolation. Of the three scheduling regimes, the flexibility reserves burden is the highest for BPA and the lowest for PGE in this case. This was modeled as a sensitivity scenario.
+ **PGE Participates in 30/15 Committed Scheduling.** PGE will be moving to this BPA VERBS option in late 2015. Similar to but more granular than the 30/60 scheduling, this regime sends PGE its wind generation based on a t-30 minute observation every 15 minutes. Because the real-time data in this study's database is in 10-minute intervals, 30/15 scheduling was modeled as 30/20 scheduling in which the scheduled transfers for

every twenty minute interval is based on the t-30 minute forecast. Relative to BPA Full Integration, this scheduling regime shifts some flexibility reserves responsibility from BPA to PGE. This was also modeled as a sensitivity scenario.

+ **PGE Self-Integration.** In this regime, PGE's wind generators were placed in the PGE BA for modeling purposes. This regime was used in all other sensitivity cases as well as the base case. This scheduling regime represents PGE's largest flexibility reserves burden out of the three, and BPA no longer needs to commit resources to manage PGE's wind. This option became the default regime for the Base Scenario for this study.

Figure 4. 30/20 Scheduling from 10-min Interval Profile and HA Forecast from 10-min Interval Profile

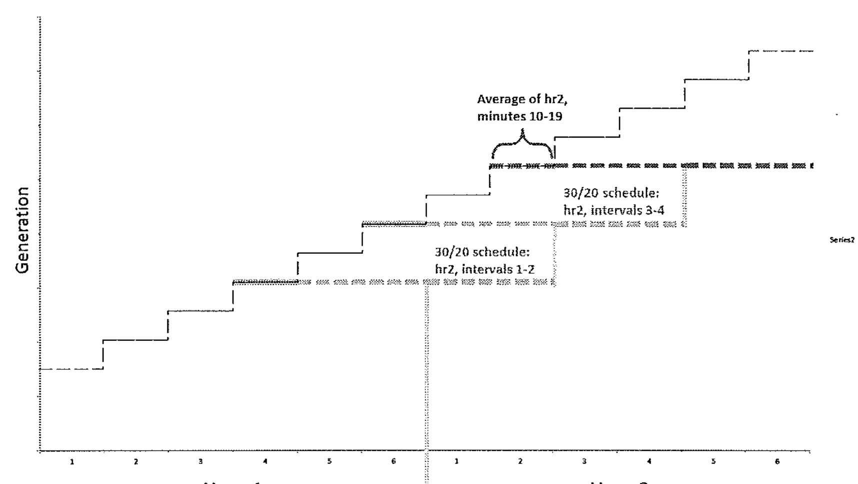
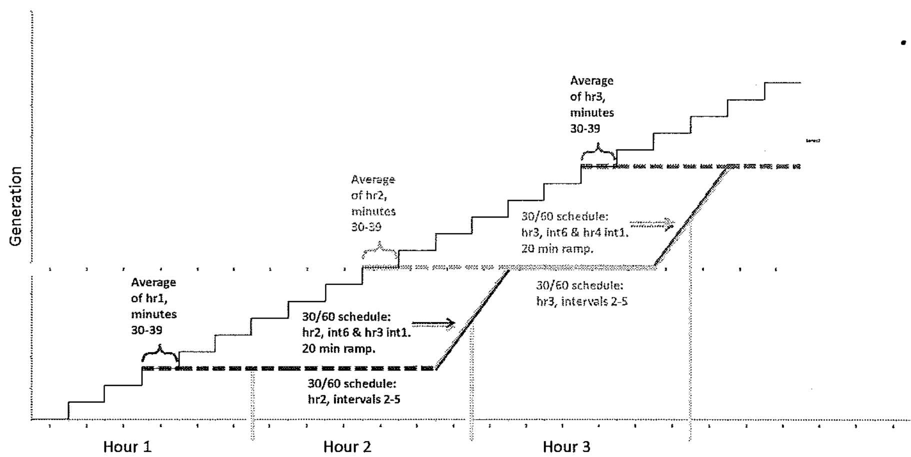
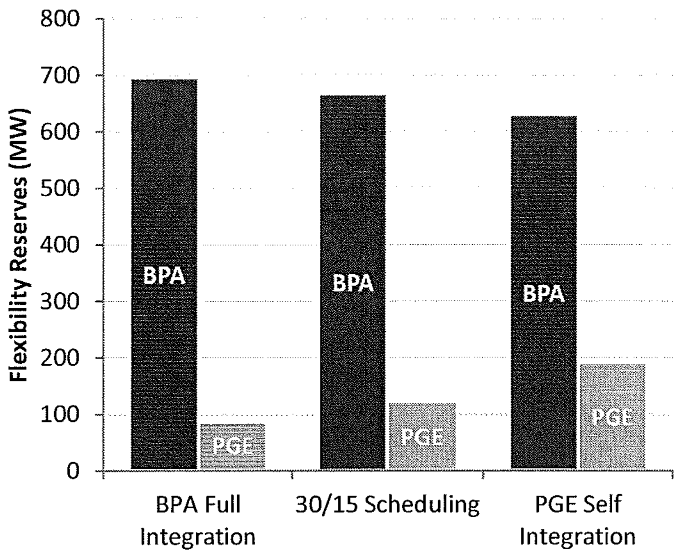


Figure 5. 30/60 Scheduling with 20-min Ramps from 10-min Interval Profile



Modelling the different wind regimes involved altering RT BAU wind profiles for BPA and PGE and changing the load following and regulating reserves accordingly. In the base scenarios, PGE Self-Integration was represented by placing PGE's wind generators in PGE's BA, and reserves were calculated to reflect PGE's full responsibility of managing their variability. In the BPA Full Integration and 30/15 Scheduling scenarios, PGE's RT BAU wind became 30/60 and 30/20 profiles from the forecasts based on the "actual" 10-minute interval profiles as described above and shown in the figures. The difference between PGE wind's "actual" 10-minute generation and the forecasts scheduled to PGE is the error for which BPA is responsible in managing. For modelling purposes, this forecasting error was split into surplus and deficit, with the surplus as an extra wind generator for BPA and the deficit as a load adder for BPA.

Figure 6. Average Load-Following Up Reserves across Scheduling Regimes for PGE Wind



2.4.3 DISPATCH SAVINGS SCENARIOS

The dispatch savings were evaluated under 11 scenarios with different assumptions regarding PGE's EIM membership, reserves reduction from resource diversity pooling, PGE's wind scheduling regime, natural gas prices, real-time transfer capability between PAC regions, and RPS levels in California and the Northwest. The scenarios were developed based on input from PGE staff to highlight changes that PGE believed both plausible to occur and also valuable to explore to test the robustness of EIM savings. Table 4 summarizes the assumptions used for each scenario modeled for calculating sub-hourly benefits.

Because PGE is interested in the relative benefits of joining the current CAISO EIM[20] or a NWPP SCED, this study has two base scenarios: one in which PGE joins the CAISO EIM and another in which PGE joins a NWPP SCED in which 11 northwestern BAs[21] operate a SCED under the same assumptions as the CAISO EIM. Both base scenarios are subjected to three sensitivities: (1) flexibility reserves are reduced to represent the potential reduction in reserve obligation as a result of a flexibility reserve pooling; (2) natural gas prices are increased throughout the WECC; and (3) significant renewable generation is added in California and throughout the Northwest. In addition to the two base scenarios and their three corresponding sensitivities, two scenarios test PGE's dispatch costs associated with varying responsibility between PGE and BPA for balancing PGE's wind. One last scenario that applies to the CAISO EIM case only increases the transfer capability from PACE to PACW from 200 MW to 400 MW.

[20] In all scenarios, CAISO, PAC, NVE, and PSE are assumed to be already participating in the CAISO EIM in order to provide the most accurate baseline scenario, given the information available over the course of this study.
[21] AVA, BCTC, BPA, IPC, MidC, NWMT, SCL, SMUD, TIDC, TPWR, and WAUW

Table 4. Overview of EIM Scenario Assumptions

	RPS Target*						
Scenario	PGE	CAISO	NWPP	PGE natural gas price ($ per MMBTU)	PACE-PACW Line (MW)	PGE Wind Scheduling Regime	Flex Reserve Reductions **
1. CAISO EIM Base	20%	33%	15%	$3.5	200	PGE Self	-
2. NWPP SCED Base	20%	33%	15%	$3.5	200	PGE Self	NWPP SCED
3. CAISO EIM Reduced Reserves	20%	33%	15%	$3.5	200	PGE Self	CAISO EIM with PGE[1]
4. NWPP SCED Reduced Reserves	20%	33%	15%	$3.5	200	PGE Self	NWPP SCED with PGE[1]
5. CAISO EIM High Gas	20%	33%	15%	$4.6	200	PGE Self	-
6. NWPP SCED High Gas	20%	33%	15%	$4.6	200	PGE Self	NWPP SCED
7. CAISO EIM High RPS	25%	40%	20%	$3.5	200	PGE Self	-
8. NWPP SCED High RPS	25%	40%	20%	$3.5	200	PGE Self	NWPP SCED
9. 30/15 Scheduling	20%	33%	15%	$3.5	200	BPA 30/15	PGE[2]
10. BPA Full Integration	20%	33%	15%	$3.5	200	BPA Full	PGE[2]
11. CAISO EIM PAC Line Update	20%	33%	15%	$3.5	400	PGE Self	-

