BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. LC 80

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2023 Clean Energy Plan and Integrated Resource Plan.	OPUC Staff Opening Comments

Contents

1 Executive Summary

1.1 Background

In its 2021 legislative session, Oregon passed House Bill 2021 (HB 2021) that directs electric utilities to reduce greenhouse gas emissions associated with electricity sold to its Oregon customers to 80 percent below its baseline emissions levels by 2030, 90 percent below baseline emissions level by 2035 and 100 percent below baseline emissions level by 2040 and for every subsequent year. Besides setting specific emissions targets, HB 2021 also requires electric utilities to consider a diverse set of resources to reach these targets, that go beyond traditional utility scale resources. These include community based renewable energy resources, demand side resources, such as energy efficiency and demand response and other customer-sited distributed energy resources. Utilities must also evaluate non-emitting emerging technologies as a potential resource to help the utility meet these emissions reduction goals as they transition out of fossil fuel powered electricity to serve Oregon customers. Utility actions must account for the resulting community impacts and benefits including providing environmental justice communities equitable access to affordable and clean energy, addressing energy burden, helping communities through job creation, community ownership of clean energy resources, and realization of potential health benefits from reduced greenhouse gas emissions. All these considerations must result in an electric utility resource plan, termed the Clean Energy Plan that is developed by the utility in collaboration with stakeholders including representatives of environmental justice communities and sets forth a plan that meets emissions reduction targets by making continual progress while striking a balance between cost, risk and community impacts and benefits for the utility's customers.

Oregon Public Utility Commission Staff (Staff) and stakeholders collaborated in Docket No. UM 2225 to develop a set of guidelines based on HB 2021 that set clear expectations for the utility with respect to its first Clean Energy Plan. These guidelines were adopted by the Oregon Public Utility Commission (the Commission) and memorialized in Orders No. 22-206, No. 22-390, and No. 22-446.

1.2 Introduction

Portland General Electric Company (PGE or the Company) filed its combined 2023 Integrated Resource Plan and Clean Energy Plan (IRP/CEP or plan) with Oregon Public Utility Commission on March 31, 2023. PGE is the first electric utility in Oregon to file its long-term resource plan following the passage of House Bill 2021 (HB 2021).

Staff acknowledges the challenges involved in addressing HB 2021 requirements in traditional utility resource planning. Staff appreciates PGE's efforts to engage stakeholders and add new voices to its planning process. PGE has been creative in evaluating community impacts and benefits, carving out alternate greenhouse gas (GHG) reduction pathways, exploring community scale and customer-sited resources, and in assessing its overall strategy to meet emissions reduction goals in a least-cost least-risk manner. These efforts are important considerations in the Commission's acknowledgment decisions.

In these opening comments Staff's goal is to evaluate PGE's IRP/CEP through the lens of HB 2021 and locate areas where the plan meets the CEP expectations, and where it falls short. This is a learning exercise for Staff as much as it is for the Company and therefore Staff's purpose is to provide recommendations that help reconcile Staff's understanding of CEP expectations and the Company's planning and resource strategy aimed at meeting them through the implementation of this IRP/CEP. To this end, Staff provides insights into some of the low regret actions or opportunities for the Company, the key challenges that could prevent the Company from implementing its planned actions, and the key vulnerabilities in its current plan that Staff believes PGE needs to address at this stage. Staff's overall goal is to ensure that the plan demonstrates a reasonable strategy to meet the emissions reduction goals, that the Company is thinking about how it can control costs, that communities are able to benefit from the Company's actions, and that Oregon customers are adequately protected against risks of under or over procurement of resources.

1.3 Plan Overview

PGE has estimated significant growth in both its energy and capacity needs over the next two decades due to high load growth projections and the required transition from fossil fuel to clean energy resources to serve the growing demand. Additionally, although the planning period is over a 20-year timeframe, the HB 2021 targets set a milestone in 2030 for PGE to reduce emissions to 80 percent below its baseline level. This has created an urgency in the Company's resource acquisition plan, and accordingly it has prioritized procurement of existing renewable energy technologies to ensure that it has the non-emitting resources in place to make the operational changes needed to meet the 2030 emissions reduction goals.

PGE provided an Addendum to its original IRP/CEP filing on July 7, 2023, with updates to its projected resource needs. PGE projects an energy need of 1307 MWa in 2030 (previously 905 MWa) under expected conditions or the Reference Case. The main drivers of these needs are increased load forecast, distributed energy resource adoption by customers and adjustments to energy contributions of its storage and contracted resources. PGE's summer and winter 2028 capacity needs are projected to be 944 MW and 827 MW respectively (previously 624 MW and 614 MW respectively; see Figure 1 below), driven primarily by increases in future load on its system.

Figure 1: Capacity Need Comparison - PGE Addendum

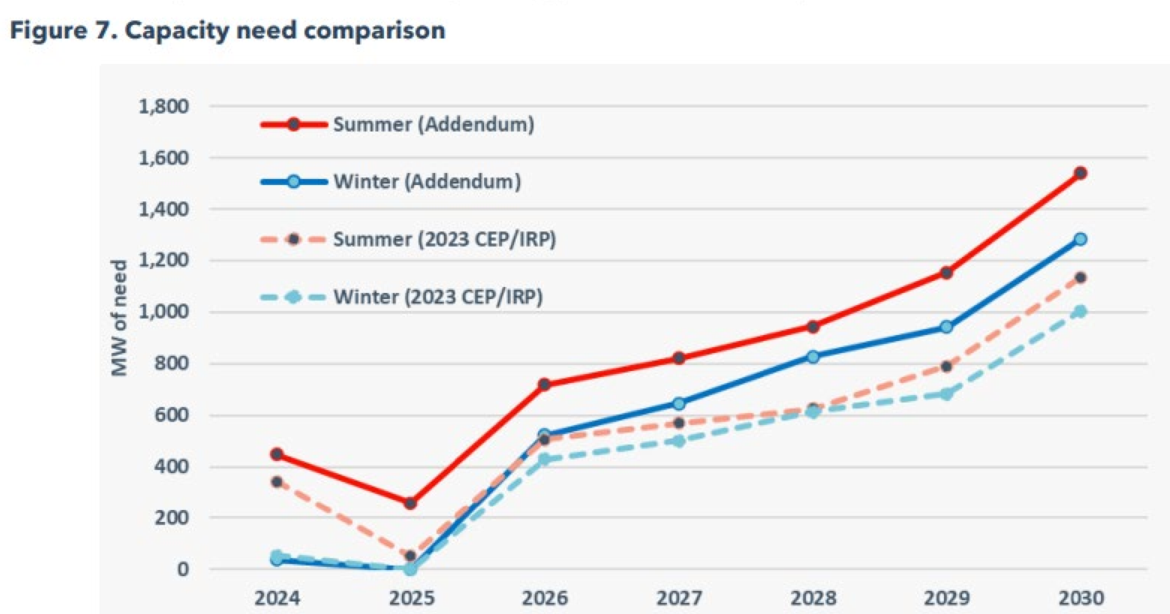
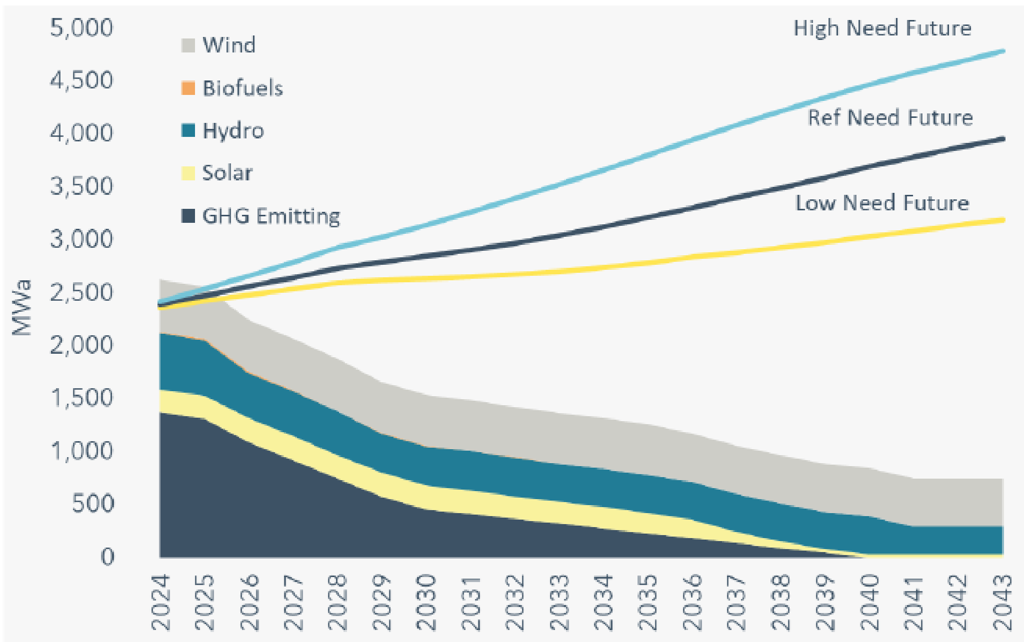


Figure 2 below shows the gap between need projections under three different scenarios and available energy from PGE's existing resources. Long-term resource planning aims to fill the gap between the Reference Case Need Future and available energy in a least-cost least-risk manner.

Figure 2: Energy Load Resource Balance - PGE Addendum

Figure 4. Energy-load resource balance in linear GHG glidepath in Reference Case future[18]



PGE's portfolio analysis identifies a linearly declining glidepath as the most efficient way to reduce emissions, around which it designs its optimal resource procurement strategy to meet the above needs. In its near-term action plan, PGE aims to acquire all cost-effective energy efficiency (EE) and demand response resources by 2028, to acquire a portion of the full community-based renewable energy resources (CBREs) potential beginning in 2026 through Request for Proposals (RFPs) and other channels, to pursue bilateral capacity contracts, and to conduct annual RFPs through 2028 for utility scale energy and capacity resources. PGE also plans to pursue and explore transmission upgrade options to accommodate the load growth on its system and integrate necessary resources to serve the load. PGE characterizes the near-term action plan as "low regrets" or the best available to meet needs and reduce emissions, given its current transmission constraints, uncertainties related to future load, cost and availability of emerging technology and potential regional market developments.

In this executive summary, Staff shares its insights on opportunities and risks related to PGE's near-term action items and summarizes Staff's findings and recommendations related to the economic and technical feasibility of PGE's resource strategy through the lens of the expectations set by the Commission in Docket No. UM 2225 Investigation into Clean Energy Plans.

1.4 Low Regrets Near-Term Actions

Staff agrees with the Company that there are low regrets near-term actions that will perform relatively well, if implemented, regardless of future uncertainties in technology, demand, and regional development. Staff perceives Low Regrets actions to have the following characteristics:

1. A flexible approach towards acquiring energy and capacity resources. Pursuing a flexible approach requires more attention to be paid to the Company's implementation strategies in the planning process, including how the various resource actions will interact and how the Company will make the decisions that control cost and risk on an ongoing basis. It may also require consideration of customer protections beyond planning and procurement practices.
2. Pursuing all energy efficiency and demand response resources that minimize long-term cost and risk. Changes to the planning, budgeting, and cost recovery of these resources may be needed to remove barriers. PGE should work collaboratively to overcome these challenges.
3. Pursuing the full CBRE potential resources through a range of actions and finding opportunities to incorporate resiliency-focused projects. Staff expects that procurement of CBREs will require different approaches than traditional small-scale and utility resource procurements and a higher level of coordination with stakeholders and communities.
4. Pursuing a broad range of options to overcome transmission constraints, offering creative solutions to address congestions, exploring alternatives, including on-system resources, providing more transparency for OPUC and stakeholders, and collaborating with regional entities.

1.5 Key Challenges

In reviewing PGE's plan, Staff has identified the following dependencies in the preferred portfolio and other implementation issues that will determine the success of this resource strategy and implementation.

Transmission

The preferred portfolio and emissions glidepath are dependent on relief of transmission constraints in the near-term and broad regional transmission access in the long-term (See Transmission strategy). Staff appreciates the Company's open exploration of transmission options and seeks to better understand when the breaking points in the Company's strategy would occur and the extent to which the preferred portfolio is feasible in the long-term without the transmission access realized through major structural reforms in the west, such as a regional transmission organization.

Emerging technologies

The preferred portfolio relies on the availability of high volumes of capacity from emerging non-emitting technologies between 2035 and 2040. Staff seeks to better understand how the Company is using this insight from its portfolio strategy to inform its overall resource strategy and what PGE plans to do if these technologies do not materialize. Further, what alternatives does the Company have, when does PGE need to decide that emerging technology is not feasible in order to take advantage of those alternatives, what are the trade-offs of those alternatives?

Near-term resource availability

The preferred portolfio relies on the several gigawatts of clean resources availability of options that will meet the reqeuirements of PGE's energy and capacity RFPs before 2030. Given the range of challgnes that Company identified for this dependency, Staff seeks to understand what the Company plans to do if it finds that these resources are not available and how it would impact other actions in the action plan.

Operational realities

The Company's glidepath is dependent on the ability to sell large amounts of emitting generation in the market. Staff seeks to understand the Company's plan in the event that it cannot sell its excess emitting energy to the market, what it's alternatives are, what the tradeoffs are, and when PGE would need to begin pursuing alterntatives in order to take advantage of them.

Load growth

Staff believes that rapid and continuous increases in customer load could pose challenges in the implementation of planned utility actions. As PGE's updated load forecasts in the July 7 Addendum filing shows, between March 2022 and June 2023, the increase in forecasted growth in both energy and capacity load has resulted in significantly higher system needs forecast. The plan should have the flexibility to accommodate these rapid changes in load by examining new resource potential to meet the heightened needs. For example, considering data center energy efficiency programs to offset increased demand among industrial customers, which in PGE's case is the largest driver of the total system load.

Community engagement

Staff finds PGE's efforts towards community outreach commendable; yet realizes there are challenges with identifying and using community inputs meaningfully amidst competing priorities. PGE is required to include community feedback in the Clean Energy Plan, including those from environmental justice communities. PGE has provided multiple opportunities to community groups to provide feedback during the development of the CEP and assisted them with understanding technical details that are inherent to utility resource planning. Staff notes issues with accessibility of PGE's planning document and accountability issues in the inclusion of specific community inputs, as also pointed out by stakeholders and discusses these in detail in the Accountability and Accessibility sections.

1.6 Key Vulnerabilities

Staff summarizes the key vulnerabilities in PGE's IRP/CEP in more detail in subsequent sections of these opening comments. These missing elements in PGE's plan could potentially indicate non-compliance with HB 2021, OAR 860-027-0400 or the Commission's orders in UM 2225 and impact Staff's recommendations for acknowledgment of PGE's IRP/CEP resource actions.

Portfolio modeling

PGE's portfolio design prevents an understanding of how these portfolios might be interacting with each other and does not allow for direct comparisons between the preferred portfolio and alternative portfolios that test different paces of GHG reductions and community benefits and impacts. PGE does not use its portfolio scoring criteria consistently across all portfolios which results in sub-optimal selection of energy efficiency resources in the preferred portfolio. It is, therefore, not clear whether the preferred portfolio is the best balance of cost, risk, emissions and community impacts and benefits. Staff addresses portfolio design issues in greater detail in Portfolio Modelling.

Transmission needs analysis

Staff believes that PGE's transmission needs analysis is critical to the Company's decarbonization strategy. Staff is concerned by the discrepancy between the vast size and uncertainty in PGE's identified transmission needs and the narrowness of the transmission strategy available to Staff and stakeholders. Staff encourages PGE to be transparent about the costs and risks of its transmission alternatives (e.g., how favorable does the backup look) and the actions that can help ensure that the transmission investments needed will come online and be on schedule. Staff comments in Transmission strategy discuss this in more detail.

GHG emissions modeling

Staff is concerned that PGE may require more resources to meet its GHG targets than are in its plan. As suggested by Staff's preliminary analysis on hourly economic dispatch of the preferred portfolio between 2024 and 2030, PGE's plans may need more clean energy during hours when its portfolio is not long to the market—for example, some combination of energy efficiency, complementary renewable energy, and energy storage to bring more clean energy to PGE loads. Staff's analysis is only preliminary, but it casts doubt on the annual approximations coming from PGE's Intermediary GHG Model that determine PGE's portfolio costs and GHG emissions. Emissions Modeling and Glidepath discusses issues around PGE's emissions modeling.

Community based renewable resources and small-scale renewable resources

Staff is concerned that the current portfolio modeling does not provide meaningful information about the benefits and limits of community based renewable energy (CBRE) resources, including HB 2021 requirements to examine the cost and opportunities of CBRE resources to offset fossil fuel resources. Staff is also concerned about the Company's lack of reporting on its small-scale renewable resources (SSR) compliance position and strategy. Staff seeks clarity regarding various aspects of PGE's CBRE and SSR strategy in CBRE Analysis.

