UE 294 / PGE / 1500
Niman – Peschka – Hager

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

# UE 294

# Net Variable Power Costs

PORTLAND GENERAL ELECTRIC COMPANY

Reply Testimony and Exhibits of

*Michael Niman*
*Terri Peschka*
*Patrick G. Hager*

June 18, 2015

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# 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. I am the Manager of Regulatory Affairs at PGE.

Our qualifications were previously provided in PGE Exhibit 400.

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

A. The purpose of our testimony is to respond to the positions various parties take with respect to PGE's net variable power cost (NVPC) forecast for 2016, including the Public Utility Commission of Oregon (OPUC) Staff, the Industrial Customers of Northwest Utilities (ICNU), and the Citizens' Utility Board of Oregon (CUB).

**Q. Please summarize your review of parties' positions.**

A. Parties have introduced positions on a range of issues. In many instances, parties recommend reductions to PGE's NVPC forecast. As described in more detail below, we believe parties' positions are (1) inaccurate, (2) opportunistic in seeking benefits (without recognizing costs or risks), or (3) based on incomplete analysis. If implemented in their entirety, parties' recommended reductions will unfairly introduce a downward bias on PGE's NVPC forecast, making it difficult for PGE to recover prudently incurred power costs under normal conditions.

**Q. What is your recommendation regarding the specific issues identified below?**

A. We recommend the Commission reject the parties' positions regarding the issues identified.

**Q. What specific issues will you address in your testimony?**

A. We will address the following issues:

- **California-Oregon Border (COB) Trading Margins**: ICNU's proposal to reflect in MONET the benefits of PGE's access to markets other than the Mid-Columbia (Mid-C) market fails to account for all costs and benefits of PGE's strategy to reduce the risk of meeting our customers' power supply requirements. Trading margins are not easily forecasted and should be more appropriately dealt with through PGE's Power Cost Adjustment Mechanism (PCAM). In addition to PGE's objection to the merits of ICNU's proposal, ICNU's analysis of historical sales and purchases trading margins is flawed; using the dataset and approach proposed by ICNU to forecast trading margins in the NVPC forecast produced by MONET would not produce a rigorous forecast.
- **Load-Net-Wind**: ICNU's proposal to reduce NVPC based on (1) a misunderstanding of PGE's reserve modeling methodology and (2) a misapplication of the root sum of squares (RSS) methodology would result in a duplicative adjustment to reserves for the combined variability of wind and load.
- **Pipeline Capacity Release Credits**: ICNU's proposal to reflect in MONET a forecast of gas pipeline capacity release credits inappropriately assumes that historical data from 2011 – 2014 are useful for forecasting 2016 test year benefits. Contrary to ICNU's opinion, multiple factors lead PGE to anticipate high gas demand in 2016.
- **Coyote Springs Forced Outage Rate**: OPUC Staff relies on an inappropriate and incomplete comparison of plant statistics in proposing to apply the methodology for the coal-plant forced outage rate calculation, as described in Commission Order No. 10-414, to the Coyote Springs plant for the current 2016 NVPC forecast and ongoing. Staff fails to provide a compelling rationale for changing an approach that is long-

standing and well-established, both for PGE and other electric utilities. If Staff decides it would like to change methodologies for gas-fired plants, it should be done in a policy/investigation docket similar to Docket No. UM 1355.

- **Carty Generating Station (Carty) Modeled Online Date**: CUB's proposal to change the modeled online date of Carty to January 1, 2016 ignores any reasonable basis for establishing a modeled online date. A more reasonable (and likely) outcome is an online date consistent with PGE's modeling.
- **Double Counting Cost of Wind Day-Ahead Forecast Error**: While CUB does not propose eliminating the cost of wind day-ahead forecast error from PGE's NVPC forecast, CUB does contend that PGE will be double counting the cost of wind day-ahead forecast error if the Renewable Resource Tracking Mechanism (RRTM) proposed by PGE and PacifiCorp in Docket No. UM 1662 is approved. We explain why a double-count does not exist, and propose no change to the modeled cost of wind day-ahead forecast error.
- **Sales for Resale**: We believe there is some confusion in CUB's recommendation that PGE analyze the treatment of sales for resale revenues in its revenue requirement calculation to determine if an amount should be used to offset rate base. While we propose no change to the treatment of sales for resale in our revenue requirement calculation, we are open to further discussions on this topic to ensure that we have appropriately understood CUB's recommendation.
- **Seasonal Super-Peak Energy Purchase**: Parties' position that PGE's modeled super-peak energy purchase should be removed from the NVPC forecast does not consider events such as load excursions or plants unexpectedly going offline. PGE's

modeling appropriately forecasts the costs that PGE expects to incur for making this intra-year purchase.

**Q. How is the remainder of your testimony organized?**

A. After this introduction, we have two sections:

- Section II: Parties' Proposed Adjustments
- Section III: Summary and Conclusion

# II. Parties' Proposed Adjustments

## A. California-Oregon Border (COB) Trading Margins

**Q. Please summarize ICNU's proposal regarding COB Trading Margins.**

A. ICNU argues that PGE's NVPC forecast is overstated, because PGE does not account for transactions at the COB market. ICNU proposes to reflect in MONET the benefits of PGE's access to markets other than the Mid-C market, primarily COB, by imputing a value derived from average historical sales and purchases trading margins. ICNU claims that customers are currently paying the cost associated with transmission access to the COB market and should therefore receive the economic benefits.

**Q. Do you agree with ICNU's proposal regarding COB trading margins?**

A. No. PGE already forecasts a benefit associated with wholesale sales from PGE plants in our MONET modeling, pricing sales at the Mid-C market (the market in which PGE predominantly trades). In proposing to reflect trading margins in PGE's NVPC forecast, ICNU fails to realize that the trading margins are a by-product of PGE's overall strategy to reduce the risk of meeting our customers' power supply requirements. PGE's PCAM is designed for this type of activity, and these sales and purchases should be considered as part of that process. Additionally, imputing a firm amount of trading margins into the forecast encourages PGE to speculate, not arbitrage, in order to meet the margin forecast amount.

**Q. How does PGE meet customer supply requirements?**

A. PGE's overall power supply objective is to meet our customers' power and reliability needs at a reasonable cost. For the next calendar year, PGE's process/strategy for procuring power is to possess a flat position for both gas and power on an average basis. That is, by the time of our final estimate for power costs in the AUT[1] (i.e., November), PGE has executed enough power and gas contracts (either physical or financial) to meet our gas and power needs while effectively setting a fixed price for our gas and power purchases.

Shortly after PGE's final estimate for power costs in the AUT is set, PGE transitions from the process/strategy described above to a process/strategy focused on reliability that monitors: (1) the changes in PGE's load forecast; (2) expected generation from our generating resources (i.e., hydro, thermal and wind); and (3) market changes in order to determine whether PGE needs to rebalance its portfolio based on the market fundamentals (e.g., higher hydro, higher gas storage levels or higher gas production, indicators that might point to a hotter summer or colder winter) that may impact operations.

**Q. What risks does PGE face in its efforts to meet customer supply requirements?**

A. PGE faces several risks that can affect our ability to meet customers' power needs physically and at the established retail prices. Examples of PGE's risks include:

**Price Risk** – Fluctuations in prices of the underlying energy commodity.

**Counterparty Performance Risk** – Counterparty's ability to operationally perform on an agreement or obligation, such as an agreement to deliver power.

**Load Risk** – Variations in load that deviate from PGE's forecast.

**Generated Volumetric Risk** – Variations in generated volumes that deviate from PGE's forecast and result in an increase or decrease to power costs. PGE faces volumetric risks associated directly with non-dispatchable and weather dependent resources such as hydro and wind.

[1] Annual Update Tariff

**Delivered Volumetric Risk** – PGE also faces volumetric risks due to transmission curtailments and system operational limits.

