Integrated Resource Planning

STAKEHOLDER FEEDBACK: May 20, 2026

Received: June 8, 2026

Stakeholder: Pat DeLaquil

Organization: MCAT

Applicable Public Meeting Date: May 20, 2026

1. Regarding the Regulatory Environment: Why is the name of the HB 2021 scenario option say 80%, when the law's 2040 requirement is 100% clean electricity use in Oregon? Please specify the "linear glidepath" for the thermal resources?

   PGE Response:

   HB 2021 80% Emissions Reductions is a shorthand description for one of the regulatory environment scenarios. While not specified in the name, the scenario models a GHG emissions glidepath that achieves the HB 2021 emissions targets of 80% reductions by 2030, 90% reductions by 2035, and 100% reductions by 2040. In this scenario, emissions associated with serving PGE's retail load decline linearly from 2027 to 2030 and from 2030 to 2040. The linear glidepath is illustrated on slide 49 of PGE's February Roundtable meeting.

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2. Under Load Forecast, four options are presented (Reference, Low, High and No Large Load Growth), but only Reference and NLL are specified in the Portfolio. How will the High and Low growth cases be assessed?

PGE Response:

For all scenarios defined as using the "standard" load forecast, when the scenario is run through PGE's capacity expansion model, ROSE-E, portfolios are produced for each of the low, reference, and high load forecasts. In fact, for each scenario run in ROSE-E, there are actually 333 different portfolios produced because each scenario is run across all combinations of the 3 need (or load) futures, 3 technology cost futures, and 37 energy price futures (3 x 3 x 37 = 333). Roundtable presentations typically focus on the resource buildout and cost outcomes for the reference case results. However, it is possible to view and analyze the portfolios produced for the other futures. Typically the results of the portfolios produced for the other futures are used to calculate portfolio cost and risk metrics that are based on the distribution of cost outcomes across all futures. These cost and risk metrics are described on slide 70 of PGE's February Roundtable. Additionally, for the 2026 IRP PGE has developed a new model (called ARIA) to conduct deeper analysis into the distribution of outcomes across the wide range of futures modeled in ROSE-E with the goal of better understanding the dynamics of cost and risk across the modeled futures. The ARIA model is described in slides 73 – 77 of PGE's February Roundtable.

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3. Under Resource Considerations, we note the scenario option of delaying PGE's exit from Colstrip from the end of 2029 to the end of 2034, which is considered under section 1 article 4 of Senate Bill 1547 from the 2016 legislative session. Please confirm that this scenario option is for informational purposes only and that PGE is not currently planning to request such authorization from the Commission.

   PGE Response:
   PGE is required by ORS 757.518 (Section 1, Senate Bill 1547 (2016)) to eliminate the costs and benefits associated with coal-fired resources from rates by the end of 2029. This is different than exiting ownership or shutting down Colstrip, decisions that are tied to the complex ownership structure and associated obligations. As noted in the request, the law also gave PGE the option of continuing to include the costs and benefits, and thus the electricity, from Colstrip in rates until the end of 2034. This short-term exemption recognized the potential cost or reliability impacts to customers of accelerating depreciation and the additional cost risks associated with market exposure and resource procurement.

   The 2026 IRP is planning for a near-term action window of 2027 – 2032, and the resource planning team included a limited number of scenarios that extend Colstrip through the end of 2034, in line with the flexibility provided in ORS 757.518, to better evaluate this resource and its effect on reliability, affordability and decarbonization. In that regard, the scenario option is designed to produce relevant information related to ODS 757.518. PGE continues to evaluate its ongoing ownership in Colstrip and its options for exiting the agreement. The Company has made no decision on whether the company will request the 5-year extension from the Commission as provided in ORS 757.518(4).

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4. Also, we recommend that a High Distributed Energy Resources (High DER) resource option be added that assumes utility rate-based investment in distribution system generation and storage systems managed to reduce peak loads and increase overall system utilization. Also, based on Comment 11 below, we recommend that the VPP bins for this scenario include utility investments in residential and commercial rooftop solar capacity coupled to substation-scale battery storage systems that can quickly provide needed new capacity while bolstering resilience and improving system utilization, thereby lowering costs for all consumers.