Colstrip exit

Due to the lack of information and analysis surrounding the Company's Colstrip options and challenges in the IRP/CEP, Staff is unable to draw any conclusions about the impact of Colstrip retirement on its resource strategy. This is discussed further in Colstrip exit.

1.7 Conclusion

Staff commends PGE for its efforts in developing its 2023 IRP and first CEP following the passage of Oregon HB 2021. Clean energy policies, growing electrification, rising competition for renewable energy resources, considerations of community based and customer-sited resources and other resource-specific constraints—for example, transmission availability—are a few factors that have introduced new dimensions and challenges in utility resource planning. PGE has shown creativity in addressing these challenges. Staff identified several areas for improvement in PGE's current and future IRP/CEP and discusses them in the subsequent sections of these comments.

2 Clean Energy Plan

2.1 DEQ review

ORS 469A.420(b) requires "The department shall use the method of measuring greenhouse gas emissions set forth in ORS 468A.280 to verify the projected greenhouse gas emissions reductions forecasted in a clean energy plan of an electric company or the information provided by an electricity service supplier under subsection (3) of this section."

Staff is working closely with DEQ and PGE to ensure that Because of the addendum and potential modeling issues with the PP DEQ has not yet performed its verification.

2.2 Strategic decarbonization questions

PGE has not fully embraced the long-term decarbonization questions in its modeling and overall focus.

Commission Order No. 22-446 directs PGE to consider five high level planning questions as part of its CEP.[1] These questions provide an opportunity for the Commission to understand the big picture implications of planning under HB 2021, gain key insights into potential obstacles inherent to the utility's plan, and understand what can be done to address those obstacles now and in the future. This was done to reconcile the limited time available to develop the first CEP with concerns about how useful the traditional IRP approach can be within the current landscape of uncertainty and resource need.

PGE's narrative is helpful, but Staff is concerned that the Company is glossing over its compliance obstacles and avoiding discussion of alternatives to its preferred actions. Staff hoped that PGE's modeling and discussion would allow more consideration of options, tradeoffs, and future decision points for the Company or the Commission—including discussion of potential costs. For example, PGE's discussion of large, negative, long-term consequences for its compliance path focuses on the potential negative consequences of external factors (i.e. potential barriers), not the potential negative consequences of PGE's planned actions. Further, PGE's plan is relatively silent on the trade-offs and feasibility of its proposed actions to enable HB 2021 compliance. Assuming that there is no riskless action, Staff requests that PGE provide additional discussion of the risks associated with the roadmap of actions the Company has selected for HB 2021 compliance.

Further, PGE expresses a belief that implementation risks are out of scope in this docket.[2] This may impact Staff's ability to consider the economic and technical feasibility,[3] and the costs and risks to the customers[4] of PGE's strategy, given this reluctance, difficulty comparing portfolios, and the vagueness of its action items.

Staff understands that the Company made its best efforts to incorporate a wide range of changes into its already complex planning framework and offers a focused list of follow-up questions that will be most helpful in clarifying the Company's answers to the key planning questions.

Recommendation 1: In Reply Comments, Staff invites PGE to respond in more detail about its long-term decarbonization strategy and provides the following questions for PGE to consider:

- ***Will PGE's plan be feasible without future market interactions and market participation?***
- ***Where are there junctures at which the Company might consider material changes in strategy that go beyond procurement volumes, for example adopting operating constraints on emitting resources, adjusting transmission requirements for renewables, joining an RTO, or other alternatives?***

[1] See Docket UM 2225, Order No. 22-446, Appendix A at 30.
[2] Docket LC 80 PGE response to Staff IR Nos. 149 and 150.
[3] ORS 469A.420(2)(b).
[4] ORS 469A.420(2)(e).

- ***What information will the Company use to determine whether a change in course may be warranted? Will the Company adjust its strategy based only on the progress of procurement, or will PGE examine additional data, like actual GHG emissions, power costs, load forecasts, and load forecast uncertainties, as the Company executes its strategy?***
- ***Under what circumstances could each of PGE's planned actions result in poor outcomes for customers?***
- ***Did PGE consider but exclude any actions because of their potential for adverse impacts to customers under one or more future scenarios?***

2.3 Emissions modeling and glidepath

Staff is concerned that PGE's modeling may not be providing a realistic estimate of the GHG emissions associated with its portfolios.

PGE estimates GHG emissions for each portfolio using a multi-step process. First, it simulates the dispatch of the existing and candidate resources in the PGE Zone Model ("PZM"). Then, in the Intermediary GHG Model, PGE allocates a portion of the economically dispatched emitting generation and market purchases to serve PGE load based on historical annual market sales data and its future GHG trajectory. PGE then brings this allocated energy into the portfolio optimization model, ROSE-E, and solves for the additional non-emitting resources needed to meet load in each year for each portfolio. The Company does not then simulate how each portfolio would perform, within the market, to serve PGE load. The final emitting resource dispatch and GHG emissions reported in the IRP are the same as the annual estimates produced by the Intermediary GHG Model. Staff believes that this creates a number of limitations for PGE's emissions reduction analysis and strategy:

1. Historical sales data may not be indicative of future sales in which PGE's portfolio and the broader market in the West look vastly different. PGE's approximations in the Intermediary GHG Model may be reasonable in the near-term but are likely not reasonable as the Company significantly expands the renewable portfolio throughout the 2020s.
2. The market sales estimates in the Intermediary GHG Model are based on annual averages and do not take into account PGE's hourly load balance. The Intermediary GHG Model does not have the granularity to recognize how often PGE's generation will exceed load and necessitate sales or curtailment.
3. It appears that PGE's approach effectively assumes that all non-emitting resource generation in the portfolio will serve PGE load and all net market sales will be from its emitting resources. To the extent that non-emitting generation is sold into the market, PGE's analysis effectively assumes that it will be able to make an equivalent amount of non-emitting purchases during other hours to retain the same amount of non-emitting energy serving load across the year. It also appears that the portfolio analysis assumes zero percent renewable curtailment throughout the analysis horizon, despite PGE's analysis presented in Appendix N, which suggests renewable curtailment could be quite significant in the 2030s. When taken together, these assumptions may overestimate PGE's ability to integrate renewable energy into its portfolio in order to serve load (i.e. through energy storage or other means), underestimate the value of energy storage to avoid renewable curtailment, and gloss over important operational issues that its system could face that would affect both cost and GHG emissions.

4. It is not clear to Staff how cost calculations in the Intermediary GHG Model factor into total portfolio costs within ROSE-E. Staff has engaged PGE in discussions to explain Staff concerns regarding the need to improve the transparency of the cost analysis and to ensure that the NPVRR includes all costs associated with all resources in the portfolio as well as the costs of market purchases and the benefits of market sales.

To better understand the achievable GHG emissions reductions associated with PGE's preferred portfolio, Staff believes that hourly modeling of the portfolio is necessary. At a minimum, this hourly modeling should incorporate economic dispatch of PGE's resources, a load balance constraint with hourly tracking of imports and exports, and hourly tracking of emitting resource dispatch and associated GHG emissions. With this information, PGE could conduct hourly GHG emissions analysis that accounts for the physical limits to its ability to meet load with renewable energy and that reflects a feasible market strategy. The hourly analysis would also allow PGE to test different ways of accounting for imports and exports to inform a more robust conversation about future market design and compliance risks.

In lieu of having this analysis from the Company, Staff conducted preliminary analysis to estimate hourly economic dispatch of the Preferred Portfolio between 2024 and 2030 using non-confidential data provided in the docket,[5] supplemented with additional publicly available data from EIA Form 860 and the GridPath RA Toolkit.[6] Where Staff relied on external data to characterize clean energy resources, inputs were calibrated to generally align with PGE's assumptions. The model also constrained the system based on the transmission rights listed in Figure 67 of the IRP[7] and assumed 1:1 transmission addition to bring all new off-system clean energy resources to load. To achieve reasonable runtimes without using proprietary software, the model neglected unit commitment-related constraints (e.g. minimum run times, minimum stable levels, etc.) for PGE's natural gas units, but it did incorporate a constraint on Colstrip Units 3 and 4 to approximately capture PGE's must take obligations.

Staff used the economic dispatch simulation to estimate a range of achievable GHG emissions trajectories under various potential strategies for interacting with the market. Three strategies regarding market sales were tested: 1) that the avoided emissions associated with market sales in each hour reflect the average emissions rate of PGE's generation (emitting and non-emitting) in that hour; 2) that PGE avoids GHG emissions in each hour by selling generation in descending order of GHG intensity (i.e., the dirtiest generation is sold at market first, "Sell Emitting First", a best case for avoiding GHGs); and 3) that PGE avoids GHG emissions in each hour by selling generation in ascending order of GHG intensity (i.e., non-emitting energy is sold at market first, "Sell Clean First", a worst case for avoiding GHGs). For each of these scenarios, Staff calculated hourly emissions associated with purchases using two alternative approaches: 1) that purchases are attributed the fixed 0.428 mtCO2/MWh unspecified emissions rate; and 2) that purchases are attributed an hourly marginal emissions rate estimated based on hourly prices and assuming that natural gas is on the margin in all positively-priced hours. The second approach

[5] The preliminary analysis was based on information from PGE's original filing and has not been updated to reflect the changes in load and resource additions in the Preferred Portfolio from PGE's Addendum filing. Staff expects that an analysis based on this updated data would yield similar directional findings, though the magnitudes of differences may change.

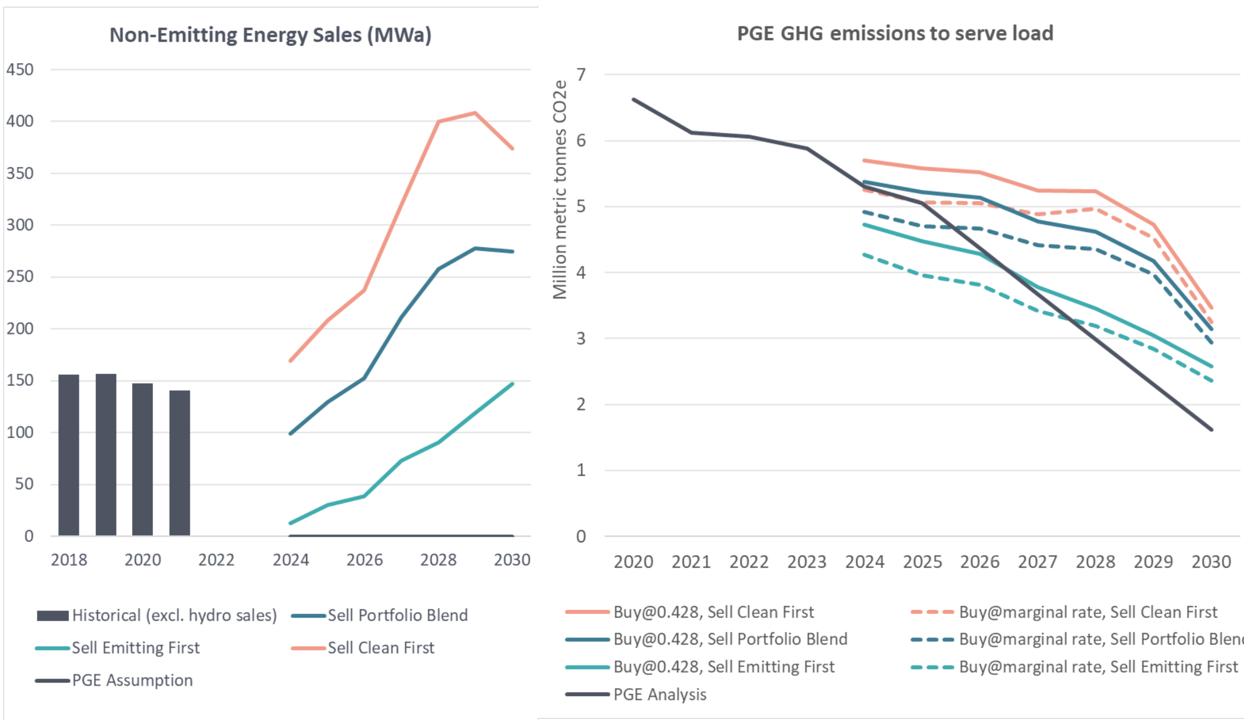
[6] Available at: https://gridlab.org/gridpathratoolkit/.

[7] The preliminary analysis was based on information from PGE's original filing and has not been updated to reflect the corrections to Figure 67 in PGE's Second Errata Filing. Staff does not expect that making such updates would materially affect the findings.

recognizes the potential for PGE to purchase non-emitting energy from the market during hours with zero or negative pricing.

Staff's preliminary analysis suggests under-accounting for non-emitting resource sales and underestimating portfolio GHG emissions may be a major vulnerability in PGE's emissions reduction strategy (See Figure 1). Staff found that PGE's GHG emissions estimates in the mid-2020s may be reasonable, but by the late 2020s, GHG emissions from the Preferred Portfolio could be well above PGE's estimates even under the most optimistic assumptions regarding sales (i.e., that it is able to preferentially sell emitting generation).[8]

Figure 3. Staff's preliminary hourly dispatch simulation of the Preferred Portfolio under Reference Case conditions



If PGE's Preferred Portfolio is not physically able to meet its GHG targets, Staff is concerned that PGE may require more resources to meet the 2030 GHG targets than are in the plan. In particular, PGE's plans may need more clean energy during hours when the portfolio is not long to the market—for example, some combination of energy efficiency, complementary renewable energy, and energy storage to bring more clean energy to PGE loads.

Staff's analysis is only preliminary, but it casts doubt on the annual approximations coming from PGE's Intermediary GHG Model that determine PGE's portfolio costs and GHG emissions. Without a similar

[8] Staff has not updated this analysis based on the updated load forecast and Preferred Portfolio in PGE's Addendum Filing but expects the findings would be directionally similar.

hourly analysis from PGE, it is difficult for Staff to confirm that PGE's plan meets the expectation set forth in ORS 469A.420(2) and in Order No. 22-446, which states:[9]

> To ensure that utility plans align with the clean energy targets in HB 2021, PAC and PGE's IRPs should:
>
> - Achieve the 2030 and 2035 clean energy targets under typical or expected weather and hydro conditions in those years. This should be demonstrated for the Preferred Portfolio and a set of alternative portfolios that test different paces of GHG reductions and different levels of community impacts; and
> - Achieve resource adequacy in 2040 with no associated greenhouse gas emissions across the tested system conditions. This should be demonstrated for the Preferred Portfolio and a set of alternative portfolios that test different paces of GHG reductions and different levels of community impact.

Staff believes that PGE has the ability to conduct hourly analysis of the Preferred Portfolio using the PZM to demonstrate whether the roadmap of actions in the Company's plan can actually achieve its GHG emissions targets under expected conditions.

Recommendation 2: Conduct hourly dispatch analysis of the Preferred Portfolio under Reference Case conditions; discuss the results and provide relevant workpapers with PGE's Reply Comments. PGE should conduct this analysis in a manner that ensures load balance in each hour and that tracks hourly dispatch, variable costs, and GHG emissions by resource as well as hourly market purchases and market sales. PGE should also report annual portfolio costs and GHG emissions based on this simulation and that PGE provide transparency into how purchases and sales affect the GHG emissions associated with meeting load.

2.4 Colstrip exit

Staff is concerned that PGE's plan does not test for an early exit from Colstrip that could be a critical dependency in its plan.

Staff is reviewing the PGE's assumptions around Colstrip and its implications for the Company's resource strategy and HB 2021 compliance strategy. PGE plans to exit its only coal fired plant, Colstrip, in 2029 despite its optimization modeling selecting a 2025 exit date from Colstrip. PGE pointed out there are practical challenges around early exit that requires Colstrip to be on its system until 2029. Staff and stakeholders note the potential trade-off between exit logistics for the Company and lost benefits for customers by having Colstrip in the preferred portfolio until 2029. PGE does not appear to have tested a portfolio with an earlier Colstrip exit within its portfolio analysis in this IRP/CEP. It is therefore not clear whether the inclusion of Colstrip in PGE's portfolio beyond 2025 (as capacity, energy, or both) appropriately balances cost, risk, the pace of GHG reductions, and community impacts and benefits.

2.5 Accountability

PGE is making an earnest effort to meaningfully engage stakeholders and community in its CEP process, but the IRP/CEP falls short on accountability.

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[9] In the Matter of House Bill 2021 Investigation into Clean Energy Plans, Docket UM 2225, Order No. 22-446 (November 14, 2022), available at https://apps.puc.state.or.us/orders/2022ords/22-446.pdf

PGE's IRP/CEP emphasizes a human-centered approach to planning, inclusive decision making, and the following desired outcomes from community engagement:

- Allow greater insights into the CEP and other planning processes needed to achieve decarbonization goals.
- Co-develop future community solutions and resiliency opportunities such as CBRE projects.
- Increase community participation, including EJ communities.
- Demonstrate transparency and accountability.[10]

Staff appreciates the Company's mobilization on this aspect of HB 2021 and UM 2225, the thoughtfulness of the materials provided in the IRP/CEP,[11] and PGE's response to initial comments[12] on the role of community feedback. However, Staff is concerned that the above outcomes are not obvious in the CEP analysis and the resulting resource actions. For instance, PGE has developed a commendable set of Community Benefit Indicators (CBIs) using stakeholder feedback; however, none of these measures of CBIs made its way into the final portfolio analysis.