**Ancillary Service Need Risk** – Variations in ancillary service needs that deviate from PGE's forecast. PGE's ancillary service needs are growing as PGE continues to add variable energy resources to its resource portfolio and accepts additional integration responsibility during the sub-hourly intervals in lieu of purchasing integration services from the source balancing authority area (i.e., BPA).

**Q. How does PGE manage these risks?**

A. PGE relies on markets and contractual instruments to reliably meet customer load while minimizing costs. More specifically, PGE relies on access to multiple physical and financial energy markets through firm transmission and transportation rights, railway contracts, electronic trading bulletin boards, and organized financial commodity exchanges to more efficiently reduce exposure to market price volatility and supply reliability.

**Q. Does PGE's access to the California market aid in managing risk?**

A. Yes. The California market can provide PGE's customers with additional supply and demand when there are limited buyers and sellers (i.e., liquidity is low) in the Pacific Northwest, which can occur when there is a lack of capacity in the region due to higher loads, regional transmission constraints, or restricted generation. Additionally, during high wind events (i.e., a time when supply is long and PGE is at risk of over-generating), there can be an abundance of supply in the Pacific Northwest, with very limited buyers.

**Q. Please provide an example.**

A. February 6, 2014 was a winter peaking event in the Pacific Northwest (PNW) and gas traded nearly 300% higher than the previous day. The day-ahead Mid-C market traded at

$216/MWh and the day-ahead CAISO Malin market traded between $114-$172/MWh for the peak period.[2] By procuring a portion of our supply from California, PGE was able to manage supply risks in a manner that provided least-cost, reliable service to our customers.

Additionally, when there is absolutely no liquidity in the hourly market in the Pacific Northwest and PGE is facing a reliability event, PGE can access the California markets with a self-schedule to purchase power from California. This type of an event occurred as recently as June 8, 2015. In general, most market participants in the PNW are subject to the same load excursions and wind patterns. On June 8, actual load was higher than market participants had predicted, and there was no liquidity in the Mid-C market (all available generation and market purchases had been procured during the previous Friday's trading session). Additionally, wind generation throughout the region generated below forecast levels and exacerbated the region's short position. PNW load serving entities who bid out of the CAISO market were able to meet customer load. However, PNW load serving entities were subject to CAISO's evening peak prices of approximately $1,000/MWh, because power was not available in the PNW.[3]

In summary, the two examples described above demonstrate how PGE can use its access to California markets to manage power supply risk. Additionally, the examples highlight a distinction in PGE's methods of using access to California to manage risk that a simple review of historical prices would miss. In the first example, market prices would have been reflective of PGE's system and operational constraints – supply was available to PGE in the PNW and California. However, in the second example market prices would not have reflected PGE's actual system and operational constraints. In order to meet our

[2] Prices for February 2014 in PGE's final NVPC were significantly less than these prices. February market purchases and sales were approximately $30.00/MWh.
[3] Simply reviewing a PNW market price would not indicate a lack of available MW.

customers' power needs, we needed to purchase power from California (irrespective of a posted Mid-C price).

**Q. Could customers be harmed if an imputed value for trading margins was incorporated into MONET?**

A. Yes. PGE Power Operations' primary goal is to reliably meet customer demand. Its secondary goal is to minimize costs. By imputing a value on an activity that is secondary, ICNU effectively creates a fixed and firm position to which PGE must then manage. This is a stark departure from PGE's present trading activity where market opportunities must first align with the primary goal of reliably meeting customer demand.

In fact, ICNU's proposal, if adopted, would incent PGE to enter into transactions for the sole purpose of monetizing a target "value" prior to (and independent of) any consideration for reliability. Therefore, PGE would be incented to engage in trading activities (largely sales into California) that would be subject to risks such as price fluctuations, transmission curtailments, and carbon import taxes that are <u>incremental</u> to PGE's primary trading activities designed to reliably meet customer demand. To the extent that PGE enters into additional purchases to meet this imputed position, these transactions would also be subject to the risks identified above.

**Q. How does MONET account for the risks described above?**

A. 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 PGE's resource portfolio under normal conditions (e.g., plant operations, water and wind flows, and weather). Risks associated with the variables are "frozen" at the final forecast date in

November. That is, PGE no longer updates its forecast to reflect changes in the variables that would result in a reduction to (or increase in) costs.

**Q. How are risks associated with the forecast variables accounted for after the final forecast is "frozen" in November?**

A. The PCAM provides a method by which differences between forecast and actuals are treated. As PGE transitions from the test year forecast to actual operations, changes in every variable necessitate additional contracting or dispatch decisions (some changes increasing NVPC and some changes decreasing NVPC). These real-world changes are difficult to forecast with any accuracy based on the risks identified above and the potential for departure from normal conditions.

**Q. Are California sales and purchases a good candidate for the NVPC forecast produced by MONET?**

A. No. California sales and purchases are not a good candidate for the NVPC forecast produced by MONET, because they are often the result of PGE's efforts to balance its portfolio and manage the risks associated with meeting our customers' supply requirements. While PGE's forecast load and generation is "frozen" at the final forecast in November, our efforts to manage the portfolio continue throughout the year. Therefore, California sales and purchases are most appropriately matched with the differences between the forecast and actuals in the PCAM.

For example, California sales in any one hour could be the result of changes in generation or load (i.e., over-generation or load underruns). In all cases, these sales should be viewed in aggregation with transactions in other hours where PGE would have purchased energy to replace under-generation or meet increased loads. The over and under of each of the hours and the optimization of the portfolio that happens for each hour should be considered together rather than isolating some hours to show benefit without accounting for other hours which would increase costs.

**Q. Would PGE monetize a portion of the benefits identified by ICNU prior to the forecast year?**

A. No. Even if forward firm fixed transactions at COB were available,[4] PGE would not consider entering into a firm commitment to deliver power, given the risks associated with it (e.g., price fluctuations, transmission curtailments, and carbon import taxes). Benefits that are subject to a high degree of uncertainty and variability and are realized via short-term transactions are not good candidates for forward arbitrage. As a result, PGE has not transacted and does not plan to transact in the prompt year based on the price spread due to the inherent risks associated with the obligation. In other words, just like most efficient markets, price spread exists because there are commensurate risks.

**Q. How else could PGE's customers receive the benefits from trading margins at COB?**

A. The Commission could eliminate the deadbands in PGE's PCAM. By eliminating the deadbands, the Commission would ensure that the benefits associated with PGE prudently meeting its fuel and purchased power obligations are fully shared with customers.

**Q. Do you have other concerns with ICNU's proposal?**

A. Yes. Notwithstanding PGE's objection to the merits of ICNU's proposal, ICNU's analysis is flawed and must be corrected. ICNU fails to recognize that PGE's trading activity occurs in the term, day-ahead and real-time markets. Therefore, the appropriate comparison of margin is not simply the recorded transaction price versus a price curve for real-time hourly

[4] Liquidity for year-ahead forward physical transaction at COB is limited.

sales or purchases. Rather, the appropriate comparison is a price curve commensurate with the market. For example, PGE executed term transactions at COB after comparing a forward price at COB against a forward price at Mid-C, not an hourly real-time price. ICNU also fails to recognize the countervailing costs associated with the sales and purchases it analyzed. Considered as a whole, PGE's findings show that using the dataset and approach proposed by ICNU to forecast trading margins in the NVPC forecast produced by MONET would not produce a rigorous forecast.

**Q. Have you considered any corrections to ICNU's model?**

A. Yes. So far, we have identified three categories of corrections in this voluminous and complex dataset. With these corrections, our draft estimates are considerably lower than ICNU's initial result, but remain highly variable and could even be close to zero, depending on the assumptions used.