*PGE BAA includes non-PGE customers, resulting in a smaller renewable energy share of BAA load than RPS target; CAISO RPS includes renewable energy from out of state imports, does not reflect behind the meter PV generation.
**Changes in load-following flexibility reserves are relative to a case with PGE self-integrated wind and CAISO EIM reserves reduced for CAISO, PAC, NVE, and PSE
[1] Reserves reduced to reflect an increase in diversity from pooling resources
[2] Reserves reduced due to BPA's larger responsibility for managing PGE's wind variability

Table 5. Renewable Capacity Added in High RPS Scenario (MW)

Region	EIM	Wind	Solar PV	Geothermal
PGE	-	484		
PG&E_VLY	CAISO	2,489	1,973	
SCE	CAISO	514	1,724	491
SDGE	CAISO	102		
AVA	NWPP	774		
BPA	NWPP	1,737	135	
FAR EAST (IPC)	NWPP	139		
MAGIC (IPC)	NWPP	120		
SMUD	NWPP	498	616	
TIDC	NWPP		84	
TREAS (IPC)	NWPP	101		

2.5 Flexibility Reserve Savings Methodology

The operational cost savings from reduced flexibility reserve requirements were estimated using the following methodology. To estimate cost savings from reduced flexibility reserve requirements, we took the difference in benefits from two scenarios: (1) a base scenario in which PGE joins an EIM without altering reserves; and (2) a reduced reserves scenario in which statistical analysis is used to determine the quantity of flexibility reserve diversity that PGE's participation would bring to an EIM.

2.5.1 FLEXIBILITY RESERVE REQUIREMENT

To determine flexibility reserve requirements, we used the real-time (10-minute) and HA schedule of load, wind, and solar data developed through the WECC VGS and PNNL study. This data is used to calculate a distribution of flexibility needs (i.e., real-time net load minus the HA net load schedule). Each BA's flexibility reserve requirements for each month and hour are calculated using a 95% confidence interval (CI), where the 2.5th and 97.5th percentiles determine the flexibility down and up requirements, respectively.[22]

2.5.1.1 Base Scenario – CAISO EIM

For the Base Scenario – CAISO EIM, the flexibility requirements for BAs in the current CAISO EIM were calculated with the following methodology. First, requirements were calculated with the 95% CI of the net load imbalance for CAISO, PAC, NVE, and PSE individually, which represent the requirements if these four BAs had to manage reserves themselves. Then, the net load profiles for the four CAISO BAs were summed before calculating the 95% CI, which was then averaged by month to produce monthly average requirements for CAISO BAs with diversity reduction.[23] Monthly averages of the individual BAs' requirements generated in the first calculations were summed to monthly average requirements for CAISO BAs without diversity reduction. The monthly average requirements with diversity were divided by those without diversity to

[22] Using the 95% confidence interval to calculate flexibility reserve requirements is consistent with the approach used in the NWPP EIM Phase 1 study.
[23] Due to diversity in forecast error and variability, the 95th percentile of aggregated real-time deviation from HA forecast for the entire EIM is a smaller level (relative to the size of the BAs) than it would be for the sum of individual EIM members.

produce monthly diversity factors by which the individual BA requirements were reduced. PGE's requirements were calculated as a standalone entity and not reduced.

2.5.1.2 Base Scenario – NWPP SCED

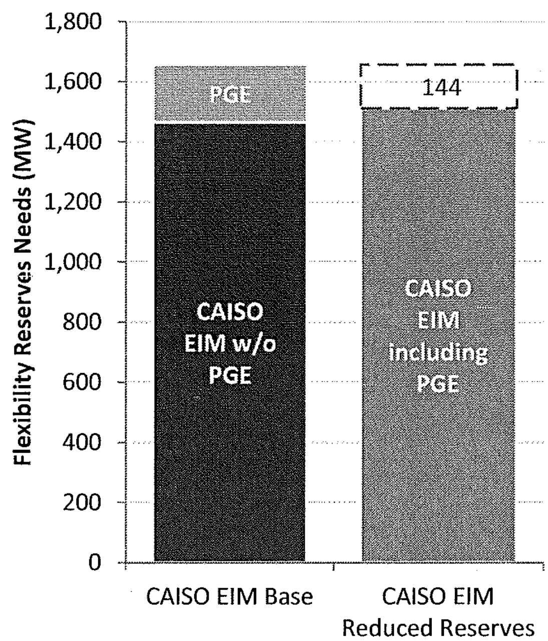
For the Base Scenario – NWPP SCED, the flexibility requirements for BAs in the current CAISO EIM were carried over as calculated in the section above. That same methodology was then applied to the BAs that would represent a NWPP SCED: AVA, BCTC, BPA, IPC, MidC, NWMT, SCL, SMUD, TIDC, TPWR, and WAUW. In this scenario as well, PGE's requirements were calculated as a standalone entity and not reduced.

2.5.1.3 Reduced Reserves Scenario – CAISO EIM

For this study, we used statistical analysis to estimate the reduction in flexibility reserves that would occur if PGE participates in the EIM or a NWPP SCED. Flexibility reserve requirements for each BA were modeled as a function of the difference between the 10-minute net load in real time versus the HA net load schedule.

For the Reduced Reserves Scenario – CAISO EIM, flexibility reserves were derived similarly to the CAISO EIM Base Scenario but included PGE in the diversity adjustment calculations. That is, PGE's individually calculated monthly average requirements were added to the CAISO EIM's monthly average requirements without diversity, and PGE's net load contributed to the CAISO EIM's monthly average requirements with diversity. This produced monthly diversity factors lower than the CAISO EIM Base Scenario, which were similarly applied to each BA's individually calculated requirements – including PGE in this scenario – in order to reduce reserves requirements for diversity. PGE's contribution to the CAISO EIM's flexibility reserves is valued by the increase in benefits from the Base Scenario to the Reduced Reserves Scenario.

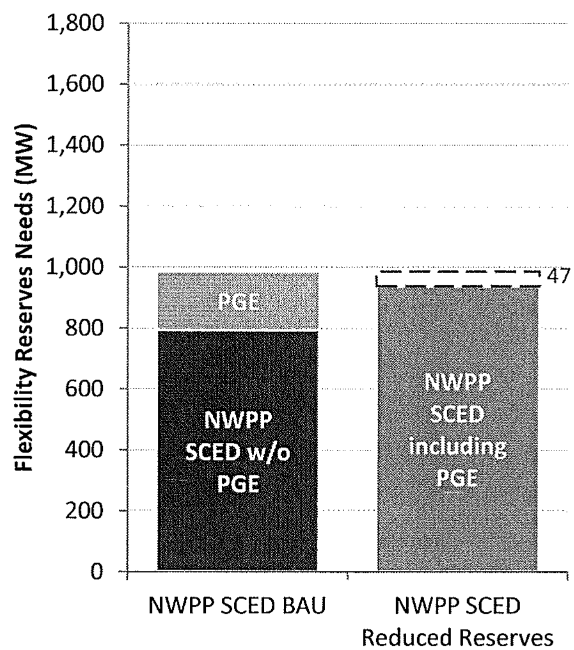
Figure 7. Load-Following Reserve Reduction for Participation in CAISO EIM



2.5.1.4 Reduced Reserves Scenario – NWPP SCED

For the Reduced Reserves Scenario – NWPP SCED, flexibility reserves were derived similarly to the NWPP SCED Base Scenario but included PGE in the diversity adjustment calculations. That is, PGE's individually calculated monthly average requirements were added to the NWPP SCED's monthly average requirements without diversity, and PGE's net load contributed to the NWPP SCED's monthly average requirements with diversity. This produced monthly diversity factors lower than the NWPP SCED Base Scenario, which were similarly applied to each BA's individually calculated requirements – including PGE in this scenario – in order to reduce reserves requirements for diversity. This approach reduced reserves beyond the optimal level, so after several iterations, this reduction was decreased by 50%. This produced a reserve reduction beneficial to both PGE and the NWPP SCED as a whole. PGE's contribution to the NWPP SCED's flexibility reserves are valued by the increase in benefits from the Base Scenario to the Reduced Reserves Scenario.

Figure 8. Load-Following Reserve Reduction for Participation in NWPP SCED



2.6 Methodology for Attributing Benefits to PGE and Other Participants

To evaluate the benefits yielded by an EIM, we calculated the difference between procurement costs in a business-as-usual case and in an EIM case. There are three components of total procurement costs in our model: hour-ahead net import costs, real-time imbalance costs, and real-time generation costs. First, we define a few terms.