Commission Order No. 22-390 requires that Company to report, "the input received through each channel, how was input incorporated into the IRP/CEP[…] and what input was not incorporated into the IRP/CEP and why was that input not incorporated." PGE provides extensive documentation of the input received from community engagement but does not do the same for other stakeholder input or explain whether, how, and why any feedback was incorporated into its plan. Staff requested more information related to the Commission's guidance and the Company rejected this request on grounds of requiring significant new work.[13] Within the context of this IRP/CEP, the de-prioritization of accountability might be most impacting Staff's ability to understand how the Company decided which parts of stakeholder CBI and CBRE acquisition strategy input to use and how.

PGE will continue to refine how it collects input and uses it to inform planning. Staff commends this commitment but seeks to clarify that its call for better engagement is not a direct call for more engagement. Major progress has been made throughout the state's energy landscape to recognize of the importance of community engagement. Hence, steps need to be taken to refine this patchwork into an efficient and effective use of resources. To make PGE's engagement efforts more authentic and worth the time and resources expended, the Company should focus on improving its accountability practices such as improvements to its stakeholder survey practices and consideration of accountability metrics which can be developed with utility Community Benefits and Impacts Advisory Group (UCBIAG) participants per ORS 469A.425 (also, see accessibility practices below).

To align with Staff's expectations for this IRP/CEP, the Company should also provide additional information about the feedback received and whether and why it included it or not in its plans.

Staff is also concerned that PGE's strategy to engage tribal communities is not well developed to date. While Staff is aware that the Company has endeavored to take steps internally through the hiring of a tribal liaison and externally, through outreach to engage tribal communities and representatives, Staff is

[10] In the Matter of *Portland General Electric Company's 2023 Clean Energy Plan and Integrated Resource Plan* hereinto referred to as "Docket LC 80, PGE 2023 IRP/CEP", Section 14.2., March 31, 2023.
[11] Docket LC 80, PGE 2023 IRP/CEP, Appendix L., pp. 561-594.
[12] Docket LC 80, PGE Response to initial comments, pp. 7-10.
[13] PGE Response to Staff IR No. 156.

concerned that the Commission will consider this important plan without that perspective. PGE should, at a minimum, make efforts to understand why the currently hosted learning labs and engagement sessions are not being accessed by the tribal communities and develop strategies to address the issue.

Recommendation 3: In Reply Comments, PGE should provide a table that identifies key feedback received by community and other stakeholders, the affiliation of the person providing the feedback, whether and where PGE incorporated the feedback, and why.

2.6 Accessibility

Staff acknowledges the challenges involved in translating a technically intensive IRP document to non-technical readers and encourages PGE to continue with its efforts towards improving the accessibility of the IRP/CEP for a broader set of readers.

Under OAR 860-027-0400(5), the CEP "must be written in language that is as clear and simple as possible, with the goal that it may be understood by non-expert members of the public." In addition, Commission Order No. 22-446 provides guidance that the "first CEP, or a designated section of the IRP that contains all information required by HB 2021, should be written for an introductory audience and include definitions of all key terms and acronyms." PGE's plan includes a CEP chapter that summarizes key aspects of its plan, as well as, the information required by HB 2021 and Commission Order Nos. 22-390 and 22-446.[14] The complexity of utility resource planning, and decarbonization planning requires technical analysis and discussion and Staff appreciates the Company's efforts to respond to the Commission's guidance and its efforts to learn how to discuss its planning activities in an accessible manner with its learning lab participants. The Company has taken its initial steps in this regard, but Stakeholder feedback indicates that there is much more progress to be made for these efforts to be truly meaningful for customers and communities.

While the Company believes that "a reader should not have to read any chapter beyond the first chapter to understand the results of our modeling and how those results inform our action plan to the 2030 targets any inconsistencies,"[15] its first attempt has produced a narrow summary that does not achieve the intent of accessibility: to connect the key findings, concepts, and decision points underlying the Company's HB 2021 compliance strategy to the impacts that it will have on customers and communities. Additionally, Staff continues to support the idea that "successful engagement may look different from the perspective of the utility and the perspectives of those who are participating in the utility's process"[16] and the accessibility of the document is best judged from the perspectives of those representing communities, or the communities themselves. By ensuring the relevant documents are readily accessible in user-friendly formats and multiple languages, PGE can enhance communities' ability to provide informed feedback and actively contribute to the process.

These procedural equity concerns are voiced by the Energy Advocates who point out that despite the Company's ambition for an accessible and human-centered approach, the draft IRP/CEP remains exclusive to industry players and technical audiences. Staff believes that an accessible and inclusive plan

[14] See Docket No. UM 2225, Commission Order No. 22-446.
[15] Docket LC 80 PGE's Response to Initial Comments, p.7.
[16] See Docket UM 2225 OPUC Staff Roadmap Acknowledgement and Community Lens Guidance, p.14.

should accommodate diverse needs and perspectives and refine technical concepts to community relevancy.

True accessibility in a highly technical space is not something that Staff anticipated would be straightforward or quick for PGE to master but is an important element that PGE should not undervalue. PGE should continue to work towards making its plan more accessible before it is too late to facilitate meaningful engagement. Staff would like to see progress on this in PGE's IRP/CEP update and subsequent IRPs/CEPs.

Recommendation 4: In Reply Comments, PGE should explain what steps it is taking for this IRP/CEP, and can take in the future, to communicate its HB 2021 compliance strategy in a manner that is accessible and meaningful to the customers and communities it serves.

2.7 Community benefit indicators

PGE has made progress in the implementation of interim community benefit indicators (CBIs) to inform planning but need refinement to provide useful insights into the balance of costs, risks, pace of emissions reduction, and community impacts of actions and options considered in the IRP/CEP.

CBI discussions in UM 2225 emphasized the need for utilities to reflect stakeholder and community values and to be as quantitative as possible. Staff appreciates the work that PGE has done to achieve this on an expedited basis. In Order No. 22-390, the Commission provided guidance that utilities should develop CBIs within five areas: system and community resilience, health and community well-being, environmental and economic impacts, and energy equity. To address the limited time that the utilities had to implement CBIs, the expectation was qualified to allow the Company to limit the number of CBIs that need to be used in portfolio analysis while more CBIs could be considered informational only.[17]

PGE's CBIs were directly compiled from the Energy Advocates in UM 2225 and scored by importance by Community Learning Lab attendees.[18] The result of this process is one portfolio CBI (pCBI), one CBI specific to CBRE resource costs that it calls a resource CBI (rCBI), and six multi-part informational CBIs (iCBI).

Staff appreciates the Company's progress and finds the iCBIs informative and the rCBI effective in influencing portfolio analysis, but refinement is needed for this analysis to fully align with Staff's vision. First, because of issues discussed in the Accountability section, it's unclear how the Company translated the input received into the specific metrics used and whether the CBIs are providing the information intended. Second, the rCBI and pCBI do not provide any real information about the benefits and impacts of different resources and options considered in the plan.

The interim CBIs provide a jumping off point for what Staff expects to be an ongoing process to understand how CBIs should be used, what is most meaningful to measure, and how it should be measured. Staff is excited to move these conversations forward within this IRP/CEP, in upcoming procurement and programmatic activities, and in preparation for IRP Updates and future IRPs. At this Stage, Staff provides initial suggestions that could improve the usefulness of PGE's CBIs in the current IRP/CEP analysis and shares a few concepts for consideration in the future.

[17] For details, please see UM 2225 Order No. 22-390.
[18] Docket LC 80, PGE 2023 IRP/CEP, Figure 112.

Portfolio scoring approach (pCBI)

Staff's goal in establishing CBIs for use in IRP analysis is to provide insights into the cost, risk, reliability, pace of emissions reductions, and community impacts of different actions and situations considered in the IRP. The Company's current approach to pCBI does not allow any comparison of the relative impact of different options and scenarios on any of the community impacts identified and has no actual impact on portfolio selection.

Staff notes the following issues with the Company's pCBI:

1. A unique CBRE focused pCBI disregards community impacts of the majority of resources chosen by the Company. Regarding portfolio analysis, it is important to note that PGE's methodology ignores important community benefits, that even PGE includes in its informational CBIs. An example is iCBI 6, "Improve efficiency and housing stock in the utility service area, including low-income housing."[19] However, in PGE's portfolio analysis, portfolios with more energy efficiency have the same CBI scores as portfolios with much less energy efficiency. Limiting the pCBI to only CBREs makes it impossible to weigh the tradeoffs of any of these courses of action in a quantifiable way. It also fails to provide information about the impact of thermal resources and the hydro system on environmental justice communities. These are major opportunities for improvement in the future.
2. Assigning equal weights to all CBI components prevents comparison of benefits from different CBRE portfolios. The Company confirms in response to Staff IR 140 that individual CBREs will have different community impacts and states that it plans to incorporate community-specific benefits in the procurement process.[20] Staff is supportive of this added granularity in the resource acquisition process but notes its impact on the usefulness of portfolio evaluation in this IRP/CEP. Staff encourages the Company to work toward pCBIs that can recognize the tradeoffs of varying levels of different resource types and locations.
3. The pCBI is unitless while all other portfolio evaluation metrics are presented in dollar terms. As a result, the only meaningful information that the pCBI presents is that more CBREs equates to some nebulous increase in community benefits that cannot be compared to any other part of the portfolio evaluation. This may have been less of a problem if the Company assigned a portfolio benefit to non-CBRE resources or even assigned different community values to different types of CBIs. Therefore, Staff finds little value in even including this in the CEP/IRP filing and recommends that the Company change this.
4. The three issues above are acutely concerning in terms of providing any meaningful evaluation of the resiliency benefits of different actions and portfolios. Staff will continue to look for opportunities to make near-term and long-term improvements to the Company's resiliency analysis.

Recommendation 5: In Reply Comments, PGE should provide an interim pCBI that captures the different benefits across all resource types across all portfolios. At a minimum, PGE should consider the quantity of energy efficiency and microgrid CBREs in each portfolio as an interim pCBI scoring metric until the Company can identify more metrics for quantifying important impacts of its potential

[19] Docket LC 80, PGE 2023 IRP/CEP, Table 26, iCBI6 is listed under the "Energy, Equity, Health & Community Wellbeing" category.
[20] Docket LC 80, PGE Response to Staff IR No. 140.

actions on communities. If the Company cannot provide this analysis, it should discuss opportunities and barriers the Company faces in meeting Staff's request.

Recommendation 6: In Reply Comments, PGE should update its portfolio scoring analysis to express the pCBI in dollar terms. If the Company is not able to provide this analysis, it should discuss the barriers that the Company faces in making this quantification.

Resource valuation approach (rCBI)

PGE explains that its rCBI approach is consistent with the region's approach to capturing the full range of benefits of demand-side resources under the 1980 Northwest Power Act and Staff understands that the Company used this approach to ensure that portfolio analysis selected a meaningful quantity of CBREs absent a more precise measure.[21]

Staff appreciates the Company's creativity in designing a rCBI that forces a recognition of the community benefits of CBRE into the modeling underlying its resource procurement decisions. While this is ad hoc, Staff notes that an alternative approach may require wholesale changes to the parameters over which the Company optimally chooses a portfolio. As the Company works to refine its CBIs and CBRE analysis in the future, Staff believes that it will be a priority to work toward a modeling approach that will be reflective of trackable CBI benefits and allows comparison of CBRE and non-CBRE actions. [22]

Informational metric improvements (iCBI)

Staff appreciates PGE's efforts to generate interim iCBIs that reflect stakeholder and community input. Staff is reviewing the iCBIs and looks forward to working with the Company and other parties to identify opportunities to be more quantitative, precise, and reflect the priorities of communities. Staff shares initial iCBI reflections below.

One near-term opportunity to improve PGE's CBIs is better reflecting benefits and impacts to tribal communities. For instance, PGE could create CBIs similar to those pertaining to all EJ communities, that specifically report on tribal communities whose members are represented by tribal governments with enterprises with which PGE interacts through contracts, resource procurement, or through its retail service.

PGE's interim iCBI 4b metric regarding workforce training and development opportunities for EJ initiatives could better capture the impacts of investments in these initiatives. Interim iCBI 6b that addresses improvements in efficiency and housing stock has many of the same limits. PGE could try to quantify these by redesigning these iCBIs to track the labor hours PGE dedicates to these initiatives, any physical money donated to these initiatives, and any workforce outcomes that can be traced back to these initiatives.

Finally, there several iCBI categories that can provide meaningful context for planning, but it's unclear how they will be directly impacted by the resource options evaluated in the IRP/CEP and actions tracked in IRP Updates. As the Company continues to refine its CBIs for use IRP/CEPs, IRP Updates, and other procurement and programmatic activities, the Company should work to identify opportunities to understand and quantify key measures in this category.

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[21] Docket LC 80, PGE 2023 CEP/IRP, p.143.
[22] Docket LC 80, PGE Response to Staff IR No.51.

2.8 CBRE Analysis

PGE has established a meaningful initial CBRE target but can improve the usefulness of it CBRE portfolio modeling and acquisition activities.

CBRE acquisition targets

In Order 22-390, the Commission directed that the utilities must establish acquisition targets for community based renewable energy (CBRE), beginning with a potential analysis which, "should inform or directly identify annual acquisition targets (e.g., MW, MWh) for CBREs."[23] For its first attempt at this analysis, PGE drew upon a range of existing stakeholder input and available analyses, which are detailed in Section 7.2.1.2. PGE modeled three proxy CBRE resource types all of which are between one and 20 MW in size, not connected directly to the transmission system, and not connected behind a single meter.[24] Through this analysis, PGE identified aggregate annual goals for CBRE acquisition starting in 2026 and reaching 155 MW of CBRE potential by 2030 as illustrated in Table 1.

Table 1: CBRE annual MW potential (cumulative installed nameplate MW-ac capacity)[25]

Resource	2026	2027	2028	2029	2030
Community-scale solar	22	28	36	42	50
Community resiliency microgrid	43	56	71	85	100
In-conduit Hydro	1	1	3	5	5
Total	66	85	110	132	155

Staff appreciates the Company's efforts to identify a meaningful role for CBREs in its clean energy resource investments. At this stage of Staff's review, it appears that the Company took this exercise seriously and identified a thoughtful analytical approach, leveraging a range of useful resources and existing community input within a limited timeframe. Notwithstanding Staff's concerns regarding the valuation and selection of CBRE resources as described in the CBI Portfolio Analysis and rCBI sections of Staff's comments, Staff finds the volume of CBRE acquisition is a reasonable initial target that can be further refined in future updates and IRP/CEP analysis.

Because this is a new analytical exercise, Staff has identified additional considerations that could improve PGE's potential analysis and capture additional CBRE opportunities.

Resource types: The CBRE potential analysis is designed to capture resource actions that are incremental to resources captured elsewhere in the IRP analysis. Therefore, the CBRE potential does not include net metering projects (solar, standalone storage, and solar + storage), community solar program projects and demand-side actions like energy efficiency and demand response. Staff is interested in understanding whether the CBRE potential analysis would improve by considering additional, proactive acquisition of

[23] See Docket UM 2225 Order 22-390, Appendix A at 26 (October 25, 2022). https://apps.puc.state.or.us/orders/2022ords/22-390.pdf.
[24] Docket LC 80, PGE 2023 IRP/CEP, p.156.
[25] Docket LC 80, PGE 2023 IRP/CEP, Table 27.

generation and/or demand-side resource types targeted based on energy burden or other community need.

Resource size: Staff notes that both the system and communities may realize benefits from net metered solar and storage systems and microgrids that are less than one MW in size. Staff is interested in understanding whether the CBRE potential analysis would be improved by considering potential for these behind the meter and small microgrid systems.

In-conduit hydro: PGE's CBRE potential study focuses only on the municipal supply systems in this IRP/CEP, but notes that at least there is some interest in this resource from one or more irrigation modernization project in its service territory. Staff is interested in understanding whether a bottom-up accounting of irrigation-hydro resource potential, including engagement with municipalities and irrigation districts, would yield a better result in future analyses.

Federal Incentives: Staff is interested in learning the impact of federal incentives from recent policies, for example, the Inflation Reduction Act, on CBRE potential.