   PGE Response:
   Thank you for your recommendation. We agree that the utility has a critical role in advancing distribution system generation and storage. Those resources are an important pathway to consider in broader system planning and an important focus area in the IRP.

   PGE uses AdopDER for estimating DER forecasts for the planning horizon of 20 years. AdopDER is specifically designed to model adoption of DER which includes distributed rooftop solar and storage that are customer-sited. In the IRP analysis we have considered three distributed energy resources (DER) adoption scenarios – low, reference and high adoption. The High DER scenario already captures elevated adoption of customer-sited rooftop solar and battery systems across residential and commercial segments. The solar resources are fully represented in the model and contribute to lowering net load and providing capacity. They are not separately added as part of the VPP bins again to avoid double counting. The customer-sited storage resources are considered as part of the VPP bins.

   PGE's VPP is the orchestration of all customer-sited DER configurations through integrated Customer and Grid technology platforms to provide energy, capacity and grid services. It includes EV chargers, batteries, smart thermostats, water heaters, and customer-owned generation that are coordinated and/or dispatched by PGE for peak load reduction and emergency response. Within the IRP framework, these customer-driven impacts are incorporated into the load and resource balance. The resulting system needs identified through the IRP then inform capacity expansion decisions, with specific resources ultimately procured through competitive solicitations or other acquisition processes.

   We would like to emphasize that PGE recognizes the value of utility-coordinated distribution system generation and storage in in enhancing flexibility, resilience, and system utilization. PGE's VPP enables unlocking of greater value from the existing customer-sited resources to meet resource adequacy challenges while keeping prices as low as possible for customers.

5. Capacity Methodology: Can PGE provide more details on how the IRP Metrics and the State RA metrics methodologies lead to different ELCCs and what those differences are?

PGE Response:

The IRP metrics and State RA metrics methodologies lead to different ELCCs because they originate from different sources. ELCCs for the IRP metrics are derived from PGE's loss of load (LOL) study which simulates energy and capacity constraints at an hourly granularity specific to PGE's load and generation fleet using Sequoia.[1] ELCCs for PGE's State RA metrics methodology are based on those published by the Western Resource Adequacy Program (WRAP) for Winter 2026-2027 and Summer 2027.[2] WRAP's ELCCs are also simulated through an hourly LOL study but are estimated based on loads and generation resources across the entire WRAP region. This study is conducted by the Southwest Power Pool using the SERVM model, as described in WRAP Business Practice Manuals (BPM) 102 and 105. ELCCs derived from any LOL study represent a technologies capacity to resolve unserved energy while respecting a system's unique constraints.[3] While both studies capture chronological energy and capacity constraints in estimating ELCCs, the granularity and specificity of the system produces variations in ELCCs which indicate different levels of precision. A brief overview of the data used to estimate ELCCs from the two methodologies is introduced below with references to detailed model documentation. Resulting ELCC estimates are compared on slide 92 of PGE's February Roundtable.

The ELCCs provided in excel format by WRAP represent average ELCCs for 10 different technology variations at various future resource penetrations. PGE derives marginal ELCCs from the average ELCCs published by WRAP for the +9GW scenario of Wind, Solar, and ESR as described on slide 94 of PGE's February Roundtable.[4] Marginal ELCCs are mapped to PGE's proxy resources and used for portfolio expansion in the State RA metrics Regulatory Environment planning scenario. Where there are gaps in

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[1] See PGE's 2019 IRP Update, Appendix K – Sequoia Overview
[2] https://www.westernpowerpool.org/resources/wrap_metrics/
[3] https://www.ethree.com/wp-content/uploads/2025/08/E3_Critical-Periods-Reliability-Framework_White-Paper.pdf
[4] https://assets.ctfassets.net/416ywc1laqmd/oh36t62jePnaIYjHNBxl6/f6a66f2c61cad892f05b6eff5e1850f6/CEP_IRP_Roundtable_Feb_26-2.pdf#page=81

overlap of State RA metrics ELCCs are based on IRP Metrics ELCCs, as described in slide 95 of PGE's February Roundtable. Of note, WRAP does not estimate ELCCs for future penetrations of Hybrid Resources, instead capacity contributions for hybrid resources are measured as the sum of resource components, as described in BPM 105.