+ Hour-ahead net imports: the hourly difference between imports and exports.
+ Locational marginal price (LMP): a given BA's generation shadow price in a certain time period (the cost of generating the next MWh of electricity).[24]
+ Real-time imbalance: the within-hour energy imbalance found in the EIM or SCED cases, where trading occurs at 10-minute intervals.
+ Average LMP: the imbalance-weighted average of all EIM or SCED BAs' LMPs.

Hour-ahead net import costs are calculated as the product of hour-ahead net imports and the locational marginal price, and then summed over all hours in the year. Real-time imbalance cost to a given BA is a 10-minute interval's imbalance multiplied by that interval's average LMP, summed over all 10-minute intervals in the year. Real-time generation costs include the variable costs of energy production modelled in PLEXOS – fuel prices, variable operation and maintenance charges, and startup costs.

Total savings associated with an EIM or SCED are the difference between the sum of hour-ahead net import costs, real-time imbalance costs, and real-time generation costs in the business-as-usual case and the EIM case. In most scenarios, the hour-ahead simulation is identical for the business-as-usual and the EIM case, meaning the hour-ahead net import costs can be ignored in the

[24] The minimum LMP used for calculating benefits was set to -$100/MWh, which is the model's penalty price for overgeneration. In overgeneration conditions, renewable resources may be curtailed but also could require replacement costs for renewable energy to fulfill RPS goals in some jurisdictions.

calculation. Table 6 provides an example of benefits parsing that highlights the methodology discussed in this section.

Table 6. Benefits Parsing in the Base Scenario, PGE in CAISO EIM

Costs (2015$ million)*	Business-as-Usual	CAISO EIM	EIM Savings
Real-Time Generation Costs	318.5	305.0	13.6
Real-Time Imbalance Costs	0.1	11.0	-10.9
Total Real-Time Procurement Costs	**318.6**	**315.9**	**2.7**

Note: Individual estimates may not sum to total due to rounding.

The reduced reserves scenarios were designed to highlight the additional savings associated with the reduction of reserves in an EIM case. The additional savings over base scenario savings are the additional benefits of the reserve reduction. However, this means that the reduced reserves EIM case must be compared to the HA and BAU cases of the base scenarios. As reserve levels differ between the two scenarios, the hour-ahead simulations will differ, and hour-ahead net imports will differ. The difference in net imports between the BAU case and the EIM case was priced at the EIM case's LMP as the EIM is the case where incremental transactions would take place.

3 Results: BPA Full Integration, 30/15 Scheduling, and PGE Self-Integration

As described in Section 2.4.2, PGE currently uses a scheduling service from BPA in which BPA integrates PGE-owned wind located in BPA's BAA and schedules energy to PGE's BAA on a 30/60 basis (also described here as "BPA Full Integration"). The anticipated transition of PGE to scheduling wind from BPA on a 30/15 basis shifts greater responsibility to PGE for managing wind variations compared to the hour-ahead persistence forecast. PGE now must move its internal generators on a 15-minute basis to address changing volumes of wind energy schedules from BPA that may be higher or lower than the hour-ahead forecast or the previous 15-minute schedule. We would expect this transition to have an upward impact on PGE's costs (excluding the impact of any potential changes to BPA service charges).

A future transition to full PGE self-integration of the wind resources, in which BPA transfers the wind output to PGE on a real-time basis, would have a larger upward operational cost impact for PGE as it would include dealing with variations throughout the hour and on a moment-by-moment basis. As noted in the previous section, it will also require PGE to carry more flexibility reserves going into each hour to be able to respond better to wind output changes.

These upward cost impacts may be offset by avoidance of BPA integration charges, but those service charges have not been considered in this study. Table 7 below displays the marginal increase in annual production costs to PGE in a given scenario, relative to BPA full integration.

Table 7. Changes in Annual Variable Costs to PGE by Wind Scheduling Regime

Costs (2015$ million)	30/15 Scheduling*	PGE Self-Integration	Percent Cost Increase (Full Self-Integration vs. 30/15)
PGE Production cost impact compared to BPA full integration	0.2	1.0	400%

*We modeled the 30/15 scheduling scenario as 30/20 scheduling, since the PLEXOS model includes only 10-minute sub-hourly time step granularity. Under 30/15 scheduling, PGE would encounter one additional change per hour compared to the PLEXOS modeling. Positive values represent an increase in production cost compared to BPA full integration

The modeling results indicate that the scenario with 30/15 scheduling creates a $0.2 million increase in production cost compared to BPA full integration. A further transition to PGE self-integration adds an additional $1.0 million in cost relative to BPA full integration and is $0.8 million higher than 30/15 scheduling. This represents a relative cost increase approximately four times larger than the change from BPA full integration to 30/15 scheduling.

This directional impact and relative cost change is in line with expectation, as self-integration places higher balancing demands on PGE's system than 30/15 scheduling and, in turn, relative to BPA full integration. The small magnitude of these cost impacts is likely reflective of a number of conservative assumptions used in the study approach and the PLEXOS model, which lead the simulation scenarios to identify a relatively low cost strategy for serving additional system balancing needs. The conservative assumptions inherent to the PLEXOS model consist of the ability to optimize PGE's hydro dispatch over a 24-hour period without cascading inflow constraints (i.e. flow impacts on a coordinated river system), no multi-stage constraints related to daily gas nomination/usage for PGE units, the use of single heat rates for each generation unit, no modeling of increased maintenance costs associated with unit cycling, and the nature of the NW bilateral markets compared to a WECC-wide optimization. This case was also modeled without significant bid-ask transaction spreads for hour-ahead purchases. Additionally, the relatively uniform efficiency of PGE's CCGT current and projected fleet in the model and the low gas average price forecast of $3.5/MMBTU for 2020 used in these scenarios result in relatively small cost changes for changes to gas portfolio dispatch efficiency.

4 CAISO EIM Results

4.1 Benefits to PGE

Table 8 below presents the simulated annual benefits of PGE participation in the CAISO EIM in 2020 under each sensitivity scenario. Each cell in the table represents the incremental benefit to PGE as a result of its participation in the CAISO EIM. These savings are each calculated as the reduction in cost compared to a PGE Self-Integration case representing the BAU. Overall, the dispatch cost savings range from $2.7 million in the base scenario to $6.1 million for PGE in the high RPS scenario. Reduced reserves in the CAISO EIM would provide PGE an additional $0.8 million of savings for the base scenario. While not directly modeled, these savings are likely applicable to the other scenarios at a similar level—resulting in $0.8 million higher total savings for all scenarios after considering the reserves requirement impact. Thus, the maximum total savings would range from $3.5 to $6.9 million.

Table 8. Annual Benefits to PGE by Scenario, CAISO EIM (2015$ million)

Scenario	Dispatch cost savings to PGE	Additional Cost savings from Flex Reserve Pooling	Total savings including dispatch and reserves
Base	$2.7	$0.8	$3.5
Sensitivity Scenarios			
High Gas Price	$5.8		
PAC Transmission Update	$3.0		
High RPS	$6.1		

*Dispatch cost savings for Sensitivity Scenarios are shown as alternatives to the Base case, not cumulative additions. Reserves savings were not modeled for the Sensitivity Scenarios.

CAISO EIM base scenario savings to PGE were $2.7 million with a decrease in annual real-time procurement costs (real-time generator production cost plus real time imbalance cost of purchases and revenue from sales) from $318.6 million in the BAU case to $315.9 million in the PGE EIM case, as described in section 2.6. As mentioned earlier, the base scenario assumptions were chosen conservatively; the savings over the range of sensitivity scenarios were uniformly higher than in the base scenario. Section 4.3 goes into more detail for each sensitivity scenario.

4.2 Incremental Benefits to Current EIM Participants

Table 9 below presents the simulated incremental benefits resulting from PGE's EIM participation to the current participants in the CAISO EIM. PGE's EIM participation is expected to create $2.5 to $3.7 million in savings to the current CAISO EIM participants across all scenarios. The base case savings for PGE and for the existing EIM participants differ by less than $0.1 million.

Table 9. Annual Benefits to Current CAISO EIM Participants by Scenario (2015$ million)

Scenario	Incremental savings to Existing EIM Participants	Additional Cost savings from Flex Reserve Pooling	Total savings
Base	$2.7	-$0.2	$2.5
	Sensitivity Scenarios		
High Gas Price	$2.7		
PAC Transmission Update	$2.8		
High RPS	$3.7		

*Dispatch cost savings for Sensitivity Scenarios are shown as alternatives to the Base case, not cumulative additions. Reserves savings were not modeled for the Sensitivity Scenarios.