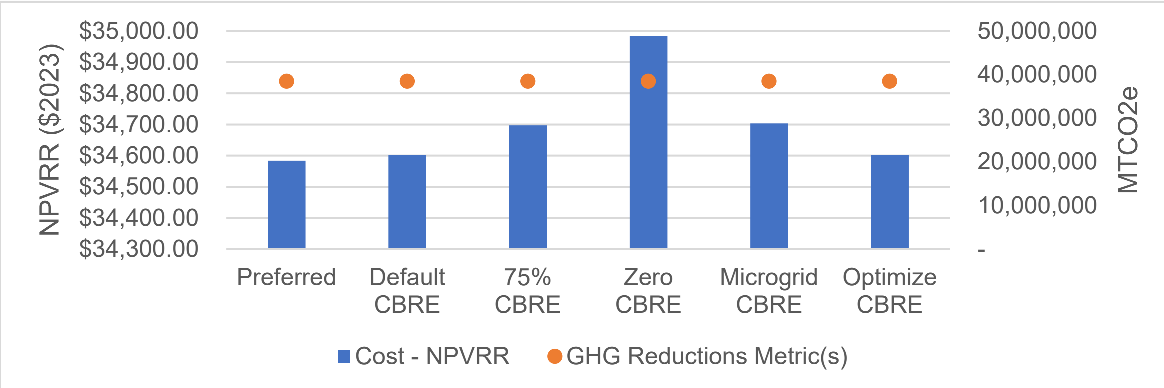
CBRE portfolio analysis

After identifying the CBRE potential and proxy CBRE resources, PGE evaluated five CBRE portfolios which varied the amount and type of CBRE:

- Default CBRE: 100 percent of CBRE achievable potential selected
- 75 percent CBRE: 75 percent of CBRE achievable potential selected
- Unavailable CBRE: No CBRE resources included
- Microgrid CBRE: Only Microgrid CBRE resources available
- Optimize CBRE: CBRE resources compete economically in the model.

As shown in Figure 4, PGE's portfolio analysis suggests that acquiring CBREs up to the projected potential lowers overall portfolio costs compared to portfolios with reduced or no CBREs, including in the Optimize CBRE run. While PGE identified a meaningful CBRE potential level and useful portfolios to test, this analysis does not appear to provide any insights about CBREs.

Figure 4. Cumulative NPVRR and GHG emissions results of portfolio analysis by CBRE portfolio26



First, the portfolio analysis does not appear to provide insights into the ability of CBREs to offset thermal resources. PGE's portfolio optimization allows CBREs to compete with supply side resources, as illustrated in Figure 4, the emissions profile of the portfolio with zero CBRE acquisition, and the portfolios that acquire all available CBRE result in identical annual emissions.

During the development of near-term CEP guidance, Staff believed that including CBREs in portfolio analysis would help satisfy the HB 2021 requirement to, "[e]xamine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy."[27] PGE's modeling approach answers part of this question by allowing CBREs to help contribute to GHG emission reductions, the Company does not appear to have provided analysis that allows the existence of CBREs to directly impact the dispatch of emitting resources or understand how that changes costs, risks and benefits of the portfolio. Staff will consider this issue when reevaluating the Commission's planning and procurement policies in 2024, but Staff also expects PGE to submit a supplemental analysis with its reply comments that better addresses the statutory requirement.

Staff notes that the dispatch analysis called for in GHG Emissions Modeling could also be used to help meet PGE's statutory requirement. In addition to simulating the dispatch and reporting costs and emissions for the Preferred Portfolio, PGE could run a second simulation with the CBREs removed from the Preferred Portfolio to understand the contribution of CBREs to reducing GHGs and the associated cost impacts. Staff expects that the cost differences from this analysis would differ from the cost differences associated with CBREs in PGE's portfolio analysis because the portfolio analysis must also replace the energy from CBREs with non-emitting generation to bring GHG emissions back down to target levels. Therefore, a description from the Company of how to interpret the cost and emissions differences from its supplemental CBRE analysis would help to foster greater transparency.

[26] Data from PGE CEP Data Template. NPVRR and MTCO2e are cumulative over the 20year planning period.
[27] ORS 469A.415(4)(d).

Additionally, Staff questions whether the CBRE portfolios provide meaningful insights into the other tradeoffs of procuring different levels of CBRE. Staff is interested in better understanding whether more information would be made available by removing any constraints on the ability to select CBRE in the optimized CBRE portfolio or removing the rCBI. Or, if there is an alternative way that PGE could stress test CBRE additions and provide insights into the volume at which CBRE may stop being a low-regrets investment. Staff suspects that the simplicity of the initial rCBI and pCBI metrics, along with the other portfolio modeling choices described in these comments, may prevent useful information from being available under PGE's current approach and this may be an opportunity for improvement in the future (See Community Benefits Indicators).

Staff appreciates the Company doing what it can to ensure that CBRE will have a meaningful role in the preferred portfolio and expects that the Company will be able to identify improvements that can more quantitatively and precisely capture the trade-offs of incorporating varying levels of CBRE into its resource mix moving forward.

Recommendation 7: In its Reply Comments, PGE should provide a supplemental analysis that satisfies the HB 2021 requirement to examine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy.

Recommendation 8: Staff invites PGE to describe the useful insights that is gathered from the CBRE portfolio analysis related to the level at which CBRE additions are no longer low-regrets actions or general insights into the trade-offs of including different levels of CBRE in the portfolio.

CBRE acquisition strategy

Along with the CBRE acquisition targets, the CEP must include a discussion of, "the actions that the utility will take in the action plan window to reach those targets e.g., utility procurements, utility run programs (existing and/or new), utility partnerships with other entities' programs, and projections for other customer and community driven actions."[28] The Company's action plan only commits to taking one action to acquire its first 66 MW tranche of CBREs by 2026: a request for proposals (RFP) for CBRE resources. In Round 0 reply comments, PGE listed additional categories of actions that it will take to acquire CBREs, including retail programs, bilateral contracts, and soliciting a request for information to understand what community priority resources and acquisition processes include.

Staff supports the Company's efforts to pursue CBREs through a broader portfolio of actions and PGE's commitment to co-developing its implementation actions with stakeholders representing the communities served by the Company. Staff expects that the process to identify, refine, and implement CBRE actions will require close coordination between Staff, stakeholders, and community input forums and looks forward to continuing to refine this strategy in the IRP/CEP and subsequent dockets. Because this is a new and complicated aspect of the IRP/CEP, Staff believes that it is particularly important for PGE to make an effort to articulate a detailed strategy for meeting its CBRE acquisition targets, controlling costs, and driving community benefits as part of the requirement to outline annual goals for actions in the CEP. Because this is a new and complex element of the Company's IRP/CEP, Staff seeks additional

[28] See Docket UM 2225, Order 22-390 Appendix A, p. 26. Accessed at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf.

clarity about the implementation risks and mitigation strategy for the Company's CBRE acquisition strategy.

Recommendation 9: In reply comments, PGE should answer the following questions about the CBRE acquisition strategy:

- ***Will the CBRE acquisition pursue CBRE technologies beyond the proxy resource types included in the CBRE potential study?***
- ***What is the Company's strategy to balance the need to control cost in CBRE acquisition with the need to optimize community benefits in its resource actions? The response should consider PGE's strategy to leverage funding resources and other partnerships, as well as, to keep the Commission aware of the key risks and decision points that are emerging in the Company's CBRE investment strategy.***
- ***What steps can the Company take to overcome implementation risks and ensure that the time and overhead associated with the Company's CBRE procurement activities is well used?***

Small scale renewables carve-out

Per ORS 469A.210, PGE is required to meet 10 percent of its aggregate electrical capacity through small scale renewable energy projects (SSR). Staff presents a back-of-the-envelope estimate of the Company's compliance obligation in Table 4 because PGE declined Staff's request to provide their own projections or enough information for Staff to estimate PGE's projected SSR resource additions. [29] PGE's lack of transparency about the compliance position and strategy is a problem because of the potential magnitude of the SSR obligation arising in less than seven years. Without more cooperation from the Company, Staff cannot determine whether the IRP/CEP has met IRP Guideline 1d. Further, Staff cannot understand whether the SSR requirement is a key challenge on which we should be concentrating resources or if any of the Company's proposed actions are critical dependencies for compliance with this statute.[30]

Table 2. Staff's rough approximation of PGE's 2030 SSR Position (MW)

Obligation	2030	2035	2040
Existing and contracted resources[31]	5,249	5,084	2,208
New additions (excl. storage)[32]	4,427	6,621	11,012
Total generating capacity	9,676	11,705	13,220
SSR obligation	968	1,171	1,322

While PGE does not characterize its compliance position or explain how compliance impacts its resource strategy or critical decarbonization planning questions, the Company uses SSR to help justify investments

[29] Docket LC 80, PGE Response to Staff IR No. 135.
[30] See Docket No. UM 1056, Order No. 07-047, Appendix A, p. 2 of 7. Accessed at: https://apps.puc.state.or.us/orders/2007ords/07-047.pdf.
[31] Existing and contracted resources were estimated using the underlying data for PGE 2023 IRP/CEP, Figure 41, p. 120 provided in PGE Response to Staff IR No. 009, Attachment A.
[32] New additions were calculated by adding cumulative additions of solar & wind, hybrid, CBRE, contract extensions and capacity found in Table 9 and Table 10 of PGE's July 7, 2023 Addendum. These figures do not reflect storage capacity or resources that may leave the Company's resource portfolio.

that benefit the Company, such as the proposed virtual power plan (VPP). PGE also suggests modifying the Commission's eligibility requirements for SSRs so that customer-sited generation and Oregon Community Solar Program resources qualify. Staff believes that these are interesting proposals but cannot consider them without any information about the Company's compliance position.

Finally, Staff agrees with the Company that SSR and CBREs represent overlapping opportunities. Staff encourages the Company to focus its SSR compliance activities on controlling costs and driving community benefits and seeks additional information from the Company about its plans to do so (See CBRE Acquisition Strategy for additional discussion of CBREs).

Recommendation 10: In Reply Comments, PGE should detail it's SSR compliance strategy that includes:

- ***The Company's compliance position including its annual projected compliance obligation MW, projected SSR resource MW, and projected SSR shortfall MW for years 2030, 2035, and 2040 at minimum.***
- ***The quantity of projected SSR resources that are existing QFs, other existing SSR types (with a description), projected QFs, projected other SSR types (with a description), or other resource types (with a description).***
- ***A detailed strategy to procure the resources needed to meet any projected 2030 SSR compliance shortfalls.***
- ***Articulation of any strategies the Company plans to deploy to control costs and drive community benefits.***

2.9 REC Transparency

Staff seeks to understand how PGE might realize value from the expected increasing number of RECs annually produced in excess of what is needed for RPS compliance.

Commission Order No. 22-446 requests that PGE include information about the RECs it will generate and how it will use them over the planning period. As illustrated in Table 5, PGE is expected to generate RECs well above its RPS requirements. However, PGE has not indicated what it will do with the RECs it over generates beyond banking them.[33] Staff notes that the accumulating banked RECs represent potential value to customers. Staff understands that there are decisions related to the potential uses of these RECs under consideration in other dockets but encourages PGE to consider how it can ensure it is managing its REC bank to the benefit of the customers bearing the costs of the generating assets.

[33] In response to Staff IR No. 63, PGE stated that it did not have a current plan related to the banked RECs and in the CEP Data Template PGE only placed RECs generated from cost-of-service resources.

***Table 3. Excess REC generation in preferred portfolio*[34]**

Year	Banked RECs (MWh)	Year	Banked RECs (MWh)
2024	37,239	**2034**	9,490,862
2025	339,606	**2035**	8,372,051
2026	1,241,610	**2036**	9,232,514
2027	2,717,669	**2037**	10,729,055
2028	3,768,717	**2038**	11,787,377
2029	5,858,432	**2039**	12,813,803
2030	5,693,497	**2040**	12,629,997
2031	7,195,240	**2041**	13,766,588
2032	7,959,636	**2042**	14,063,737
2033	8,706,720	**2043**	14,545,227

Recommendation 11: In Reply Comments, PGE should provide the volume of banked RECs that it anticipates will expire if they are not used over the planning horizon and discuss how it can plan to utilize its banked RECs to benefit customers.

3 Portfolio Modelling

PGE developed 39 portfolios to explore various resource strategies and to test the impacts of key assumptions—for example the availability of emerging technologies, the availability of additional transmission, and participation in an RTO. PGE's approach is to test specific design questions or assumption across a subset of portfolios in which all other assumptions and constraints were held constant. For example, subsets of portfolios were developed to determine its preferred GHG trajectory, the level of energy efficiency to pursue, the amount of CBREs to pursue, and the transmission options to pursue. PGE then used the insights from these portfolio tests to develop design constraints for the Preferred Portfolio. These constraints included the following:

- A linear GHG trajectory
- No additional EE beyond the forecasted cost-effective EE
- 155 MW of CBREs by 2030
- 400 MW South of Allston upgrade in 2027
- Access to up to 800 MW of additional transmission to WY and NV

Staff is concerned that by testing each design decision in isolation, PGE may be missing important interactions between these decisions. For example, the portfolios that test different GHG trajectories and transmission expansion options do not allow the model to consider additional EE, which could affect the value of transmission and the cost implications of different GHG trajectories.

[34] Staff compiled this table based on data from PGE's July Addendum data template update. The quantity of banked RECs is assumed to represent the excess RECs generated beyond RPS and voluntary bundled program needs based on the preferred portfolio reference case. It also includes the assumption of meeting 20 percent of the RPS obligation using unbundled RECs for each year in the planning horizon (2024-2043).

Furthermore, Staff notes that the key assumptions used in the preferred portfolio are not consistent with those used to test other portfolios.[35] This is problematic since the optimization outcome in a specific portfolio category using a specific set of constraints may not be optimum when subject to a different set of constraints.

These issues make it difficult for Staff to understand how PGE's portfolio analysis is balancing cost, risk, GHG emissions and community impacts and benefits, whether the preferred portfolio yields a reasonable strategy for PGE to reach HB 2021 emissions goals, and whether PGE's Action Plan is adequately addressing risks and barriers that could prevent it from reaching these goals (i.e., technical and economic feasibility).

3.1 Comparability

PGE's portfolio design approach prevents direct comparisons between the preferred portfolio and alternative portfolios that test different paces of GHG reductions and community benefits and impacts.

PGE's portfolio analysis makes it difficult to use the preferred portfolio to compare options or identify insights about key decarbonization planning questions. Across most of the portfolios that PGE used to develop design constraints for the Preferred Portfolio (i.e., the GHG trajectory portfolios, EE portfolios, and CBRE portfolios), it held all other assumptions (e.g., transmission availability, emerging technology availability, etc.) constant. This ensured comparability between the portfolios. However, PGE adopted a different set of assumptions when it designed the Preferred Portfolio.

When designing and evaluating the Preferred Portfolio, PGE assumed that an additional 800 MW of transmission could be acquired to access markets and diverse renewables in Nevada and Wyoming. Staff estimates that this assumption reduced portfolio costs by over $4 billion (nearly 12 percent of the total NPVRR of the preferred portfolio). PGE assumed that this transmission was not available in designing and evaluating nearly all (37 out of 39) of the portfolios that tested alternative resource strategies to the preferred portfolio and so those portfolios have significantly higher costs than the preferred portfolio due to that single assumption. Comparisons between the preferred portfolio and these alternatives are therefore not meaningful.

Staff has no visibility into how the assumption of additional transmission access into Nevada and Wyoming might affect the relative economics of alternative resource strategies that were constrained in the Preferred Portfolio (e.g., different GHG trajectories, different levels of CBREs, and additional EE). Furthermore, Staff questions the reasonableness of assuming access to additional transmission into Nevada and Wyoming within the preferred portfolio when PGE has described no plans to acquire such transmission, nor has PGE expressed confidence that such transmission will be available to acquire. A preferred portfolio that assumes such transmission will be available to acquire may be highly risky.

Recommendation 12: PGE should re-design and re-evaluate the Preferred Portfolio without assuming up to 800 MW of additional transmission to access markets and distant renewables. The availability of these options should be considered as a scenario or sensitivity, rather than a key component of the Preferred Portfolio. In making this adjustment, PGE should ensure that a large set of alternative portfolios that test varying paces of GHG reductions and varying community benefits can be directly compared to the preferred portfolio.

[35] See PGE response to Staff IR No. 153 for a comparison of constraints across selected portfolios.

3.2 Portfolio scoring

PGE does not use a consistent set of metrics that balance cost, risk, the pace of GHG reductions, and community benefits to compare portfolios and select the Preferred Portfolio.

PGE states that the portfolio tests are used to develop design principles for the preferred portfolio, but portfolios do not do this on a consistent basis. Most design decisions for the preferred portfolio appear to be based on a comparison of the traditional cost and risk IRP metrics. One exception is energy efficiency, where PGE tests additional energy efficiency beyond what was identified as cost effective by the ETO and found that additional energy efficiency would reduce both cost and risk. However, PGE used a different criterion—near-term cost impacts—to exclude the consideration of additional energy efficiency from the Preferred Portfolio.

PGE uses an admittedly blunt instrument to attempt to quantify community benefits across portfolios that does not allow comparison of the tradeoffs of different utility investment strategies that add different resource types or reflect operational changes to existing resources (See Portfolio scoring approach (pCBI)). To quantify the pace of GHG emissions reductions, PGE reports cumulative GHG emissions for each portfolio in the CEP Data Template but does not appear to adopt this as a formal portfolio scoring metric in the IRP. It is unclear how the pace of GHG emissions reductions might be considered in future decisions by the Company, including in future RFPs.

