Portland General Electric Company
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November 21, 2023

Via Electronic Filing

Public Utility Commission of Oregon
Attention: Filing Center
P.O. Box 1088
Salem, OR 97308-1088

Re: LC 80 – Portland General Electric Company's 2023 Clean Energy Plan and Integrated Resource Plan
Reply to Staff Round 2 Comments and Recommendations

Dear Filing Center:

Enclosed for filing today in the above-referenced docket is Portland General Electric Company's (PGE) replies to OPUC Staff's Round 2 Comments and Recommendations on PGE's 2023 Clean Energy Plan (CEP) and Integrated Resource Plan (IRP).

In Chapter 1 of these comments, PGE has provided summary level point-by-point responses to Staff's Draft Recommendations (Section 1.1) and Expectations for Future IRP/CEPs (Section 1.2). The remainder of the document contains detailed responses and the results of new analytical work organized by topic areas. PGE continues to appreciate the detailed feedback received through the review process to date, which shaped changes to the updated preferred portfolio included in these comments.

Kristen Sheeran, PGE's Senior Director of Strategy Integration and Planning, leads PGE's CEP and IRP work. Please direct any questions or communications regarding these comments to: pge.opuc.filings@pgn.com.

Sincerely,

/s/ Riley Peck

Riley Peck
Senior Manager, Regulatory Strategy
Resource & Regulatory Strategy

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Chapter 1. Introduction

PGE offers these Reply Comments in response to OPUC Staff's Round 2 Comments in the LC 80 docket. We acknowledge the time Staff has invested in the process and appreciate the work devoted towards PGE's 2023 CEP/IRP. PGE has benefited from the discussions in the LC 80 docket and looks forward to both creating a viable path to Acknowledgement for this CEP/IRP and recognizing the expectations for future CEP/IRP cycles.

We have focused our response, in this round of comments, on each of Staff's recommendations and expectations, summarizing our response in this chapter and addressing them in more detail in later chapters. The key topic areas include transmission, energy efficiency, modeling, portfolio analysis and additional issues. PGE has incorporated the relevant recommendations and updated the contract extension assumptions based on recent bilateral market executions, and revised the Preferred Portfolio which is provided in **Section 5.3** and Action Plan which is provided in **Section 5.4**.

While there remain areas of improvement for future CEP/IRP cycles, PGE believes that the revised CEP/IRP Action Plan firmly aligns with the state's public policy goals and mitigates risks for customers while balancing affordability and emissions reduction during a highly dynamic period of change for our industry.

1.1 Summary of Responses to Draft Recommendations

In their latest comments Staff provided 10 Draft Recommendations for LC 80. Each Staff recommendation is copied below (in italics), followed by a summary of PGE's response.

> *<u>Draft Recommendation 1:</u> The Commission should acknowledge PGE's Customer Action Items subject to the following conditions:*
>
> - *PGE pursues all cost-effective EE, which means pursuing all EE identified through the IRP as providing for the best balance of cost, risk, community impacts, and pace of GHG reductions. This includes the additional 53MWa of energy efficiency that PGE identified as cost-effective in the current IRP/CEP.*
> - *PGE engages collaboratively in addressing EE implementation issues with Staff, Stakeholders, and Energy Trust of Oregon, including Energy Trust's 2024 budget, further exploration of securitization of EE, and a 2024 effort to update avoided cost methods to include the full value of HB 2021 compliance and avoided transmission.*

PGE has considered Staff's Draft Recommendation 1 and has adjusted its Action Plan to include the 53 MWa of additional EE (detailed in **Section 5.4**). PGE is actively collaborating with the ETO on their 2024 budget and utility specific action plan as per schedule and anticipates no delays or major obstacles to ETO's timelines for completion stemming from PGE. As energy efficiency expands to play a greater role in the decarbonization, PGE looks forward to investigating, with Staff and Stakeholders, strategies to mitigate near-term rate impacts, including through securitization of EE or other rate mechanisms. Issues specific to avoided cost inputs to energy efficiency are discussed below in Draft Recommendation 2.

> *Draft Recommendation 2: That the Commission not acknowledge PGE's EE avoided cost inputs and direct PGE to propose a new method for calculating avoided costs that could be used in Docket No. UM 1893. The avoided cost proposal should resolve the shortcomings identified by PGE and Staff, including but not limited to the shift from one avoided capacity value to annual values, the impact of constraints observed in the model, and the need to procure clean electricity not captured by forward prices.*

PGE is still actively considering this Draft Recommendation and does not have a response at this time. However, PGE commits to providing a comprehensive response to this Draft Recommendation ahead of Staff's Report and Final Recommendations on December 14th, 2023.

> *Draft Recommendation 3: The Commission should acknowledge PGE's CBRE Action Item subject to the condition that PGE pursue the broader range of procurement actions that it identified in comments in this docket.*

PGE agrees with this Draft Recommendation.

> *Draft Recommendation 4: The Commission should acknowledge PGE's Energy and Capacity Action Items subject to the following conditions:*
>
> - *PGE must adjust its ongoing procurement targets for both energy and capacity resources to reflect the additional energy efficiency resources Staff recommends PGE include in its Customer Action Item.*
> - *Before issuing its next utility-scale RFP, PGE will file a proposal for a Long Lead Time Resource RFI in LC 80 and facilitate a stakeholder discussion of findings from and reactions to the RFI.*

PGE agrees with both components of this Draft Recommendation. The Company has updated its Action Plan components to reflect the additional energy efficiency recommended by Staff (provided in **Section 3.1**) and will continue to update those targets going forward based on updated input information.

PGE is amenable to running a long-lead time process as described in our May 19, 2023 filing in UM 2274. This process will seek to better understand how we should prepare the grid for future non-emitting resources with a projected COD 5+ years in the future.

PGE anticipates initiating this process in the first quarter of 2024. PGE commits to issuing the RFI to market at that time. If the RFI has not yet been issued to market by the end of Q1 2024, PGE will provide an update filing in LC 80 to discuss progress and next steps. PGE will facilitate a discussion of the appropriate findings and reactions with stakeholders once available.

> *Draft Recommendation 5:* *That the Commission not acknowledge the transmission action items as presented, and direct PGE to file a transmission study that thoroughly evaluates the Company's options to alleviate South of Allston and Cross Cascades South congestion by the next IRP Update.*

PGE partially agrees with this Draft Recommendation. The Company agrees with the need to provide a comprehensive transmission study that fully evaluates transmission constraints and potential opportunities to alleviate them. PGE respectfully recommends acknowledgment that PGE will continue to evaluate options via a transmission study in advance of the next IRP update. The study should analyze transmission constraints associated with load service and potential opportunities to alleviate them. This is further discussed in **Chapter 2** below.

> *Draft Recommendation 6:* *That if PGE does not provide revisions to its emissions and transmission modeling in time for review in this docket, the Commission decline to acknowledge the Company's long- term resource strategy beyond the Action Plan. The Commission should direct the Company to make the following revisions and resubmit the revised plan before its IRP/CEP Update in 2025:*
>
> - *PGE shall present an hourly analysis of its GHG emissions associated with its retail electricity load.*
> - *PGE shall either remove the WY and NV proxy resources from consideration through 2030 or develop and justify more reasonable assumptions for the capacity contribution of these resources and any additional market access enabled by their associated transmission.*
> - *PGE shall update the Preferred Portfolio accordingly.*

PGE partially agrees to this Draft Recommendation. In these Comments, PGE presents portfolio results (in **Section 5.1**) that removed WY and NV proxy resources as well as investigated and adjusted the assumptions about market capacity. The Preferred Portfolio was adjusted accordingly in **Section 5.3.4**. The Company also provided an hourly analysis of its GHG emissions associated with retail load (in **Section 4.1).** However, as described above the Company continues to have serious concerns about the usefulness of the analysis and has accordingly elected not to adjust the Preferred Portfolio and Action Plan based on this analysis. PGE continues to be willing and eager to work with Staff and stakeholders to address the many methodological questions posed above to determine the most appropriate manner to verify the ability of the Preferred Portfolio to meet HB 2021 emission reduction requirements. Accordingly, PGE believes Staff's recommendation to decline acknowledgment of PGE's long-term resource strategy beyond the Action Plan is unwarranted.

> *Draft Recommendation 7: The Commission should direct PGE in the IRP/CEP update to conduct SSR compliance analysis considering compliance with and without contributions from net-metered customer resources. If PGE anticipates pursuing a compliance strategy that includes net metered resources, the Company must include a timeline and strategy for appropriate administrative changes.*

PGE partially agrees with this Draft Recommendation. PGE supports more robust inclusion of SSR constraints in the IRP/CEP update. However, PGE believes Staff's focus on compliance analysis, which is not required until 2029 per Order 21-464, and regulatory procedural timelines, which are outside of PGE's control, are unnecessary. To provide insight into small-scale renewable (SSR) needs and actions, PGE suggests using the CEP/IRP update to review existing and forecast SSR (incorporating projections including some or all rooftop solar) and recommend new actions or updates to acknowledged actions as necessary. SSR analysis developed for the CEP/IRP update will be improved by market insights from CBRE acquisition efforts in 2024 and updates to DER adoption forecasts that better account for the effects of federal, state and local funding sources and programs.

> *Draft Recommendation 8: The Commission should direct PGE to work collaboratively with Staff, stakeholders, peer utilities, and the CBIAGs in a dedicated working group to develop clear, actionable improvements to community and stakeholder engagement in subsequent IRP/CEPs by December 31, 2024.*

PGE agrees with this Draft Recommendation.

> *Draft Recommendation 9: The Commission should direct PGE to conclude its process to develop informational and portfolio CBIs and provide baseline metrics prior to filing its next IRP/CEP Update. If PGE cannot complete this effort by this timeline, PGE should provide a detailed status update and explanation of how it will ensure that remaining issues are resolved as soon as practicable.*

PGE agrees with this Draft Recommendation, and appreciates the flexibility provided as it works to develop these new approaches.

> *Draft Recommendation 10: The Commission direct PGE to include a report on federal incentive implementation and its key impacts on the Company's Action Plan and 2030 resource strategy with its IRP/CEP Update.*

PGE agrees with this Draft Recommendation.

1.2 Summary of Responses to Staff Expectations

In its Round 2 Comments Staff listed several expectations for future CEP and IRP filings (italicized below). Per Staff, these expectations will be "carried through to the Commission's investigation into planning and procurement policies and/or PGE's development of its next IRP/CEP." PGE would appreciate clarification from Staff that these expectations are put forward not as prescriptive guidance but as topics to revisit in future planning and scoping activities. PGE is largely supportive of these expectations, but where applicable suggests the following changes (identified in bold) with accompanying explanations, most of which are intended to preserve future flexibility to focus future analytical improvements on the most high-value topics. Unedited expectations denote PGE's full agreement.

Customer Actions

- *Include all EE identified as optimal in the Preferred Portfolio in the Action Plan, regardless of funding source,* **or an explanation as to why it was excluded**. *Ensure that other resource actions are informed by the overall target/optimal EE level.*

PGE does not believe this expectation to be appropriate without this addition. IRPs evaluate many trade-offs between resource selection, and in the next two-to-three years it is entirely plausible that the economic and regulatory landscape changes such that there is a compelling reason why the Company exclude quantities of EE deemed 'optimal' by the modeling approach employed. PGE does not believe Staff should pre-determine years in advance the choices the company can take based on its portfolio analysis.