**1. Price**: By comparing recorded transaction prices to the Mid-C PowerDex hourly price, ICNU does not properly compare the prices that PGE traders would have considered when entering into the transaction. ICNU also assumes all transactions would have been real-time transactions. In reality, PGE also entered into day-ahead and term transactions. Table 1 compares PGE's realigned price comparisons to those made by ICNU. PGE's changes ensure that transactions are more appropriately compared to forward curves and indices at the time PGE entered into the real-time, day-ahead, and term transactions. Correcting the dataset to reflect proper price comparisons reduces ICNU's average estimate by approximately one-third or more.

**Table 1: ICNU Price Analysis vs. PGE Price Analysis**

| | **Hour-Ahead (Real-Time)** | | **Day-Ahead (Pre-Schedule)** | | **Term** |
|---|---|---|---|---|---|
| ICNU | Recorded Transaction Price vs. Mid-C PowerDex Hourly | | Same as Hour-Ahead | | Same as Hour-Ahead |
| PGE | Hour-Ahead LMP[1] vs. Mid-C PowerDex Hourly | Hour-Ahead COB Transaction Price vs. Mid-C PowerDex Hourly | Day-Ahead LMP[1] vs. Mid-C ICE Daily Index | COB ICE Daily Index vs. Mid-C ICE Daily Index | COB Transaction Price vs. Mid-C Forward Curve |

[1] Locational Marginal Price for CAISO transactions (i.e., California side of COB).

**2. Nevada-Oregon Border (NOB) Transactions**: ICNU's analysis includes transactions entered into at the NOB market, but ignores the transmission costs associated with the transactions. PGE does not have firm transmission rights to NOB.[5] Removing these transactions from the dataset further reduces ICNU's average estimate.

**3. California Market Costs**: Sales destined for the California market are subject to certification with the California Air Resources Board and a carbon tax. Accessing the CAISO market (i.e., imports and exports) also includes additional charges for transmission access charges to the grid and uplift costs that are calculated in the settlement process. Correcting the dataset to reflect an estimate for transmission access charges, uplift costs, and an estimate for the carbon tax applied to sales delivered into California reduces ICNU's average estimate by approximately one-third or more. Additionally, 2012 should be excluded from the analysis. California's requirements for CARB certification of power sales (and the applicable carbon tax) took effect in 2013, making 2012 materially different from the 2013 and 2014 data.

[5] PGE's firm transmission rights ended on June 30, 2012.

**Q. Please summarize PGE's response to ICNU's proposed adjustment.**

A. PGE proposes to continue to not include the costs and benefits of California trading margins in the NVPC forecast produced by MONET. For the reasons stated above, PGE's PCAM is the appropriate mechanism for addressing variables (such as trading margins) that are the by-product of PGE's overall strategy to manage the risks associated with meeting our customers' power supply requirements.

## B. Load-Net-Wind

**Q. Has ICNU correctly described PGE's modeling of reserve requirements?**

A. No. ICNU misunderstands PGE's modeling of reserve requirements, and ICNU's application of the root sum of squares (RSS) methodology is incorrect.

**Q. Why is root sum of squares not an appropriate methodology for PGE's load-net-wind calculations?**

A. RSS is a method used to prevent double-counting of reserves if the combined variability of load and wind is not already accounted for. However, PGE's existing methodology is based on the load-net-wind concept, which incorporates the combined variability of aggregated load and wind that will occur given 2016 operating conditions.[6] Therefore, PGE is not double counting reserves, and using RSS will result in a duplicative adjustment for the combined variability of wind and load.

**Q. What is the basis of ICNU's assumption?**

A. ICNU's assumption is based on a National Renewable Energy Laboratory (NREL) report cited in their reply testimony, "Double counting in one form or another is probably the most

[6] The operating conditions referenced consist of an hourly bilateral market, 15-minute wind scheduling under BPA VERBS, and an illiquid sub-hourly market.

common error made in integration studies. This usually results from failing to account for aggregation benefits, either among wind facilities and/or between wind and load."[7] PGE's methodology aggregates the output from our wind facilities and computes reserves based on load net of the aggregated wind, which accounts for the combined variability of multiple wind resources and load.

**Q. How does PGE account for wind in its reserve requirement calculation used for NVPC in this proceeding?**

A. The load-net-wind reserves in MONET are derived using PGE's Resource Optimization Model (ROM) "load-net-wind" reserve methodology. These consist of reserves required to integrate load variance within the operating hour ("load following") and reserves required to integrate the 15-minute schedule to schedule wind variance that occurs within the operating hour. As stated in PGE's response to ICNU Data Request No. 130,

> "Because the northwest market operates on an hourly bi-lateral basis and there is no liquid sub-hourly market, PGE must use its system, by holding reserves, to balance the within hour variability of load."

And PGE's Response to ICNU Data Request No. 131,

> "PGE has selected to schedule its wind resources under BPA's Variable Energy Resource Balancing Service (VERBS) 30/15 Committed Scheduling beginning in October 2015. As a result of this election and the lack of a liquid sub-hourly market, PGE will need to carry additional reserves to integrate the 15-minute schedule to schedule variance that occurs within the operating hour… PGE notes that, under VERBS 30/15, BPA will integrate the variances that occur within each 15-minute scheduling period."

The total load-net-wind reserves in MONET do not account for the variances within each 15-minute wind schedule, because BPA will use its system to integrate these variances.[8]

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[7] ICNU/100, Mullins/12.
[8] Within 15-minute schedule integration is performed by BPA under VERBS and consists of imbalance, following, and regulation reserves.

**Q. Please briefly explain how PGE's reserve requirement calculation incorporates the load-net-wind concept.**

A. PGE's reserve requirement calculation can be organized into three steps.

**Step #1: Calculate reserves needed for load following only**. Using historical data, PGE develops *hourly* load following reserves and a corresponding baseline percentage of time (e.g., 95%) where the load following reserves were sufficient to meet load variations. We then realign and scale data to the 2016 test year to develop test year hourly load following reserves, compare these reserves to test year load variations, and adjust the reserves to maintain the same baseline percentage.

**Step #2**: **Calculate reserves needed for wind under PGE's planned operating paradigm (i.e., 30/15 committed scheduling).** PGE uses a derived formula representative of the relationship between the 30/60 persistence forecast and the four 30/15 persistence forecasts for each hour to determine the amount of reserves needed to integrate the 15-minute schedule to schedule variances from PGE-owned wind resources.[9,10] If the 15-minute deviations of load net of scheduled wind generation exceed the amount of reserves held for load-only, then additional reserves are needed to integrate load-net-wind variations. We add the calculated wind reserves to the load following reserves to arrive at an initial load-net-wind reserve amount.

**Step 3: Scale reserves to keep the same level of reliability as when PGE integrated only load.** Lastly, we scale the wind reserves so that the percentage of time when the *load-net-*

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[9] The 30/60 persistence forecast and the first 30/15 persistence forecast for each hour are the same forecast.
[10] The derived formula is based on the difference between the 30/60 persistence forecast and each of the four 30/15 persistence forecasts for a given hour because there is no liquid sub-hourly market in the northwest and, under VERBS, the best information regarding forecasted wind schedules prior to the start of the operating hour is the 30/60 persistence forecast.

*wind* reserves is sufficient to meet *load-net-wind* variations is equal to the baseline percentage established based on load only variations in the first step.

**Q. What aspects of wind are included in PGE's load-net-wind reserve requirement calculation?**

A. In PGE's calculation, load is only netted with the 15-minute schedule to schedule wind variance, which includes ramping, to derive an *hourly* reserve requirement that represents the capacity needed to integrate load and 15-minute schedule to schedule wind variance. As detailed above, there is no liquid sub-hourly market in the northwest so PGE will need to use its system to balance within-hour load variability and 15-minute schedule to schedule wind variance by holding capacity for the *entire operating hour*. PGE's calculation does not include the within 15-minute schedule wind variability because BPA will be integrating this component and this variability is not available to offset load variability, to the extent an offset occurs.