ELCCs estimated in Sequoia represent site specific proxy resources whose generation profile is measured endogenously against PGE load and generation, modeling the energy and capacity constraints specific to PGE's system. ELCCs for over 40 different resource technologies are estimated in PGE's LOL study which are also marginalized for use in portfolio expansion. In contrast to the WRAP study, hybrid resource ELCCs are estimated endogenously, capturing the interactive relationship between resources behind the interconnection.

6. Transmission Expansion: The North of Pearl transmission path was shown to consistently and significantly have the most constrained number of hours. The distribution network downstream of this path should be a focused target for implementation of distributed energy resources that can allow near-term load growth while at the same time reducing peak loads and increasing overall system utilization to help lower rates for all customers.

PGE Response: Thank you for your comment and continued engagement in our planning processes. We continue to enhance and review regional and local Transmission options in our Transmission modeling and appreciate the feedback. For clarification, the North of Pearl flow gate is heavily impacted by economic energy transfers from California and the desert Southwest to the Pacific Northwest which includes the Portland area. While we continue to evaluate the need for local system mitigations, including non-wire solutions, the ultimate solution for the North of Pearl flow gate is new transmission infrastructure to allow reliable energy transfers across the region. PGE and BPA have jointly developed a set of transmission projects that will add significant capacity to the North of Pearl path in the 2026-2033+ timeframe. Details of these plans are available in PGE's Local Transmission Plan (posted on OASIS) and on BPA's "Grid Expansion and Reinforcement Portfolio" website.

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7. Content: Do you have any questions or concerns with PGE's approach to modeling a cost cap scenario? Are there any assumptions you would change or add to this proxy policy analysis?

Cost-Cap Scenario: Because any Section 10 filing needs to be based on actual costs as documented by contracts or other financial commitments. We see this scenario as informational only but a useful planning exercise within the IRP process, that will help identify portfolios with lower rate impacts.

PGE Response: Thank you for your comment and continued engagement in our planning processes. PGE agrees that the continual progress analysis included in the IRP is not based on actual costs and does not change any procedural or evidentiary requirement for a Section 10 filing.

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8. Using the latest "approved" revenue requirement as a starting point for this scenario is OK, but the methodology of how model results are used to generate every parameter in the forecast future revenue requirements needs a detailed explanation.

   PGE Response: Open OPUC rulemaking docket no. AR 685 will define the requirements relating to cost cap implementation, though development is still in an informal stage at this time. It is anticipated that initial revenue requirement will be required to start from a latest Commission-adopted on the books revenue requirement, with more information to guide assumptions for forecasted rate impact analysis to be descried in rules. It is important to note that the scenario design for IRP is not intended to exactly reflect cost cap implementation as any HB 2021 Section 10 investigation is meant to rely on more actual and known forward-looking costs and likely investments, which is different than proxy cost analysis in IRP for a long-term planning-basis. In accordance with OAR 860-090-0060(7), PGE is developing the Continual Progress scenario for this CEP/IRP with the intention of any assumptions and results to be used for evaluation and consideration within the CEP/IRP context. PGE agrees transparency in analysis assumptions is important and the 2026 CEP/IRP will include detailed description of assumptions and methodology underlying Continual Progress and other scenario analysis.

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9. The use of a Reliability only scenario can provide a suitable comparison to the HB2021 scenario as long as all clean technology options remain the same in each scenario design. The projected ELCCs are critical to the projected capacity needs and so need better definition and explanation.

PGE Response:

The intent of the Reliability Only (RO) scenario is to provide a counterfactual to the HB2021 scenario. To provide an effective counterfactual to HB2021, the ELCCs used in the RO scenario are the same as those in the HB2021 scenario. Further, there is no difference in the quantity or timing of clean technology availability. As such, resource buildouts and costs in the RO scenario are driven by excluding the emissions constraint associated to HB2021 and the ability to elect new gas contracts as a potential cost-optimized resource option for planning purposes. Relaxing the constraints which represent the policy effect of HB2021 results in a planning environment that addresses reliability and affordability with available resource types. Therefore, comparing the results of the RO and HB2021 scenarios is intended to estimate the costs attributed to acquiring resources for HB2021 compliance.