CBRE Actions

- *Improve the precision of the CBRE potential analysis, which may include a bottom up, community-driven potential analysis that is validated with AdopDER analysis.*
- *Articulate a more comprehensive and proactive CBRE acquisition strategy that includes leveraging a wide range of existing and proposed procurement pathways, identifying funding and technical assistance opportunities that can ensure lower costs and greater benefits, and continual community, Staff, and stakeholder engagement.*
- *Quantify the costs and benefits of offsetting fossil fuel resources with CBREs with enough precision to support a meaningful discussion of the tradeoffs of CBRE and non-CBRE resource actions* **where applicable**.

PGE supports these expectations with this addition. Staff presupposes here that opportunities exist for CBREs to offset fossil fuel resources and that there are tradeoffs that exist between CBRE and non-CBRE resources. Especially for a CEP/IRP to be filed two years from now these may not be true; the addition provides flexibility to not devote scarce modeling resources unless needed.

Energy and Capacity Actions

- *If PGE issues another RFP before the Commission concludes an investigation into its planning and procurement policies, Staff expects the Company file a list of all* **relevant** *modeling inputs and assumptions that influence capacity and energy need, avoided costs, and project capacity, energy, and/or flexibility valuation. The Company should identify those inputs and assumptions it would anticipate updating prior to issuing future RFPs and those it assumes would only change as part of a new IRP filing or IRP Update.*
- *Include a proposal for the use of CBIs in scoring the next utility-scale RFP bids.*
- *Be dynamic with procurement targets and consider how market intelligence from RFPs might inform demand side resource valuation or procurement strategies for resources not participating in bidding opportunities.*

PGE supports the first expectation above with a narrower focus. The addition above is needed because the comprehensive list of modeling inputs and assumptions includes many that need not be discussed. For example, PGE's load forecast uses time-series econometrics, which relies on the assumption that model error terms are not correlated over time. There are many more that pertain specifically to time-series, and more still that apply to other modeling techniques. While technically they are all assumptions that influence estimates of system need, many of them cannot be plausibly expected to be discussed and/or changed in the development of the next CEP/IRP. Some judgement will be needed to limit the list of inputs and assumptions to practical purposes.

GHG Modeling

- *If PGE cannot adapt its modeling framework to conduct hourly dispatch analysis of the Preferred Portfolio to demonstrate that the Preferred Portfolio can achieve the Company's 2030 GHG target under DEQ accounting rules to achieve all of the requirements of Draft Recommendation 6, Staff still expects PGE to develop this capability* **at an appropriate and informative timestep** *for its next IRP/CEP.*

PGE is open to pursuing these improvements for the next IRP/CEP, subject to these proposed modifications. PGE continues to have significant concerns (listed below in **Section 4.1**) about the usefulness of using hourly analysis to attempt to answer questions about GHG accounting. This addition provides the flexibility to the Company to investigate with Staff and stakeholders the cost and benefits of different modeling solutions that could possibly achieve the same goal.

Transmission Modeling

- *Provide a comprehensive transmission study showing the options PGE has explored, including the use of on-system resources, for instance DERs and CBREs, existing and new regional and inter-regional transmission systems, and others, in determining the transmission projects that can be realistically and feasibly selected to meet 2030 emissions targets. Staff expects that a more rigorous analysis of transmission needs* **could** *use power flow models.*
- *Provide a more detailed analysis of PGE's transmission product assumptions including an analysis to reconcile its transmission assumptions with those required in WRAP that better quantifies curtailment risk.*
- *Better explain how proxy transmission capacity levels align with the Company's peak needs and overall resource strategy.*

Regarding the first bullet in this section, PGE agrees with Staff that a more comprehensive analysis of the costs and benefits of transmission options is needed and commits to sharing that work before the next IRP Update. However, at this point it is not clear that power flow models will be needed to achieve these ends. PGE suggests this edit to highlight the significant uncertainty in the best approach to model transmission constraints and the possible options to alleviate them.

Portfolio Analysis

- *Provide portfolio analysis that allows more direct comparison of tradeoffs of different resource strategies.* **Potential examples could include:** *precisely capturing the CBIs of portfolios beyond the inclusion of CBREs, allowing comparison of the CBIs of the entire portfolio of actions and allowing GHG emissions to vary across portfolios.*

PGE believes it is appropriate for Staff to expect a comprehensive examination of the relevant tradeoffs in resource options. However, with more than two years before the next CEP/IRP is filed PGE does not believe it is appropriate to set the means to which PGE should achieve those ends. The portfolio analysis presented in the 2023 CEP/IRP was significantly different than that contained in the 2019 IRP, which again was much different than the 2016 IRP. It is very plausible to believe in the next two years PGE will develop yet another different approach. While the Company can commit now to working with both Staff and Stakeholders to develop that approach, it does not believe Staff should mandate its expectations of the specific means to achieve the desired ends this far in advance.

Reliability Analysis

- *PGE must address the additional requirements in HB 2021, namely GHG emissions and community impacts, by either integrating emissions and community impacts with the cost benefit measures or by using separate* *measures for emissions and community impacts in its portfolio scoring.*

PGE believes this expectation would be more appropriately grouped into the "Portfolio Analysis" section but is otherwise supportive.

- *Evolve the RA planning standard in a manner consistent with a 1 in 10 years standard or otherwise identified in the investigation into planning and procurement policies in 2024* ***if appropriate****.*

It is not clear at this point that the benefits of modifying PGE's current methods of evaluating resource adequacy (ideally better estimates of system need) are worth the costs associated with a redevelopment. For example, hypothetically if doing so would refine PGE's estimates of capacity need by 2 MW but caused the Company to be unable to make other important adjustments in its models due to limited time and resources, it would be hard to classify it as an appropriate requirement. Additionally, as described in **Section 4.2**, it is plausible that findings from WRAP analysis will only be supplemental to the IRP (as opposed to driving different estimates of resource need); aligning methodology might not lead to better and more effective analysis. The addition above provides the company flexibility over the next two years to best determine where and how to adapt its modeling to the future regulatory environment.

- *Rerun the preferred portfolio through the Company's RA model (e.g., Sequoia) and verify if the portfolio meets RA standards.*

PGE generally completes this step with each iteration of its Preferred Portfolio and will continue to do so going forward.

- *Consider portfolio effects of similar or complementary resources in ELCC calculations of its resource portfolios in its next IRP/CEP* **where beneficial***.*

Adding extra dimensions to ELCC analysis does not necessarily lead to better analysis. Proxy resource ELCCs are generalizations, and increasing the complexity of these estimates could lead to both similar results and other questions of interest not being addressed. This addition provides the Company flexibility to determine whether and how portfolio effects and complementary resources are incorporated.

- *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. [Discussed in Round 1]*

Small-scale Renewable Energy

- *Include quantitative SSR ~~compliance~~ analysis that specifies the Company's* **need** *~~compliance position~~ and actions that it plans to take to acquire the needed resources.*

PGE requests a revision of this language to eliminate a new expectation for SSR compliance reporting. Administrative rules adopted pursuant to AR 622, adopted by OPUC following passage of HB 2021, are clear that SSR compliance reporting shall begin in 2029. Staff's draft expectation for future IRPs would duplicate that compliance reporting. PGE believes that it is appropriate to incorporate SSR targets in need determination and the near-term action plan quantitatively without inclusion of a duplicative compliance analysis.

- *~~Include cost information that support the Company's strategy to meet the SSR requirements in a manner that controls costs and drives benefits to communities.~~*

PGE does not believe this expectation is necessary, per our comment on the previous item. Though we have highlighted opportunities to align SSR deployment with community benefits provided by CBREs in our CEP/IRP, SSR resources are not inherently associated with community benefits any more than any other resource type. IRP analysis generally seeks to evaluate costs, risks, emissions and community benefits, so explicit inclusion of SSR goals as a constraint in IRP analysis will satisfy the objective of Staff's comment.

Community Engagement

- *Provide detailed documentation of community, stakeholder, and CBIAG input received in the development of the IRP/CEP and clearly explain whether and how the input was used to inform the Company's plan.*
- *Present the CEP in a manner that is accessible, clear, and transparent. There should be evidence of proactive measures taken to integrate community feedback into iterations of CEP analysis and subsequent actions. A methodical approach to demonstrating the influence of community input on the resource actions and strategies outlined in the CEP is needed to validate the evidence of environmental justice principles in the planning process.*

We are committed to continuing to develop mechanisms for community, stakeholder, and CBIAG input and providing greater transparency and clarity in communicating how that input was considered and incorporated in IRP/CEP analysis. As noted above, we fully agree with Draft Recommendation 8 to develop standards in collaboration with a working group that best achieves the aim of greater transparency and clarity in how PGE incorporates community input. PGE continues to work to produce a CEP that is accessible, clear and transparent and looks forward to continued stakeholder engagement on these important issues.

Community Benefits

- *Staff is supportive of the Company's proposal to hold a process to further develop pCBIs with the help of a third party.*
- ~~*Staff also plans to consider minimum expectations for CBI development and use in portfolio modeling in the Commission's re-examination of planning and procurement policies in 2024.*~~
- ~~*Among other things, Staff will look for PGE to:*~~
    - ~~*More precisely capture pCBIs and iCBIs with improved methods.*~~
    - ~~*Expand pCBI beyond CBREs in portfolio analysis, including recognizing the tradeoffs of varying levels of different resource types and locations. Staff would expect this to show that CBIs levels are different in portfolios with more EE for example.*~~
    - ~~*Consider the impact of thermal and hydro systems on EJ communities.*~~
    - ~~*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.*~~
    - ~~*Better inform CBIs and methods with input from stakeholders and community.*~~
    - ~~*Enhance tribal-focused CBIs.*~~
    - ~~*Use CBIs to better reflect the health impacts of EE.*~~
    - ~~*Enhance the ability of CBIs to better reflect the resiliency benefits of actions—CBRE and not CBRE.*~~

At this point, since we have not begun the process of developing CBIs with community input, we do not believe it to be appropriate for Staff to articulate specific expectations in this proceeding. We look forward to developing CBIs with input from stakeholders and communities and evolving our methods for meaningfully integrating CBIs in portfolio analysis to provide a more comprehensive view of the benefits of different resources to communities.

Federal Incentives

- *The Company should take ownership over the successful implementation of federal incentives and provide updates about the impact on its current strategy as information becomes available.*

RECs

- *Staff is committed to working with the Company to identify the appropriate REC analysis for future IRP/CEPs in the Commission's investigation into planning and procurement policies and/or development of PGE's next IRP/CEP.*
- *Staff does not plan to discuss REC disclosure, communications, and transparency policies after the Commission order in Phase 1 of UM 2273 is released.*

Chapter 2. Transmission

2.1 PGE's Response

While Staff does not undermine the need for transmission resources in general, they believe that additional analysis is needed to guide decision making around transmission. In their Draft Recommendation 5, Staff states that the Commission should not acknowledge the two transmission action items (South of Allston and Bethel to Round Butte) as presented and requested the Commission direct PGE to file a comprehensive transmission study by the next IRP update.

PGE agrees with Staff's Draft Recommendation 5 to conduct a transmission study in advance of the next IRP update. As noted by Staff, additional analysis on the South of Allston flowgate is warranted, and a clearer linkage between the Bethel to Round Butte line and PGE's preferred portfolio would help inform stakeholder review.

PGE therefore recommends that the transmission section of the IRP Action Plan be clarified:

> PGE will perform a transmission study in advance of the next IRP update analyzing the potential impacts and benefits of transfer capability along constrained transmission paths within PGE's system, in the Pacific Northwest, and the market and resource potential of importing generation from inter-regional climate zones and markets that PGE does not typically access today. The study will specifically analyze the benefits and impacts of Trojan to Harborton and Bethel to Round Butte, as potential solutions, to alleviate congestion on South of Allston and Cross Cascades.