**Q. Has PGE's methodology been reviewed in previous proceedings and by third parties?**

A. Yes. In the 2011 IRP Update planning cycle, PGE's methodology was subject to a review process that consisted of involvement from external stakeholders, public meetings, a technical review committee (TRC) of industry experts, and a subject-matter consulting expert, EnerNex.[11] Additionally, PGE's methodology and any changes to our methodology were again reviewed in the 2013 IRP planning process. This review also consisted of public meetings and a TRC of industry experts.

[11] PGE's TRC consisted of the following members: J. Charles Smith, Executive Director, Utility Wind Integration Group (UWIG); Michael Milligan, PH.D., Principal Analyst, National Renewable Energy Laboratory (NREL); Brendan Kirby, P.E., Consultant with NREL; Michael Goggin, Manager of Transmission Policy, American Wind Energy Association (AWEA).

**Q. Please summarize PGE's position with respect to ICNU's proposed correction.**

A. PGE's load-net-wind methodology correctly accounts for the combined variability of load and wind, given the hourly bilateral market, 15-minute scheduling of wind, and an illiquid sub-hourly market. ICNU's proposal to use RSS is incorrectly applied and will result in an incorrect adjustment to the load-net-wind reserves in MONET, resulting in a double-count of the aggregation benefit of load and wind combined variability. PGE recommends that the Commission reject ICNU's RSS proposal.

### C. Pipeline Capacity Release Credits

**Q. Please describe ICNU's proposed adjustment related to pipeline capacity release credits (capacity release).**

A. ICNU proposes including in PGE's NVPC forecast an adjustment to reflect the potential for capacity release in 2016. ICNU estimates this adjustment by using the average amount of long-term and short-term release credits generated from 2011 through 2014.[12]

**Q. Has PGE included an offset for capacity release in previous annual NVPC filings?**

A. Yes. PGE has previously included a cost offset related to its one long-term capacity release agreement with Occidental Energy (Occidental) for each year the contract has been in place. The contract expires on October 31, 2015 and therefore no long-term capacity release agreement is included in PGE's 2016 NVPC forecast.

**Q. Why did PGE not renew the Occidental contract?**

A. PGE decided not to renew the Occidental contract for several reasons, but primarily because PGE no longer has the path to release.

[12] ICNU/100, Mullins/17.

**Q. Please explain.**

A. PGE's original capacity contract with Occidental was from Sumas to Kern River. As part of this transaction, PGE agreed to release the southern half of the path, from Stanfield to Kern River, back to Occidental. However, throughout the contract term, PGE experienced Operational Flow Orders (OFOs) on the path, restricting the deliverability to the Kelso-Beaver Pipeline from Sumas.[13] Upon renewing this contract, PGE sought to shorten the path from Sumas to Kelso-Beaver, giving PGE firm delivery rights at Kelso-Beaver. Beginning November 1, 2015, the Williams Companies, owners of the Northwest Pipeline, allowed PGE to shorten the path from Sumas to Kelso-Beaver. By shortening the path to acquire firm delivery rights, PGE eliminates the reliability risk (and additional cost) associated with potential OFOs, which can restrict gas flows and curtail PGE's contracted volume. With the shorter path, PGE no longer has the Stanfield to Kern River portion of the path to release. PGE Exhibit 1501 shows the Northwest Pipeline system map, including the key points of the path described above.

**Q. Can you quantify the risk associated with the OFO obligations?**

A. Yes. OFOs create a reliability risk, because they can reduce the gas volumes PGE purchased to fuel gas-fired plants needed for customer load. At the time PGE made its decision to shorten the path, OFO obligations were stranding between 3,000 to 6,000 Dth of gas per day during the winter. Using the Northwest Pipeline tariff rate of $0.41 per Dth, this amounts to approximately $1,230 to $2,460 a day in stranded transportation capacity.

[13] OFOs would direct PGE to deliver gas to Stanfield.

**Q. Will PGE be paying a lower rate as a result of the shorter line?**

A. No. The tariff rate that PGE pays has not changed as a result of shortening the line. The reason for shortening the path is that it provides PGE with firm delivery rights for its entire contracted capacity, eliminating the risk of stranded transportation due to OFO obligations. By eliminating this risk, PGE reduces the reliability risk we described above.

**Q. Has PGE held any other long-term capacity release agreements since 2011?**

A. No.

**Q. Are any new long-term capacity release agreements expected in 2016?**

A. No. Without the Stanfield to Kern River portion of the Northwest Pipeline, PGE no longer has unused or excess capacity to release.

**Q. When was the last short-term capacity release?**

A. PGE has not released any pipeline capacity on a short-term basis since September 2012.

**Q. Is it reasonable to assume PGE will make short-term capacity releases to the market in 2016?**

A. No. Consistent with 2013, 2014, and thus far in 2015, it is extremely unlikely that PGE will make short-term capacity releases to the market in 2016. PGE's gas requirements are significantly expanding in 2015 and 2016 due to an increase in market heat rates and the increasing need for wind integration services.

**Q. Will your storage contracts allow PGE the flexibility to release capacity as ICNU has suggested?**[14]

A. No. Contrary to ICNU's assumption, the increasing need for wind integration services will keep the demand high for PGE's Clatskanie based plants (PGE's Port Westward 2 plant in

[14] ICNU/100, Mullins/19

particular). The maximum capacity PGE is able to transport on the Northwest Pipeline is 103,307 Dth per day, while PGE's three gas-fired plants served from this line are capable of using up to 218,000 Dth per day.[15]

PGE's current Gap Services storage agreement with Northwest Natural allows PGE to hold up to 1.6 million Dth of storage at a fill rate of up to 36,000 Dth per day. From this reserve, PGE has the ability to withdraw up to 90,000 Dth per day. Therefore, based on PGE's maximum capacity and the length of time it takes to fill its storage reserves, PGE will likely use any excess gas capacity to refill its storage reserves. Additionally, if PGE were to release transport capacity on the Northwest Pipeline and rely solely on storage, PGE would be prematurely reducing this storage and would not have the transport necessary to refill its storage during periods when the plants are required to dispatch, potentially putting our system reliability at risk.

**Q. Does PGE expect to recognize, or is PGE reasonably capable of recognizing, any Capacity Release Revenues during the 2016 test year?**

A. No. As stated above, PGE's one long-term release contract is ending in 2015, and PGE has not engaged in any short-term release agreements for close to three years. Additionally, an increase in market heat rates is increasing gas demand (not decreasing it). Finally, PGE expects to rely more heavily on gas-fired resources for wind integration services, further constraining the ability to release any gas transport capacity. For all of these reasons, it is highly unlikely PGE will be able to recognize any long-term or short-term capacity release revenues during 2016.

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[15] Port Westward 1 = 64,000 Dth, Port Westward 2 = 44,000 Dth, and Beaver = 110,000 Dth

## D. Coyote Springs Forced Outage Rate

**Q. Please summarize Staff's proposal regarding the Coyote Springs forced outage rate.**

A. OPUC Staff asserts that Coyote Springs, a baseload natural-gas fired plant, is the functional equivalent of a baseload coal plant, and therefore PGE should be required to apply the methodology for the coal-plant forced outage rate calculation (as described in Commission Order No. 10-414) to the Coyote Springs plant for the current 2016 NVPC forecast and on an ongoing basis.

**Q. What is the basis for Coyote Springs' plant forced outage rate assumed in PGE's 2016 test year NVPC forecast?**

A. PGE follows the four-year average method first documented in the "1984 Staff Memo". Using this well-established method, PGE calculates the forced outage rate for the Coyote Springs plant (Unit 1) from a rolling four-year average of plant statistics.