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10. Finally, rather than design the scenario to stop meeting HB 2021 targets the first time the cost cap is projected to be reached, we propose that for IRP purposes, the incremental cost of HB 2021 compliance be a standard calculation for every portfolio.

PGE Response:
The CEP/IRP and long-term planning are important steps informing PGE decision-making, procurement needs, investment opportunities, and operations. However, the scenario analysis is best used as directionally informative, as modeling has its limitations and costs represented in CEP/IRP are proxy assumptions based on best available information for a 20-year forward-looking view. Known new project costs are not incorporated into the planning modeling, nor can they be due to future uncertainties in contract/ownership structures, build costs, and otherwise. Importantly, the scope of IRP cost analysis has never included total system revenue requirement nor rate impact estimates due to the uncertain nature of 20-year forecasts and detailed decision-making specific to individual rate cases. Further, IRP cost results typically reflect changes and additions in generation and transmission costs only, and do not attempt to contemplate all utility-relevant spending nor revenues. Estimates do not include costs from the rest of PGE, such as those associated with administrative costs, grid modernization, other transmission and distribution maintenance and upgrades, wildfire mitigation or actual generation costs. Therefore, IRP scope may not entirely reflect a meaningful estimate of all relevant incremental costs that could impact compliance with HB 2021 or any other policy. Overall, an analysis of cost of compliance is a different kind of analysis than IRP strictly contemplates. Additionally, there will always be cost impact uncertainty due to ongoing policy discussions and implementation in and out of Oregon, such as cost allocation to new large customers, the impact of other states' clean energy policies on market prices, and more.
Cost and price results represented in the CEP/IRP can still be indicative for evaluating options to decarbonize, and are directionally informative for understanding potential futures and impacts, but on a planning-basis, in accordance with OAR 860-090-0060(7)(g)(A)-(B).

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11. "Content: Does the proposed VPP binning and application provide a credible and appropriate representation of these resources within IRP modeling?"

    Regarding Virtual Power Plants and Distributed Energy Resources, we appreciate the updated approach of creating distinct bins of VPP/DER resources that will be integrated into the resource optimization process rather than being treated as load modifiers as in the previous IRP.

    PGE Response:

    Thank you for the feedback. We appreciate your support for the updated approach to representing VPP/DER resources as selectable supply-side options in the IRP process.

12. "Content: What additional assumptions, or clarifications are needed to ensure confidence in the implementation and evaluation of VPP resources in the IRP?"

    For VPP bins: Rooftop solar installations are one of the exceptions to what gets included in the VPP bins. We believe this specific exception creates a significant missed opportunity to further examine DER option, where residential and commercial rooftop solar capacity drives substation-scale battery storage systems that can quickly provide needed new capacity while bolstering resilience and improving system utilization, which can lower costs for all consumers.

    PGE Response:
    PGE uses AdopDER to model and estimate customer adoption of distributed energy resources (DER) which includes distributed rooftop solar (both residential and commercial). In the IRP analysis we have considered three DER adoption scenarios which reflect low, reference and high adoption of customer-sited DER. These resources are fully represented in the model and contribute to lowering net load and providing capacity.

    The VPP resources which are included as part of the five bins are being modeled and included as a resource option that are evaluated as part of all resource options for potential selection in portfolios. Since the entire rooftop solar capacity is already included in the estimation of the net load so this specific resource is already selected and does not need to be evaluated again as part of the VPP bins. Including them as part of the VPP bins would lead to double counting of capacity.

    We recognize the value of coordinating distributed solar with storage. The integration and orchestration of customer-sited resources (which includes rooftop solar and storage which may or may not be co-located) is a central goal of PGE's VPP, and forecasted capacities of these resources are included in the IRP analysis. The resulting capacity needs and opportunities for additional substation-scale resources (including storage) are evaluated downstream in the IRP through optimal portfolio expansion analysis. See response to question 4 for more detail.

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13. ELCC calculations: How were the 2030 incremental capacity potential values from AdopDER calculated? What are the key assumptions driving these values?

PGE Response:

The 2030 incremental capacity potential values for VPP resources are based on a combination of current program participation and projected future program expansion.