This modified approach will make clear that PGE is not seeking acknowledgment to move forward with specific projects, but rather acknowledgment that it is prudent to study options that seek to optimize the portfolio and comply with any obligations under the OATT as mandated by the FERC.

Transmission Study Analysis to be Conducted in Advance of the Next IRP Update

As mentioned, PGE agrees to Staff's recommendation to conduct a transmission study in advance of the next IRP update to provide analysis designed to further inform stakeholder review of the impacts and benefits of transmission solutions in PGE's preferred portfolio.

The transmission study will be designed to analyze, utilizing traditional production cost, power flow, and other modeling techniques, the portfolio value of certain types of resources, geographical location of such resources, and any associated transmission that best performs in PGE's preferred portfolio to continue serving PGE customers reliably under various scenarios as the portfolio is decarbonized. A few questions the study would aim to address include:

1. *PGE Service Territory*: What transmission projects can address current constraints on the transmission system as well as what transmission projects will be required to address forecasted load growth.

2. *Pacific Northwest*: What transmission rights are available today to meet forecasted load growth and what projects would be helpful in meeting future load growth or anticipated constraints.

3. *Inter-regional*: What transmission projects could be pursued to provide access to inter-regional climate zones and markets designed to diversity PGE's generation portfolio.

As illustrated in Figure 66 of PGE's CEP/IRP, nearly all key flowgates that serve PGE load across Bonneville Power Administration's system are constrained and significantly oversubscribed out into the future (with South of Allston showing a capacity availability of negative 1,500 MW in 2030 and Cross Cascades South showing an availability capacity of negative 5,900MW).

While assessing PGE paths that could alleviate congestion is a helpful starting point, we also plan to assess whether specific projects in the Pacific Northwest could help to alleviate the flowgate congestion that could impact delivery of future resources to PGE.

Additionally, PGE received feedback through the CEP/IRP process that greater granularity is needed when assessing options for importing generation from climate zones and markets that PGE does not typically access today. To better analyze this potential in future resource plans, we will study accessing various climate zones and markets to better articulate what would be gained through investment in inter-regional transmission to Montana, Wyoming, the Desert Southwest, etc.

PGE anticipates highlighting this climate zone and market assessment within the study and including the outputs in future resource planning in support of proxy inter-regional transmission/resource pairings.

PGE's obligations under FERC's OATT

Per the terms of PGE's OATT, Attachment O, PGE has the obligation as a transmission provider to construct interconnection and network upgrades as driven by generator interconnection activities. Currently, both the Bethel to Round Butte and South of Allston (Trojan to Harborton) paths, along with other paths, have generation projects in the queue that may obligate PGE to construct the transmission facilities in the future.

The Large Generator Interconnection Procedures/Application (LGIP/LGIA) process is mandated by the FERC and is comprised of multiple steps as PGE's transmission organization supports potential interconnection generating customers through such process. The process begins with the potential generator submitting an interconnection application – which includes information on the project and projected in-service date – and entering PGE's queue. From there, PGE and the applicant engage in scoping meetings, PGE conducts technical studies (economic and power flow cost/benefit), and PGE and the applicant discuss the results of such studies and associated actions/costs to upgrade the transmission system facilities (if any). If the customer selects to proceed, PGE must tender an LGIA to the customer and the customer then can elect to execute the LGIA, and if executed PGE must construct network upgrades identified during the study process.

While it cannot be assumed that all resources in the queue will be built, any of the resources executing a large generator interconnection agreement (LGIA) will obligate PGE to construct network upgrades on a timeline that is likely to meet the generating project's in-service date and may or may not align with PGE's IRP planning cycle.

Bethel to Round Butte

PGE is experiencing significant interest from developers along the Bethel to Round Butte path and believes there is a reasonable likelihood that one or more LGIAs will be executed in the near-term necessitating upgrades in compliance with PGE's obligations under the OATT. Currently there are 16 projects in the queue seeking to interconnect along the Bethel to Round Butte path, comprising approximately 5,000 MW of generation capacity. The majority of applicants are in the "scoping meeting complete" phase, and a couple have progressed into technical studies.

In addition to the large queue, PGE believes that additional capacity between PGE's service territory and non-emitting resource rich areas east of the Cascade Mountains, and a more robust connection to the Northwest AC Intertie, will provide incremental access to markets and benefits for PGE customers. The study as identified in the proposed action item would analyze the value of the additional capacity.

Trojan to Harborton on the South of Allston Path

South of Allston is comprised of two distinct elements: generators currently in the queue along PGE's Trojan to Harborton path, and a larger examination of South of Allston as a contractual path to allow resources to be delivered to PGE from other interconnection points. As with Bethel to Round Butte, PGE proposes to study the value of a Trojan to Harborton facility upgrade specifically to accommodate the interconnection requests, and to highlight any potential customer benefit of that upgrade becoming part of PGE's preferred portfolio.

There are currently a few projects seeking to interconnect to PGE's Trojan to Harborton facilities, with an approximate capacity of 400 MW. These projects, solar and battery energy storage system (BESS) hybrid resources along with a wind generator seeking to interconnect at Trojan, are currently engaged in scoping meetings with PGE transmission. Several other BESS standalone projects requesting interconnection in the northern part of PGE's service territory that, when studied, are likely to identify additional upgrades necessary.

For the South of Allston flowgate operated by BPA, PGE does not have unilateral control over how rights are scheduled and operated. This means energy that flows across South of Allston – which is co-owned by PGE, BPA and PacifiCorp – could be at risk of curtailment absent upgrades. This impacts energy flowing to PGE from nearly any direction, hence the complexity of the constraint at South of Allston. The study will identify any potential constraints driven by contractual rights or commercial constraints at South of Allston through production cost modeling. This analysis will supplement the Trojan to Harborton analysis completed to date and provide directional guidance on whether PGE should take additional action to expand rights along the South of Allston path or in the alternative pursue other paths or solutions.

PGE notes that we will also separately be studying South of Allston congestion alleviation through joint path studies with BPA and PacifiCorp, as part of our obligations as a co-owner of the path.

Chapter 3. Energy Efficiency

3.1 Action Plan change

PGE has considered Staff's Draft Recommendation 1 and has included the following action within the Action Plan (summarized in **Section 5.4**). The associated Preferred Portfolio is detailed in **Section 5.3**.

- *Action 1C. Acquire 32 MWa of additional EE.*

PGE identified 53 MWa of additional EE by 2030 as beneficial for customers over the planning horizon. Within this Action Plan window, by 2028, PGE plans to acquire 32 MWa at lowest cost.

Furthermore, PGE supports Staff's recommendation for additional collaboration with Staff, stakeholders and Energy Trust on topics including EE budgeting and securitization options. PGE views this collaboration as essential to EE's ability to play a critical role in decarbonizing the energy sector. To accomplish this objective, PGE supports emphasis on specific areas of reform to help balance affordability and decarbonization:

1. Discussing securitization and other rate reforms to address the magnitude and timing of EE costs to customers, above traditional levels of EE investments.
2. Supporting Energy Trust to develop guiding principles in addition to the existing cost-effectiveness framework to actively consider utility rate impacts.
3. Creating an appropriate mechanism, consistent with the above guiding principles, to set targets for outside funding and requirements for regular reporting.
4. Including PGE in formalizing the divisions of labor and funding allocations established between ETO other organizations such as ODOE, DEQ, PCEF and NEEA.
5. Exploring the co-deployment of flexible load and EE programs focusing on how these programs can help customers participating in the Income Qualified Bill Discount (IQBD).

3.2 Cost-effectiveness inputs for UM 1893

PGE is actively considering Staff's Draft Recommendation 2 and will provide a comprehensive response to this Draft Recommendation ahead of Staff's Report and Final Recommendations on December 14th, 2023. Earlier in the docket, PGE provided the information for UM 1893 using the established methodologies and format requested by Staff and has supported Staff in understanding the areas of discrepancy between the established UM 1893 methods and portfolio analysis. PGE also notes that historically, IRPs have provided the input data for avoided costs associated with specific dockets and that this is new area of discussion within IRP dockets.

PGE agrees with Staff that the selection of additional EE bin 3 does indicate that a large value is attributed to EE resulting in its selection in the IRP. As previously noted, PGE expects this large value to be associated with avoiding future transmission needs and associated resources, which will require annual accounting of net costs to be consistent with the dynamics seen in portfolio analysis. From an UM1893 perspective, determining an approach to incorporate these elements and updating the established method for energy value, which currently uses energy prices, PGE believes these modifications would largely align cost-effectiveness outcomes with those of the IRP.

However, PGE highlights the following issues with Staff's analysis and does not see it as a useful reference to determine the magnitude of impact or source of avoided cost input values. First, the levelized cost of $0.097/kWh based on Figure 9 within Ext. Study-II. EE methodology only reflects the incremental cost of the technology and does not reflect the full cost to customers such as program delivery costs, which can increase the levelized costs by 30-40 percent. This also applies to levelized cost of each bin highlighted in Table 2 of Staff's Round 2 comments, where Staff employed a simple average and did not account resource specific nuances such as the type of savings (discretionary vs. lost opportunity) or the program delivery costs. PGE has provided the levelized cost of energy (LCOE) of each additional EE bin in its response to Staff DR 200-Attachment A in this proceeding. Additionally, Staff also misidentified the levelized cost of the Nevada solar and transmission resource option, which would have been $0.185/kWh in 2026. Lastly, the analysis compared the levelized cost of EE to the net cost of capacity the Nevada solar and transmission resource, which is inappropriate comparison because the levelized cost only accounts for cost elements whereas the net cost includes relevant resource benefits.

Chapter 4. Modeling

4.1 Hourly emissions modeling

PGE appreciates the attention and thought that Staff has brought to the issue of emissions reduction compliance. Adequately describing the system need and articulating what incremental generation resource additions provide are the two main functions of an IRP, and demonstrating a plan that can be plausibly thought to achieve the emission reduction targets established in HB 2021 is a core function of the CEP. In its Round 2 Comments Staff presented a response to the analysis presented in Section 4.7.1 from PGE's Reply Comments and a recommendation that PGE present an hourly analysis of GHG emissions associated with serving retail load.

PGE's comments in this section reiterate critical issues described in detail in PGE's Reply Comments that PGE is concerned have been addressed in the analysis conducted by Staff. They consider the implications of Staff's analytical recommendations, and present initial quantitative results from such an analysis despite our continued caution that these results are not useful to decision-making. PGE cautions these results should serve to highlight opportunities for further investigation and model refinement in subsequent cycles.

Additionally, while Staff's analysis provides useful direction for future modeling by highlighting critical yet unsolved questions about long-term modeling, these concerns do not warrant any change in the CEP/IRP Preferred Portfolio or Action Plan. Instead, PGE believes the Energy Action component of the Action Plan has been appropriately justified by the modeling in the CEP/IRP and that its acknowledgement represents an important step towards meeting 2030 targets.

Staff's Round 2 Comments included a draft analysis of PGE's emissions forecasts that examined PGE's assumption of equal market balancing. Essentially, PGE's Intermediary GHG model (estimated at a yearly time-step) relied on the assumption that sub-yearly differences in supply and demand would effectively balance.[1] Accordingly, the model's yearly modeling would align with the Company's capacity expansion. Staff questioned this assumption, suggesting that the emissions implications of PGE being long or short to the market were not equal across the year. If true, PGE's yearly analysis could be understating its resource need, and its Preferred Portfolio would not be demonstrating a plausible pathway for the Company to comply with HB 2021. In Section 4.7.1 of its Reply Comments PGE responded

[1] For example, a balanced yearly model (where average total generation met average yearly demand) would assume that periods of length (where generation exceeded demand) were equaled and offset by periods where the Company were short.

to this analysis by providing analysis on the resulting hourly energy position of the Preferred Portfolio. The three main takeaways from the analysis were that:

1. Results were extremely sensitive to several input assumptions that have not been thoroughly investigated;
2. It was reasonable to believe that once those significant questions were resolved, it was likely that PGE's Preferred Portfolio had in a long-term planning perspective some short hours; and
3. There is not a clear method to investigate the emissions implications of those short hours, primarily due to the significant uncertainty about market availability of non-emitting energy.