4.3 CAISO EIM Results Discussion

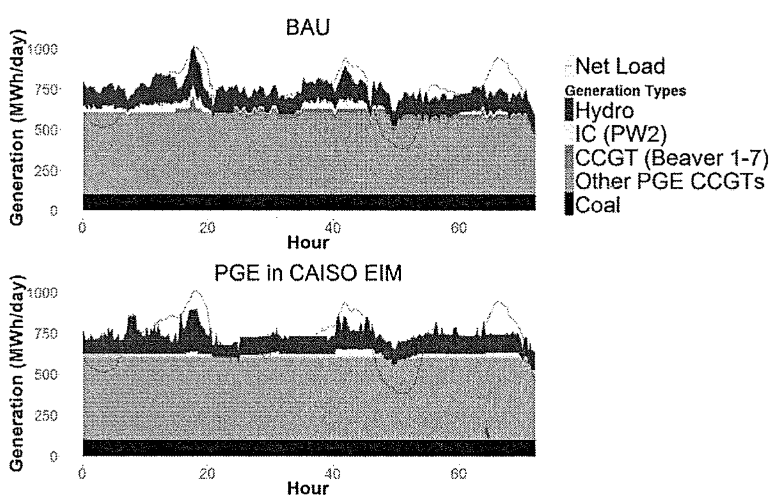
4.3.1 BASE SCENARIO

The CAISO EIM base scenario brings $2.7 million of savings to PGE, as well as $2.7 million to the existing EIM participants. Various factors underlie EIM participation benefits in the scenarios modeled. In all scenarios, EIM participation enables PGE to export and import in real time with other EIM participants to respond to intra-hour imbalances. This relieves PGE of the need to start up and run its most expensive gas generators—in particular, its higher marginal cost CCGT plant, Beaver Units 1-7. In addition to lower overall output, the EIM scenario also reduces the number of yearly starts of Beaver 1-7 by 37 during the year, which yields a material amount of savings. The within-hour flexibility provided by the EIM also enables PGE to run its share of Colstrip coal units at optimal efficiency, when, in the business-as-usual simulation, PGE is frequently forced to ramp

Colstrip dispatch up and down during the spring seasons to provide additional flexibility, reducing operating efficiency.

The following chart provides a closer graphical look at the relationship between savings and generation, displaying PGE's dispatchable generation in real time over a three-day period in December with significant production cost savings to PGE relative to BAU levels.

Figure 9. PGE Real-Time Dispatchable Generation, CAISO EIM, December 12-14



The reduction in starts of the Beaver CCGT plant (Units 1-7) is most notable in this figure. Over this three-day period, PGE alternates between importing and exporting energy with neighboring BAAs. EIM participation enables greater flexibility in transaction, allowing PGE to have more economic trades within the hour and to import in certain hours to avoid higher-priced thermal dispatch.

4.3.2 RESERVES POOLING SCENARIO

The CAISO EIM reduced reserves scenario brings $3.5 million of savings to PGE, which is $0.8 million higher than the savings in the CAISO EIM base scenario. In the reduced pooling sensitivity scenario, additional diversity from EIM participation reduces the load-following reserve requirements, leading to additional dispatch flexibility for PGE and greater savings than in the base scenario. The savings associated with reduced reserves are relatively small - $0.8 million relative to the base scenario, and would likely be in a similar range if additional reserve reductions were applied to other sensitivities.

4.3.3 HIGH GAS PRICE SCENARIO

The CAISO EIM high gas price scenario brings $5.8 million of savings to PGE, which is $3.1 million higher than the savings in the CAISO EIM base scenario. PGE often relies on its gas generators and IC units for much of its generation flexibility. The high gas scenario greatly increases the cost of this business-as-usual method of providing flexibility. Hence, the additional flexibility provided by the EIM becomes much more valuable when gas prices are high.

At the same time, four of PGE's gas generators (the Port Westward CC unit, Carty, the Boardman Replacement unit, and Coyote Springs) are more efficient than all but two gas generators in the entire CAISO EIM (the exceptions being small CTs in CAISO and PACE) in the high gas price scenario. Accordingly, PGE's gross exports increased much more upon joining the EIM in the high gas scenario than in the base scenario, as Table 10 illustrates. Savings from joining the EIM are significantly higher in the high gas scenario than in the base scenario ($3.1 million) as a result of these two phenomena.

Table 10. PGE Annual Gross Exports in Base Case and High Gas Scenario (GWh)

Scenario	BAU	EIM	Increase
Base	1,838	2,214	376
High Gas	1,794	2,350	556

4.3.4 UPDATED PACIFICORP TRANSMISSION SCENARIO

The CAISO EIM scenario with updated PAC transmission assumptions produces savings $0.3 million higher than the savings to PGE in the CAISO EIM base scenario (=$3.0 million in the PacifiCorp alternative transmission case - $2.7 in the base case). Savings to PGE in the scenario with a 200 MW increase in transfer capability from PACE to PACW were slightly higher than in the base scenario. We initially hypothesized that more transmission capacity would allow all EIM participants to take advantage of greater trading capabilities with PACE and increase savings somewhat over the base scenario. However, the increase in savings over the base scenario was negligible.

4.3.5 HIGH RPS SCENARIO

The CAISO EIM high RPS scenario brings $6.1 million of savings, which is $3.4 million higher than the savings in the CAISO EIM base scenario to PGE. As expected, a higher renewables portfolio standard increased savings to PGE dramatically, as the EIM provides valuable resources for low-cost handling of the added variability in net load.

5 NWPP SCED Results

5.1 Benefits to PGE

Table 11 below presents the simulated annual benefits of PGE participation in a NWPP SCED in 2020 under each sensitivity scenario. It is important to note that these are the projected benefits from PGE becoming the twelfth member of an already-functioning eleven-member SCED. Each cell in the table represents the incremental benefit to PGE as a result of its participation in a NWPP SCED.

Further, it is assumed for the purposes of this study that the market functionality of the rules of a NWPP SCED is largely similar to that of the CAISO EIM.

Table 11. Annual Benefits to PGE by Scenario, NWPP SCED (2015$ million)

Scenario	Dispatch cost savings to PGE in SCED	Additional Cost savings from Flex Reserve Pooling	Total savings
Base	$4.6	$0.7	$5.3
Sensitivity Scenarios			
High Gas Price	$6.4		
High RPS	$7.2		

*Dispatch cost savings for Sensitivity Scenarios are shown as alternatives to the Base case, not cumulative additions. Reserves savings were not modeled for the Sensitivity Scenarios.

The expected EIM benefits to PGE range from $4.6 million in the base scenario to $7.2 million for the study year in the high RPS scenario. NWPP SCED base scenario savings to PGE were $4.6 million with a decrease in annual procurement costs from $437.4 million to $432.8 million. As mentioned earlier, the base scenario assumptions were chosen conservatively; the savings over the range of sensitivity scenarios were almost uniformly higher than base scenario savings. Section 5.3 goes into more detail for each sensitivity scenario.

5.2 Incremental Benefits to Current NWPP SCED Participants

Table 12 below presents the simulated incremental benefits to the proposed original participants in the NWPP SCED resulting from PGE's participation.

Table 12. Annual Benefits to Participants of a NWPP SCED (2015$ million)

Scenario	Incremental savings to Existing SCED Participants	Additional Cost savings from Flex Reserve Pooling	Total savings
Base	$2.7	-$1.1	$1.6
Sensitivity Scenarios			
High Gas Price	$2.8		
High RPS	$3.2		

*Dispatch cost savings for Sensitivity Scenarios are shown as alternatives to the Base case, not cumulative additions. Reserves savings were not modeled for the Sensitivity Scenarios.

5.3 NWPP SCED Results Discussion

5.3.1 BASE SCENARIO

The NWPP SCED reduced reserves scenario brings $4.6 million of savings to PGE. Various factors underlie EIM participation benefits in the scenarios modeled. In all scenarios, EIM participation enables PGE to export and import in real time with other EIM participants to respond to intra-hour imbalances. This relieves PGE of the need to start up and run its higher heat rate gas generators, such as the Beaver 1-7 CCGT plant. These sub-hourly operations from participation in the NWPP SCED also enable PGE to run its share of the Colstrip coal plant more efficiently, particularly during the spring season with high hydro runoff. Another major driver of PGE savings in the SCED is reduced dispatch of the higher marginal cost Beaver plant. In addition to lower overall output, the EIM scenario decreases the number of annual starts at the Beaver plant from 100 down to 31, yielding a material cost reduction.

5.3.2 REDUCED RESERVES SCENARIO

The NWPP SCED reduced reserves scenario brings $5.3 million of savings to PGE, which is $0.7 million higher than the savings in the NWPP SCED base scenario. In the reduced reserves sensitivity scenario, additional diversity from EIM participation yields lower load-following reserve requirements, leading to additional dispatch flexibility for PGE and greater savings than in the base scenario.

5.3.3 HIGH GAS PRICE SCENARIO

The NWPP SCED high gas price scenario brings $6.4 million of savings to PGE, which is $1.8 million higher than the savings in the NWPP SCED base scenario. PGE relies on their gas generators and IC units for much of their generation flexibility. The high gas scenario greatly increases the cost of this business-as-usual method of providing flexibility. Hence, the additional flexibility provided by the EIM becomes much more valuable when gas prices are high, and savings from joining the EIM are significantly higher than in the base scenario (by $1.8 million).

5.3.4 HIGH RPS SCENARIO

The NWPP SCED high RPS scenario brings $7.2 million of savings to PGE, which is $2.6 million higher than the savings in the NWPP SCED base scenario. As expected, a higher renewables portfolio standard increased savings to PGE dramatically, as a SCED would provide valuable resources for low-cost handling of the added variability in net load.