**Q. Please describe the forced outage events at Coyote Springs in 2013.**

A. The Coyote Springs plant uses a General Electric (GE) steam turbine to generate power from waste heat recovered from the gas turbine. The steam is formed in the heat recovery steam generator. In October 2012, the steam turbine bearing vibration levels started to increase, and reached the alarm level (6 mils) in February 2013. The plant was shut down for on-site inspection and testing to determine the cause(s). Nothing significant, however, was found; no surface cracks were detected. Balance weights were installed to reduce rotational imbalance, and the plant was restarted. Vibration levels were lower than pre-outage levels, but subsequently began to increase. Additional balance modifications were made, but they were unsuccessful – the vibration levels continued to rise.

The plant was again shut down in April 2013 for inspection and again no major problems were discovered. Magnetic particle testing (MT) was performed on the steam turbine rotor to check for cracks, but none were found. The rotor was shipped offsite for more detailed inspection and testing at GE's repair shop in Bangor, Maine. GE's analysis indicated a problem with the mid-span coupling that connects the high pressure (HP) and low pressure (LP) sections of the steam turbine rotor. Disassembly and inspection of the mid-span coupling revealed fretting and relaxation of the coupling bolts (the bolts are tightened during installation to provide the proper clamping force). The fretting to the coupling surface was repaired (this surface is normally inaccessible) and new bolts were installed and tightened to achieve the proper pre-load. The rotor was balanced in a high-speed spin-balance pit and returned to Coyote Springs.

The plant resumed operation in July 2013. On August 16, vibration levels on the unit began to shift and increase. On August 24, the unit tripped on high vibration. Multiple balance adjustments were unsuccessful, and the plant was again taken off-line on August 29. Non-Destructive Examination (NDE) using surface methods revealed a crack in the steam turbine rotor shaft at the transition radius between the LP turbine shaft and the mid-span coupling bolt flange. Although the same area was inspected during previous shutdowns using MT, a crack must be open to the surface (surface connected) to be reliably detected with MT or liquid penetrant methods. By August the crack had propagated to the surface and had progressed about 170 degrees circumferentially around the shaft.

The rotor was then shipped offsite to Alstom for metallurgical examination and repair. Alstom was selected based on their extensive expertise with steam turbine rotor weld repairs, including the successful repair of the Boardman steam turbine rotor. The cracked portion of the LP coupling was removed and replaced with weld material, then machined to form a new LP coupling flange. The HP side of the coupling was examined to verify that a similar corrosion and cracking problem did not exist. The rotor was high-speed balanced and shipped back to Coyote Springs. The rotor was installed and the plant successfully returned to power generation on November 30, 2013.

**Q. Did Staff present evidence in the current case to demonstrate that the Coyote forced outage events in 2013 were outside all normal phenomena anticipated?**

A. No. Staff appears to suggest that a high forced outage rate for a single year is, by itself, reason for adjusting the 48-month average. Staff relies on North American Electric Reliability Council (NERC) Generating Availability Data System (GADS) data to show that the range of effective forced outage rates (EFOR) for all plants (sized 200 MW – 299 MW) of all fuel types was about 6.6 percent – 10.1 percent in the years 2007 – 2011 (Staff/100, Crider/7-8). Staff then incorrectly states that the EFOR used by PGE to model Coyote Springs is "an order of magnitude greater than the highest EFOR in this range". An order of magnitude greater than 10.1 percent is effectively 100 percent. PGE's EFOR used for Coyote Springs is more appropriately characterized as approximately "two-times greater than 10.1 percent".

**Q. Was Staff's comparison appropriate?**

A. No. By comparing the Coyote Springs EFOR to the EFOR for plants of all size and fuel types, Staff incorrectly assumes that Coyote Springs' peer group is plants of all size and fuel type. Staff also incorrectly ignores the distribution of the annual averages reported. While the proceeding schedule in this docket does not provide the time necessary for PGE to develop the most comparable peer group, a limited review of gas-fired plant data compared to coal-fired plant data readily available to PGE shows important differences. PGE reviewed the distribution of EFOR for: (1) gas-fired combined cycle plants (sized 200 MW – 299 MW) from 2007 – 2013; and (2) coal-fired plants of similar size to the Boardman plant (sized 500 MW – 599 MW) from 2007 – 2013. To analyze the differences in the data sets, PGE employed a statistic to measure the size of the tail in a "fat tail" distribution. In this case a "fat tail" distribution exhibits skewness in the data (i.e., the data are not symmetrically distributed around its mean) and indicates a tendency for a plant to have a larger outage. As the tail gets "fatter", the tendency to have a larger outage increases. The tail measure formula is:

$$\frac{\boldsymbol{Mean\ of\ the\ EFORs - Median\ of\ EFORs}}{\boldsymbol{Standard\ Deviation\ of\ the\ EFORs}}$$

A distribution has a normal distribution if the result of this formula is zero. A non-zero result indicates a degree of "fatness" in the tail. The larger the number, the "fatter" the tail (i.e., a stronger tendency to have a larger outage). Table 1 shows the results of PGE's calculation.

**Table 1: Tail Measure for Gas-Fired Plant and Coal-Fired Plant EFORs**

| | Gas-Fired Plants | Coal-Fired Plants |
|---|---|---|
| Mean - Median | 4.53 | 2.79 |
| Standard Deviation | 12.94 | 11.31 |
| Tail Measure | 0.35 | 0.25 |

As shown in Table 1, the tail measure for the gas-fired plants is greater than the tail measure for the coal-fired plants, showing that the historical dataset for gas-fired plants exhibits a stronger tendency for longer outages. The differences in distributions suggest that the data for plants of all fuel types are not a reasonable benchmark for identifying outliers.

Furthermore, Staff provides no evidence for identifying an outlier within the data distributions.

**Q. Does Staff have a recommendation for Coyote Springs' forced outage rate?**

A. Yes. Staff recommends that the Commission require PGE to exclude outliers from the calculation of the Coyote Springs' forced outage rate. Staff's recommended action for removing outliers is for PGE to extend the methodology currently applied to coal plants (and described in Commission Order No. 10-414) to the Coyote Springs plant (Staff/100, Crider/10-11).

**Q. Has Staff provided evidence showing their recommendation produces a better forecast?**

A. No, they have not.

**Q. Do you agree with Staff's recommendation?**

A. No. Staff's recommendation is unsupported by anything other than a judgment that the Coyote Springs forced outage rate in 2013 is an outlier. Staff fails to provide a compelling rationale for changing an approach that is long-standing and well-established.

**Q. Doesn't Staff's recommendation also affect other utilities in Oregon that have gas-fired generation?**

A. Yes. If Staff decides it would like to change methodologies for gas-fired plants, it should be done in a policy/investigation docket similar to Docket No. UM 1355. Doing so would ensure that a change in methodologies is well-reasoned and not based on a single occurrence. In the docket, parties and all utilities, not strictly PGE, would consider an appropriate set of alternatives based on the consideration of items such as data sets, time periods, types of gas-fired units, and the non-normal distributions of EFOR outcomes.

**Q. What is PGE's proposal for the 4-year average?**

A. PGE proposes no change to the 4-year average used in its NVPC forecast for the Coyote Springs forced outage rate, but if such a change is desired, a generic investigation that would include all utilities with gas-fired generating plants should be opened.

### E. Carty's Modeled Online Date

**Q. Please summarize CUB's position regarding PGE's modeling of Carty's online date in MONET.**

A. CUB claims that PGE's forecast of Carty's modeled online date is not based on a likely outcome and recommends that the NVPC benefits of Carty be forecast beginning January 1, 2016. CUB bases its claim on (1) a contention that PGE has very little information on the record which allows for a good estimation of the in-service date; and (2) an assertion that the recent history of Port Westward 2 and Tucannon River Farm (i.e., plants coming online ahead of schedule) support a change in PGE's assumptions (CUB/100, Jenks-McGovern/6).

**Q. What is PGE's current expectation for Carty's online date?**

A. As listed in PGE Exhibit 300, Table 1, PGE expects Carty to be online in the second quarter of 2016. PGE's expectation continues to be the second quarter of 2016.