For existing PGE demand response programs, we utilize a hybrid approach to estimate capacity over time. For the current year (e.g., 2025), incremental capacity is based on observed program enrollments multiplied by the planning value (average kW reduction per enrollee per event) derived from historical performance. For future years, capacity growth is driven by forecasted enrollment expansion modeled in AdopDER, which applies Bass diffusion curves to reflect program adoption over time based on assumptions around program maturity, duration, and market saturation. This results in MW impacts that evolve consistently with expected customer adoption.

For non-PGE or future DR programs, capacity is estimated by first identifying the eligible customer population and assuming a level of potential participation. These resources are then evaluated using simulated dispatch events based on TMY weather data and season-specific operating assumptions (e.g., event timing, duration, and frequency). Load impacts are informed by evaluation-based performance assumptions, with studies conducted by firms such as Resource Innovations, which simulate DR events and estimate resulting customer load reductions.

For Distributed Standby Generation (DSG), incremental capacity assumptions are based on information regarding potential customers who may be eligible to participate and have communicated interest.

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Received: June 25, 2026

Stakeholder: OPUC Staff

Organization: OPUC Staff

Applicable Public Meeting Date: May 20, 2026

Community Benefit Indicators (CBIs) (Slides 8 – 28)

Content: Do you understand how PGE has applied CBIs to Portfolios in the 2026 IRP/CEP?

14. Please provide specific examples (one for each category of CBIs) for how CBIs are impacting decision-making.

PGE Response:

On content: seeking more information on CBIs: In accordance with OAR 860-090-0100(5), the 2026 CEP/IRP will have more detailed information and data on historical measured values of CBIs for the previous three years and how this information is informative to PGE and planning. For CBIs for which PGE does not yet have reportable data, more description will be provided. Regarding which metric will align with which CBI, PGE provided a draft table describing this report out in the June 2026 Roundtable.[5] As indicated, some measured values will be relevant to more than one CBI.

15. Please provide more information on how community engagement feedback on CBIs from CBIAG and other sources is actually being utilized. For example, how does PGE reconcile differences in recommendations and perspectives between community engagement feedback and the Company's position (e.g., disagreements on CBI inclusion and ranking)?

PGE Response:

PGE values its relationship with the CBIAG. PGE's coordination with communities and the CBIAG is ongoing, CBI have been discussed through stakeholder roundtables, and will be further described in the 2026 CEP/IRP.

Throughout this IRP cycle, community engagement efforts have focused on providing opportunities to community to learn about resource planning and how it is relevant to their lives and learning more about community perspectives, rather than soliciting detailed

5 https://assets.ctfassets.net/416ywc1laqmd/4JHmwOPlcaks2vCQsQfRDL/38d092dd2dd743256c389f7f892f5b36/CEP_IRP_Roundtable_Jun_10__2026_-_5.pdf#page=15.

feedback on technical modeling assumptions. Similarly, PGE continues to work closely with the CBIAG to build understanding of the CEP/IRP process and identify meaningful opportunities for participation as members deepen their familiarity with the planning framework and identify where they want to engage.

PGE discussed CBIs with the CBIAG in April of 2026, at which point members asked for additional time to continue the discussion of the current CBI framework. PGE has committed to continuing this conversation and will look to find additional time to work with the CBIAG in Q1 2027.

PGE recognizes that stakeholders bring a range of priorities and perspectives regarding the issues that should be analyzed and considered through resource planning. Consistent with previous planning cycles, PGE seeks to balance these diverse interests while appropriately considering feedback and community-informed priorities from all stakeholders. As community interests continue to evolve, PGE works with stakeholders, including the CBIAG, to identify which considerations are best reflected in long-term planning models and which may be more effectively addressed through complementary efforts outside of the IRP process, including matters related to CBRE development and implementation.

Purpose: Does PGE's development and continued use of CBIs in the IRP/CEP process make sense?

16. Staff requests that the Company update its CBI list that identifies all applicable categories instead of just one at a time.

PGE Response:

Thank you for your feedback. PGE will review and incorporate as able in the 2026 CEP/IRP.

17. Please provide more specific methodological information about the CBI development and use process, including from identifying a CBI, measuring it, and then making portfolio decisions based on that CBI.