In its Round 2 Comments Staff presented analysis that largely ignored points 1 and 3 above and took the most conservative approach to #2 to suggest a wide difference between the emissions outcomes of the Preferred Portfolio and HB 2021's target. In its Draft Recommendation 6 Staff asks PGE to use the analysis presented in its Reply Comments to estimate its emissions outcomes on an hourly level.

In its Round 2 Comments Staff suggests that PGE provided three justifications for wanting to delay such an emissions analysis in its Reply Comments:

1. That an hourly timestep is not the best timestep for this analysis;
2. Differences in resource GHG emissions intensities between IRP modeling and DEQ accounting; and
3. The accuracy of the hourly load shapes.

PGE believes each to be a surprising misrepresentation of its position. The Company has never stated a desire to delay any modeling. Instead, PGE raised what it believes to be several critical issues that limit both the accuracy and precision (and thus the usefulness) of any such analysis created today. PGE highlighted the preference of hourly modeling (and not a different granularity) to be unjustified by Staff, and it noted that much more thought should be put into the trade-offs of all possible options. The differences in emission rates were mentioned in PGE's Reply Comments solely to highlight how the PZM emissions estimates (calculated in Aurora) would not line up with other emissions calculations, and why they were not used in PGE's analysis. PGE was pleased that Staff acknowledged that hourly load shapes 'warrants further attention', but notes that Staff's results did not include any caveats of caution.

Further, Staff did not address several other concerns raised in PGE's Reply Comments, nor did Staff recognize that its results could be sensitive to them. These are highlighted again below with the hope that they remain a focus as consideration of any resulting emission forecasts created from such an analysis today:

- *Allocating thermal generation:* While PGE followed Staff's direction to estimate the total thermal dispatch based on forecasts of market prices, the Company has the option of using that generation for serving retail load (and contributing to the cap of emissions established in HB 2021) or selling it to the wholesale market. Determining the quantity and timing of modeled sales has a large effect on PGE's resulting energy position.
- *Market Purchase Allocation:* There are a variety of methods to allocate the market purchases determined by the Intermediary GHG model such that the market purchases would not occur in hours in which the company was long.
- *Energy Storage Dispatch:* Storage resources are currently modeled for price arbitrage only. Changing the orientation of battery storage to the Company's energy position would likely have a large effect on the number and size of PGE's short positions. Depending on the allocation of thermal generation, market prices are found to only be slightly correlated with the Company's energy position (if at all). This suggests there are many hours in which a storage resource is either charging or idle with energy when the Company is short.
- *Hybrid Dispatch:* Not all storage resources can be operated either for arbitrage or the company's energy position.
- *Overfitting:* The extrapolation of very specific, idiosyncratic, and influential inputs leads to results that are significantly more uncertain than appropriate in directing resource acquisition decisions.
- *Choice of C-level:* Increasing this choice of C-level would reduce the thermal generation available for serving retail load.
- *Non-emitting Market Generation:* PGE's simulated market prices and the corresponding availability for non-emitting generation are extremely sensitive to the resource buildout employed.

From a conversation with Staff after their Round 2 Comments were filed, PGE understands while Staff believes each of the above to be real concerns, Staff also believes that all areas of IRP modeling have limitations; these do not constitute reasons to prevent an hourly analysis of GHG estimates in LC 80 or to modify both the Preferred Portfolio and the Action Plan based on it. PGE continues to maintain that while the Company certainly can produce this analysis, its usefulness remains low. As demonstrated below, there remains significant sensitivity of its results to different modeling choices, and the Company believes modifying resource acquisition targets at this point is premature.

However, to respond to the second bullet in Staff's Draft Recommendation #6, PGE here builds on the analysis presented in its Reply Comments to provide some estimates of the resulting GHG emissions from the resources included in the Preferred Portfolio.[2] This analysis (and most importantly its conclusions) continues to highlight the concerns

[2] PGE here uses the Preferred Portfolio presented below in **Section 5.3.4**.

articulated above. In both analyses from Staff and PGE the forecast of total 2030 emissions begins with a construction of PGE's energy position. This is done by estimating the difference between hourly demand and total expected generation.

Resources have a range of flexibility, with respect to generation, in PGE's IRP dispatch model, with wind and solar resources having fixed hourly generation profiles, hydro resources meeting monthly energy targets, and storage and thermal resources dispatching based on simulated market prices subject to operational constraints. For timing and convenience neither analysis adjusts the behavior of storage resources, which as mentioned above the Company does believe is appropriate.[3]

There are important differences between previous analyses and this in the allocation of both thermal generation and unspecified market purchases. Staff's analysis starts with the constrained total generation of PGE's thermal resources, then in hours of length it removes that 'excess' generation (as its associated emissions).[4] The analysis PGE presented in its Reply Comments started in the same place but 'moved' that excess generation to hours of deficit.[5] PGE believes a better approach would be to run the PZM optimization in Aurora with no GHG constraints on thermal generation. From the total unconstrained thermal economic dispatch, a subset of thermal generation is removed to align with the quantity of thermal generation identified in the IGHG model. The first step in doing this is to apply basic assumptions to depict how PGE would model export of excess thermal generation:

1. *Remove short positions during negatively priced hours*: all emitting generation in those hours is sold and replaced by non-emitting generation. PGE is assumed adequate.
2. *Maximize use of thermal generation for retail load in hours where PGE's non-emitting resources are short*: all thermal generation beyond which is needed to be balanced in that hour is sold.

Using these steps creates a new energy position, where the total unconstrained gas output is ~8.9 million MWh while the total (HB 2021) constrained gas output is ~2.6 million MWh. After removing the total thermal deemed 'excess' in the two steps above (~4.4 million MWh), a remaining ~1.9 million MWh needs to be sold for this analysis to align with the IGHG model.[6] While there are many methods to do this, below PGE presents two:

[3] Currently, there are hours in which PGE is short but storage resources are charging (exacerbating the deficit) and vice versa.

[4] It then adds unspecified energy (and its associated emissions) to address all deficits.

[5] This approach effectively ignored thermal operational constraints, which was noted in footnote #123 of PGE's Reply Comments.

[6] Staff's analysis utilized two approaches to account for emissions of thermal generation that is sold to the market. All of PGE's analysis in the CEP/IRP and LC 80 (including this) has relied on one (sales of specified power).

1. **Price-Sorting**: To focus on the concern about the availability of non-emitting generation, PGE could prioritize highest priced hours to retain thermal generation. This addresses the concerns raised by Staff about the timing of market purchases occurring during hours that non-emitting generation is scarce. To the extent that it is more difficult to procure non-emitting generation during high priced hours, this method would simulate market purchasing behavior and thermal generation to reflect that scarcity. After ordering the short positions according to market prices, thermal generation can be removed up to the quantity in the IGHG model. From there PGE could look to the market to purchase generation (both with and without associated carbon content) and/or resource additions (incremental to the Action Plan) to address hours in which the Company were short.[7]
2. **Deficit-Sorting**: PGE instead could prioritize the depth of its hourly energy position. The assumption would be that there is always some non-emitting generation available across the WECC, but PGE may be constrained by the size of its hourly need. By ordering hours by the size of the deficit and addressing the biggest problems first, the Company could have more success meeting demand for the remaining hours.

Once the proper method of thermal reduction is determined, a choice of allocation market purchases must be made. Like thermal generation, PGE believes this analysis should align with the assumptions in the IGHG model, which currently estimates that ~1.47 million MWh of unspecified energy is purchased to serve retail load in 2030. The same two options of allocation (Deficit- and Price-Sorting) are applied, however there are many other approaches that could be modeled. PGE uses these options to create two scenarios to examine the resulting carbon implications below.

Under the assumption of a liquid non-emitting energy market with sufficient depth, there would be no change in emission forecasts in either scenario.[8,9] On the other extreme, if as Staff assumes there is no market for non-emitting generation and instead all hours of deficit are only able to be met with additional purchases of unspecified energy, the Company's emissions would increase beyond the 1.62 MMTCO2 identified in the IGHG model and applied in all other IRP analysis.

Such a result would not be compliant with HB 2021. As noted above, PGE highlighted both the sensitivity of any resulting emission forecasts to this assumption as well as the lack of evidence for it. In their Round 2 Comments, Staff did not provide any evidence supporting

[7] The market price at which this inflection point occurs is $39, which represents the 68th percentile of all market prices (meaning thermal generation is only retained for the third highest-priced hours of the year.)
[8] In this scenario, the only remaining question would be the cost implications of those market purchases relative to the market sales of PGE's excess generation.
[9] With the assumption that sub-hourly differences perfectly balance.

their continued use of this assumption.[10] Indeed, PGE does not believe such evidence exists: there is tremendous uncertainty about the composition of the market going forward. One common argument is that renewable mandates and economic forces will lead to a substantial decarbonization in generation supply, and that the Company will have much greater access to non-emitting generation. On the other hand, many highlight that policy requirements will sharply increase the demand for that non-emitting generation, such that far less carbon-free energy is available. While supply is relatively straightforward to model, understanding the size, quantity, and location of the demand for non-emitting generation is incredibly difficult, and PGE continues to look for a credible and appropriate way to address this uncertainty in its modeling.[11]

To respond to Staff's Draft Recommendation 6, PGE uses Staff's assumption of no availability of non-emitting generation on the market at any non-negatively priced hour when PGE's preferred portfolio is short to create a forecast of 2.51 MMTCO2e.

Following the assumption of no non-emitting market energy available, to return to HB 2021 compliance PGE would need to increase its planned resource procurement targets in order to reduce the frequency and extent of short hours. Currently PGE's modeling is unable to demonstrate the least-cost least-risk size, type, and timing resource additions to address these hours of deficit. While some insight can be gleaned through the formula-based analysis presented below, PGE hopes the issue of model overfitting mentioned above demonstrate that such insight is insufficient to adjust its current Preferred Portfolio, Action Plan, and resulting RFP acquisition targets.

When establishing the hourly energy position using the Deficit-Sorting Method, the Company could not likely be able to rely only on adding solar to address the shortfalls: there are 1,486 hours where there is no generation by any of the proxy solar resources. Note that the number of hours of no generation by proxy solar resources decreases to 1,275 hours when the Price-Sorting Method is employed. While there are no hours that PGE is short without generation from some proxy wind resource, their disparate generation profiles lead to a very small ratio of additional proxy resource MW added to hours of deficit alleviated. If PGE were to build enough wind capacity to cover every hourly deficit as modeled, the capacity requirements would be extreme. Using the hourly maximum of all regional wind capacity utilization rates requires an additional ~43 or 101 GW of wind nameplate capacity

[10] In a conversation with PGE Staff did mention that the resulting hourly energy position heatmap presented in Figure 7 of its Reply Comments conformed with other regional decarbonization studies. PGE finds this argument unconvincing: as described in both its Reply Comments and this document, making different modeling choices described can significantly alter the size, depth, and timing of hours of deficit.