**Q. What is the relationship between the substantial completion date for Carty and PGE's modeled start date?**

A. As CUB indicates in its opening testimony, PGE did select the substantial completion date provided by the engineering, procurement and construction (EPC) contractor as the modeled start date in MONET. PGE selected this date, because it is the most reasonable point estimate for Carty's online date based on the schedules provided to PGE. In fact, in PGE's response to CUB Data Request No. 053, we indicated that the scheduled first fire date for Carty has moved from November 2015 to December 2015. Between December 2015 and May 2016 the EPC contractor will need to complete functional tests, reliability tests, performance tests and commissioning activities. Under no reasonable circumstance, will the EPC contractor reach substantial completion by January 1, 2016, which CUB suggests as a modeling assumption (CUB/100, Jenks-McGovern/5). The most reasonable (and likely) outcome is an online date consistent with PGE's modeling.

**Q. What is PGE's current forecast for NVPC benefits associated with Carty?**

A. In PGE's April 1, 2015, MONET update, PGE increased its modeled dispatch benefit for partial year operations from $0.98 million to $1.6 million. More importantly, for the purposes of setting prices, PGE annualized the amounts for Carty. We derived the dispatch benefit in the revenue requirement by taking the dispatch benefits for Carty's operations in 2016 and multiplying the benefit by the ratio of 12 month loads to the lesser amount of load during Carty's operating period in 2016. This results in a reduction of approximately $2.6 million in the revenue requirement (based on PGE's April 1, 2015 MONET update) and ensures that pricing in 2016 will wholly allocate the benefit forecast of $1.6 million to customers during Carty's partial year operations in 2016.

**Q. CUB asserts that shareholders benefit if Carty comes online earlier than May 2016. Is this true?**

A. No. If PGE made no update to Carty's modeled online date, customers will receive a greater portion of the annualized $2.6 million benefit as Carty's online date moves closer to January 1, 2016.

**Q. What is PGE's proposal for the modeled Carty online date?**

A. PGE proposes no change to the modeled Carty online date. CUB's proposal to model the Carty online date as January 1, 2016 ignores any reasonable basis for establishing a modeled online date. Additionally, CUB appears to ignore the fact that, for the purposes of setting prices, PGE annualized Carty's dispatch benefit and customers will receive an increased portion of the $2.6 million annualized benefits if Carty begins operations earlier than May 16, 2016.

### F. Double-Counting Cost of Wind Day-Ahead Forecast Error

**Q. CUB contends that PGE is double counting wind day-ahead forecast error costs. Do you agree?**

A. No. CUB contends that PGE will be double counting the cost of wind day-ahead forecast error if the Renewable Resource Tracking Mechanism (RRTM) proposed by PGE and PacifiCorp in Docket No. UM 1662 is approved. PGE's cost of wind day-ahead forecast error is included in our NVPC forecast, not in our proposed RRTM.

The cost of wind day-ahead forecast error estimates the cost of the changes necessary in PGE's non-wind resource portfolio and market position that result from the need to re-optimize PGE's system in an effort to accommodate the differences between the day-ahead and hour-ahead forecasts for wind generation.

The RRTM does not include the costs related to changes in PGE's non-wind resource portfolio and market position that result from the difference between the day-ahead and the hour-ahead forecasts. Rather, the RRTM is aimed largely at the value of annual energy variance (i.e., the variance between forecast annual wind energy market value and actual annual wind energy market value).

**Q. What is PGE's proposal for the modeled cost of wind day-ahead forecast error?**

A. PGE proposes no change to the modeled cost of wind day-ahead forecast error. PGE's position appears to align with CUB, which does not propose eliminating the adder in this docket (CUB/100, Jenks-McGovern/6).

## G. Sales for Resale

**Q. CUB believes that PGE should analyze the treatment of sales for resale in its revenue requirement calculation to determine if the revenue should be used as an offset to rate base, do you agree?**

A. No. CUB's recommendation appears to confuse capital expenditures and rate base with fixed expenses. While sales for resale are incorporated in PGE's NVPC forecast (which does include variable and some fixed power costs), PGE could just as easily report the revenue separately in its revenue requirement calculation. This would more clearly show that the revenue offsets both variable and fixed expenses in the revenue requirement calculation. However, there would be no difference in the total revenue requirement result.

We believe there is some confusion in CUB's statement that "in unregulated industries, revenues above variable costs are applied to fixed costs" (CUB Exhibit 100, page 10, lines 16-17). In all industries, the relationship between revenue and variable costs or cost of goods sold represents contribution margin (unit contribution to fixed costs) or gross margin respectively. For purposes of developing a revenue requirement, PGE reclassifies sales for resale to power costs to establish <u>net</u> variable power costs and because sales for resale is an integral component of our power cost forecast as developed by the MONET model. As noted above, the reporting location of sales for resale will not affect the end-result of the revenue requirement calculation.

**Q. Are there instances where sales for resale are treated as part of capital costs?**

A. Yes. Prior to a plant's online date, test energy costs and the resulting sales are included as part of a plant's capital costs.

**Q. What is PGE's proposal for the treatment of sales for resale in its revenue requirement calculation?**

A. PGE proposes no change to the treatment of sales for resale in its revenue requirement calculation. However, PGE is open to further discussions on this topic to ensure that we have appropriately understood the recommendation.

## H. Seasonal Super-Peak Energy Purchase

**Q. Please summarize parties' positions regarding PGE's modeled seasonal super-peak energy purchase.**

A. CUB, ICNU, and OPUC Staff all propose removing the modeled super-peak energy purchase from PGE's NVPC forecast. All parties maintain that PGE no longer needs the purchase given the addition of new capacity resources. ICNU also states that: (1) the MONET model already accounts for the cost of making additional super-peak purchases in the test period and; (2) the purchase is not known and measurable.

**Q. Do you agree with their position?**

A. No. Parties did not consider events such as load excursions going above a 1:2 load scenario or plants unexpectedly going offline. For instance, OPUC Staff cite PGE's analysis of our annual energy load-resource balance under a 1:2 load scenario in the 2011 and 2013 Integrated Resource Plans. CUB and ICNU rely on a summation of the approximate capacity from the addition of Port Westward 2 and Carty to maintain that the new plant additions to PGE's resource portfolio should mitigate any need for the super-peak energy purchase.

**Q. Under what conditions did PGE's 2013 Integrated Resource Plan (IRP) show that PGE's reserves would be insufficient to meet customer demand?**

A. In addition to the 1:2 load scenario that OPUC Staff cites, we did complete analyses in our 2013 IRP to measure the adequacy of our reserves to meet customer demand under a 1-in-5 and 1-in-10[16] load excursion event during the summer months, which have high and particularly volatile prices as the entire western grid peaks. While our analysis described in the 2013 IRP focused on 2015, a similar analysis applied to 2016 would have shown that PGE's reserves were not sufficient to meet customer demand if we were to simultaneously experience an extreme weather event (i.e., 1-in-10) and an unplanned outage from a large thermal plant (e.g., Boardman). This result is shown in PGE Exhibit 1502.

**Q. Are expected parameters of the contract, such as price, known and measurable?**

A. Yes. Based on PGE's past experience it is common for counterparties to only show willingness to enter into a transaction on an intra-year basis. That is, risks such as unit outages, transmission curtailments, and declines in hydro generation are too difficult for a counterparty to quantify in the forward year. Therefore, counterparties are likely to only enter into a super-peak energy sale on an intra-year basis after more information about the current year is available to the counterparty. At that time, counterparties are aware of <u>expected</u> unit outages, transmission curtailments, and hydro generation. Consequently, PGE cannot sign a contract until next year, but we can estimate the expected parameters of the contract, including price, based on our past experience.