Recommendation 13: PGE should adopt a scoring metric for the pace of GHG reductions so that there is full transparency into the tradeoffs between cost, risk, the pace of GHG reductions, and community impacts and benefits across all its portfolio analysis. PGE should consider whether the Social Cost of GHGs for each portfolio might help to contextualize cost tradeoffs between portfolios.

Recommendation 14: If PGE seeks to consider near-term cost impacts alongside long-term cost impacts, the Company should design a scoring metric for near-term cost impacts, apply it consistently across all portfolios, and justify the use of this criterion in planning and procurement decisions.

Recommendation 15: In the future, PGE should justify portfolio analysis findings and any design principles used to develop the Preferred Portfolio based on all scoring metrics, not just those that address cost and risk.

3.3 Preferred Portfolio risks for customers

Staff is concerned that the capacity strategy PGE has taken in the 2023 IRP/CEP may present a heightened level of risk that the Company needs to address.

PGE takes a linear glidepath to greenhouse housereductions in the Preferred Portfolio with normal weather conditions as an assumption for energy contribution. For capacity, PGE primarily continues to utilize its thermal generation fleet to meet load excursions until 2040. This capacity strategy provides both opportunities and risks to customers, which are detailed below for consideration. Currently, due to the high level of uncertainty concerning emerging technologies, Staff recommends additional analysis from PGE to fully evaluate the level of risk associated with its preferred portfolio's capacity approach.

PGE's preferred portfolio shows backloading of a vast majority of the decarbonization capacity need to the end of the planning window (2037-2040), due to the availability of its thermal fleet to compensate for abnormal weather conditions until 2040. In its IRP modeling methodology, PGE removes all thermal generation from the model in 2040, driving the company's capacity need to over 2,000 MWs in that year—based on the March 2023 load forecasts. To help maintain a more reasonable pace of procurement, the company places an arbitrary "cap" in the model, limiting the amount of additional capacity in any particular year to 500 MWs. This modeling approach pushes the large capacity needs into 2038 to prepare for the removal of the thermal fleet in 2040. Figure 5 below from the July 7, 2023 IRP/CEP Addendum filing details the specific capacity additions in the Preferred Portfolio.

Figure 5 Preferred Portfolio resource additions

Table 10. Preferred Portfolio resource pathway 2031-2043 (incremental additions)

Values in nameplate MW	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
DR (cost effective)	11	8	9	8	5	11	7	7	7	1	6	11	3
EE (cost effective)	34	34	32	31	29	28	25	23	19	16	15	11	9
Storage	0	32	100	100	100	100	68	100	100	2100	0	0	0
Solar & wind	522	347	341	363	469	500	500	500	500	500	483	255	225
Hybrid	0	0	0	0	0	0	0	0	0	0	0	0	0
CBRE	0	0	0	0	0	0	0	0	0	0	0	0	0
Tx market access	0	0	0	0	0	0	0	0	0	0	0	0	0
Capacity	0	0	0	18	134	135	256	500	500	500	0	0	0
GHG glidepath (MMT CO2e)	1.5	1.3	1.1	1.0	0.8	0.6	0.5	0.3	0.2	0.0	0.0	0.0	0.0

PGE determined this strategy was the best path forward to manage costs in the near-action planning window and to position the company to take full advantage of any emerging technologies that could provide an alternative to currently available commercial storage options, primarily battery storage. As discussed further in the Emissions Modeling and Glidepath section, Staff is concerned that PGE may be understating the resources it needs to achieve the Company's GHG targets by 2030. The increased need on its system requires further scrutiny into its current capacity procurement targets and strategy.

Staff finds that additional analysis is warranted to evaluate if the earlier onboarding of capacity is feasible to decrease the risk of not securing adequate levels by 2040. A simple change to the methodology to decrease the capacity "cap" in the model would enable PGE and Staff to analyze the implications of de-risking PGE's Preferred Portfolio capacity strategy.

Further, Staff seeks to understand how this portfolio insight is informing PGE's long-term decarbonization strategy. Does the Company view the ability to acquire this level of capacity on a just-in-time basis as a critical dependency for its ability to comply with HB 2021, or does the Company see these additions as a guidepost for more incremental capacity additions on a more realistic glidepath such that it will feasibly secure the level of capacity resources that the model needs when thermal resources are no longer economically dispatched. What are the cost and other trade-offs of these two options?

Recommendation 16: In its Reply Comments, PGE should provide additional analysis that decreases the annual capacity cap in the modeling methodology and discuss the findings as they relate to the capacity acquisition strategy.

Recommendation 17: In Reply Comments, the Company should explain how the capacity additions in the Preferred Portfolio have informed the long-term decarbonization strategy as it relates to acquiring non-emitting capacity over time.

4 Energy Efficiency Strategy

PGE did not select all available cost-effective energy efficiency (EE) in its preferred portfolio. In the 2023 Preferred Portfolio, PGE chose to select EE initially identified by Energy Trust of Oregon (ETO) using values provided by PGE, based off its 2019 IRP which does not reflect a clean energy compliant strategy. PGE's 2023 IRP/CEP portfolio analysis found that an additional 50MWa of EE by 2030 minimizes long-term cost and risk, but the Preferred Portfolio did not include this quantity.

The additional 50 MWa of EE would reduce long-term costs by $476 million. Incorporating additional EE would not further reduce cumulative GHG emissions because PGE would use the EE to avoid other clean energy resource acquisitions while holding emissions constant. An additional 50 MWa of EE would also increase benefits that accrue to customers and its communities but would also increase near-term costs relative to no additional EE by 0.27 cents per kWh on average between 2024 and 2028.

The additional 50 MW identified by PGE *is cost-effective*. Cost-effectiveness generally equates to all EE up to the avoided cost of alternative resources plus a 10 percent adder.[36] Instead, PGE selected EE based on avoided costs that are both out of date and does not reflect a forecast consistent with the HB 2021 compliance requirements.

4.1 EE in portfolio analysis

Staff is concerned that PGE did not analyze additional EE consistently with other resources.

While PGE expressed concerns about execution risk through ETO, it did not provide comparable analysis for other resources. Staff addresses inconsistent treatment of EE with respect to portfolio scoring in the Portfolio Analysis Section.

Staff asked PGE to elaborate on procurement risk for acquiring additional transmission. PGE responded: *Unquantified procurement and execution risks have the potential to impact the ability to acquire the quantity, timing, and price of transmission identified in the Preferred Portfolio. The quantity of transmission available for acquisition will depend on many factors not captured in portfolio analysis. If procurement and execution risks impact the quantity, size, and price of acquiring the transmission identified in the Preferred Portfolio, they have the potential to impact compliance with HB 2021 targets*.[37]

PGE provided a similar response to OPUC DR 150 which posed a similar question on storage.

Based on the available information, Staff believes that acquiring additional EE through ETO has a smaller, more quantifiable risk than many of the other resources PGE presents in the preferred portfolio. ETO has a proven record of meeting goals in most years and on average exceeds IRP goals for cost-effective EE

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[36] See ORS 469.631; ORS 757.054; *In the Matter of Investigation into the Methodology and Process for Developing Avoided Costs Used in Energy Efficiency Cost-Effectiveness Tests*, Docket UM 1893, Order 22-483 (December 14, 2022), Docket UM 1893, Energy Trust of Oregon Presentation (September 30, 2022).

[37] Docket LC 80, PGE response to Staff IR No. 149.

and has had success scaling up. Notably, ETO's natural gas programs now account for 23 percent of its budget today. Overall, after discussing with ETO, Staff is confident that it can reliably acquire an additional 50 MW of cost-effective energy efficiency by 2030. Further, Staff finds that given the acquisition targets for alternative resources including 216 MW of EE, 1,200 MW of transmission, and 475 MW of storage, the relative size of the risk of an additional 50 MW of energy efficiency is much smaller.

Additionally, PGE's modeling shows high scores for both capacity value and annual ELCC for EE resources.[38] Staff highlights the various almost immediate benefits associated with EE resources for all customer classes including lowering energy bills and enhancing building resilience. The pre-CEP avoided costs used in this IRP/CEP further limit the ETO's ability to expand acceptable program offerings to energy burdened and historically underserved customers.

4.2 Valuation of avoided costs

Staff is concerned that PGE has shared inadequate information regarding value of avoided resources.

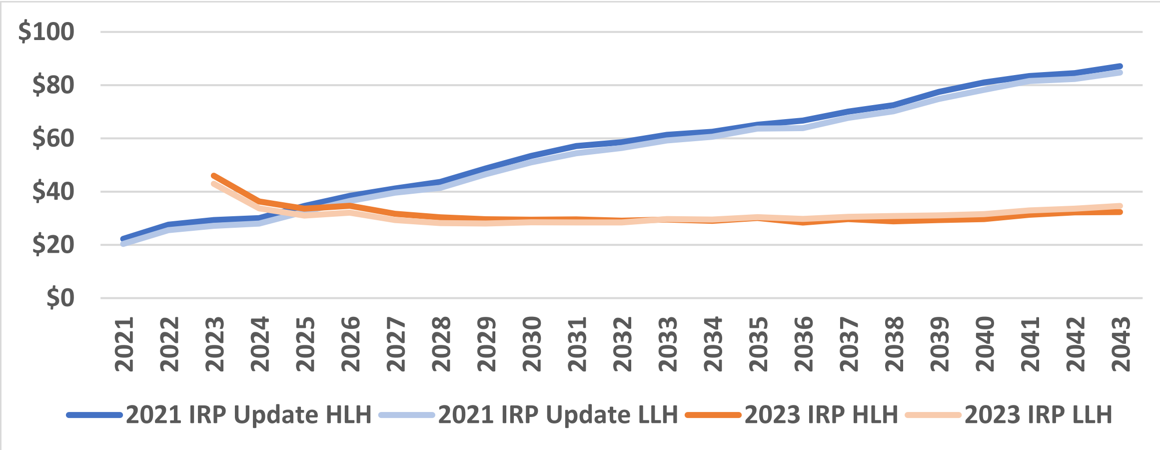
At the June 13, 2023, Special Public Meeting and in Round 0 Reply Comments, PGE stated that the avoided costs of this IRP/CEP will be used by ETO in the budgeting once the IRP/CEP is acknowledged.[39] However, Staff has not seen evidence that appropriate avoided costs are available as an outcome of this IRP for the proper valuation of energy efficiency. It is unclear how PGE evaluated the benefits associated with carbon reductions and avoided clean energy purchases from EE resources. PGE's IRP/CEP assumes no additional cost of carbon compliance in Oregon over the planning horizon. In response to Staff's questions on including clean energy in capacity and energy values, the Company cited the use of a four-hour battery in place of simple-cycle combustion turbines as a capacity resource and indicated that additional analysis needs to be done to account for clean energy in deriving energy values.[40]

Staff concludes that the energy and capacity values available as an outcome of the 2023 IRP do not capture the clean energy value of EE. PGE claims that the cost of complying with HB 2021 is captured within the capacity and energy value, and yet the energy value produced by the IRP reflects energy from an emitting resource, and hence, does not represent the energy value of energy efficiency. The value of energy in PGE's 2023 IRP/CEP is so low that Energy Trust estimates using these numbers for avoided costs for EE would result in a *reduction* in PGE's avoided costs for EE and would more than offset any increase in value based on switching to a four-hour battery for capacity.

The following graph illustrates the difference in forward market prices between the 2019 IRP and the forward market prices of provided by PGE in the 2023 IRP:

[38] Docket LC 80, PGE 2023 IRP/CEP, p.245, Table 51.
[39] Docket LC 80, PGE Reply to Round 0 Comments, p.21.
[40] Docket LC 80 PGE response to Staff IR Nos. 76 and 100.

Figure 6: Comparison of PGE's forward market prices from previous IRP filing to current CEP/IRP[41]



4.3 Near-term cost concerns

Staff believes that OPUC has tools to mitigate rate shocks to customers.

PGE discusses concerns about near-term costs in the IRP.[42] While SB 1547 (2016)[43] does not address timing issues related to acquisition of cost-effective EE, it is still a reasonable consideration with respect to the plan overall. The tradeoff between near-term costs and long-term bill savings is an important decision criterion. It also delays immediate bill savings and other non-energy benefits associated with EE discussed above, for program participants. Staff notes that the OPUC has tools to mitigate rate shocks to customers, and PGE should work with the Commission in relevant processes to consider mechanisms such as amortization to lower near-term cost impacts of additional EE.

4.4 Collaboration with ETO budget process

Staff is proactively trying to facilitate collaboration between PGE and ETO regarding EE budget.

PGE notes that the EE selection represented in the preferred portfolio uses data from the 2019 IRP and that data from this 2023 IRP/CEP will be used by Energy Trust going forward. While this has been a traditional practice, Staff believes that a change in this practice is warranted given the urgent and significant need to procure clean energy resources to meet HB 2021 emissions reduction goals (e.g., 80 percent below baseline emissions level by 2030) in an affordable and equitable manner.

At the Special Public Meeting on June 13, 2023, the Commission expressed interest in learning if PGE and ETO could update ETO's 2024 budget soon enough to impact EE procurement targets in this IRP cycle. The Commission also indicated that a ramp-up starting in 2027 may be too late. Staff is working with Energy Trust and PGE to address these concerns. In discussions with Energy Trust, Staff understands that additional EE by 2030 can be procured if there are increases in the 2024 budget and commitment to a

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[41] Docket UM 1893, PGE's avoided cost data submission for 2022 and Docket LC 80, PGE's response to Staff IR No. 76.

[42] Docket LC 80, PGE 2023 IRP/CEP, pp. 278-279.

[43] ORS 757.054 (3)

multi-year investment to ramp up EE acquisition programs. As of July 10, PGE has yet to schedule a meeting with Energy Trust dedicated to this topic.

Recommendation 18: PGE should include 50MWa of additional energy efficiency in its preferred portfolio and qualify its Customer Resources Action items by describing its strategy to procure this additional EE within the Action Plan window.

Recommendation 19: In its Reply Comments PGE should provide an update on its collaborative efforts with ETO towards procuring additional EE resources by 2030.

5 Transmission strategy

In its IRP/CEP, PGE proposes that, "transmission planning will need to evolve from an approach based primarily on reliability and load service to a more proactive approach that aligns with our future load service needs as we decarbonize." For the first time, PGE endeavors to capture this change by identifying solutions to transmission-related constraints in its portfolio modeling and identifies both near-term transmission actions and potential longer term transmission solutions. Staff has concerns in each of these areas.

PGE includes an estimate of future transmission needs in Table 7 of the 2023 IRP/CEP Addendum filing, which is reproduced in Table 1.

Table 4. PGE's identified transmission need (from Table 7 of the 2023 IRP/CEP Addendum)

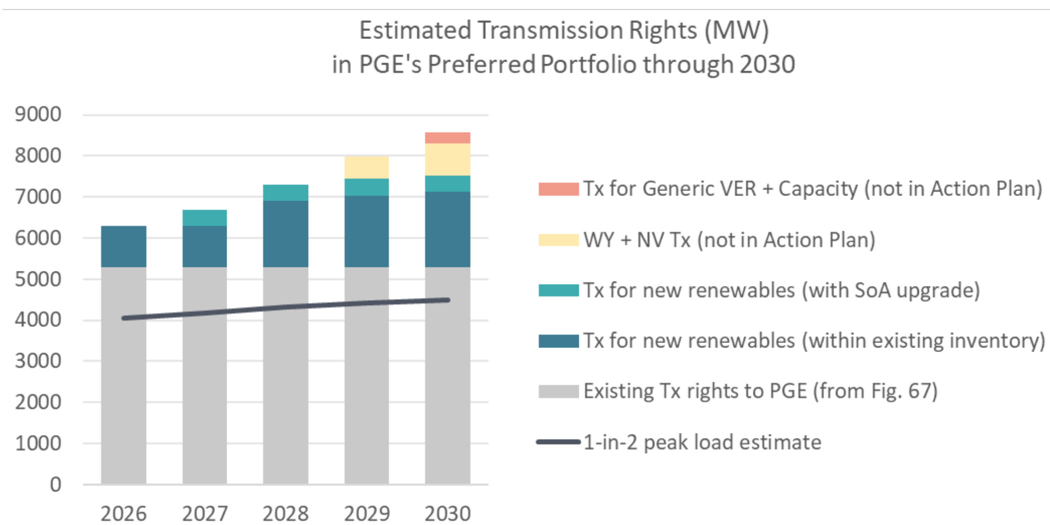
	Estimated transmission need (MW)	
Year	**2023 CEP/IRP**	**Addendum Filing**
2026	0	0
2027	0	0
2028	0	355
2029	159	1,051
2030	768	1,658
2035	3,005	4,568
2040	7,468	9,403

The concept of transmission need is new to PGE's planning analysis. Staff appreciates the Company's progress in this area and believes it is worth further exploration. Staff's understanding is that this transmission need represents the cumulative amount of additional off-system capacity (renewable and generic capacity) that is added to the Preferred Portfolio that exceeds PGE's estimates of BPA's inventories of long-term firm and conditional firm transmission into PGE. Staff's understanding is that PGE's analysis effectively requires 1:1 long-term firm or conditional firm transmission for every MW of off-system renewables added to the portfolio and that the identified transmission need is predicated on the assumption that PGE will carry this transmission strategy forward indefinitely. Staff notes that this strategy may not be PGE's only option for integrating renewables on to its system. Furthermore, it is important to note that the transmission need identified by PGE is largely unrelated to the transmission that PGE needs to serve its peak load. Staff questions whether these numbers constitute a "need" or whether there are alternative strategies that PGE could pursue to avoid some portion of this transmission expansion. Staff discusses this further in the Modeling and transmission strategy section.