6 Summary: Comparison of Results for CAISO EIM and NWPP SCED

6.1 Differences in Savings

Table 13 below illustrates the differences in savings to PGE in the base scenario and sensitivity scenarios between the CAISO EIM and a NWPP SCED.

Table 13. Annual Savings to PGE from Participation in CAISO EIM or NWPP SCED (2015$ million)

Scenario	CAISO EIM Savings	NWPP SCED Savings
Sub-hourly Dispatch Savings only		
Base Case	$2.7	$4.6
High Gas Price	$5.8	$6.4
Alt. Transmission Transfer	$3.0	N/A
High RPS Case	$6.1	$7.2
Dispatch and Reserve savings		
Base Case with Reserve Pooling	$3.5	$5.3

Across all scenarios, PGE savings from a NWPP SCED are $0.5 to $2 million higher than savings from the CAISO EIM. Against the backdrop of nearly $440 million in simulated yearly procurement costs for PGE, these numbers are fairly small but worth consideration.

6.1.1 BASE SCENARIO

The base scenario savings for PGE joining the CAISO EIM are $2.7 million, and the base scenario savings for PGE joining a NWPP SCED are $4.6 million, a difference of $1.9 million. In both scenarios, PGE manages to run Beaver CCGT Units 1-7 less in a NWPP SCED or CAISO EIM compared to the respective BAU cases (see the blue circle in Figure 10 and Figure 11). PGE is able to start the Beaver units even fewer times in the NWPP SCED than in the CAISO EIM—31 starts compared to 71, which provides additional savings. Overall, PGE's gas dispatch is lower and at a smoother output level in a NWPP SCED than in the CAISO EIM, particularly during the spring season.

Figure 10. PGE Daily Dispatchable Generation, CAISO EIM

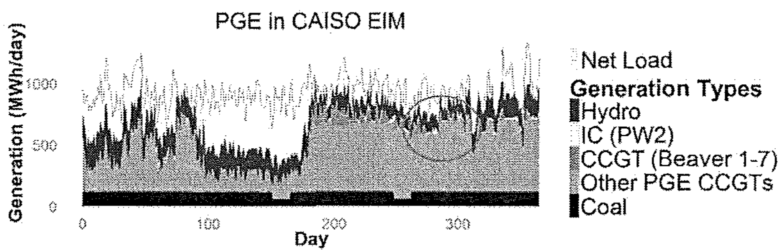
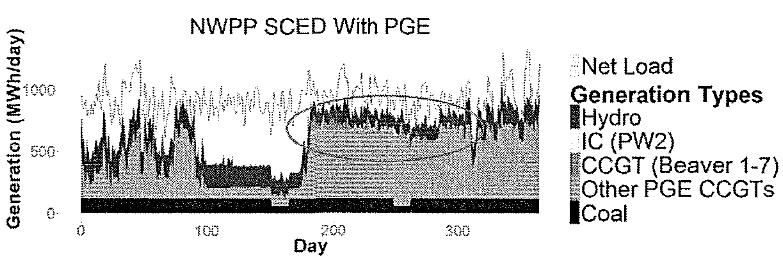


Figure 11. PGE Daily Dispatchable Generation, NWPP SCED



6.1.2 REDUCED RESERVES SCENARIO

The reduced reserves scenario savings for PGE joining the CAISO EIM are $3.5 million, and the reduced reserves scenario savings for PGE joining a NWPP SCED are $5.3 million, a difference of $1.8 million. This difference is commensurate with the base case difference, as reserves provide similar value in both the EIM and SCED.

6.1.3 HIGH GAS PRICE SCENARIO

The high gas price scenario savings for PGE joining the CAISO EIM is $5.8 million, and the high gas price scenario savings for PGE joining a NWPP SCED is $6.4 million, a difference of $0.6 million. The high gas price scenario's generation illustrates an informative dispatch difference between the CAISO EIM and NWPP SCED scenarios. In most months, the gas generation difference between the base scenario and high gas price scenario is zero for both the CAISO EIM and NWPP SCED. Yet in April and May, NWPP SCED gas generation is cut by 50% in the high gas price scenario as compared to the base scenario, while CAISO EIM gas generation decreases by only 20%. PGE increases output of one or more gas plants nontrivially in four months in the CAISO EIM but only in one month in a NWPP SCED. PGE's ability to leverage its gas generation in the CAISO EIM but not in a NWPP SCED brings the savings gap between the two scenarios closer than in any other scenario, to just $0.6 million.

6.1.4 HIGH RPS SCENARIO

The high RPS scenario savings for PGE joining the CAISO EIM are $6.1 million, and the high RPS scenario savings for PGE joining a NWPP SCED are $7.2 million, a difference of $1.1 million. The NWPP SCED BAs' high levels of hydro generation enable them to respond well to the increases in net load variability associated with a high RPS even in the base scenario. Thus, the incremental benefit of a NWPP SCED is relatively lower than that of the CAISO EIM, which cannot as efficiently meet the much more variable net load in this scenario.

Exhibit 403C

Confidential

UE XXX / PGE / 500
Cody

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE XXX

Pricing

PORTLAND GENERAL ELECTRIC COMPANY

Direct Testimony and Exhibits of

Marc Cody

April 1, 2016

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.

Q. What is the purpose of your testimony?

A. This testimony describes the following:

- The estimated base rate price impacts from this filing anticipated to occur on January 1, 2017.
- The calculation of Schedule 125 prices.
- The calculation of the changes in the applicable System Usage and Distribution prices for individual rate schedules related to Special Conditions 1 and 2 of Schedule 129 Long-Term Transition Adjustment.

PGE will file the final Schedule 125 prices incorporating the final updates to Net Variable Power Costs (NVPC) on November 15. The changes in the other applicable base rate schedules will also be filed at that time.

Q. What are the base rate impacts of the proposed $28.8 million reduction in Schedule 125 prices?

A. Table 1 below summarizes the estimated 2017 COS base rate impacts for selected rate 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	-1.4%
Sch 32 Small Non-residential 30 kW or less	-1.4%
Sch 83 Non-residential 31-200 kW	-1.7%
Sch 85 Secondary 201-4,000 kW	-1.3%
Sch 85 Primary 201-4,000 kW	-1.3%
Sch 89 Primary Over 4,000 kW	-1.4%
Sch 89 Subtransmission Over 4,000 kW	-1.3%
Schedule 90 Over 100 MWa	-1.4%
COS Overall	-1.4%

Q. What other price changes do you expect to occur on January 1, 2017?

A. I anticipate changes to various supplemental schedules to occur on January 1, 2017:

1) The Schedule 102 Regional Power Act Credit will change because, presuming normal weather, the current amortization of the $10.8 million owed to customers in the balancing account should be largely complete by the end of 2016.

2) For Schedule 105 Regulatory Adjustments, the current $3.1 million credit for the Power Resources Cooperative transaction will be reduced to approximately $226,000. Also, the $2.6 million credit for Port Westward capital costs will terminate at the end of 2016. In addition, PGE will amortize the intervener funding balancing accounts (approximately $1.2 million) through Schedule 105. Other miscellaneous items may also be amortized through Schedule 105.

3) Schedule 109 Energy Efficiency Funding Adjustment may have price changes because the ETO may wish to increase the level of funding for energy efficiency. PGE will obtain more information from the ETO this summer.

4) The Schedule 122 Renewable Resource Automatic Adjustment Clause prices will reflect the updated revenue requirements of the PPS Solar project from UE 297 and remove the current amortization of the $2.9 million property sale gain.

5) Schedule 123 Decoupling will continue to be a credit for Schedule 7 and 32 customers in 2017. PGE does not yet have enough information to develop estimates of the LRRA portion of Schedule 123 applicable to other rate schedules.

6) Schedule 143 Spent Fuel Adjustment will be priced to amortize a credit of approximately $17 million in 2017 pursuant to the UE 294 Stipulation. This will be an increase in prices relative to the 2016 credit prices that will be implemented when the Carty generation station becomes operational in 2016.

7) Schedule 145 Boardman Power Plant Decommissioning Adjustment will have minor prices changes due to applicable projected energy and revenue requirement.

II. Calculation of Schedule 125 Prices

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

A. I determine the Schedule 125 amount by comparing the projection of 2017 NVPC to the amount of NVPC that is recovered through the NVPC portion of current energy prices (NVPC prices), multiplied by the 2017 load forecast by schedule (NVPC revenues). The difference between 2017 NVPC and NVPC revenues constitutes the Change in NVPC. This amount, either positive or negative, is multiplied by 1.0335 to account for revenue sensitive costs such as uncollectibles and franchise fees. Page 1 of PGE Exhibit 501 provides a summary of the Schedule 125 amount of ($28.8) 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 501 demonstrates the calculation. I multiply the NVPC prices determined in UE 294 by the respective projected energy billing determinants to calculate the amount of NVPC projected to be recovered for the 2017 test period. For 2017, I project NVPC revenues of $451.4 million. This amount is carried over to Page 1 of PGE Exhibit 501 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. I 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 2017 Base Generation Revenues?