[16] The 1-in-5 and 1-in-10 load excursions are calculated peak occurrences that represent a probability of loads exceeding a load forecast (based on a 1 in 2 summer scenario). For example, a 1-in-5 load excursion is a summer scenario that has a 20% probability of occurring.

**Q. Do you agree with ICNU's assertion that MONET captures the pricing of the super-peak energy purchase and therefore no cost adder is needed?**

A. No. Potential sellers charge a risk premium to compensate for the unquantifiable risks of entering into a forward sales agreement months ahead of actual delivery. Potential sellers also assign a premium value for energy delivered during the highest hourly load period. This premium is over and above the values in the shaped forward price curve used to price power purchases and sales in MONET, which is based on normal conditions for modeled variables (e.g., water and wind flows and weather). The shaped forward price curve is appropriate for pricing standard products such as peak and off-peak purchases, but due to the lack of liquidity and market depth for the super-peak energy product, it is not reasonable or prudent to assume that the forward price curve used in MONET is capturing the premium that sellers require for the sale of super-peak energy on a forward basis.

**Q. What is PGE's proposal for the modeled super-peak energy purchase contract?**

A. PGE proposes no change to the modeled super-peak energy purchase contract. PGE's modeling appropriately forecasts the costs that PGE expects to incur for making this intra-year purchase in 2016.

## III. Summary and Conclusion

**Q. In closing, please summarize your proposals regarding the issues identified by parties.**

A. We recommend the Commission reject the parties' positions regarding the issues identified. With respect to each issue, our proposals are summarized below:

- **California-Oregon Border (COB) Trading Margins**: PGE proposes to continue to not include the costs and benefits of California trading margins from the NVPC forecast produced by MONET. The PCAM is the appropriate mechanism for addressing variables (such as trading margins) that are the by-product of PGE's overall strategy to manage the risks associated with meeting our customers' power supply requirements.
- **Load-Net-Wind**: PGE proposes no change to its load-net-wind modeling methodology. The methodology correctly accounts for the combined variability of load and wind given the hourly bilateral market, 15-minute scheduling of wind, and an illiquid sub-hourly market.
- **Pipeline Capacity Release Credits**: Due to numerous variables that will increase PGE's gas demand, PGE does not expect to recognize capacity release revenues during 2016. The Commission should reject ICNU's proposal to include an adjustment to reflect the <u>potential</u> for revenue.
- **Coyote Springs Forced Outage Rate**: PGE proposes to continue the use of the four-year average method, which is long-standing and well-established. If Staff decides it would like to change methodologies for gas-fired plants, it should be done in a policy/investigation docket similar to Docket No. UM 1355.

- **Carty Modeled Online Date**: PGE proposes no change to Carty's modeled online date. PGE's assumption is the most reasonable (and likely) outcome.
- **Double Counting Cost of Wind Day-Ahead Forecast Error**: PGE proposes no change to the modeled cost of wind day-ahead forecast error. A double-count does not exist between PGE's modeled cost of wind day-ahead forecast error and the RRTM.
- **Sales for Resale**: While we propose no change to the treatment of sales for resale in our revenue requirement calculation, we are open to further discussions on this topic to ensure that we have appropriately understood the recommendation.
- **Seasonal Super-Peak Energy Purchase**: PGE proposes no change to the modeled super-peak energy purchase contract. PGE's modeling appropriately forecasts the costs that PGE expects to incur for making this intra-year purchase.

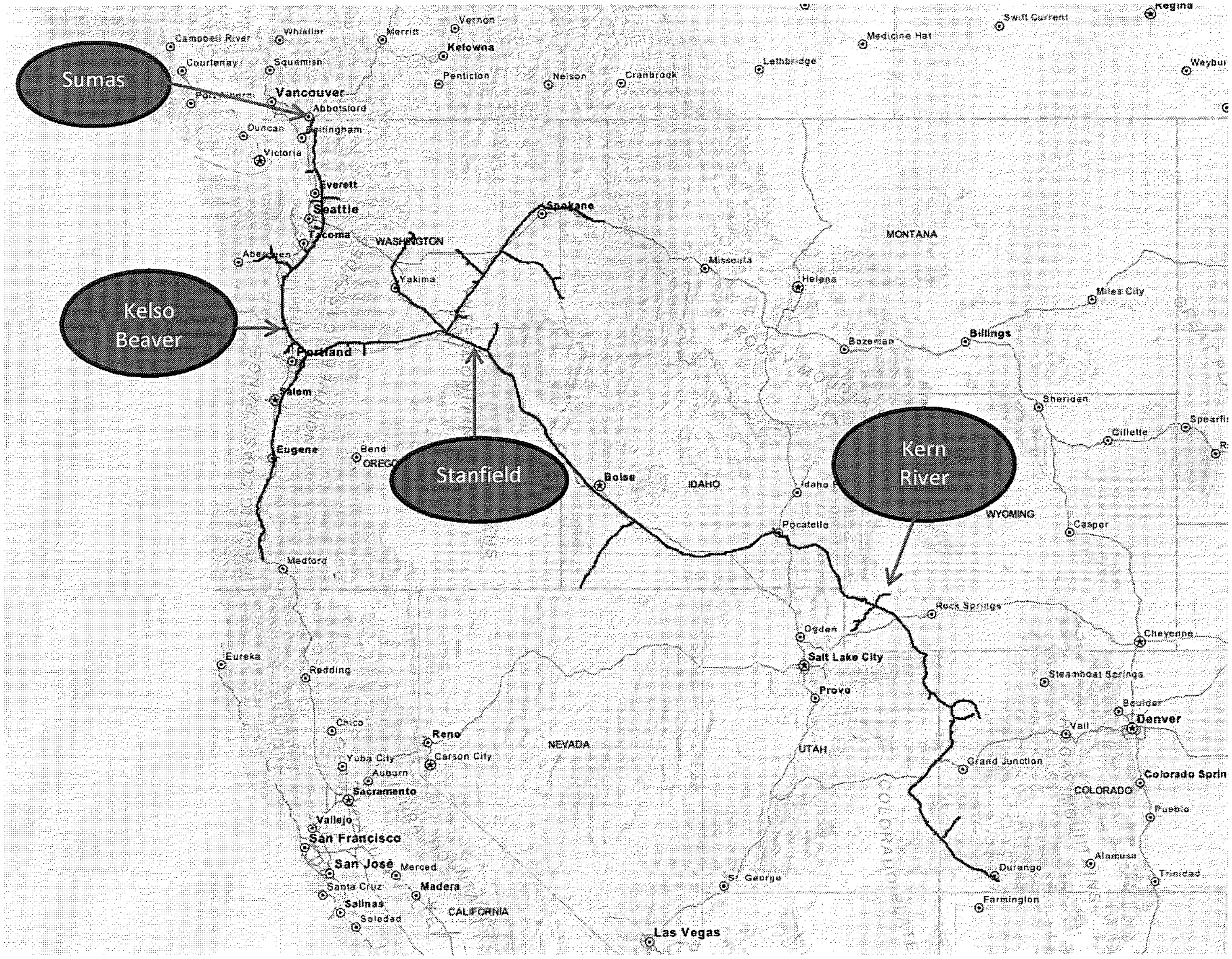
**Q. Does this conclude your testimony?**

A. Yes.

*List of Exhibits*

| PGE Exhibit | Description |
|---|---|
| 1501 | Northwest Pipeline System Map |
| 1502 | 2016 Summer Capacity Based on 2013 IRP Load Resource Balance Data |

## Northwest Pipeline with Key Points Described in PGE Exhibit 1500 Identified



## 2016 Summer Capacity Based on 2013 Integrated Resource Plan Data

Based on 2013 Integrated Resource Plan Load Resource Balance data with 1:10 load from same forecast (SDEC13) and Boardman Outage.

No additional updates.