[11] Staff did mention that such a market could bring a cost-premium which should equate to the cost of adding new non-emitting generation. PGE agrees it could, though again this will depend on yet poorly understood supply and demand dynamics.

using Deficit- and Pricing-Sorting Methods, respectively. These unrealistic results highlight the overfitting problem described above as both the renewable generation profiles and the Company's energy position are fixed in each hour. However, it is useful to take away from these results that variable energy resources will not likely address energy generation deficits by themselves.

This conclusion is also true of storage resources and energy efficiency. Starting with the same energy position, a 5,000 MW addition of four-hour batteries will result in over 20 percent of hours in 2030 that are short using the two methods.[12] Increasing both the duration and the starting charge of the storage lead to reductions in the number of those hours, but similar to renewables, there is no practical nameplate MW addition that completely (or even closely) reduces all of PGE's short hours. Adding a flat 300 MWa of additional energy efficiency (beyond both the cost-effective quantities and additional 53 MWa added in the Action Plan) still leaves over 9.1 and 6.2 percent of hours of deficit using the Deficit-Sorting and Price-Sorting Methods, respectively.

The combination of renewables, storage, and energy efficiency significantly reduces the total MWs required to address all hours of deficit; however, it still identifies substantial incremental resource need. After adding 500 MW each of wind, solar, and four-hour storage and 50 MWa of EE, there remain 2.8 percent of hours in the Deficit-Sorting Model and over 2.8 percent of hours in the Price-Sorting Model in which PGE would be required to purchase generation from the market. In each case, assuming the company must use unspecified market purchases to cover short positions, the Company's forecasted emissions will exceed the 1.62 MMTCO2 requirement. As modeled, the size of the required resources above all resources currently represented in the Preferred Portfolio would dramatically increase costs and procurement risk, among many others.

PGE has pointed out that the Preferred Portfolio produces short hours when PGE will be reliant on market purchases. These results are extremely sensitive to several input assumptions that have not been thoroughly investigated. There is not a clear method to investigate the emissions implications of those short hours and PGE has pointed out several concerns that highlight the challenges in the input assumptions.

Key to Staff's concerns is the assumption that markets for non-emitting generation will not be available in any non-negatively priced hour when PGE is short. PGE believes that there is insufficient evidence for this conclusion. Modeling the size, quantity, and location of the demand for non-emitting generation is incredibly difficult. Despite these challenges, PGE is committed to look for a credible and appropriate way to address this uncertainty in its modeling.

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[12] Storage modeling ignores all losses and excludes all possibilities of charging from or discharging to the market.

In this analysis, PGE provides estimates of the resulting energy profile and emissions from the resources included in the Preferred Portfolio to highlight the sensitivity of the model results. PGE considers various procurement scenarios to determine how it might reduce its dependence on non-emitting market purchases. The results suggest that to reduce the dependence on market transactions, PGE would face dramatically higher costs and procurement risk.

While PGE continues to maintain that while the Company can produce the hourly analysis that Staff has recommended, its usefulness remains low. As demonstrated below, there remains significant sensitivity of its results to different modeling choices, and the Company believes modifying resource acquisition targets at this point is premature.

4.2 Resource adequacy

PGE appreciates Staff's recognition of PGE's involvement in the evolving conversation surrounding RA metrics and reliability analysis, as well as the work PGE has done so far. In Staff's Round 2 Comments, Staff notes an inability of the current Preferred Portfolio to meet a 1 day in 10 years LOLE standard in the near term, expressing concern that PGE will be unable to meet the requirements of Oregon's RA program.[13] Further, Staff recommends PGE develop its RA planning standard to align with this LOLE standard or other standard identified via continued investigation in 2024 for the next IRP/CEP.[14]

At this time, PGE is unable to fully quantify the benefits of modifying the current RA standard deployed in the Company's resource adequacy modeling. The Company would hope that changes in methodology lead to improved estimates of system need but that is not guaranteed. Due to this uncertainty, it is unclear to PGE if the costs associated with the redevelopment needed to change the applied RA standard justify the perceived benefits.

PGE points to a recent GridLab report on the WRAP that highlights "[p]lanners and policymakers should view WRAP and utility reliability modeling as parallel initiatives, each informing but not displacing the need for the other."[15] WRAP modeling is short term compared to the mid- and long-term analysis included in IRP modeling. This prevents the inclusion of WRAP inputs past the time horizon and total replacement of IRP modeling with that used for the WRAP, further highlighting the supplemental role that WRAP analysis will have in utility modeling.[16] The WRAP is continuing to evolve and will require additional support in order to allow utilities to fully utilize reliability insights beyond the near-term

[13] Staff Round 2 Comments at 26
[14] Staff Round 2 Comments at 27
[15] GridLab, 2023, The Western Resource Adequacy Program: Considerations for Planners and Policymakers, www.gridlab.org/ publications, p. 4
[16] *Ibid.*

planning horizon.[17] Given the current parallel nature of the WRAP analysis and its evolving role in IRP planning, PGE believes that fully aligning methodologies might not lead to improved or more effective analysis.

As the conversation continues to evolve, PGE will continue to assess the costs and benefits of changing the current RA standard and pursue actions that are deemed the most appropriate given the future regulatory environment.

4.3 ELCC Methodology

Staff explains that, although PGE is shown to have adequate portfolios given the chosen reliability metric, they agree with AWEC's previous concerns that current ELCC curves of similar resources could overestimate capacity contribution and propose that they might possibly be underestimating the benefits of combining complementary resources as well.[18] Staff states the expectation that "PGE should also consider portfolio effects of similar or complementary resource in ELCC calculations of its resource portfolios in its next IRP/CEP."[19]

As stated in PGE's Round 1 Comments, the Company agrees that the portfolio effect can impact estimates of resource ELCCs.[20] However, adding additional dimensions to ELCC calculations will not necessarily lead to improved analysis overall. PGE is particularly concerned that expanding analysis around the portfolio effect (and others) will increase the time needed for analysis and likely result in the need to compromise and reduce work in other areas, such as number of resources being tested or number of resource levels being tested.[21] Additionally, some aspects of expanding this analysis may not be feasible, as discussed in PGE Round 1 Comments.[22] The ELCCs for proxy resources are intended to be generalizations and it is possible that increasing the complexity surrounding their calculation would lead to similar results while causing other areas of improvement to be left unaddressed. In the past, PGE has taken the Preferred Portfolio resources and ran them through the adequacy model to assess system adequacy and determine if the portfolio effect is skewing ELCC values.[23] PGE sees this as the best option to analyze the portfolio effect at this time but is open to evaluating other approaches with Staff and stakeholders before the next IRP and applying updated methodology where it is deemed to be beneficial.

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[17] *Ibid.*
[18] Staff Round 2 Comments at 26
[19] Staff Round 2 Comments at 27
[20] PGE Round 1 Comments at 36
[21] PGE Round 1 Comments at 36
[22] PGE Round 1 Comments at 36
[23] PGE Round 1 Comments at 36

4.4 WRAP Transmission

In Staff's Round 2 Comments, Staff puts forth a future expectation that PGE will "[p]rovide a more detailed analysis of PGE's transmission product assumptions including an analysis to reconcile its transmission assumptions with those required in WRAP."[24] Staff highlights uncertainty surrounding which WRAP obligation, "the day of operations" need or forward showing obligation, should be applied when estimating transmission requirements over a long time period.[25] Staff goes on to suggest that PGE needs to refine its analysis of transmission assumptions using power flow models.[26]

PGE recognizes Staff's comment and appreciates the acknowledgement of the uncertainty that currently exists when estimating transmission needs to meet WRAP obligations. At this time, PGE believes it appropriate to assume an amount of long-term transmission rights equal to 100 percent of energy delivered to load on firm transmission, as required by "the day of operations" need WRAP obligation. There is a high level of uncertainty surrounding the ability to acquire additional firm transmission in the short-term market as there is limited to no firm ATC and an inability to redirect existing long-term rights on a firm basis. Based on this, if PGE were to base its transmission need estimates on the WRAP forward showing obligations (requiring reservations of at least 75 percent of needed transmission) PGE would ultimately be unable to meet the 100 percent firm transmission requirement for "the day of operations" given the lack of short-term firm ATC to fill the difference. Therefore, to avoid this shortfall, PGE sees it appropriate to estimate transmission requirements need based on the 100 percent 'day of operations' need obligation.

Additionally, PGE does not see adding power flow models to analysis of transmission assumptions as feasible. Due to the recent addition of the North of Pearl flow gate, there is no available historic information on the flowgate and the associated flows, leaving a gap in data needed to fully understand the current transmission environment and create reflective flow models. Moreover, PGE does not have visibility into all e-tags that have an impact on this new flowgate, further limiting the ability to accurately represent flows on the system.[27] Combined with limited internal information and resources, PGE sees these issues as roadblocks in employing power flow modeling in analysis of these transmission assumptions, making it infeasible to include at this time.

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[24] Staff Round 2 Comments at 23
[25] Staff Round 2 Comments at 21
[26] Staff Round 2 Comments at 22
[27] An e-tag, also referred to as a NERC tag represents a transaction on the North American bulk electricity market scheduled to flow within, between, or across electric utility company territory.

Chapter 5. Portfolio Analysis

5.1 Transmission proxy resources

Staff expresses a lack of confidence in portfolio modeling results starting in the late 2020's because of PGE's approach to modeling GHG emissions (addressed in **Section 4.1** of these comments) and proxy transmission resources.[28] With regards to the proxy transmission resources, Staff believes that the capacity contribution assumption associated with the resources is overly optimistic. Staff notes that the Preferred Portfolio is long on capacity beginning in 2029.[29] Staff notes that it does not find PGE's assumptions regarding the capacity provided by proxy NV and WY transmission to be reasonable and therefore does not consider the RA metrics reported by PGE to meaningfully reflect the Company's expected RA position in 2030.[30] Staff recommends that PGE either remove the WY and NV proxy resources from consideration through 2030 or develop and justify alternative assumptions for the capacity contribution of the resources and update the Preferred Portfolio accordingly.[31]

In response to Staff DR 208, PGE explained that in addition to the NV solar and WY wind resources, transmission expansion proxies are assumed to provide access to markets that can provide additional capacity. Market access was assumed to allow the proxy transmission resources to provide perfect capacity (100 percent ELCC). Due to the limited access to energy resources created by transmission constraints, the model has limited options to choose from to meet 2030 energy requirements. As a result, the addition of WY wind and NV solar to the Preferred Portfolio to meet energy needs adds more capacity than is needed to meet PGE's RA requirements. PGE agrees that the market access assumption is creating an inappropriate over-crediting of capacity to the transmission expansion resources and in response to Staff's concern, PGE has redesigned the transmission proxy resources as described below and re-run the Preferred Portfolio using the updated assumptions.

To address this issue, PGE has removed the market access assumption entirely from the WY and NV transmission expansion proxy resources. The WY and NV transmission resources now provide only the capacity and energy benefits associated with the specific renewable resources accessed with the transmission. The costs of the resources account for the costs of the transmission access and the cost of the renewable resources, while the cost of market access (represented by the cost of a 6-hr battery) has been removed. PGE has incorporated these updated assumptions into the new Preferred Portfolio, which incorporates this and

[28] Staff Round 2 Comments at 4
[29] Staff Round 2 Comments at 26
[30] Staff Round 2 Comments at 26
[31] Staff Round 2 Comments at 16

other updates. Results for the new Preferred Portfolio are presented in **Section 5.3.4**. These results include updated resource adequacy metrics from modeling of the new Preferred Portfolio in Sequoia.

