Integrated Resource Planning

STAKEHOLDER FEEDBACK: April 8, 2026

Received: June 25, 2026

Stakeholder: OPUC Staff

Organization: OPUC Staff

Applicable Public Meeting Date: April 8, 2026

1. Transmission Constraints: Methodology & Approach (Slides 16 – 27)

Process: What remaining questions do you have regarding PGE's transmission methodology? What additional information would support your understanding of PGE's transmission constraints and GridView capabilities?

Please explain how the transmission constraint presented on slide 22 is correlated to the Loss of Load Probability (LOLP) matrix from LC 80. Please explain whether the Company has developed LOLP hours for this IRP and if so, please indicate where they can be found.

Has the Company considered the marginal transmission capacity evaluation proposed by Sylvan Energy Analytics as an alternative method for assessing constraints and associated costs.

PGE Response:

The LOLP matrix for LC80 is located at figure 44 of the 2023 CEP/IPR. A draft LOLP matrix for the 2026 CEP/IRP can be found in the Dec. 10, 2025 CEP/IRP Roundtable 25-8, slide 35. Comparing the transmission constraint heatmap on slide 22 of the April Roundtable, there is not a significant overlap between the hours of greatest transmission constraint and hours of greatest reliability risk, where most transmission constraints occur in the solar production hours of spring. The correlation between the updated transmission constraint heatmap on slide 12 of the July 22, 2025 CEP/IRP Roundtable 26-6 and the draft 2026 CEP/IRP heatmap shows less of an overlap between transmission and reliability constraints as BPA's updated TTC values for use in 10-year planning horizon significantly reduce the month and hours with transmission constraints.

2. **Content: Between PGE's proposed used of existing long-term transmission rights, transmission expansion options and use of short-term non-firm transmission, do you think PGE's proposed methodology well captures system transmission constraints?**

Staff is interested in understanding how PGE's assessment of non-firm congestion differs from how it was evaluated in the 2025 RFP and whether that process highlighted opportunities for improvements. Please plan to provide the study materials, including assumptions, inputs, findings, and any associated workbooks that can help Staff review and provide feedback on the approach.

Staff is pleased to see consideration of the role of non-firm transmission options and will be interested in seeing how consideration on non-firm transmission impacts resource selection. Staff would like to understand more about whether the consideration of new transmission products at BPA is likely to influence modeling assumptions and how the Company is considering any risks associated with new BPA non-firm transmission products.

How does the company see using non-firm transmission in RFP evaluation and what other potential costs are assumed to ensure energy needs are met in times of congestion?

How does the modeling consider the tradeoffs between transmission expansion and the role of VPPs, NWA, and DSM?

Can the Company describe or characterize the types of transactions that occur on transmission segments for which it has rights? For example, importing, exporting, engaging in markets, etc. Will the study characterize anything about the nature of the utilization and drivers of congestion?

Any Other Feedback?

PGE shared that it is utilizing customer sited storage to convert non-firm energy into a capacity contribution resource. How is PGE considering utility scale storage resources as an option to utilize non-firm energy to be able to contribute to capacity? How will this consideration impact resource selection?

How will GETs analysis and the GridView analysis speak to each other?

PGE Response:

Sylvan Comparison:

PGE has reviewed the Sylvan Energy Analytics proposal and its planning recommendations. The IRP team considers forecasting the availability of non-firm transmission availability forecasting as a responsive approach to the recommendations of the Sylvan proposal. Both approaches rely on short-term transmission products to increase maximize the use of BPA's existing transmission system: 1) Short-term redirects or 2) Non-Firm transmission. From an operations perspective, the forecasted availability of these products is similar. Short-term redirects are most likely to be granted when the transmission system is unconstrained and non-firm transmission is available. Short-term redirects are not granted when the transmission system is congested and suspension of short-term redirects is pursued as a congestion management tool. These are the same conditions in which non-firm transmission is forecasted to be unavailable.

Differences from the 2025 RFP:

The main difference between the 2025 RFP non-firm assessment and the proposed use of GridView PCM results is that the 2025 RFP relied on historical observations to identify patterns path congestion while the GridView approach relies on fundamental forecasts of transmission utilization. Results, particularly those updated in the July 2026 round table are comparable to those used in the 2025 RFP. The new approach allows PGE to forecast how the conditions would mitigate or degrade should transmission upgrades be energized or delayed relative to plans. They also account for forecasted changes in the WECC wide power system, in particular additions of VERs in CAISO. As discussed in the roundtable, non-firm is a contingent product, with lowest priority, that cannot be reserved long term. For these reasons, the product poses significant reliability and financial risks. PGE appreciates the additional methodology recommendations from Energy Strategies and will consider whether those statistical refinements can be included in future assessments including future RFPs.

RFP Inclusion:

PGE is not proposing a specific RFP methodology at this time.

Tradeoffs:

The Gridview methodology is specific to use of non-firm transmission on BPA's transmission system. It does not directly influence transmission expansion, VPP, NWA, or DSM analysis other than through the ability of non-firm generation resources to satisfy system needs otherwise met with alternative resources.