PGE Response:

On purpose: seeking more method detail: PGE appreciates the feedback regarding approach to CBIs. In accordance with OAR 860-090-0100, the 2026 CEP/IRP will include more detailed information on CBI development, tracking, and how this information is used in planning. The June 2026 roundtable[6] provided more detail on some draft historical measured values for select CBIs, including information regarding how this data informs PGE. The presentation also described how pCBIs are and are not used in portfolio analysis and decisions within the IRP planning framework.

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Portfolio Analysis Scenarios (Slides 29 – 41)

Content: Are there any key planning portfolios/scenarios you believe are missing from this list that you would want to see analyzed?

18. Staff would like to know more about how the large load forecast was determined for the reference case?

PGE Response:

PGE's large load forecast is developed on an individual basis, by customer, by month, for a select number of large customers. The forecast is assessed quarterly based on review of monthly historical data, economic and industry trends, and discussions with PGE's customer account management team. These conversations allow both qualitative and quantitative information from the customer (via their account manager) about business operations and expectations for the future to be considered in the load forecast. Relevant contracting and load service plan information is also reviewed to ensure the most up to date load ramp information is included where available.

For the core growth only load scenario considered in the May 2026 load forecast run, PGE assumes that those customers who are deemed eligible for service under Schedule 96 stop growing by end of year 2026. Loading levels are held constant for the forecast horizon.

19. How is the possibility of accelerated electrification accounted for in portfolio analysis?

PGE Response:

The high need forecast considers accelerated electrification. The load forecast considered includes the high case transportation electrification forecast and the reference case building electrification forecast. Both reflect acceleration as compared to the reference load forecast, which considers the reference case transportation electrification forecast and low case building electrification forecast.

20. How will PGE consider EDAM benefits and obligations in its IRP analysis?

PGE Response:

From a planning perspective, PGE's market representation is intended to capture the value of regional market access rather than simulate EDAM operations. The WECC model develops regional market prices while accounting for transmission constraints and congestion. These prices are then used as inputs to the PGE Zonal Model (PZM), which represents wholesale market transactions without system-level transmission constraints, although resource-specific transmission assumptions are retained where appropriate.

Unlike the PZM, EDAM economically dispatches resources across participating balancing authorities while respecting transmission availability, transmission rights, and reliability constraints. Consequently, EDAM does not provide unlimited access to regional markets. Because the PZM does not explicitly model these operational transmission constraints, it should not be interpreted as a simulation of EDAM operations or a direct estimate of EDAM benefits. Rather, the PZM provides a planning abstraction that captures the economic value of regional market access but does not represent the operational efficiencies, transmission utilization, or production cost savings that result from EDAM implementation.

Due to this modeling design, it is difficult for IRP to explicitly model EDAM benefits and obligations without implementing major changes. These changes could not be made in time for the 2026 CEP/IRP.

Cost Cap Scenario Update (Slides 42 – 48)

Content: Do you have any questions or concerns with PGE's approach to modeling a cost cap scenario? Are there any assumptions you would change or add to this proxy policy analysis?

21. What is PGE's understanding of the spending constraint and emissions constraint regarding HB 2021 cost cap? How is it differentially applying the spending and emissions constraints to the cost cap scenario?

PGE Response: The 2026 CEP/IRP will include detailed narrative of methodology and assumptions for all scenarios. For the Continued Progress scenario as presented, a spending limit informed by HB 2021 Section 10 provisions is applied to the Reliability Only (RO) scenario assumptions, meaning the models are not constrained by GHG emissions limits, but achieve incremental additional emissions reductions compared to RO, as enabled by the availability of limited funds for incremental additional clean energy.

Purpose: Do you agree that it is important for PGE to perform this proxy cost cap scenario analysis in the 2026 IRP/CEP?

22. Staff is still unclear on the purpose and benefits of this cost cap scenario. Please provide a list of other scenarios the Company considered and why the cost cap scenario was more important for the Company to model than the other draft scenarios**.**

PGE Response: On content, PGE aims for transparency in analysis assumptions and the 2026 CEP/IRP will include detailed description of assumptions and methodology underlying all scenario analysis.