A. I present this calculation, which is simply the 2017 projected energy billing determinants times the tariff energy prices inclusive of Carty, on page 2 of PGE Exhibit 501.

Q. For the calculation of 2017 generation revenues, do you include the impacts of Carty on the prospective energy prices?

A. Yes. I use the current energy prices adjusted for the prospective Carty incremental energy prices in calculating prospective 2017 energy revenue. I also include the impacts of Carty's UE 294 dispatch benefits of approximately $1.5 million in the NVPC prices.

Q. Do you also include the effects of the change in how state and federal production tax credits (PTCs) are included in fixed and variable energy prices?

A. Yes. Consistent with the testimony in PGE Exhibit 400, I adjust the UE 294 fixed and variable energy prices such that UE 294 fixed prices are increased by approximately $81.5 million and UE 294 NVPC prices are reduced by the same amount. PGE Exhibit 502 contains a step-by-step analysis of how the fixed and NVPC prices are adjusted for both PTCs and Carty.

III. Calculation of System Usage and Distribution Prices

Q. Why do you propose to change the System Usage and Distribution Prices for the various rate schedules?

A. I propose this because it is consistent with Special Conditions 1 and 2 of Schedule 129. These Special Conditions specify that PGE annually true-up the collections or credits related to prospective Schedule 129 payments made by long-term direct access (LTDA) customers at the time that PGE files final rates for Schedule 125.

Q. How do you allocate the Schedule 129 Transition Adjustment payments from LTDA customers to the rate schedules?

A. Consistent with Special Condition 1 of Schedule 129, I allocate the prospective Schedule 129 payments from LTDA customers who enrolled prior to the 2014 service year to Schedules 85, 89, 90 and their direct access equivalent schedules. I allocate the Schedule 129 payments received from customers who enrolled effective 2014 and later to all customers on the basis of equal cents per kWh. I then compare these allocations of 2017 Schedule 129 payments to the amount that is currently embedded in the System Usage and Distribution prices determined in UE 294. For Schedules 85, 89, 90 and their direct access equivalent schedules, the System Usage Charges are expected to increase by 0.52 mills/kWh. For other schedules, the System Usage or Distribution Charges are expected to decrease by 0.01 mills/kWh. PGE Exhibit 503 contains the detail behind the price change calculations.

Q. In addition to truing-up the Schedule 129 Transition Adjustment payments, what other factors may cause changes to the System Usage or Distribution Charges?

A. Should additional enrollment in LTDA occur in September 2016 for service commencing in 2017, PGE will allocate the additional Schedule 129 Transition Adjustments from that enrollment window consistent with Special Condition 1, and, additionally, allocate the incremental changes in fixed generation revenues consistent with Special Conditions 2 and 3.

Q. How do you propose to adjust the fixed generation costs and applicable Schedule 129 transition adjustments consistent with the change in PTCs mentioned above?

A. Consistent with the UE 262 Second Partial Stipulation, LTDA customers who enroll for the 2015 service year and thereafter are subject to changes in the Schedule 129 Transition Adjustments commensurate with Commission-approved changes in PGE fixed generation costs. However, for the 2015 and 2016 LTDA vintage customers, it would be unjust to adjust their transition adjustments by the full amount of the change in fixed generation costs due to a reclassification of PTC credits from a fixed cost to a variable cost. Therefore, I propose to adjust the fixed generation costs, and hence the Schedule 129 Transition Adjustments for these two vintages on the basis of the <u>change</u> in PTCs embedded in prices from UE 294. This seems most consistent with the manner in which other customers will be treated due to the change in legislation. This change in the amount of PTCs embedded in prices, approximately 0.30 mills/kWh, will be used to update the Schedule 129 transition adjustments for the 2015 and 2016 LTDA customers effective January 1, 2017. PGE will have to continue to separately account for the 2015 and 2016 LTDA vintages until the cessation of their Schedule 129 Transition Adjustments, commencing in 2020 and 2021.

For the 2017 vintage enrollment window that PGE will file in June and September, PGE intends to use the fully adjusted fixed generation costs, because the projections of NVPC will include the full amount of projected PTCs by year.

Q. Do you have an exhibit that provides details regarding the prospective changes in PTCs applicable to Schedule 129 for the 2015 and 2016 LTDA vintages?

A. Yes. PGE Exhibit 504 demonstrates the calculation of the unit change in PTCs by rate schedule.

Q. Does a potential change in the Distribution Charges for the Outdoor Lighting Schedules 15, 91, 95, 491, 495, 515, 591, and 595 mean that the Compliance Filing to this docket may include changes to the numerous fixture prices included in these schedules?

A. Yes. The true-up of Schedule 129 Transition Adjustments may require changes in the fixture prices for these rate schedules.

IV. Qualifications of Witness

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, rate design, and tariff administration.

Q. Does this complete your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
501	Calculation of Schedule 125 Prices
502	Calculation of Adjusted Fixed and Variable Generation Prices
503	Calculation of System Usage and Distribution Prices
504	Calculation of Unit Changes in PTCs

PORTLAND GENERAL ELECTRIC
Calculation of Schedule 125 Prices

Schedules	2017 Calendar COS Energy MWh	2017 Base Generation Revenues	Generation Allocation	2017 Base NVPC Revenues	Sch 125 Allocation	2017 NVPC Revenues	2017 Sch 125 Price mills/kWh	2017 Sch 125 Revenues
Schedule 7	7,619,900	$531,968	45.76%	$206,271	($13,184)	$193,087	(1.73)	($13,182)
Schedule 15	16,086	$907	0.08%	$352	($22)	$329	(1.40)	($23)
Schedule 32	1,605,508	$104,149	8.96%	$40,362	($2,581)	$37,781	(1.61)	($2,585)
Schedule 38	30,948	$1,856	0.16%	$722	($46)	$676	(1.49)	($46)
Schedule 47	21,027	$1,591	0.14%	$617	($39)	$578	(1.88)	($40)
Schedule 49	64,687	$4,874	0.42%	$1,890	($121)	$1,769	(1.87)	($121)
Schedule 83	2,870,906	$184,067	15.83%	$71,342	($4,562)	$66,780	(1.59)	($4,565)
Schedule 85-S	2,421,923	$151,079	13.00%	$58,489	($3,744)	$54,745	(1.55)	($3,754)
Schedule 85-P	695,058	$42,277	3.64%	$16,487	($1,048)	$15,439	(1.51)	($1,050)
Schedule 89-S	0	$0	0.00%	$0	$0	$0	(1.49)	$0
Schedule 89-P	755,381	$44,598	3.84%	$16,860	($1,105)	$15,755	(1.46)	($1,103)
Schedule 89-T	60,948	$3,613	0.31%	$1,342	($90)	$1,253	(1.47)	($90)
Schedule 90	1,583,672	$87,851	7.56%	$35,253	($2,177)	$33,075	(1.37)	($2,170)
Schedule 91	61,486	$3,465	0.30%	$1,344	($86)	$1,258	(1.40)	($86)
Schedule 92	3,234	$185	0.02%	$72	($5)	$67	(1.42)	($5)
TOTAL	17,810,764	$1,162,480	100.00%	$451,403	($28,810)	$422,593		($28,817)

2017 NVPC ($000)	$423,527
2017 NVPC Revenues ($000)	$451,403
Change in NVPC	($27,876)
Revenue Sensitive Adj. 3.35%	($934)
Sch 125 Revenue Requirement	($28,810)

PORTLAND GENERAL ELECTRIC
Calculation of Generation and NVPC Revenues

Schedule	2017 Calendar MWh	Energy Price	2017 Base Energy Revenues	NVPC Price	2017 NVPC Revenues
Sch 7					
Block 1	6,234,233	68.50	$427,045	27.07	$168,761
Block 2	1,385,667	75.72	$104,923	27.07	$37,510
Sch 15	16,086	56.36	$907	21.86	$352
Sch 32	1,605,508	64.87	$104,149	25.14	$40,362
Sch 38					
On-peak	17,105	64.44	$1,102	23.34	$399
Off-peak	13,842	54.44	$754	23.34	$323
Sch 47	21,027	75.67	$1,591	29.35	$617
Sch 49	64,687	75.35	$4,874	29.22	$1,890
Sch 83					
On-peak	1,907,185	69.15	$131,882	24.85	$47,394
Off-peak	963,721	54.15	$52,185	24.85	$23,948
Sch 85-S					
On-peak	1,583,914	67.57	$107,025	24.15	$38,252
Off-peak	838,008	52.57	$44,054	24.15	$20,238
Sch 85-P					
On-peak	437,644	66.38	$29,051	23.72	$10,381
Off-peak	257,415	51.38	$13,226	23.72	$6,106
Sch 89-S					
On-peak	0	66.41	$0	22.74	$0
Off-peak	0	51.41	$0	22.74	$0
Sch 89-P					
On-peak	439,672	65.31	$28,715	22.32	$9,813
Off-peak	315,709	50.31	$15,883	22.32	$7,047
Sch 89-T					
On-peak	39,423	64.57	$2,546	22.02	$868
Off-peak	21,525	49.57	$1,067	22.02	$474
Sch 90					
On-peak	911,448	61.84	$56,364	22.26	$20,289
Off-peak	672,224	46.84	$31,487	22.26	$14,964
Sch 91/95	61,486	56.36	$3,465	21.86	$1,344
Sch 92	3,234	57.16	$185	22.17	$72
Totals	17,810,764		$1,162,480		$451,403