Looking at the results of this modeling, Staff notes the extreme scale of these numbers in the long-term (reaching almost 10,000 MW of additional transmission by 2040) and how quickly the need arises (over 1,000 MW of additional transmission by 2029). PGE has flagged this a key barrier and indicated that acquiring transmission is a critical dependency of its decarbonization strategy. While Staff completely agrees, Staff is also concerned that the Company's modeling approach is at risk of miscalculating the amount of transmission needed to deliver clean energy resource to load which complicates the Company's ability to articulate a clear transmission strategy at this time.

Figure 4 shows Staff's estimate of the total amount of transmission rights implied by PGE's Preferred Portfolio through 2030, broken out by existing merchant rights, rights for new renewables that are within PGE's estimates of BPA's long-term firm and conditional firm inventories, rights that could become available with PGE's proxy transmission additions, and additional transmission rights that could be needed for off-system renewable and capacity additions.[44]

Figure 7: Staff's analysis of PGE's transmission rights implied by the Preferred Portfolio through 2030



Staff is also concerned that the transmission additions in the Preferred Portfolio changed so dramatically between the filed IRP and the recently filed Addendum. Specifically, the Wyoming and Nevada transmission additions through 2030 increased from 255 MW in the filed IRP to 800 MW in the Addendum, driven by updates to PGE's load forecast. Despite how sensitive the transmission needs appear to be to the load forecast, PGE does not directly address the risk that it may have severely underestimated or overestimated future transmission needs within the plans.

[44] Staff's analysis assumes that all off-system resources, Generic VER, and Generic Capacity require 1:1 transmission rights, which appears to be consistent with PGE's approach to estimating transmission need. Staff's 1-in-2 peak load estimates are based on the updated load forecast and DER forecasts provided in the Addendum filing, assuming the same load factor as the filed IRP.

Staff believes that at this stage, PGE's transmission need should be better explored as a potential breaking point for the success of the Company's decarbonization strategy. Staff encourages PGE to be transparent about the costs and risks of its transmission alternatives (e.g., how favorable does the backup look) and the actions that can help ensure that the transmission investments needed will come online and be on schedule.

5.1 Near-term transmission actions

Staff is concerned that PGE's near-term transmission actions are not supported by its portfolio analysis.

PGE includes two transmission actions in the Action Plan. Action 5A states that PGE plans to "pursue options to alleviate congestion on the SoA flowgate." When asked for more detail about the options to relieve this congestion, PGE indicates that it plans "to study whether a new Trojan-Harborton 230kV line, using currently PGE-owned existing rights-of-way is a feasible and cost-effective solution."[45] PGE supports this action in portfolio analysis by testing a proxy transmission upgrade that would theoretically increase the long-term firm available transfer capacity from proxy renewable resources in the northwest to PGE by up to 400 MW at a cost of $0.54/kW-mo. This proxy transmission upgrade allows the model to select additional northwest renewables prior to relying on PGE's more expensive Generic VER resource.[46] In PGE's transmission portfolio tests, adding the full 400 MW in 2027 reduced the NPVRR by $3.2 billion, relative to a portfolio with no transmission upgrades, which instead relied on more Generic VER. Based on this analysis, PGE constrains the Preferred Portfolio to include the full 400 MW upgrade in 2027.

Staff agrees with the Company's characterization of the SoA congestion issue and believes that alleviating congestion on the South of Allston flowgate will bring value to the region and to PGE customers. However, Staff observes that the Company has only cited one tangible option that it will explore to relieve this congestion and therefore has not provided very much analysis that demonstrates the costs of funding the proposed upgrade will outweigh the benefits or how this upgrade compares to alternatives.

This is PGE's first attempt at modeling transmission investments at this level. Contemplating specific transmission investments within the confines of a utility IRP is tenuous for a utility situated like PGE.[47] Staff commends PGE's efforts and would like to understand if and when PGE expects to provide the detailed cost/benefit analysis needed to determine if PGE should make a commitment to invest in specific upgrades or pursue alternatives. The alternative to SoA tested in the IRP/CEP was hypothetical in that it relied on the Generic VER resource in the event that the SoA upgrade was not available. Because the Generic VER resource is not a real, tangible alternative to alleviating constraints on SoA, Staff considers the identified cost differences to be arbitrary.

[45] Docket LC 80, PGE Response to Staff IR No. 91.

[46] PGE explains on page 255 of the IRP that the Generic VER resource capacity factor and capacity contributions are based on a weighted average of the renewables selected in the Preferred Portfolio, and its costs are set to 105% of the most expensive proxy resource so that the Generic VER is always selected last.

[47] As PGE explains in its IRP/CEP, "PGE's unique footprint necessitates collaborative planning with Bonneville Power Administration (BPA) and regional peers to deliver resources to PGE's service area and to serve load within PGE's footprint. Transmission planning and development often takes longer than the Integrated Resource Plan (IRP) action window time horizon, necessitating early proactive efforts." Staff notes that PGE is responsible for making requests and financial commitments to other entities that must construct upgrades to secure transmission, which can be awkward to align with IRP acknowledgement decisions.

Given the scale of transmission needs over time, Staff is also curious if PGE has considered pursuing multiple options to further reduce congestion on the SoA flowgate—for example the use of on-system battery storage to reduce the impact of incremental renewables on the SoA flowgate (See Modeling and transmission strategy**)**. It may be that a portfolio of solutions yields the best outcome for customers, rather than focusing solely on transmission upgrades. Staff interprets PGE's Action 5A to be inclusive of a range of possible solutions to alleviate congestion, despite the fact that PGE's analysis focuses on a transmission upgrade.

PGE also alludes to South of Allston upgrades providing load service benefits in addition to delivery of renewables.[48] If this upgrade is driven in part by load service drivers, Staff would like to understand how the costs and benefits of PGE investing in upgrades change under the load growth presented in the IRP Addendum.

Further, PGE states that,"[a]s part of the CEP/IRP portfolio analysis, it was identified that incremental South of Allston Path capacity is necessary before 2030" and that "…transmission development often takes longer than the traditional CEP/IRP action plan window time horizon, often taking more than 10 years."[49] Staff appreciates the Company surfacing these implementation risks, and would like to understand how feasible these upgrades are by 2030 and what the Company's alternatives for this upgrade are in the event that it is not possible. Staff believes that it is difficult to consider the reasonableness of the Company's resource strategy and HB 2021 compliance strategy without a high level of transparency into these critical elements of the Company's transmission strategy.

In Action 5b, PGE proposes to "explore options to upgrade the Bethel-Round Butte line (from 230 to 500 kV)". The Company explains that it is, "widely accepted that most new resources will be located east of PGE's service area, on the other side of the Cascade Mountain Range" and that the Company already owns the Round Butte 230 kV line that runs that path. Staff understands the practical benefits of pursuing an upgrade to an existing line that the Company owns but is concerned about the relationship between this action item and the Preferred Portfolio. Staff could not find in the IRP/CEP or PGE's data request responses the quantity of additional transmission (in MW) that the Bethel-Round Butte upgrade would provide or any information about its potential costs. Staff is also concerned that the Company has not incorporated this upgrade into its portfolio analysis at all, let alone provided the information needed to confirm that the costs of this type of investment is supported by PGE's analysis. Further, Staff would like to understand if the Company's preferred portfolio would select a different amount of on-system or off-system non-emitting resources if the costs and benefits of Bethel Round Butte were included.

Similar to SoA, Staff believes that PGE should continue to explore its options to upgrade Bethel Round Butte, but in order to determine the investment reasonable, Staff needs more information about the balance of cost and benefits analysis into the effects of the additional transmission on PGE's selection of on or off-system resources and its thermal fleet operations and GHG emissions. In order to determine that the Company's resource strategy and HB 2021 compliance strategy are reasonable, Staff and stakeholders need more transparency into actions that the Company believes will improve the feasibility

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[48] While not described in the IRP/CEP, BPA also suggests that these upgrades would be driven by reliability, load service, and delivery of renewables to Portland. See Bonneville Power Administration, The Evolving Grid Update on the State of Transmission, April 27, 2023, accessed at: https://www.bpa.gov/-/media/Aep/transmission/transmission-business-model/042723-evolving-grid-bpat-final.pdf#page=21.

[49] Docket LC 80 PGE Response to Staff IR No. 146.

of these upgrades coming to fruition and consideration the Company's alternative options and backup plan if these upgrades cannot be made in time to fulfill the projected needs.

Recommendation 20: In Reply Comments, PGE should help Staff understand the following questions related to its near-term transmission action items:

- ***Is PGE's Action 5A inclusive of a range of possible solutions to alleviate congestion? What are these solutions?***
- ***When does PGE expects to provide the detailed cost/benefit analysis needed to determine if PGE should make a commitment to invest in transmission upgrades related to Action 5A and 5B and/or pursue alternatives? Does this include consideration for drivers of transmission upgrades that are not captured in the IRP, such as reliability?***

5.2 Longer term solutions

PGE's Action Plan provides no insight into its strategy towards obtaining apparently critical regional transmission resources.

PGE includes additional transmission access to Wyoming and Nevada in the Preferred Portfolio to increase market access, support resource adequacy, and allow PGE to access more diverse renewables. Both options are selected in large quantities as early as 2029 in the Preferred Portfolio (553 MW by 2029 and 800 MW by 2030[50]), suggesting that they are critical components of PGE's strategy over the next six years. Despite citing the long development times for transmission throughout the IRP, PGE does not address the Wyoming and Nevada transmission options within the Action Plan, describe how this transmission might become available on the timeline modeled in the Preferred Portfolio, or explain what alternative options the Company will explore to mitigate the risk that this transmission does not become available. As described in the portfolio analysis section (See Comparability), PGE's inclusion of this transmission option in the Preferred Portfolio also makes it impossible to directly compare the Preferred Portfolio costs to those of almost all other portfolios.

Staff understands that the ability secure this type of regional transmission access is a critical piece of the Company's resource actions and decarbonization strategy. Given the complexities of regional transmission expansions and access, Staff would like to understand when the Company believes that it will know if access to these transmission resources will be feasible and what the Company's actions will be if they need to pivot due to infeasibility. PGE's response to Staff Recommendation 12 should provide some insight into the implications of regional transmission uncertainties and related mitigation efforts by the Company.

5.3 Modeling and transmission strategy

Staff has questions about whether PGE's transmission modeling approach is too simplistic to capture a realistic amount of transmission needed, and how this is impacting PGE's decarbonization strategy.

Staff appreciates that PGE has incorporated transmission-related constraints into portfolio analysis in this IRP. However, Staff has two primary concerns with PGE's transmission modeling and the limitations that it places on PGE's ability to develop a viable long-term transmission strategy in the context of HB 2021.

[50] Docket LC 80, PGE 2023 IRP/CEP Addendum: Portfolio Analysis Refresh, p.25.

1. PGE's analysis may be undervaluing resources that avoid transmission upgrades.

In PGE's portfolio optimization, access to renewable resources is limited based on BPA's long-term firm and conditional firm inventory using a set of simplified transmission zones. Resources can only be selected within a zone up to the maximum estimated transfer capability from the zone to PGE. Transmission upgrades can be triggered to increase the amount of renewables that can be selected. On-system resources, like energy efficiency, demand response, battery storage, and CBRE's do not have associated transmission constraints. They can therefore help to avoid transmission only to the extent that they reduce the amount of off-system renewable energy needed to meet PGE's GHG targets.

In PGE's modeling, on-system resources that provide clean energy and reduce GHGs, like CBREs and energy efficiency, can avoid off-system renewables and therefore also avoid transmission upgrades. However, on-system resources that primarily provide capacity and do little to avoid GHGs, like demand response and battery storage, cannot help to avoid transmission upgrades in PGE's modeling because they do not avoid the need for off-system renewables. This modeling framework neglects important transmission-related value streams for on-system dispatchable resources. Specifically, this framework ignores the ability to use on-system batteries and demand response to alleviate congestion on key transmission paths without incurring the costs of transmission upgrades.

In the next IRP, PGE should adopt a transmission modeling framework that accounts for the ability of on-system resources to help alleviate transmission congestion**.**

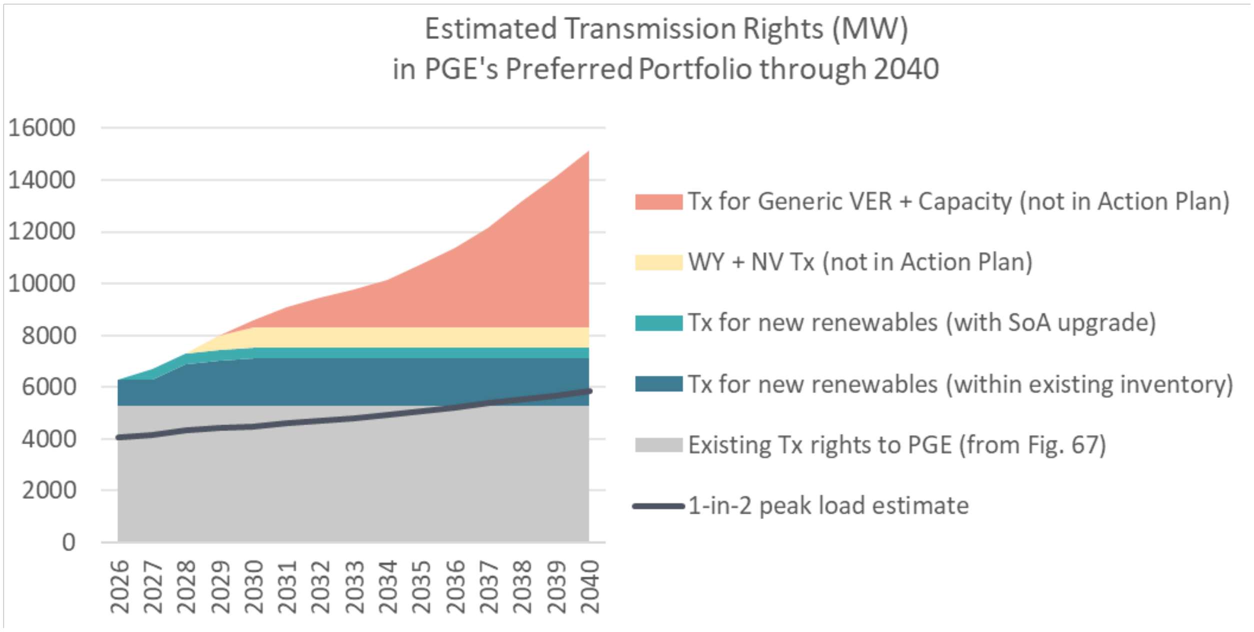
2. PGE's transmission strategy is not sustainable in the context of HB 2021.

PGE's analysis assumes that adding long-term firm and conditional firm transmission rights to the portfolio on a 1:1 basis with renewable additions is the only way to integrate renewable energy on to the system. As PGE adds significant renewables to its system, Staff is concerned that continuing with this business-as-usual strategy may effectively prioritize the avoidance of transmission-driven renewable curtailment risk over all other cost and risk considerations and may threaten the feasibility of PGE's plans. It is not clear to Staff that this risk warrants such a rigid transmission strategy going forward.

Figure 5 shows Staff's estimation of PGE's transmission rights implied by the Preferred Portfolio through 2040.[51] Staff notes that the total transmission rights into PGE's system will far exceed the peak demand if PGE does not materially adjust its long-term transmission strategy in the context of HB 2021. Eventually, most of these transmission rights would necessarily go unused or be used for purposes other than serving load.

[51] Staff's analysis assumes that all off-system resources, Generic VER, and Generic Capacity require 1:1 transmission rights, which appears to be consistent with PGE's approach to estimating transmission need. Staff's 1-in-2 peak load estimates are based on the updated load forecast and DER forecasts provided in the Addendum filing, assuming the same load factor as the filed IRP.

Figure 8 Staff's analysis of PGE's transmission rights implied by the Preferred Portfolio through 2040



This raises several questions from Staff's perspective: How will PGE demonstrate that accumulating these transmission rights is in customers' interests or use excess transmission rights to directly benefit customers? What alternatives should PGE analyze to reduce costs to customers and to avoid unnecessarily over-constraining BPA's transmission inventory? Alternative strategies could involve relying to some extent on short term firm or non-firm transmission, allowing new resources to use PGE's existing transmission rights or to share transmission rights with other resources, allowing resources to secure transmission rights to less constrained points on the transmission system and limiting transmission rights across constrained paths based on what is needed for load service, and/or joining an RTO. All of these options could bring about new risks and Staff believes that a more rigorous understanding of these risks will support more informed planning decisions related to transmission.