This is a conservative assumption and represents the low-side bookend compared to the high-side bookend that the perfect capacity assumption represented. PGE considers this conservative assumption the most appropriate measure to address the issue in the current CEP/IRP cycle given there was insufficient time to conduct a study that would produce informative estimates in the time since the issue was raised by Staff. PGE posits that the ability of transmission expansion to allow access to diversified markets will provide capacity benefits to PGE that lie somewhere between the perfect capacity assumption and the new zero market access assumption. There is lower correlation with PGE's peak loads and prices in the locations accessed by transmission expansion compared to locations within the PNW. This supports the idea that transmission expansion will provide the opportunity to access additional capacity contracts.

PGE will continue to explore this topic with the goal of being able to refine our modeling approach by informing more specific assumptions regarding market access through transmission expansion in the next IRP. While this update will improve the precision with which portfolio capacity additions match RA metrics, it is still reasonable to suspect that in future portfolio modeling the company might end up capacity or energy long in some instances. This is because, even with further refinement of assumptions, in portfolio modeling that relies on resources that supply a mix of energy and capacity it may not be possible to select a combination of resources that supplies exactly the amount of needed energy and capacity without exceeding needs for one or the other.

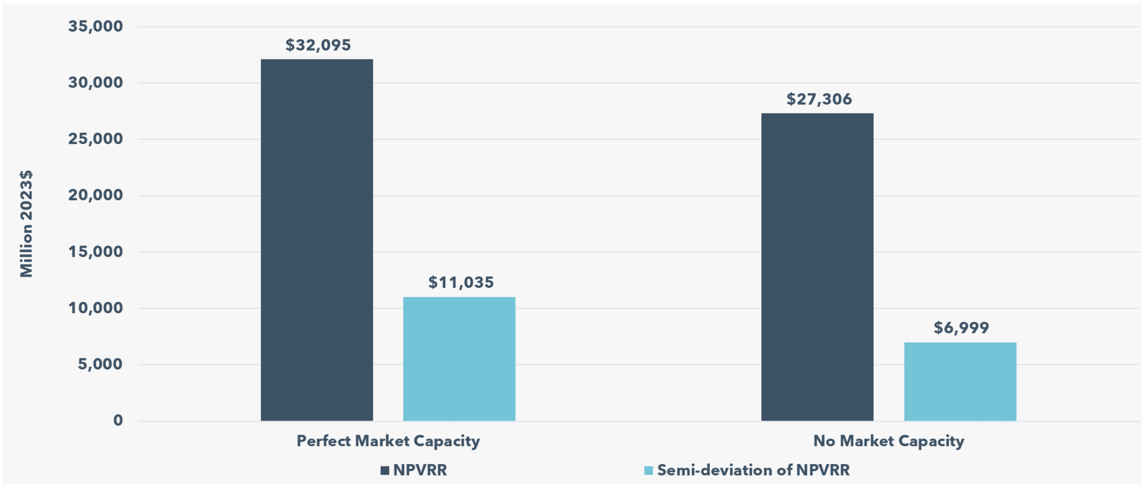
To show the effect of the change in the transmission market capacity access assumption in isolation, PGE modeled the Preferred Portfolio with only the transmission capacity contribution changed and has included the results for informational purposes ('No Market Capacity'). The resource buildout through 2030 of the 'No Market Capacity' portfolio is shown in **Table 1**. Compared to the previous Preferred Portfolio (as described in Section 6.2.4 of PGE's Round 1 Reply Comments), in 2030 the portfolio contains 75 MW more generic VER, 241 MW more storage, and 99 MW less transmission expansion. The increase in storage additions in 2030 suggest that while the model was long on capacity under the previous market access capacity assumptions, when the transmission expansion options provide no market capacity, additional capacity must be added to meet needs.

Figure 1 shows the cost and risk metrics of the 'No Market Capacity' portfolio compared to results under the prior assumptions. Perhaps counterintuitively, removing the market access perfect capacity results in a lower-cost portfolio, reducing NPVRR from $32.1 billion to $27.3 billion. Caution should be taken in the interpretation of these results. While this outcome may initially seem counterintuitive because more resources are now needed to meet capacity needs, the result can be explained by the fact that the cost of both the transmission expansion resources and the generic resources has decreased. The cost of the generic resources is defined as 105 percent of the cost of the NV solar and transmission resource, so a change in the cost of it flows through to the cost of the generics. The decrease in NPVRR associated with the updated assumptions should therefore be viewed as a change driven by modeling constructs, rather than an indication that access to market capacity is not a valuable potential resource in the portfolio.

Table 1. Cumulative buildout of the 'No Market Capacity' portfolio

	2024	2025	2026	2027	2028	2029	2030
Wind	0	0	690	1090	1504	1528	1528
Solar	0	0	0	0	0	155	227
Hybrid	0	0	299	299	299	1010	1010
Battery Storage	0	0	0	0	0	0	241
Pumped Hydro Storage	0	0	0	0	0	0	0
Offshore Wind	0	0	0	0	0	0	0
CBREs	0	0	66	85	110	133	155
WY Tx	0	0	0	0	376	400	400
NV Tx	0	0	0	0	0	155	227
Generic VER	0	0	0	0	0	0	406
SoA Tx	0	0	0	400	400	400	400
Additional EE (MWa)	0	0	0	0	0	0	0
Non-GHG-Emitting Contract Extension	0	0	200	200	200	200	200
Cost-effective EE (MWa)*	30	60	90	120	150	183	216
Cost-effective DR*	133	162	183	199	211	218	228

Figure 1. Cost and risk effects of removing transmission market capacity assumption[32]



5.2 Contract Extension Proxy Resource

In response to recent bi-lateral negotiations, executions, and expectations, PGE has updated prior assumptions on contract extensions as detailed in **Table 2**.[33] The new contract extension values include changes to 2024 and 2025 are based on bi-lateral executions while from 2026 through 2030 PGE has adopted planning assumptions.

Table 2. Change in contract extension assumptions in the Preferred Portfolio

	Prior Assumptions			New assumptions		
	Summer Capacity (MW)	Winter Capacity (MW)	Energy (MWa)	Summer Capacity (MW)	Winter Capacity (MW)	Energy (MWa)
2024	0	0	0	600	500	323
2025	0	0	0	500	500	323

[32] Because this comparison is provided to isolate the impacts of the change in the transmission market access capacity assumption relative to the prior Preferred Portfolio presented in PGE's Round 1 Reply Comments, the portfolios shown in this figure do not include updated capacity and energy need numbers reflected in the new Preferred Portfolio.
[33] PGE is open to providing additional information under confidentiality, as needed. Additionally, publicly available information related to PGE's agreement with Grant PUD regarding the Priest Rapids project is available here: 653167e5bfea5-2023-10-24-commission-meeting-packet.pdf (grantpud.org)

	Prior Assumptions			New assumptions		
	Summer Capacity (MW)	Winter Capacity (MW)	Energy (MWa)	Summer Capacity (MW)	Winter Capacity (MW)	Energy (MWa)
2026	200	200	90	500	500	323
2027	200	200	90	500	500	323
2028	200	200	90	500	500	323
2029	200	200	90	500	500	323
2030	200	200	90	500	500	323

5.3 Preferred Portfolio

5.3.1 Energy Efficiency

A discussed in **Chapter 3**, PGE has considered Staff' Draft Recommendation 1 to include additional EE in the Preferred Portfolio and has updated the portfolio accordingly by adding the 53 MWa identified through portfolio analysis as the optimal amount from a NPVRR-minimization perspective. The new Preferred Portfolio, which contains 53 MWa of additional EE by 2030 and other updated assumptions is presented in **Section 5.3.4**. To demonstrate the impact of the additional EE in isolation, PGE also ran an informational portfolio '53 MWa Additional EE' that adds 53 MWa of EE to the Preferred Portfolio from Round 1 Comments without any other assumption changes. Results show that adding 53 MWa of additional EE to the Preferred Portfolio in isolation lowers NPVRR by approximately $532 million.

Despite agreeing with Staff's Draft Recommendation 1 to add 53 MWa of EE to the Preferred Portfolio, PGE believes that Staff's statement implying that quantity of EE has been identified as providing the best balance of cost, risk, community impacts, and pace of GHG reductions is overly broad. While it is true that 53 MWa of energy efficiency was identified through portfolio analysis as the optimal quantity from a cost and risk perspective, there is no finding from portfolio analysis to support the statement that it is optimal from a pace of GHG reductions perspective. PGE identified the linear GHG-reduction glidepath as the optimal path from amongst the five paths studied in the decarbonization pathway portfolio group. This finding was made independently from the study of EE quantity and all alternative levels of EE studied were compared using the common assumption of the linear GHG-reduction glidepath. Therefore, adding the 53 MWa of additional EE to the Preferred Portfolio does not change PGE's rate of decarbonization, which is determined by the choice to use the linear GHG-glidepath.

Further, PGE believes that Staff's characterization of PGE's initial decision to not include additional EE in the Preferred Portfolio as a decision to "reject a high performing portfolio on the basis of near-term cost impacts"[34] mischaracterizes the Company's approach to portfolio analysis. As described in **Section 5.3.2**, portfolios were analyzed to gain insight into key decision points about how to construct the Preferred Portfolio. Portfolios within the groups studied were not accepted or rejected as the Preferred Portfolio, but instead were used to inform the decisions made in construction of the Preferred Portfolio. In addition to long-term cost and risk metrics the EE portfolios were compared based on near-term cost impacts because of the unique financing characteristics of EE resources. The findings that the additional EE increased near-term cost impacts informed PGE's initial decision to exclude the 53 MWa of EE from previous versions of the Preferred Portfolio. As noted in **Chapter 3**, PGE supports adding the 53 MWa of additional EE to the Preferred Portfolio and working toward solutions that will alleviate concerns about the near-term cost impacts of EE going forward.

5.3.2 Comparability of the Preferred Portfolio

Staff raises concerns that PGE's approach of isolating groups of portfolios in categories with different sets of assumptions prevents a direct comparison of portfolio risks and costs (a topic that Staff raised in Round 1 comments as well).[35] Staff characterizes this approach as an inconsistent treatment of portfolios that results in the non-comparability of PGE's Preferred Portfolio with alternatives. Further, Staff emphasizes that to evaluate whether the Preferred Portfolio is the best balance of cost, risk, emissions, and community impacts, Staff needs to be able to compare it with alternative portfolios. Staff notes that while this is not an IRP requirement, IRP Guidelines are predicated on the expectation that all resources be evaluated on a consistent and comparable basis. Specifically, Staff highlights the availability of transmission expansion resources in the Preferred Portfolio as a key factor putting it "in another universe" relative to other portfolios because the resources are not available in other portfolios.[36]

PGE is committed to working with Staff and stakeholders to refine and improve the Company's approach to portfolio modeling in future CEP/IRPs. Nevertheless, PGE continues to defend the methodological choice to use portfolio groups to isolate the effects of key resource decisions on portfolio outcomes and utilize the resulting insights to inform the

[34] Staff Round 2 Comments at 23
[35] Staff Round 2 Comments at 23
[36] Staff Round 2 Comments at 24

design of the Preferred Portfolio. PGE disagrees with Staff's position that the ability to evaluate the Preferred Portfolio is dependent on it being directly comparable to all other portfolios analyzed. As PGE described in our Response to Round 1 Comments, the Company's approach to portfolio analysis relies on the design of groups of portfolios constructed to be comparable to other portfolios within the group.[37] This approach allows resources to be compared on a consistent and comparable basis within their groups by holding assumptions that are not being tested constant within the group. This approach allows impacts of key resource decisions to be isolated and provides insights that inform the construction of the Preferred Portfolio.