UE 294 Fixed and NVPC Prices

Schedule	Cal. MWh	Generation Allocation	Generation Fixed	NVPC	Fixed mills/kWh	Fixed Revenues	NVPC mills/kWh
Sch 7	7,595,790	45.69%	$248,016,642	$243,563,554	32.65	$248,002,544	32.07
Sch 15	16,536	0.08%	$435,852	$428,027	26.36	$435,889	25.88
Sch 32	1,587,972	8.87%	$48,143,681	$47,279,271	30.32	$48,147,316	29.77
Sch 38	33,325	0.17%	$938,296	$921,449	28.16	$938,422	27.65
Sch 47	20,503	0.13%	$725,673	$712,644	35.39	$725,616	34.76
Sch 49	63,807	0.41%	$2,248,464	$2,208,094	35.24	$2,248,572	34.61
Sch 83	2,863,545	15.81%	$85,821,744	$84,280,833	29.97	$85,820,436	29.43
Sch 85-S	2,452,676	13.16%	$71,437,635	$70,154,987	29.13	$71,446,456	28.60
Sch 85-P	752,298	3.97%	$21,524,149	$21,137,687	28.61	$21,523,242	28.10
Sch 89-S	0	0.00%	$0	$0	27.44	$0	26.95
Sch 89-P	698,192	3.46%	$18,802,056	$18,464,469	26.93	$18,802,310	26.45
Sch 89-T	60,237	0.29%	$1,600,512	$1,571,775	26.57	$1,600,486	26.09
Sch 90-P	1,534,030	7.59%	$41,177,892	$40,438,551	26.84	$41,173,371	26.36
Sch 91/95	68,786	0.33%	$1,813,075	$1,780,522	26.36	$1,813,202	25.88
Sch 92	3,243	0.02%	$86,696	$85,139	26.73	$86,682	26.25
Totals	17,750,940	100.00%	$542,772,367	$533,027,000	30.58	$542,764,544	30.03

Category	Rev. Req.	Percent
Fixed	$542,772	50.45%
Variable	$533,027	49.55%
Total	$1,075,799	100.00%

Fixed and NVPC Prices Adjusted for Senate Bill 1547

Schedule	Cal. MWh	Generation Allocation	Generation Fixed	NVPC	Fixed mills/kWh	Fixed Revenues	NVPC mills/kWh
Sch 7	7,595,790	45.69%	$285,254,483	$206,325,714	37.55	$285,221,915	27.16
Sch 15	16,536	0.08%	$501,292	$362,587	30.32	$501,372	21.93
Sch 32	1,587,972	8.87%	$55,372,094	$40,050,858	34.87	$55,372,589	25.22
Sch 38	33,325	0.17%	$1,079,174	$780,571	32.38	$1,079,052	23.42
Sch 47	20,503	0.13%	$834,627	$603,689	40.71	$834,694	29.44
Sch 49	63,807	0.41%	$2,586,054	$1,870,503	40.53	$2,586,113	29.31
Sch 83	2,863,545	15.81%	$98,707,236	$71,395,341	34.47	$98,706,387	24.93
Sch 85-S	2,452,676	13.16%	$82,163,460	$59,429,161	33.50	$82,164,651	24.23
Sch 85-P	752,298	3.97%	$24,755,838	$17,905,997	32.91	$24,758,123	23.80
Sch 89-S	0	0.00%	$0	$0	31.56	$0	22.82
Sch 89-P	698,192	3.46%	$21,625,044	$15,641,481	30.97	$21,623,005	22.40
Sch 89-T	60,237	0.29%	$1,840,817	$1,331,470	30.56	$1,840,829	22.10
Sch 90-P	1,534,030	7.59%	$47,360,443	$34,255,999	30.87	$47,355,512	22.33
Sch 91/95	68,786	0.33%	$2,085,295	$1,508,302	30.32	$2,085,596	21.93
Sch 92	3,243	0.02%	$99,712	$72,122	30.75	$99,719	22.24
Totals	17,750,940	100.00%	$624,265,571	$451,533,796	35.17	$624,229,557	25.44

Category	UE 294 Rev. Req.	Adjust for PTCs	Adjusted Rev. Req.	Percent
Fixed	$542,772	$81,493	$624,266	58.03%
Variable	$533,027	($81,493)	$451,534	41.97%
Total	$1,075,799	$0	$1,075,799	100.00%

UE 294 NVPC Prices Adjusted for Carty

Schedule	UE 294 NVPC mills/kWh	Carty NVPC mills/kWh	Total mills/kWh
Sch 7	32.07	(0.09)	31.98
Sch 15	25.88	(0.07)	25.81
Sch 32	29.77	(0.08)	29.69
Sch 38	27.65	(0.08)	27.57
Sch 47	34.76	(0.09)	34.67
Sch 49	34.61	(0.09)	34.52
Sch 83	29.43	(0.08)	29.35
Sch 85-S	28.60	(0.08)	28.52
Sch 85-P	28.10	(0.08)	28.02
Sch 89-S	26.95	(0.08)	26.87
Sch 89-P	26.45	(0.08)	26.37
Sch 89-T	26.09	(0.08)	26.01
Sch 90-P	26.36	(0.07)	26.29
Sch 91/95	25.88	(0.07)	25.81
Sch 92	26.25	(0.07)	26.18

UE 294 NVPC Prices Adjusted for Carty and Senate Bill 1547

Schedule	UE 294 NVPC mills/kWh	Carty NVPC mills/kWh	Total mills/kWh
Sch 7	27.16	(0.09)	27.07
Sch 15	21.93	(0.07)	21.86
Sch 32	25.22	(0.08)	25.14
Sch 38	23.42	(0.08)	23.34
Sch 47	29.44	(0.09)	29.35
Sch 49	29.31	(0.09)	29.22
Sch 83	24.93	(0.08)	24.85
Sch 85-S	24.23	(0.08)	24.15
Sch 85-P	23.80	(0.08)	23.72
Sch 89-S	22.82	(0.08)	22.74
Sch 89-P	22.40	(0.08)	22.32
Sch 89-T	22.10	(0.08)	22.02
Sch 90-P	22.33	(0.07)	22.26
Sch 91/95	21.93	(0.07)	21.86
Sch 92	22.24	(0.07)	22.17

UE 294 Change in Fixed Prices Adjusted for Senate Bill 1547

Schedule	UE 294 Fixed Gen. mills/kWh	Adjusted Fixed Gen. mills/kWh	Delta mills/kWh
Sch 7	32.65	37.55	4.90
Sch 15	26.36	30.32	3.96
Sch 32	30.32	34.87	4.55
Sch 38	28.16	32.38	4.22
Sch 47	35.39	40.71	5.32
Sch 49	35.24	40.53	5.29
Sch 83	29.97	34.47	4.50
Sch 85-S	29.13	33.50	4.37
Sch 85-P	28.61	32.91	4.30
Sch 89-S	27.44	31.56	4.12
Sch 89-P	26.93	30.97	4.04
Sch 89-T	26.57	30.56	3.99
Sch 90-P	26.84	30.87	4.03
Sch 91/95	26.36	30.32	3.96
Sch 92	26.73	30.75	4.02

UE 294 Change in Fixed Prices Adjusted for Carty and Senate Bill 1547

Schedule	UE 294 Fixed Gen. mills/kWh	Carty Fixed Gen. mills/kWh	Total mills/kWh
Sch 7	37.55	5.09	42.64
Sch 15	30.32	4.11	34.43
Sch 32	34.87	4.73	39.60
Sch 38	32.38	4.39	36.77
Sch 47	40.71	5.51	46.22
Sch 49	40.53	5.49	46.02
Sch 83	34.47	4.67	39.14
Sch 85-S	33.50	4.55	38.05
Sch 85-P	32.91	4.43	37.34
Sch 89-S	31.56	4.39	35.95
Sch 89-P	30.97	4.31	35.28
Sch 89-T	30.56	4.33	34.89
Sch 90-P	30.87	4.04	34.91
Sch 91/95	30.32	4.11	34.43
Sch 92	30.75	4.16	34.91

PORTLAND GENERAL ELECTRIC
CALCULATION OF SYSTEM USAGE AND DISTRIBUTION PRICES
Allocation of Schedule 129 Transition Adjustment
2017

Schedules	Cycle Energy	Percent	Allocations ($000)	mills/kWh
Schedule 85-S	2,835,758	39.6%	($1,257)	(0.44)
Schedule 85-P	983,979	13.7%	($436)	(0.44)
Schedule 89-S	12,780	0.2%	($6)	(0.44)
Schedule 89-P	1,366,442	19.1%	($605)	(0.44)
Schedule 89-T	383,871	5.4%	($170)	(0.44)
Schedule 90-P	1,576,114	22.0%	($698)	(0.44)
TOTAL	7,158,944	100.00%	($3,172)	(0.44)
		TARGET	($3,172)	