Staff understands that evaluating many of these options in terms of cost and risk may require PGE to undertake more granular modeling. PGE may need to conduct zonal dispatch modeling with contractual transmission constraints to understand how to better utilize the existing transmission rights or to reduce the additional transmission rights that PGE needs to meet load and achieve the GHG targets. Staff understands that this type of analysis is likely not feasible within the timeline of this IRP cycle, however this type of more granular analysis may be necessary for PGE to develop a feasible long-term transmission strategy in the context of HB 2021.

In the next IRP, PGE should explicitly model alternative transmission strategies for its renewable buildout and explore the costs, risks, GHG emissions, and community impacts implications of those alternative strategies.

Recommendation 21: In Reply Comments, PGE should explain the long-term transmission strategy for complying with HB 2021. In this strategy, PGE should identify the specific risks that the transmission strategy protects against and describe how the Company plans to use transmission rights to benefit customers when they are not needed for load service, with quantitative information where possible.

6 RFP strategy ("Energy and Capacity actions")

The Company's IRP analysis calls for multiple Requests for Proposals (RFPs) seeking non-emitting energy resources and, as necessary, non-emitting capacity resources, over the next seven years. The Company's RFP strategy emphasizes the acquisition of non-emitting energy resources in the near-term and includes a goal to acquire an equal portion of its 2030 reference case energy need through an annual RFP. For all RFP actions, the Company provides less certainty about its capacity acquisition strategy, stating that, "PGE will pursue the procurement of these resources in a staged approach, first acquiring any beneficial opportunities in the bilateral market, and second by conducting one or more RFPs to meet any remaining capacity needs through the Action Plan window."[52] The Company references the accelerated procurement framework that will be proposed in the UM 2274 2023 RFP docket and expresses a commitment to continue to work with regulators and stakeholders to find ways to accelerate the acquisition timeline while retaining an emphasis on engagement and feedback throughout the process.[3]

Given the level of uncertainty discussed throughout these comments, Staff appreciates the Company's focus on adaptive procurements that can capture currently available technologies during the Action Plan window. In evaluating the Company's RFP strategy, Staff is considering whether the Company has presented a well-formed strategy to control costs, to have the resources in place that are needed to reduce dispatch of thermal resources in 2030 and beyond, and to access available co-benefits. Staff's initial review has surfaced two questions about the meaningfulness of the information the Company has provided about its RFP strategy, beyond the broader capacity and transmission acquisition risks discussed in the portfolio analysis section (See Preferred Portfolio Risks for Customers).

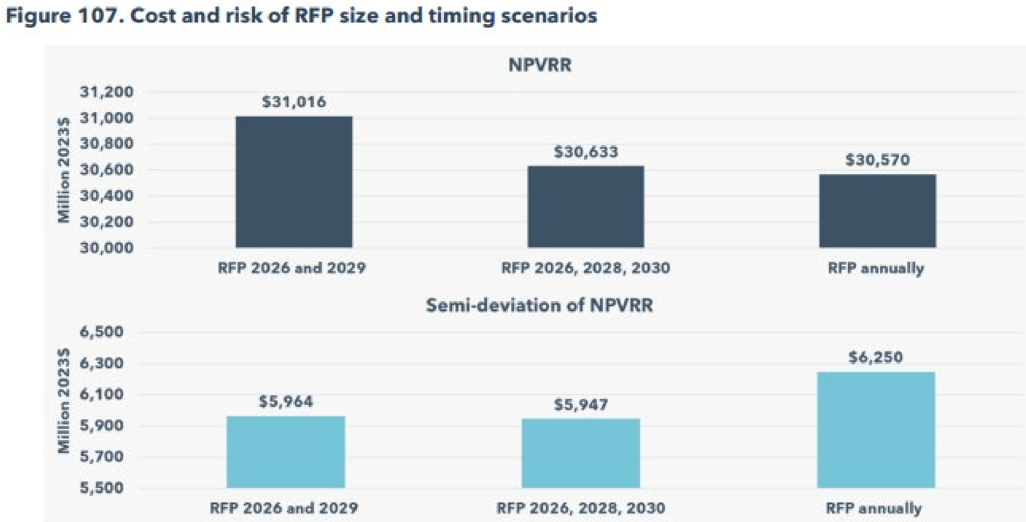
6.1 Pace of near-term actions

Staff has clarifying questions about the insights provided by RFP pacing analysis and the Company's consideration of economic and technical feasibility.

PGE provides a sensitivity analysis that examines three RFP pacing scenarios: annual, every other year, or every three years through 2031. Figure 9 illustrates that annual procurements yield the lowest long-term portfolio cost but carry relatively higher risk in higher need futures.[53]

[52] Docket LC 80, PGE 2023 IRP/CEP, p.310.
[53] Docket LC 80, PGE 2023 IRP/CEP, p.300.

Figure 9 PGE's RFP Pacing Scenario Analysis[54]



Staff appreciates the Company's exploration of procurement pacing options but is unsure how to use this analysis to inform its review of the Company's RFP action items. Staff understands the intuitive advantages of smaller, more frequent procurements that the Company describes in its IRP discussion and believes that there are practical risks of a just-in-time procurement approach.[55] However, Staff suspects that the cost and risk metrics are more a product of the Company's modeling choices, such as annual procurement constraints interacting with the RFP scenario constraints, and do not provide much information about the trade-offs of different procurement pacing options. Staff invites the Company to describe any additional insights that can be gleaned from this portfolio analysis and how they were used to inform its RFP strategy. For example, does this analysis provide insights about front-loading or back-loading procurement volumes across its annual RFPs or help the Company understand how to implement its annual procurements in any other way?

Staff also appreciates PGE sharing sensitivity analysis to evaluate the risks of supply chain disruptions.[56] However, Staff is also unsure how the results influence the Company's interpretation of the RFP pacing analysis and whether any other economic and technical feasibility insights can be used to inform PGE's RFP pacing strategy.

Staff expects to have a better sense for near-term market-depth and pricing issues as PGE's 2023 RFP docket progresses and looks forward to further discussions as appropriate when RFP bid data is available. In the meantime, PGE can provide further discussion about how its IRP/CEP analysis provides useful insights about the trade-offs of pacing (both timing and sizing) of its energy and capacity RFP actions.

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[54] Docket LC 80, PGE 2023 IRP/CEP, p.300.

[55] See Docket No. LC 82, PacifiCorp's Amended 2023 IRP, May 31, 2023, p.325, in which PacifiCorp's the Preferred Portfolio calls for as much as 7,500 MW of battery capacity additions in the region by 2030.

[56] Docket LC 80, PGE 2023 IRP/CEP, pp.301-302.

Recommendation 22: In Reply Comments, PGE should explain whether the RFP pacing and supply chain analysis provide any quantitative insights into its pacing options. The Company should also indicate the extent to which it plans to constrain its annual RFPs to match the annual RFP scenario energy and capacity additions.

6.2 Acquisition flexibility

Staff seeks more clarity about the implementation of the Company's procurement strategy and the interaction between capacity and energy options beyond RFPs, such as EE, DR, and CBREs.

PGE seeks to implement an accelerated procurement strategy to maximize flexibility to protect customers from making costly or unnecessary investments in an uncertain planning environment. Staff appreciates the need for a nimble approach but needs more information about the implementation logistics and how the annual RFPs and other resource actions strategies might interact.

The Commission recognized the benefits of a flexible procurement strategy in granting PGE's request to pursue concurrent tracks for the review of its 2023 CEP/IRP and its 2023 RFP.[57] In PGE's 2023 RFP Docket (UM 2274), PGE proposes to establish an RFP structure that will be approved for ongoing use throughout the CEP/IRP Action Plan Window. Following each solicitation, PGE would seek acknowledgment of a final shortlist. Upon closing one round of procurement, PGE could file an updated needs assessment based on the results of the prior round and move towards another solicitation using the same RFP structure. PGE suggests that the approval of this structure could occur in their next RFP docket as illustrated in Figure 10.

Figure 10: An example of PGE's Proposed Procurement Approval Plan[58]

Staff appreciates PGE's effort to more fully explicate how a flexible procurement process could work in practice but has several questions about its proposal. While PGE's filing says that each new round of procurement will begin with an updated needs assessment, Staff would like further explanation of what variables will feed into those updated needs assessment. PGE specifically mentions incorporating the results from last procurement round, and the need remaining from the most recently filed IRP/CEP or IRP/CEP Update, but Staff would like to know how new information on CBREs and SSRs, bilateral negotiations, transmission, and other resource actions will be included in the updated needs assessment, and whether the Company makes a distinction between need identified in a "filed" IRP/CEP and that in an "acknowledged" IRP/CEP.

Staff also believes PGE needs to provide more details about potential offramps once an RFP is approved for use in multiple rounds of procurement. While the idea of an open-ended RFP that would be in effect

[57] See Commission Order No. 23-146.

[58] See Docket UM 2274, PGE's Planning and Procurement Forecast, July 17, 2023, p.3.

for multiple rounds of procurement makes sense as a way to streamline the regulatory process, the Commission would still require opportunities to change course during the process. Staff would like PGE to describe how and when that could or would occur. Finally, Staff requires more explanation of how PGE will decide to close one round of procurement and begin another, particularly if there are still resources on a Commission acknowledged final shortlist that it is choosing not to pursue.

PGE's procurement approach is designed to balance the risks of over-procurement, under-procurement, and lost opportunities to maximize a range of different resource benefits. While this flexibility is meaningful in the current planning and policy environment, Staff seeks to better understand how the Company plans to maximize the benefits of the procedural and regulatory flexibility PGE has sought and minimize the risks. Staff also notes that there are tools outside of the planning process that should be explored to further protect customers from the risks of investments once they have been made.

Recommendation 23: In Reply Comments, PGE should provide more details about its proposed RFP framework, including the specific methodology to update the needs assessment, potential offramps, and how PGE will make a determination to close one round of procurement and begin another.

Recommendation 24: In Reply Comments, PGE should describe how the Company will respond if an RFP does not result in its targeted procurement level. This should include how its procurement activities will inform its other resource actions, for example would the Company increase EE and other non-RFP resources if new cost or market depth information is available through RFPs.

Recommendation 25: PGE should provide regular updates to LC 80 participants on its target procurement volume for the 2023 RFP as new information and analysis warrant.

7 Modeling Improvements Discussion

7.1 Load forecast

Staff believes PGE should consider using climate models in its load forecast to capture climate change impacts, adopt a logical and transparent strategy toward model selection and account for increased electrification effects in its winter peak forecast model.

Long-term load forecasting is fundamental to establishing a utility's future energy and capacity needs. At present load forecasting seems to be considerably more challenging than it has been in the past due to considerations of climate change impacts on energy consumption, increasing quantities of distributed energy resources (DERs) such as energy efficiency, rooftop solar and batteries, on electric systems, as well as policies leading to increased electrification.

Policies promoting the growth of building and transportation electrification, will most likely lead to higher demand for electricity. However, at the same time, increases in DERs could potentially lower net energy load on the utility's system. All this necessitates that the load forecast models capture future trends in energy use, peak needs, and the sources of load uncertainty in a reasonable manner.

Staff evaluated whether PGE's top-down energy and peak forecast models reasonably capture climate change related weather pattern and future electrification impacts, and other potential drivers of energy demand.

Climate Change Impacts

PGE uses "normal" weather conditions in its top-down load forecast models by including heating and cooling degree days that capture a gradually warming temperature trend observed since 1975 using a "hinge" method with data since 1941. This method extrapolates and estimates normal weather trend from a linear and relatively flat normal weather function for 1941-1975, after which the function slopes upward.

Staff believes this to be a reasonable and simple approach to account for climate change impacts. However, climate models capture various nuances of climate change and can be more effective in generating long-term normal trends, which may not necessarily be linear. This would impact PGE's estimates of yearly energy and seasonal capacity needs. PGE should try to refine its approach to capturing the effects of climate change in its load forecast by including climate models as opposed to linear extrapolation of weather data.

Staff appreciates that PGE compared its methodology to various climate models and finds the forecast used in the IRP to be within the ranges from the different climate models. The figures[59] below from Appendix D shows how PGE's linear normal climate trend compares with four different climate models.

Figure 11: Annual Cooling Degree Day Forecasts

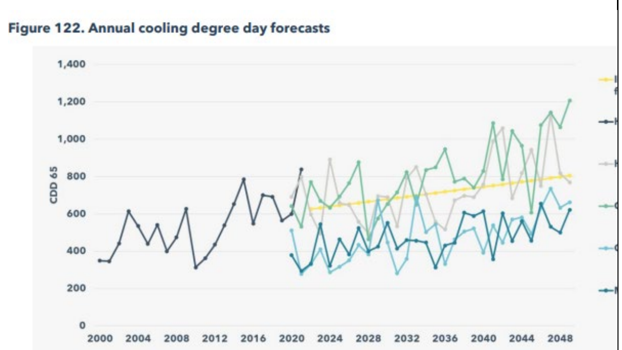
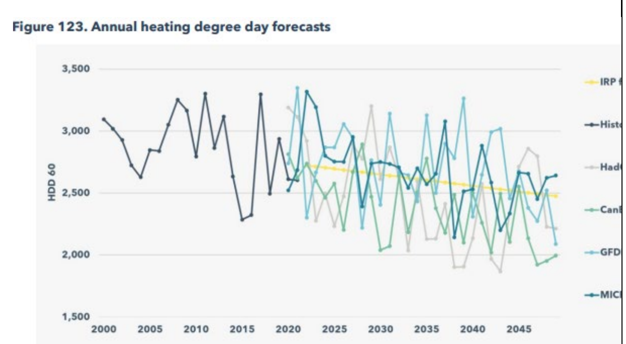


Figure 12: Annual Heating Degree Day Forecasts



Energy Forecast Models

PGE performs a top-down regression-based forecast for the residential, commercial, and industrial sectors, and then adjusts the forecast values for DERs including energy efficiency, passive DERs and EVs to calculate the final load forecast used in the IRP analysis.

PGE explains that it has tested alternative model specification for different economic and weather variables for each forecast group, as well as selection of lags using "automatic" ARIMA, in response to Staff's recommendations in LC 73.[60] Staff appreciated PGE's inclusion of the section on model development and evaluation discussion in this IRP/CEP. However, as Staff discusses below, it is not clear

[59] Docket LC 80, PGE 2023 IRP/CEP, Section D.4.
[60] Docket LC 80, PGE 2023 IRP/CEP, Section D.1.3.

which criteria PGE used and what alternative economic indicators PGE considered for the selection of lags and economic drivers in the long-term energy models for residential and commercial sectors.

The industrial model uses Total Oregon Personal Income as an economic driver. While PGE shows how it used model selection criteria to select the economic driver variable for the industrial load forecast model, it is not clear how the number of lags was selected for the final model. Also, using Oregon Personal Income as a driver for industrial growth makes little intuitive sense.

Staff suggests PGE use a two-step process by letting the regression model choose the AR and MA terms automatically first and then use manual selection and compare the two models to find the one has the smaller modeling errors. PGE may have done this already, but it is not clear in the current description of the modeling approach.

PGE does not use an out-of-sample forecast for cross validation of its forecast models. This is a departure from its 2019 IRP. Staff believes cross validation is important to evaluate model performance and PGE should work around sample size limitations and use cross validation in load forecasts in its next IRP. Staff acknowledges that PGE states it will use cross validation methods in future.

Peak Forecast Models

PGE estimates two peak load forecast models, for summer and winter each. The summer peak demand forecast model includes a variable capturing the increase in the use of air conditioners in the PNW area. The coefficient estimate for this variable is positive and statistically significant[61] and indicates that all else equal an increase in the usage of AC will increase summer load on PGE's system. Staff appreciates this analysis as it reflects an important trend in electricity demand by PGE's customers.

Staff points out that in contrast, the winter peak load forecast model does not capture similar increase in expected usage and therefore ignores potential load coming onto the system from rising use of electric heat pumps in PGE's service area. PGE expressed that it did not find a need to incorporate that at this point. However, as discussed in the IRP/CEP, PGE's service area set a record for its winter season net system peak at 4113 MW on December 20, 2022.[62] Additionally, Staff notes that increases in the number of workers who work from home will affect winter heating demand in the same way it will affect summer cooling usage. Federal incentives are also expected to increase the demand for heat pumps for both home heating and cooling. Moreover, PGE's Deep Decarbonization Study indicates that building electrification results in the system shifting from a dual summer-winter peak to distinctly winter peak.[63] Therefore, Staff believes, that PGE's winter peak load forecast model could be improved by capturing increased usage of electric heating.