Broadly, the continued progress scenario will aim to help investigate what additional cost and resources can contribute to the portfolio, beyond what is needed for reliability only, to unlock some level of emissions reductions to continue progress toward HB 2021. The 2026 CEP/IRP will present more detailed review of findings once modeling is done and analyzed. Regarding proposed scenarios, PGE first presented these as draft at the January 2026 roundtable,[7] and the Continued Progress scenario (formerly called Cost Cap) was indicated as intending to be part of the analysis at that time and has continued to be, while other scenarios have also since been added to the list and were presented as draft at the

[7] https://assets.ctfassets.net/416ywc1laqmd/648yr09TbUuEKlYWqjnAUM/339dcd83770f22492009be2d2e5f6e9d/CEP_IRP_Roundtable_Jan_26-1.pdf#page=87.

May 2026 roundtable[8] with some preliminary results of select scenarios presented as draft at the June 2026 roundtable.[9]

8 https://assets.ctfassets.net/416ywc1laqmd/iOtlq68CuHUHy2e6d0Jv7/f822e4294d6c0035a1d75299a83bf491/CEP_IRP_Roundtable_May_20_-_4.pdf#page=40.

9 https://assets.ctfassets.net/416ywc1laqmd/4JHmwOPlcaks2vCQsQfRDL/38d092dd2dd743256c389f7f892f5b36/CEP_IRP_Roundtable_Jun_10__2026_-_5.pdf#page=35.

VPP Integration & ELCC Review (Slides 67 – 80)

Content: **Does the proposed VPP binning and application provide a credible and appropriate representation of these resources within IRP modeling?"**

23. Staff would like a more granular look into ELCC binning, and would like to know what measure is in each bin and see the capacity available and ELCC for each planning year after 2030.

PGE Response:

ELCCs had been calculated for 2030 and the associated ELCC values for VPP were presented as part of the May roundtable. Updated values of ELCCs based on updated load forecast will be presented at the July IRP roundtable.

24. Staff is interested in understanding the impact of incentive value on DR selection (e.g., that higher DR incentives would lead to higher DR adoption). Staff suggests allowing Rose-E to select from a more dynamic resource selection of DRs with varying levels of customer incentives.

PGE Response:

PGE uses AdopDER to forecast adoption of different DR measures. Low, reference and high DER adoption scenarios are modeled to estimate the different values of capacity of each DR that gets adopted by customers over the next 20 years. The AdopDER model considers different assumptions and inputs, and that includes incentive rate to estimate the forecasted adoption. The IRP analysis takes the adoption and load impact data as inputs to its model. IRP is focused towards determining how much of the forecasted capacity of each binned VPP resource is being selected as part of the portfolios. In this decision it evaluates the net costs, available capacity and ELCCs of the binned VPP resources alongside relevant information on other resource options. Incentive impacts are reflected through AdopDER adoption scenarios and through the levelized net cost assumptions assigned to each VPP bin. ROSE-E evaluates those resulting capacity, cost, and ELCC inputs when selecting resources.

Content: **What additional assumptions, or clarifications are needed to ensure confidence in the implementation and evaluation of VPP resources in the IRP?**

25. How does the Company determine which VPP resources will result in true capacity benefit (e.g., should load shifting resources be included in the final model?)

PGE Response:

PGE determines whether a VPP resource provides capacity benefit by evaluating whether its modeled availability, dispatch shape, duration, and expected performance align with hours of system need and reduce loss-of-load risk. Load shifting resources should be included where the modeled shift can reliably reduce demand during critical system hours and where the resulting ELCC reflects that contribution. The capacities, real levelized costs, and ELCC methodology inform the capacity benefit that can be achieved from each bin through load shifting. During times of peak system load we have seen the significant real-world benefits that are provided by VPP resources through load shifting. Our goal is to capture the true benefits by modifying the methodology using best available parameters. It should be noted that the VPP ELCC and real levelized net cost estimates are based on typical observations and not based on the maximum potential of the resources so the estimates are conservative in nature. This is done to avoid overstating contributions. This is PGE's first iteration of detailed VPP resource modeling within the IRP optimization framework, and PGE expects to continue improving the granularity, transparency, and analytical treatment of VPP resources in future planning cycles.