ALLOCATION OF TRANSITION ADJUSTMENT FOR POST 2013 VINTAGE CUSTOMERS

Schedules	Cycle Energy	Percent	Allocations ($000)	mills/kWh
Schedule 7	7,618,630	39.2%	($1,669)	(0.22)
Schedule 15	16,086	0.1%	($4)	(0.22)
Schedule 32	1,606,481	8.3%	($352)	(0.22)
Schedule 38	30,967	0.2%	($7)	(0.22)
Schedule 47	21,104	0.1%	($5)	(0.22)
Schedule 49	64,604	0.3%	($14)	(0.22)
Schedule 83	2,871,168	14.8%	($629)	(0.22)
Schedule 85-S	2,835,758	14.6%	($621)	(0.22)
Schedule 85-P	983,979	5.1%	($216)	(0.22)
Schedule 89-S	12,780	0.1%	($3)	(0.22)
Schedule 89-P	1,366,442	7.0%	($299)	(0.22)
Schedule 89-T	383,871	2.0%	($84)	(0.22)
Schedule 90-P	1,576,114	8.1%	($345)	(0.22)
Schedules 91/95	61,486	0.3%	($13)	(0.22)
Schedule 92	3,234	0.0%	($1)	(0.22)
TOTAL	19,452,704	100.00%	($4,262)	(0.22)
		TARGET	($4,262)	

Change in Schedule 129 Transfer Payment Amount 2017

Schedules	Current mills/kWh	2017 mills/kWh	Change mills/kWh	Tariff Category
Schedule 7	(0.21)	(0.22)	(0.01)	Distribution
Schedule 15	(0.21)	(0.22)	(0.01)	Distribution
Schedule 32	(0.21)	(0.22)	(0.01)	Distribution
Schedule 38	(0.21)	(0.22)	(0.01)	Distribution
Schedule 47	(0.21)	(0.22)	(0.01)	Distribution
Schedule 49	(0.21)	(0.22)	(0.01)	Distribution
Schedule 83	(0.21)	(0.22)	(0.01)	System Usage
Schedule 85-S	(1.18)	(0.66)	0.52	System Usage
Schedule 85-P	(1.18)	(0.66)	0.52	System Usage
Schedule 89-S	(1.18)	(0.66)	0.52	System Usage
Schedule 89-P	(1.18)	(0.66)	0.52	System Usage
Schedule 89-T	(1.18)	(0.66)	0.52	System Usage
Schedule 90-P	(1.18)	(0.66)	0.52	System Usage
Schedules 91/95	(0.21)	(0.22)	(0.01)	Distribution
Schedule 92	(0.21)	(0.22)	(0.01)	Distribution

TOTAL

Change in Fixed Generation from Return/Departure of Long-term Direct Access

Schedules	Enrollment Period	Returning/ Departing MWh	Current Fixed Gen. Recovery mills/kWh	PTC Change in Fixed Gen. Recovery mills/kWh	Adjusted Fixed Gen. Recovery mills/kWh	Reduction in Fixed Gen. Revenues ($000)
Schedule 85-S	O		29.16	4.37	33.53	$0
Schedule 85-P	O		28.64	4.30	32.94	$0
Schedule 89-S	O		27.47	4.12	31.59	$0
Schedule 89-P	O		26.96	4.04	31.00	$0
Schedule 89-T	O		26.60	3.99	30.59	$0
Schedule 90-P	O		26.87	4.03	30.90	$0
Schedules 91/95	O		26.41	3.96	30.37	$0
Schedule 92	O		26.41	3.96	30.37	$0

Total Change in Fixed Generation Revenues (000)	$0
Applicable MWh	19,452,704
Change to Distribution/System Usage Charge (mills/kWh)	0.00

Note: Current fixed generation does not include Carty; will be upated with Carty compliance filing
Note: Current fixed generation recovers 0.03 mills/kWh for PPS Solar

Total Change in Distribution/System Usage Charge 2017

Schedules	Sys. Usage Current mills/kWh	Sch 129 Change mills/kWh	Fixed Gen. Change mills/kWh	Total Change mills/kWh	2017 Sys. Usage mills/kWh	Category
Schedule 7	3.15	(0.01)	0.00	(0.01)	3.14	Distribution
Schedule 15	(0.47)	(0.01)	0.00	(0.01)	(0.48)	Distribution
Schedule 32	3.69	(0.01)	0.00	(0.01)	3.68	Distribution
Schedule 38	3.27	(0.01)	0.00	(0.01)	3.26	Distribution
Schedule 47	(57.07)	(0.01)	0.00	(0.01)	(57.08)	Distribution
Schedule 49	(78.91)	(0.01)	0.00	(0.01)	(78.92)	Distribution
Schedule 83	8.49	(0.01)	0.00	(0.01)	8.48	System Usage
Schedule 85-S	1.16	0.52	0.00	0.52	1.68	System Usage
Schedule 85-P	1.11	0.52	0.00	0.52	1.63	System Usage
Schedule 89-S	0.77	0.52	0.00	0.52	1.29	System Usage
Schedule 89-P	0.74	0.52	0.00	0.52	1.26	System Usage
Schedule 89-T	0.71	0.52	0.00	0.52	1.23	System Usage
Schedule 90-P	0.59	0.52	0.00	0.52	1.11	System Usage
Schedules 91/95	6.11	(0.01)	0.00	(0.01)	6.10	Distribution
Schedule 92	2.02	(0.01)	0.00	(0.01)	2.01	Distribution
Schedule 515	(1.98)	(0.01)	0.00	(0.01)	(1.99)	Distribution
Schedule 532	1.95	(0.01)	0.00	(0.01)	1.94	Distribution
Schedule 538	1.66	(0.01)	0.00	(0.01)	1.65	Distribution
Schedule 549	(80.94)	(0.01)	0.00	(0.01)	(80.95)	Distribution
Schedule 583	6.77	(0.01)	0.00	(0.01)	6.76	System Usage
Schedule 485/585-S	(0.35)	0.52	0.00	0.52	0.17	System Usage
Schedule 485/585-P	(0.36)	0.52	0.00	0.52	0.16	System Usage
Schedule 489/589-S	(0.67)	0.52	0.00	0.52	(0.15)	System Usage
Schedule 489/589-P	(0.68)	0.52	0.00	0.52	(0.16)	System Usage
Schedule 489/589-T	(0.68)	0.52	0.00	0.52	(0.16)	System Usage
Schedule 490/590	(0.86)	0.52	0.00	0.52	(0.34)	System Usage
Schedule 491/495/591/595	4.60	(0.01)	0.00	(0.01)	4.59	Distribution
Schedule 492/592	0.49	(0.01)	0.00	(0.01)	0.48	Distribution

Note: Prices include Carty

PORTLAND GENERAL ELECTRIC
Calculation of Unit Changes in Production Tax Credits Related to Senate Bill 1547

Schedules	2017 Calendar COS Energy MWh	Current PTCs mills/kWh	2017 PTC Revenues	PTC Allocation	2017 PTC Allocations	2017 PTC Price mills/kWh	Change in PTC Price mills/kWh
Schedule 7	7,619,900	(4.90)	($37,338)	45.69%	($34,836)	(4.57)	0.33
Schedule 15	16,086	(3.96)	($64)	0.08%	($59)	(3.69)	0.27
Schedule 32	1,605,508	(4.55)	($7,305)	8.94%	($6,816)	(4.25)	0.30
Schedule 38	30,948	(4.22)	($131)	0.16%	($122)	(3.94)	0.28
Schedule 47	21,027	(5.32)	($112)	0.14%	($104)	(4.96)	0.36
Schedule 49	64,687	(5.29)	($342)	0.42%	($319)	(4.94)	0.35
Schedule 83	2,870,906	(4.50)	($12,919)	15.81%	($12,054)	(4.20)	0.30
Schedule 85-S	2,421,923	(4.37)	($10,584)	12.95%	($9,875)	(4.08)	0.29
Schedule 85-P	695,058	(4.30)	($2,989)	3.66%	($2,789)	(4.01)	0.29
Schedule 89-S	0	(4.12)	$0	0.00%	$0	(3.84)	0.28
Schedule 89-P	755,381	(4.04)	($3,052)	3.73%	($2,847)	(3.77)	0.27
Schedule 89-T	60,948	(3.99)	($243)	0.30%	($227)	(3.72)	0.27
Schedule 90	1,583,672	(4.03)	($6,382)	7.81%	($5,955)	(3.76)	0.27
Schedule 91	61,486	(3.96)	($243)	0.30%	($227)	(3.69)	0.27
Schedule 92	3,234	(4.02)	($13)	0.02%	($12)	(3.75)	0.27
TOTAL	17,810,764		($81,716)	100.00%	($76,242)		

2017 PTCs ($76,242)