Finally, PGE included a STEP0811 indicator variable, beginning in November 2008, in its winter peak forecast model. PGE explained that this variable is intended to capture a large customer load reduction PGE experienced in November 2008 and marks the inception of the Great Recession. Staff appreciates the modeling detail; however, Staff seeks clarification as to why this variable does not appear in the

[61] Docket LC 80, PGE Response to Staff IR 008, Attachment B, Load Forecast.
[62] Docket LC 80 PGE 2023 IRP/CEP, Section 6.1.2.3.
[63] Docket LC 80, PGE 2023 IRP/CEP, Deep Decarbonization Study, p.67.

summer peak forecast model equation[64] as the impacts continue through the remainder of the time used in both models.

Staff is currently reviewing PGE's updated load forecasts filed in the July 7, 2013, Addendum and will address any issues with the update in future comments.

7.2 RA assessment

PGE's RA planning standard appears to be less stringent than in prior plans, less stringent than potential future resource adequacy requirements, and less rigorous than its modeling allows.

PGE resource adequacy analysis adopts a loss of load hour (LOLH) based planning standard of 2.4 hours of lost load per winter season and 2.4 hours of lost load per summer season, or 4.8 hours per year of lost load, while prior IRPs planned to 2.4 hours per year of lost load. In contrast, Staff's understanding is that the Western Resource Adequacy Program plans to use a loss of load expectation (LOLE) based standard of one summer event and one winter event in 10 years. A one event in 10-year LOLE standard has also been discussed for use in Oregon's resource adequacy program in UM 2143. Staff understands that in the near-term, RA events are likely to be much shorter than 24 hours, and so achieving a one event in 10 years or a one winter event and one summer event in 10 years LOLE standard would likely result in much fewer than 4.8 hours per year of lost load (for example, two four-hour events in 10 years would result in a 0.8 hours per year of lost load).

Staff believes that PGE has the ability to quantify the LOLE (in events per year or events every 10 years) of the portfolios with the Sequoia model. Unlike LOLH-based standards like the 2.4 hours per year standard, LOLE-based standards require resource adequacy models that are time sequential and can therefore track (and count) multi-hour loss of load events. Sequoia is a time sequential model and therefore should be able to count distinct events (or days with loss of load events) and calculate LOLE. Staff appreciates that rules have not yet been adopted in UM 2143 and it may have been premature for PGE to plan to standards adopted in those rules within this planning cycle. However, given the broad use of the one day in 10-year LOLE standard and PGE's ability to calculate the LOLE from Sequoia, Staff believes that this information should be provided. Furthermore, it is not clear from the information provided in the IRP and PGE's responses to Data Requests whether PGE has run the Preferred Portfolio back through Sequoia after developing it in ROSE-E to confirm that it meets its RA criteria.

Recommendation 26: PGE should calculate and report the LOLH and LOLE of the Preferred Portfolio in each year and explain why it chose to plan for that level of reliability.

7.3 Consideration of Western Resource Adequacy Program

PGE's RA analysis does not consider the potential benefits of joining the Western Resource Adequacy Program.

Staff understands that PGE has committed to joining the Western Resource Adequacy Program (WRAP) and the WRAP may transition into binding operations as early as 2025.[65] The benefits of the WRAP

[64] Docket LC 80, PGE 2023 IRP/CEP, Appendix D, p.472.
[65] https://www.westernpowerpool.org/private-media/documents/2023-03-10_WRAP_Draft_Design_Document_FINAL.pdf.

program may have been difficult to estimate during the current planning cycle, but Staff expects that in future IRP/CEP, PGE will incorporate any adjustments to system reliability needs, savings opportunities for PGE customers or any other benefits that may result from PGE's continued participation in the program.

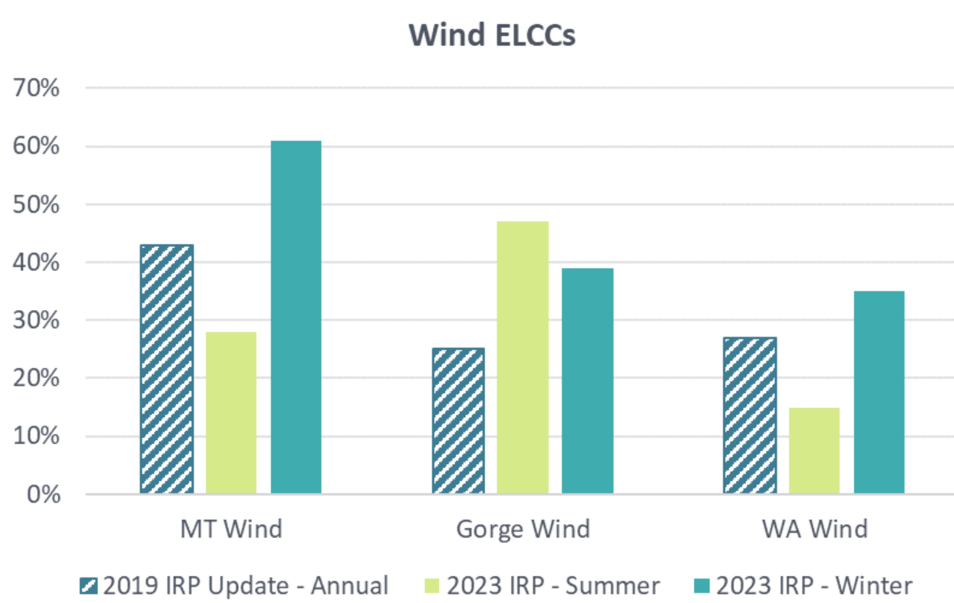
Recommendation 27: PGE should account for the benefits of the WRAP program in future IRPs if it plans to continue as a participant in the program.

7.4 PGE's resource ELCCs

Staff is concerned that PGE's analysis may be overestimating the capacity contribution of Gorge Wind in the portfolio analysis.

The Gorge Wind ELCC appears to be much larger than in the 2019 IRP Update (see Figure 2) and it is not clear to Staff why this would be the case. PGE indicates in its response to OPUC Data Request No. 71 that the wind shapes in Sequoia were developed using NREL's System Advisor Model. Staff requests that PGE explain why Gorge Wind ELCCs have increased so much since the 2019 IRP Update.

Figure 13. Wind ELCC comparison between 2019 IRP Update and 2023 IRP



Staff is also reviewing the tuned ELCCs provided in Appendix K. Staff requests that PGE provide additional discussion of why there are such large differences between the tuned ELCCs and the ELCC curves used in portfolio analysis.

Recommendation 28: In Reply Comments, PGE should explain why the Gorge Wind ELCC has increased so dramatically since the 2019 IRP Update.

Recommendation 29: In Reply Comments, PGE should explain why there are such large differences between the tuned ELCCs in Appendix K and the ELCC curves used in portfolio analysis.

7.5 Flexibility analysis

Staff is concerned about the increased potential for unserved energy to occur in Summer and seeks to understand the implications of dynamic renewable curtailment for integration costs.

The flexibility analyses performed by Blue Marble Analytics for PGE includes a system flexibility adequacy analysis, a flexibility value analysis of candidate new resources, and an integration cost analysis of new variable energy resources. A power system's "flexibility" refers to its ability to balance supply and demand over varying timeframes, under varying constraints, and under varying conditions. In this evaluation Staff is seeking to ensure that the Company's system has the flexibility required throughout the year to prevent occurrences of unserved energy, especially as the makeup of the system evolves and additional variable generation resources are added.

Blue Marble Analytics used the Grid Path power-system planning platform to perform these analyses, using average-year conditions and inputs. Overall, the methodology used in the analyses is consistent with the Company's prior IRP. Blue Marble used the Grid Path platform to create a multi-stage optimal commitment and dispatch model of PGE's system and enforce constraints such as minimum up and down-times, minimum loading levels, ramp rate limits, load following requirements, and market access limits with an objective of minimizing total system operating costs. The primary metrics that the flexibility adequacy analysis relies upon are unserved energy due to flexibility shortages (USE_{flex}) and estimated system headroom,[66] the latter indicating how close the system might be to a flexibility-related violation. Staff assessed whether Blue Marble's analyses reasonably capture PGE's estimated system flexibility needs.

System Headroom

Compared to the Company's prior IRP flexibility study, the system's estimated headroom seems to have generally improved with the system operating with roughly 500 MW or less of headroom 20 percent of the time, compared to operating with roughly 300 MW or less of headroom 20 percent of the time in the prior study. This phenomenon can also be observed in the system headroom quintiles by month figure, "Figure 4," in the Blue Marble study showing that the median monthly headroom level has increased for every month except for May and June compared to the prior study. PGE's system is expected to operate with lower levels of headroom in the months of May and June compared to the prior analysis. In particular, the prior analysis did not show system headroom falling below roughly 1,000 MW in the month of June, while the current analysis for June shows outlier events of the system operating with headroom in the sub 200 MW range. As the Blue Marble study states, estimated system headroom can be used to gauge how close the system may be to a flexibility-related violation. Based on this, it appears that the potential for an unserved energy event in the month of June has substantially risen.

Overall, the flexibility adequacy analysis showed improvements in system performance and indicates that additions of renewables and storage will improve the system's ability to flexibly ramp and further reduce occurrences of unserved energy.

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[66] "System headroom is the amount of capacity available in each time period minus the capacity used up in order to meet system requirements such as load and reserves..." Blue Marble "Flexibility Studies", p.5.

Integration Costs & Dynamic Renewable Curtailment

The Grid Path simulation of the PGE system allows curtailment of renewable resources at no additional cost, such that any cost savings associated with dynamic renewable curtailment are reflected in the integration cost estimates of new variable energy resources. The Company states in response to OPUC DR 125 that no flexibility benefit is associated with dynamic renewable curtailment. Staff will continue to evaluate the magnitude of renewable curtailment observed in the flexibility studies and seek to understand what conditions cause this action to be taken and what impact it has on integration costs of new resource options.

8 Summary of Recommendations

Recommendation 1: In Reply Comments, Staff invites PGE to respond in more detail about its long-term decarbonization strategy and provides the following questions for PGE to consider:

- Will PGE's plan be feasible without future market interactions and market participation?
- Where are there junctures at which the Company might consider material changes in strategy that go beyond procurement volumes, for example adopting operating constraints on emitting resources, adjusting transmission requirements for renewables, joining an RTO, or other alternatives?
- What information will the Company use to determine whether a change in course may be warranted? Will the Company adjust its strategy based only on the progress of procurement, or will PGE examine additional data, like actual GHG emissions, power costs, load forecasts, and load forecast uncertainties, as the Company executes its strategy?
- Under what circumstances could each of PGE's planned actions result in poor outcomes for customers?
- Did PGE consider but exclude any actions because of their potential for adverse impacts to customers under one or more future scenarios?

Recommendation 2: Conduct hourly dispatch analysis of the Preferred Portfolio under Reference Case conditions; discuss the results and provide relevant workpapers with PGE's Reply Comments. PGE should conduct this analysis in a manner that ensures load balance in each hour and that tracks hourly dispatch, variable costs, and GHG emissions by resource as well as hourly market purchases and market sales. PGE should also report annual portfolio costs and GHG emissions based on this simulation and that PGE provide transparency into how purchases and sales affect the GHG emissions associated with meeting load.

Recommendation 3: In Reply Comments, PGE should provide a table that identifies key feedback received by community and other stakeholders, the affiliation of the person providing the feedback, whether and where PGE incorporated the feedback, and why.

Recommendation 4: In Reply Comments, PGE should explain what steps it is taking for this IRP/CEP, and can take in the future, to communicate its HB 2021 compliance strategy in a manner that is accessible and meaningful to the customers and communities it serves.

Recommendation 5: In Reply Comments, PGE should provide an interim pCBI that captures the different benefits across all resource types across all portfolios. At a minimum, PGE should consider the quantity f energy efficiency and microgrid CBREs in each portfolio as an interim pCBI scoring metric until the

Company can identify more metrics for quantifying important impacts of its potential actions on communities. If the Company cannot provide this analysis, it should discuss opportunities and barriers the Company faces in meeting Staff's request.

Recommendation 6: In Reply Comments, PGE should update its portfolio scoring analysis to express the pCBI in dollar terms. If the Company is not able to provide this analysis, it should discuss the barriers that the Company faces in making this quantification.

Recommendation 7: In its Reply Comments, PGE should provide a supplemental analysis that satisfies the HB 2021 requirement to examine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy.

Recommendation 8: Staff invites PGE to describe the useful insights that is gathered from the CBRE portfolio analysis related to the level at which CBRE additions are no longer low-regrets actions or general insights into the trade-offs of including different levels of CBRE in the portfolio.

Recommendation 9: In reply comments, PGE should answer the following questions about the CBRE acquisition strategy:

- Will the CBRE acquisition pursue CBRE technologies beyond the proxy resource types included in the CBRE potential study?
- What is the Company's strategy to balance the need to control cost in CBRE acquisition with the need to optimize community benefits in its resource actions? The response should consider PGE's strategy to leverage funding resources and other partnerships, as well as, to keep the Commission aware of the key risks and decision points that are emerging in the Company's CBRE investment strategy.
- What steps can the Company take to overcome implementation risks and ensure that the time and overhead associated with the Company's CBRE procurement activities is well used?

Recommendation 10: In Reply Comments, PGE should detail it's SSR compliance strategy that includes:

- The Company's compliance position including its annual projected compliance obligation MW, projected SSR resource MW, and projected SSR shortfall MW for years 2030, 2035, and 2040 at minimum.
- The quantity of projected SSR resources that are existing QFs, other existing SSR types (with a description), projected QFs, projected other SSR types (with a description), or other resource types (with a description).
- A detailed strategy to procure the resources needed to meet any projected 2030 SSR compliance shortfalls.
- Articulation of any strategies the Company plans to deploy to control costs and drive community benefits.

Recommendation 11: In Reply Comments, PGE should provide the volume of banked RECs that it anticipates will expire if they are not used over the planning horizon and discuss how it can plan to utilize its banked RECs to benefit customers.

Recommendation 12: PGE should re-design and re-evaluate the Preferred Portfolio without assuming up to 800 MW of additional transmission to access markets and distant renewables. The availability of these options should be considered as a scenario or sensitivity, rather than a key component of the Preferred Portfolio. In making this adjustment, PGE should ensure that a large set of alternative portfolios that test varying paces of GHG reductions and varying community benefits can be directly compared to the preferred portfolio.

Recommendation 13: PGE should adopt a scoring metric for the pace of GHG reductions so that there is full transparency into the tradeoffs between cost, risk, the pace of GHG reductions, and community impacts and benefits across all its portfolio analysis. PGE should consider whether the Social Cost of GHGs for each portfolio might help to contextualize cost tradeoffs between portfolios.

Recommendation 14: If PGE seeks to consider near-term cost impacts alongside long-term cost impacts, the Company should design a scoring metric for near-term cost impacts, apply it consistently across all portfolios, and justify the use of this criterion in planning and procurement decisions.

Recommendation 15: In the future, PGE should justify portfolio analysis findings and any design principles used to develop the Preferred Portfolio based on all scoring metrics, not just those that address cost and risk.

Recommendation 16: In its Reply Comments, PGE should provide additional analysis that decreases the annual capacity cap in the modeling methodology and discuss the findings as they relate to the capacity acquisition strategy.

Recommendation 17: In its reply Comments, the Company should explain how the capacity additions in the Preferred Portfolio have informed the long-term decarbonization strategy as it relates to acquiring non-emitting capacity over time.

Recommendation 18: PGE should include 50MWa of additional energy efficiency in its preferred portfolio and qualify its Customer Resources Action items by describing its strategy to procure this additional EE within the Action Plan window.

Recommendation 19: In its Reply Comments PGE should provide an update on its collaborative efforts with ETO towards procuring additional EE resources by 2030.

Recommendation 20: In Reply Comments, PGE should help Staff understand the following questions related to its near-term transmission action items:

- Is PGE's Action 5A inclusive of a range of possible solutions to alleviate congestion? What are these solutions?
- When does PGE expects to provide the detailed cost/benefit analysis needed to determine if PGE should make a commitment to invest in transmission upgrades related to Action 5A and 5B and/or pursue alternatives? Does this include consideration for drivers of transmission upgrades that are not captured in the IRP, such as reliability?

Recommendation 21: In Reply Comments, PGE should explain the long-term transmission strategy for complying with HB 2021. In this strategy, PGE should identify the specific risks that the transmission strategy protects against and describe how the Company plans to use transmission rights to benefit customers when they are not needed for load service, with quantitative information where possible.

Recommendation 22: In Reply Comments, PGE should explain whether the RFP pacing and supply chain analysis provide any quantitative insights into its pacing options. The Company should also indicate the extent to which it plans to constrain its annual RFPs to match the annual RFP scenario energy and capacity additions.

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Recommendation 25: PGE should provide regular updates to LC 80 participants on its target procurement volume for the 2023 RFP as new information and analysis warrant.

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Dated at Salem, Oregon, this July 27, 2023.

Sudeshna Pal

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Sudeshna Pal
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Energy Resources and Planning Division