Drivers of Congestion:

Energy Strategies analysis shared on the July roundtable identified BPA wind, CA Solar, and PNW load as the main drivers of North of Pearl related congestion.

3. Price Futures Update (Slides 28 – 37)

Process: New for the 2026 IRP, PGE is attempting to forecast the wholesale price risk associated with changes in WECC wide large load growth and generation technology build out. Do you understand and agree with the proposed methodology change?

What are the primary drivers of the increased volatility in pricing from the IRP Update to the 2026 IRP?

To what extent are various assumptions influencing this volatility (large loads, natural gas prices, transmission constraints, etc.)?

How does the Company mitigate risks associated with considering a broader range of possible future prices?

PGE Response:

It is hard to capture a comprehensive view of the sources of increased price volatility, but the inclusion of Uplift (or Fast Start Pricing) in all price futures and higher load forecasts (putting disproportionate pressure on non-solar hours peak prices) are two key contributors.

A description of how price futures are constructed will be included in the 2026 IRP.

In portfolio analysis, each scenario is analyzed across 333 different futures representing all combinations of the 37 price futures, 3 technology cost futures, and 3 need futures. For each future analyzed, an optimized portfolio of resources is produced that minimizes the net present value of costs across the 20-year planning horizon. This range of cost outcomes across all futures provides a rich distribution of results from which to consider variability and risk. In the 2026 IRP, PGE will be extending the risk analysis done on the 333 portfolios using the new model ARIA to compare how each portfolio performs across each of the 333 futures allowing additional richness from the data to be captured and utilized in the selection of a portfolio that is least cost and least risk across a very large number of potential future outcomes. This information will inform portfolio scoring and the selection of a least-cost/least-risk portfolio.

4. Energy Values for Resources (Slides 38 – 41)

Content: Energy Values increased substantially from the 2023 CEP/IRP Update primarily due to higher market price forecasts. Are the resulting 2026 IRP energy values in line with your expectations?

To what extent is the modeling able to reflect assumptions about market participation? Is the Company able to consider historical location marginal price averages? How do these proxy value compare with bid prices in the last two RFPs?

PGE Response:

The modeling of price futures in the WECC includes limitations on market purchases relative to regional transmission limits. The modeling of emission in the PZM incorporates an emissions constraint that is calculated based upon various assumptions about market participation.

The IRP currently does not include historical locational marginal price averages in its representation of market participation.

The proxy values in the 2026 IRP are more aligned with the most recent 2025 RFP rather than the 2023 RFP as the 2026 IRP and 2025 RFP both use price curves generated from Wood Mackenzie's 2024H2 input database.

5. Market Emission Factor Scenario (Slides 53 – 63)

Content: The market emission factor forecast is informed by the CAISO method that is currently being explored, and assumes that States across the region are making progress towards and meeting current clean energy and decarbonization targets. Do you have any questions regarding this approach? Are there other methods PGE should consider?

Staff generally feels that using CAISO's reporting methodology is reasonable. Since it is unknown whether DEQ will adopt the CAISO methodology for HB 2021, Staff would like to know what other sensitivities the Company is considering to provide guardrails around the forecast.

What assumptions regarding market dispatch preferences are considered and accounted for?

PGE Response:

On content: the CAISO-informed alternative emission factor scenario is just one of many scenarios to be presented in the 2026 CEP/IRP. Given time and resource constraints, PGE has elected not to perform West-wide analysis for the purposes of this inaugural, exploratory scenario. PGE did not conduct the West-wide analysis underlying and informing the market emission factor forecast, but rather, as described, relied on existing analysis from the Brattle Group that was leveraged in the 2023 CEP/IRP Update informing potential clean energy surplus available in a Western market. This existing forecasted dataset has been reworked for the purposes of understanding the emissions associated with all resources potentially available in a Western market to inform the annual market emission factors used in the alternative emission factor scenario. Given the need for standalone robust analysis to forecast such an emission factor, leveraging an existing dataset was seen as advantageous given information regarding its assumptions and design have already been described as part of a previous IRP cycle. As indicated in the comment, the context of what the forecast itself includes and says regarding policy implementation, underlying cost assumptions, load forecasts, and otherwise are all important, were noted in the roundtable slides, and will be included in discussion in the 2026 CEP/IRP for contextualizing the emission factor analysis. The Brattle Group conducted the dispatch modeling using Aurora, with more information available in the "Clean Energy Surplus Modeling Study"[1] on PGE's 2023 CEP/IRP Update website.

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1 https://assets.ctfassets.net/416ywc1laqmd/7mZDwnJnvwNczJQ78fAk4m/a0a5516ee737ccd7f1aed5b09285ea1a/Brattle_PGE_Estimating_Hourly_Clean_Energy_Surplus_Available_in_the_WECC_Market__Appendix_F._Market_for_non-emitting_energy_.pdf.