As PGE noted in Round 1 Reply Comments, the number of possible combinations of portfolios analyzed in the CEP/IRP is infeasibly large to consider comparison of all combinations. Portfolio analysis in the CEP/IRP consisted of seven EE, eleven transmission, five CBRE, five decarbonization, four optimized, two targeted-policy, and six emerging technology portfolios. This would create and infeasibly large 92,400 combinations of portfolios and judgment is needed to determine which set of portfolio choices are appropriate to compare. This issue was not addressed in Staff's Round 2 Comments.

While PGE maintains that it is infeasible and unnecessary for the Preferred Portfolio to be directly comparable to every other portfolio, Staff's assertion that the transmission expansion proxies were made available only in the Preferred Portfolio is untrue. First, as staff notes, PGE responded to their request to run the Preferred Portfolio without transmission expansion options in Round 1 Comments by providing the requested analysis. Additionally, PGE also modeled multiple portfolios in the transmission group of the CEP/IRP analysis that make transmission expansion available ('WY in 2026', 'NV in 2026', 'WY in 2028', and 'NV in 2028')[38]. While the purpose of this in PGE's modeling approach was to compare the impact of availability of transmission expansion relative to other portfolios in the group, it also means that the Preferred Portfolio is not in a "different universe" from these portfolios in this regard as Staff suggests.

5.3.3 Generic resources

Staff expresses concern that the use of generic VER and capacity resources in PGE's Preferred Portfolio prevents visibility into the type of technologies needed to reach 2030 and 2040 emissions reduction goals, the costs associated with the technologies, and the risks of technologies not materializing.[39]

[37] Section 6.3 Preferred Portfolio. Available at: https://edocs.puc.state.or.us/efdocs/HAC/lc80hac131341.pdf
[38] PGE has re-run these portfolios with updated assumptions so they can be compared to the new Preferred Portfolio and will provide the results upon request.
[39] Staff Round 2 Comments at 23

PGE agrees that it would be ideal to have more clarity on the mix of resources that will be available to achieve emissions reduction targets in 2030 and beyond and is committed to continue to refine our approach to portfolio modeling generally, and specifically to continue to improve our abilities to model emerging resources. PGE explored the potential roles of a wide range of emerging technologies in meeting PGE's resource needs in the CEP/IRP and aims to improve the level of information available through plans to issue an RFI for long lead time resources. Additionally, PGE has increased the specificity of the resources in the Preferred Portfolio since the filed CEP/IRP through the inclusion of pumped storage hydro and offshore wind.

However, the availability of information about emerging resources is imperfect and PGE stands by its approach of using generics and the choice to not include technologies with high degrees of uncertainty associated with development timelines, performance characteristics, and costs in the Preferred Portfolio. There is uncertainty associated with the modeling of all resources in the IRP, which relies on proxy resources with generalized characteristics to represent the types of resources that PGE expects to become available for acquisition in the future. Because the amount of uncertainty increases as more distant outcomes are contemplated, it is appropriate that the characteristics of the proxy resources become more generalized to capture this increased uncertainty. Without better information about these resources, including them in the Preferred Portfolio may be more specific than using generics, but it is not necessarily more informative or actionable. The generic resources represent placeholders for the range of technologies that will emerge to fill the need and does not signal a lack of interest in any specific resources that may become available. Instead, it represents a willingness to acknowledge uncertainty and an openness to considering a wide variety of resources as better information becomes available.

5.3.4 Updated Preferred Portfolio

In this section, PGE presents the results of the updated Preferred Portfolio. The updated Preferred Portfolio contains three updates to assumptions compared to the previous version presented in PGE's Reply to Round 1 Comments. The three updates, which are discussed in detail in the preceding sections of this chapter, are:

1. Add 53 MWa EE (see **Section 5.3.1**);
2. Remove the perfect capacity associated with market access for transmission expansion resources (see **Section 5.1**); and
3. Update assumptions about extension of certain hydro and capacity contracts (see **Section 5.2**).

Figure 2 shows the cost and risk metrics of the previous Preferred Portfolio and the new Preferred Portfolio. With the updated assumptions, portfolio NPVRR decreased by $5.5

billion, driven mainly by a combination of a decrease in overall resource additions because of updated assumptions about contract extensions and changes in the cost of the generic resources (created by the change in assumptions about transmission expansion, as discussed in **Section 5.1**). Cumulative resource additions through 2030 in the Preferred Portfolio are shown in **Table 3**. Changes in 2030 relative to the Round 1 Comments Preferred Portfolio include:

- Additional EE increase from 0 MWa to 53 MWa
- Battery storage increase from 0 MW to 74 MW
- Non-GHG-emitting contract extension increase from 200 MW to 500 MW
- Wind decrease from 1528 MW to 1407 MW
- Solar decrease from 326 MW to 0 MW
- Generic VER decrease from 331 MW to 0 MW
- Transmission expansion decrease from 726 MW to 279 MW
- Hybrids decrease from 1010 MW to 1000 MW

Table 3. Cumulative resource buildout in Preferred Portfolio through 2030[40]

	2024	2025	2026	2027	2028	2029	2030
Wind	0	0	321	721	1111	1407	1407
Solar	0	0	0	0	0	0	0
Hybrid	0	0	0	0	0	429	1000
Battery Storage	0	0	74	74	74	74	74
Pumped Hydro Storage	0	0	0	0	0	0	0
Offshore Wind	0	0	0	0	0	0	0
CBREs	0	0	66	85	110	133	155
WY Tx	0	0	0	0	0	279	279
NV Tx	0	0	0	0	0	0	0
Generic VER	0	0	0	0	0	0	0
SoA Tx	0	0	0	400	400	400	400

[40] This table continues to show the shift from standalone solar and storage to hybrid (solar plus storage) resources first seen in the July 7th Addendum. Since the latest change to the production and investment tax credits available to some generation resources, hybrid solar plus storage resources provide essentially the same the energy and capacity benefits as an equivalent amount of standalone solar and storage. Hybrid resources however, benefit from some cost-saving benefits of co-location that make them slightly less costly than an equivalent quantity of standalone resources, giving them an economic edge over standalone resources in portfolio analysis.

	2024	2025	2026	2027	2028	2029	2030
Additional EE (MWa)	0	0	12	22	32	43	53
Non-GHG-Emitting Contract Extension*	600	500	500	500	500	500	500
Cost-effective EE (MWa)*	30	60	90	120	150	183	216
Cost-effective DR*	133	162	183	199	211	218	228
**Clearwater Wind **	311	311	311	311	311	311	311
**Seaside Storage **	0	0	200	200	200	200	200
**Troutdale Storage **	0	200	200	200	200	200	200
**Evergreen[41] Storage **	0	75	75	75	75	75	75

* Contributions reduce need
** 2021 RFP resources
*** 100 MW in 2024 is summer-only, capacity-only

Figure 2. Cost and risk metrics of the Preferred Portfolio

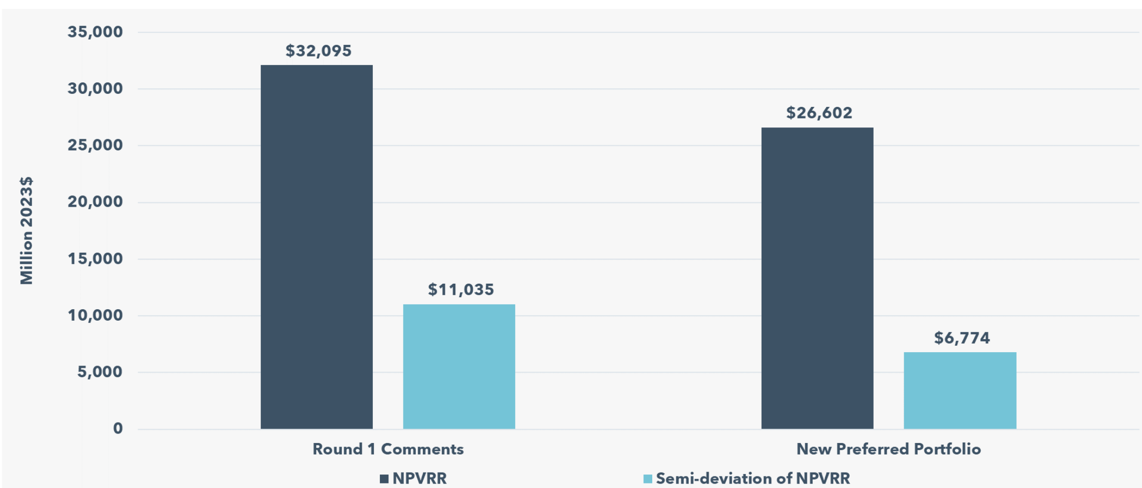


Table 4 provides an update of Table 2 from the filed CEP/IRP, providing a summary of total resource actions from 2023 through 2030, showing incremental new resources added by year (it does not show resource losses). It includes the IRP Preferred Portfolio resources and non-CEP/IRP resource actions (2021 RFP resources, qualifying facility resource additions, GFI solar additions, etc.).[42] **Table 4** also includes PGE's retail load service GHG emissions

[41] The Evergreen Storage project is now called Constable Storage project.
[42] As a result of including non-CEP/IRP and non-RFP resources the values in this table will differ from those in **Table 3**. For simplification purposes, generic VER resources and 5 MW of QF biomass are included in the wind & solar values.

glidepath from 2023 through 2030. **Table 5** shows incremental resource actions and includes PGE's retail load service GHG emissions glidepath from year 2031 through 2043.

Table 4. Preferred Portfolio resource pathway through 2030 (incremental additions)

Values in nameplate MW	2023	2024	2025	2026	2027	2028	2029	2030
DR (cost-effective)	24	26	25	19	14	11	8	9
EE (cost-effective)	31	30	30	30	30	31	33	33
EE (additional)	0	0	0	12	10	10	11	10
Storage	0	0	275	274	0	0	0	0
Solar & wind	30	734	69	331	410	400	306	10
Offshore wind	0	0	0	0	0	0	0	0
Hybrid (solar + battery)	0	0	0	0	0	0	429	571
CBRE	0	0	0	66	19	25	23	22
Transmission expansion	0	0	0	0	0	0	279	0
Contract extension*	0	600	0	0	0	0	0	0
GHG glidepath (MMTCO2e)	5.9	5.3	5.0	4.4	3.7	3.0	2.3	1.6

* 100 MW is summer-only, capacity-only

Table 5. Preferred Portfolio resource pathway through 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
EE (additional)	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage	315	0	0	0	0	0	0	0	0	2411	0	0	0
Solar & wind	1155	0	0	0	0	454	541	467	467	659	484	257	225
Offshore wind	0	237	233	250	254	13	13	0	0	0	0	0	0
Hybrid (solar + battery)	10	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
Transmission expansion	321	0	0	0	0	0	41	0	0	159	0	0	0
Capacity	36	0	72	97	139	138	212	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 modeled the new Preferred Portfolio in Sequoia to check the resource adequacy metrics of the updated resource buildout. Inclusion of the Preferred Portfolio differed slightly compared to earlier iterations. The transmission associated with Wyoming wind and Nevada solar was no longer modeled as providing perfect capacity to the system with the contribution from these resources now being solely dependent on resource characteristics. This iteration also included capacity contribution from three buckets of EE that were previously not incorporated in the resource portfolio. Finally, the assumed MWs associated with contract extensions increased and were included in the model's final value representing perfect capacity. The associated resource adequacy levels stay between 0.366 and 1.386 LOLH from 2026 through 2030 and satisfy the 2.4 LOLH per year target used by PGE in all years shown in **Table 6**. Compared to the RA metrics provided for PGE's Addendum Preferred Portfolio, the model shows a general increase in LOLE, but continues to remain adequate based on the LOLH values.