Column B aligns with the Load Resource Balance charts in the 2013 Integrated Resource Plan. Need is equal to the 1:2 Summer Peak plus Operating Reserves and the Planning
Column C is based on Column B but adjusted for a 1:10 Load (without reserves) and a Boardman outage.

| (A) | (B) | (C) |
|---|---|---|
| **Summer capacity LRB** | | |
| | **2013 IRP** | |
| | **1:2 + Reserves** | **01:10 + Outage** |
| (MW) | **2016** | **2016** |
| Gas | 1,754 | 1,754 |
| Hydro | 970 | 970 |
| Renewables | 71 | 71 |
| EE | 124 | 124 |
| Non-Hydro Contracts | 209 | 209 |
| Demand Response | 45 | 45 |
| DSG | 110 | 110 |
| Coal | 756 | 296 |
| **Total Resources** | **4,039** | **3,579** |
| | **1:2 Load + Reserves** | **1:10 Load** |
| **Need** | **3,721** | **3,707** |
| **Surplus or (Deficit)** | **318** | **(128)** |
| Boardman | | 460 |

## CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **PGE's UE 294 - REPLY TESTIMONY (Net Variable Power Cost)** 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 18th day of June 2015.

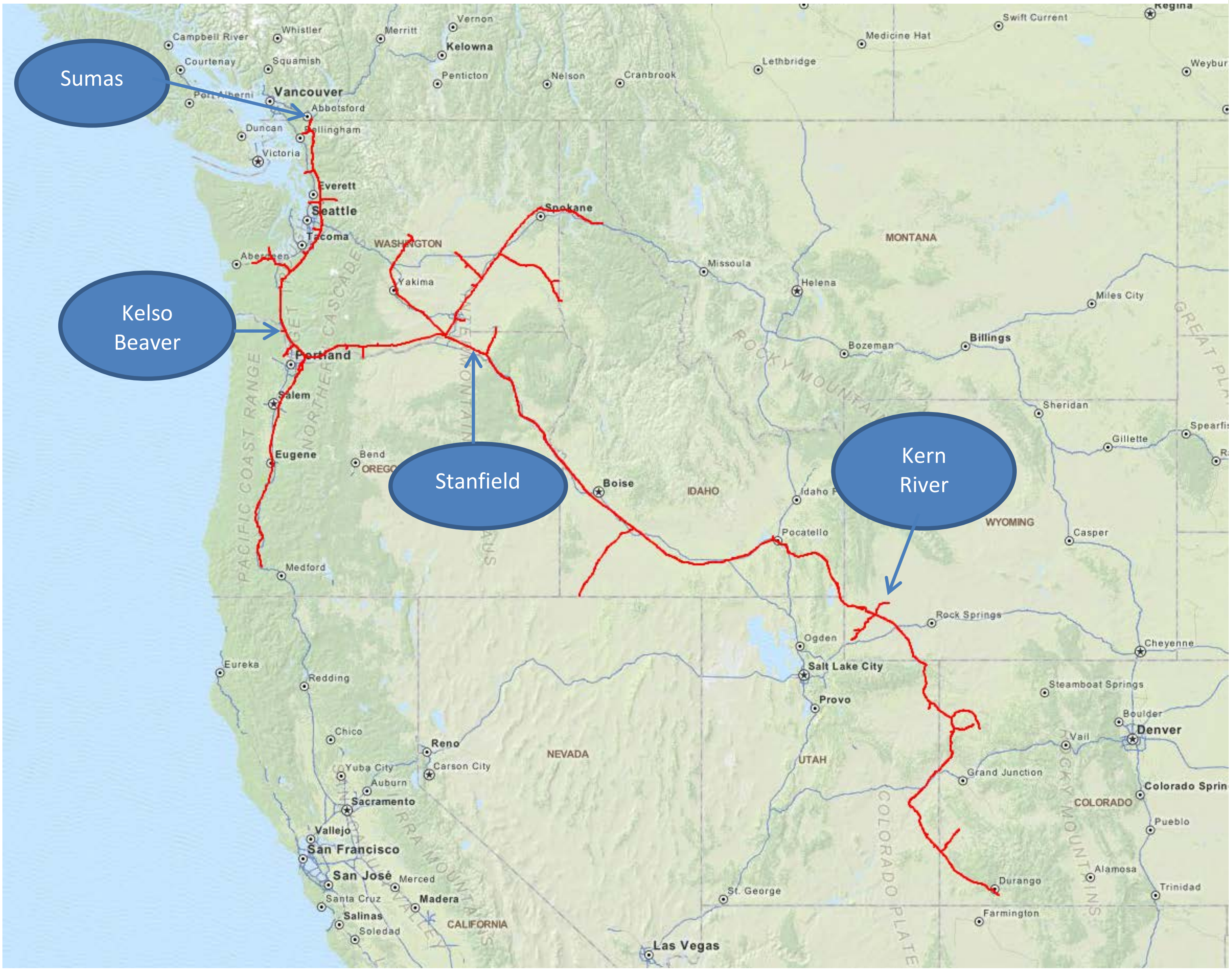
Jay Tinker

Jay Tinker
Portland General Electric Company
121 SW Salmon Street, 1WTC0702
Portland, OR 97204
Telephone: 503-464-7002
Fax: 503-464-7651
E-Mail: jay.tinker@pgn.com

**SERVICE LIST**
**OPUC DOCKET # UE 294**

| | |
|---|---|
| Judy Johnson (C)<br>PUBLIC UTILITY COMMISSION OF OREGON<br>judy.johnson@state.or.us | Johanna Riemenschneider (C)<br>PUC – DEPARTMENT OF JUSTICE<br>Johanna.riemenschneider@state.or.us |
| Douglas C. Tingey (C)<br>PORTLAND GENERAL ELECTRIC COMPANY<br>doug.tingey@pgn.com | Jay Tinker (C)<br>PORTLAND GENERAL ELECTRIC COMPANY<br>pge.opuc.filings@pgn.com |
| OPUC Docket<br>CITIZENS' UTILITY BOARD OF OREGON<br>dockets@oregondub.org | Robert Jenks (C)<br>CITIZENS' UTILITY BOARD OF OREGON<br>bob@oregoncub.org |
| Sommer Templet (C)<br>CITIZENS' UTILITY BOARD OF OREGON<br>sommer@oregoncub.org | Greg Bass (C)<br>NOBLE AMERICAS ENERGY SOLUTIONS<br>gbass@noblesoultions.com |
| Kevin Higgins (C)<br>ENERGY STRATEGIES LLC<br>khiggins@energystrat.com | Gregory Adams<br>RICHARDSON ADAMS PLLC<br>greg@richardsonadams.com |
| S Bradley Van Cleve (C)<br>DAVISON VAN CLEVE PC<br>bvc@dvclaw.com | Tyler C. Pepple (C)<br>DAVISON VAN CLEVE PC<br>tcp@dvclaw.com |
| Bradley Mullins (C)<br>DAVISON VAN CLEVE PC<br>brmullins@mwanalytics.com | Diane Henkels<br>CLEANTECH LAW PARTNERS, PC<br>dhenkels@cleantechlaw.com |
| James Birkeland<br>SMALL BUSINESS UTILITY ADVOCATES<br>James@utilityadvocates.org | Wendy Gerlitz (C)<br>NW ENERGY COALITION<br>wendy@nwenergy.org |
| Nona Soltero<br>FRED MEYER STORES/KROGER<br>Nona.soltero@fredmeyer.com | Erin Apperson<br>PACIFIC POWER<br>erin.apperson@pacificorp.com |
| Kurt Boehm<br>BOEHM KURTZ & LOWRY<br>kboehm@bkllawfirm.com | Oregon Dockets<br>PACIFICORP, DBA PACIFIC POWER<br>oregondockets@pacificorp.com |
| | Jody Cohn<br>BOEHM KURTZ & LOWRY<br>jkyler@bkllawfirm.com |
| | |
| | |

## Northwest Pipeline with Key Points Described in PGE Exhibit 1500 Identified



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