The RA metrics produced by the updated Preferred Portfolio show increased alignment between the amount of capacity needed for resource adequacy and the amount of capacity provided by the resources in the Preferred Portfolio. This indicates that the removal of the market access perfect capacity assumption for transmission expansion resources has substantially reduced the amount of surplus capacity in the portfolio. However, a LOLH of 0.578 in 2030 indicates that the Preferred Portfolio still contains capacity in excess of the amount needed to achieve the target of 2.4 LOLH.

Despite the over-achieving of RA metrics in 2030, PGE believes that the resource mix in the Preferred Portfolio represents an appropriate buildout for meeting the combination of energy and capacity needs. In 2030, energy needs are met, but not exceeded. This indicates that an appropriate number of resources are being added to the portfolio and that the surplus capacity can be explained by the addition of resources that provide both energy and capacity for the purpose of meeting energy needs. When both energy and capacity needs exist, and the resource available to meet the needs provide a mix of both types of benefits, one of the needs will end up driving resource additions. In 2030, energy need is the binding constraint that drives resource additions. The amount of capacity provided by those resources may exceed the amount required for resource adequacy from a capacity perspective, but they do not represent an overall over-building of resources when all types of needs are considered.

As discussed in **Section 5.1**, perfect alignment of capacity and energy additions to need is unlikely to happen in modeling that relies on a limited set of resources that provide a mix of energy and capacity. This modeling limitation is exacerbated by the realities of the transmission-constrained system that PGE is attempting to model. These constraints result in a smaller set of resources available for selection, further limiting the imperfect ability of the model to match both energy and capacity needs. While there are 74 MW of capacity-only storage resources in the portfolio in 2030, they are added earlier, in 2026, to meet a capacity need that exists in that year. The exceedance of annual RA metrics in 2026 can be explained by differences that arise in conducting RA modeling across multiple temporal granularities using both seasonal and annual time-steps. Capacity additions in 2026 are driven by summer need. The addition of sufficient capacity to meet summer needs results in excess capacity on an annual basis because needs are lower throughout the rest of the year. As a result, LOLP in 2026 is lower than 2.4 because it is an annual measure and the additions are being driven by seasonal needs. Therefore, while annual LOLP is lower than the reliability target, the amount of capacity added is not in excess of what is needed for sufficiency on a seasonal basis. The LOLH of zero hours in 2043 is driven by both the fact that the capacity need being addressed in portfolio modeling is actually larger in 2040 than 2043 and that energy need continues to grow through 2043. Therefore, the combination of adding sufficient resources to meet 2040 capacity need and continuing to add resources for energy need in 2043 results in more capacity than in needed for RA sufficiency in 2043.

Table 6. Yearly RA metrics of the Updated Preferred Portfolio

Year	LOLH	LOLE
2026	1.091	0.162
2027	0.878	0.144
2028	1.386	0.244
2029	0.681	0.169
2030	0.578	0.104
2036	1.929	0.351
2043	0	0

5.4 Action Plan

PGE has incorporated several updated assumptions that have influenced the composition of the Preferred Portfolio presented in these reply comments. The updates have resulted in three changes to the resource target numbers in the Action Plan, which are described below and shown in **Table 7**.

1. **Customer actions**: The targeted quantity of energy efficiency has increased from 150 MWa to 182 MWa, incorporating the 32 MWa of additional EE that has been identified as beneficial to customers over the planning horizon and added to the Preferred Portfolio through 2028.[43]

[43] The remainder of the 53 MWa of EE in the Preferred Portfolio is added later in 2029-2030.

2. **Energy action**: The addition of 53 MWa of EE through 2030 reduces the annual energy target from 261 MWa to 251 MWa as a result of reducing the total quantity of energy sought by 2030 from 1307 MWa to 1254 MWa.[44]
3. **Capacity action**: The addition of 32 MWa of EE through 2028 reduces the quantity of capacity sought in the Action Plan window from 944 MW in summer and 827 MW in winter to 905 MW in summer and 787 MW in winter.

While updated assumptions about the increase in size of non-emitting contract extensions have reduced the quantity of other resources in the Preferred Portfolio in 2030, these changes have not impacted the size of the Energy action and Capacity action. Instead, additional resources represented by the new contract extension assumptions are captured in a similar manner to traditional supply-side resources like wind, solar, and storage selected in portfolio modeling as potential new resources in the Preferred Portfolio, which can contribute to meeting needs. PGE will pursue multiple procurement avenues including bi-lateral activities, RFPs, and CBRE RFPs to fill the need represented in the Energy and Capacity Actions. Other key components of the Action Plan have remained unchanged. This includes the use of a linear decline in emissions to meet 2030 targets, pursuing 66 MW of CBREs, and continuing to explore options to address transmission congestion across BPA's system.

Table 7. Potential updates to Action Plan resource targets

		LC 80 Addendum	PGE Round 2 Comments
Customer actions	Acquire all cost-effective energy efficiency **plus additional quantities identified in CEP/IRP analysis**[45]	150 MWa Cumulative 2024-2028	**182** MWa Cumulative 2024-2028
	Incorporate customer demand response	211MW summer & 158 winter by 2028	Unchanged
CBRE action	Issue RFP for all available and qualifying CBRE resources	66 MW by 2026	Unchanged
Energy action	Conduct one or more RFPs to acquire sufficient energy to position PGE to meet the forecasted 2030 need	261 MWa (1307 MWa / 5 total years) per year through 2028 (783 MWa in Action Plan window)	**251** MWa (**1254** MWa / 5 total years) per year through 2028 (**751** MWa in Action Plan window)

[44] Consistent with the treatment of cost-effective EE and DR, the acquisition of additional EE is accounted for differently in the Action Plan than conventional supply-side resources and CBREs. EE additions are assumed to lower energy and capacity targets, while CBRE's and conventional supply-side resources in the Preferred Portfolio represent potential resources to be acquired through future RFPs to fulfill the needs represented in the energy and capacity actions.
[45] As described in **Chapter 3**, PGE plans to acquire the additional 32 MWa of EE at lowest cost.

		LC 80 Addendum	PGE Round 2 Comments
Capacity action	Conduct one or more RFPs to acquire sufficient capacity to meet forecasted 2028 needs	944 MW summer & 827 MW winter	**905** MW summer & **787** MW winter
Transmission actions	Pursue options to alleviate congestion on the South of Alston (SoA) flowgate	n/a	Clarified to focus on developing a comprehensive transmission study
	Explore options to upgrade the Bethel-Round Butte line (from 230 to 500 kV)	n/a	Clarified to focus on developing a comprehensive transmission study

Chapter 6. Additional Issues

6.1 Small Scale Renewables

Staff raises questions about PGE's SSR analysis, questioning whether PGE anticipates all net-metered resources could become eligible as SSR and how customer solar managed in a VPP could operate akin to supply options. Staff has identified areas of uncertainty that are not yet resolved, and we hope to advance answers through workstreams including Smart Grid Test Bed implementation, Flex Load Multi-Year Planning and Distribution System Planning.

PGE agrees with Staff that the next IRP should include SSR analysis in a more explicit way. However, Staff's Draft Recommendation 7 misses important nuances and is overly prescriptive on three points. First, incorporation of SSR requirements into IRP modeling should not take the form of a compliance analysis, a process for which was already established by Order No. 21-464. Second, PGE should not be directed to model "net-metered customer resources" as a binary on or off from an SSR perspective, as our hope is that by our next IRP cycle, significant additional clarity will be available about the ability of different types of customer resources (e.g., with or without storage, or enrolled in different optional programs) to serve as capacity resources and contribute to SSR requirements. And lastly, accountability for any necessary changes to administrative rules rests with OPUC and these should not be altered as part of acknowledgment of PGE's action plan; rather PGE can provide more details in the next IRP about the extent to which DERs may be capable of SSR eligibility.

6.2 Community Engagement

We appreciate the detailed feedback provided by Staff regarding our community engagement efforts related to the CEP/IRP. PGE is committed to aligning our practices with the requirements of HB 2021 and Commission Order No. 22-390, and we value the insights shared by both Staff and stakeholders.

PGE acknowledges the concerns raised, particularly regarding the authenticity of our community engagement efforts and the need for more inclusion of environmental justice principles in our action plan. Also, we understand the importance of transparency, improving accessibility, and implementing an accountable engagement process, and we are taking proactive steps to address these concerns.

PGE agrees with Staff's Draft Recommendation 8. We support establishing a workgroup to define successful community engagement, develop codifiable standards and guidelines, enhance understanding of community expectations, and propose improvements for future IRP/CEPs. We look forward to collaborating with Staff, stakeholders, peer utilities, and the

Community Benefits Impact Advisory Group (CBIAGs) in this endeavor. We commit to actively participating in the working group to assist in evolution of the proposed improvements and goals and outcomes stated.

We appreciate the opportunity to collaborate and enhance our community engagement processes. We are confident that the collaborative efforts outlined in the working group will lead to actionable insights and improvements, resulting in a more inclusive, transparent, and accountable approach to our future CEP/IRP.

6.3 Community Benefits

PGE supports Staff's Draft Recommendation 9 and is pleased that Staff appears to support PGE's proposed pathway of working with stakeholders and a third-party consultant to develop more functional CBIs. Creating credible estimates of CBIs is a priority for the Company, and PGE plans to follow the proposed pathway to develop the use of CBIs for the IRP/CEP update. PGE's approach to CBIs will aim to articulate how community benefits vary between portfolios, what community benefits are associated with PGE's Action Plan, and how RFP design and scoring can encourage additional and more specific benefits. The approach will also prioritize compatibility with PGE's existing suite of models. PGE looks forward to sharing its progress and thinking with Staff as it considers further defining expectations for CBI development. While PGE supports Staff's recommendation to conclude our process of developing informational and portfolio CBIs and providing baseline metrics by the next IRP Update (as articulated in Draft Recommendation 9), the Company believes it is premature to establish itemized deliverables at this juncture (like those identified in Staff's Expectations for future CEP/IRPs).

6.4 Federal Incentives

Staff highlights the importance of accounting for the various federal incentives in the Infrastructure Investment and Jobs Act (IIJA) and the Inflation Reduction Act (IRA) in long-term resource planning.[46] Staff specifically highlights discussion from PGE's Round 1 Reply Comments on the interest of stakeholders in the Justice40 initiative and PGE's expressed willingness to provide updates on the topic going forward.[47] Staff notes appreciation of PGE's attempts to include IIJA and IRA incentives in annual portfolio cost calculations and the updated DER forecasting in the Addendum. Staff recommends that PGE take ownership over the successful implementation of federal incentives and provide updates about the

[46] Staff Round 2 Comments at 32

[47] Section 9.5 Tax incentives and funding opportunities. Available at: https://edocs.puc.state.or.us/efdocs/HAC/lc80hac131341.pdf

impacts on the Company's Action Plan and 2030 resource strategy with its IRP/CEP Update."[48]

PGE appreciates Staff's comments and agrees with the recommendation to continue working on appropriate accounting of federal incentives and providing an update on progress in the CEP/IRP Update.

6.5 RECs

Staff highlights the substantial potential monetary value of RECs forecasted to be generated in excess of PGE's compliance needs in coming years and notes the importance of focusing on customer value in PGE's managing of these RECs.[49] Staff notes that in PGE's Round 1 Reply Comments, PGE asserted that the Renewable Portfolio Standard Implementation Plan (RPIP) is the place to explore these issues, then notes that the Commission has subsequently clarified that the CEP/IRP will be the appropriate venue going forward. Based on that Commission clarification, Staff states that the CEP/IRP will be the main forum for understanding the Company's REC position and management strategy going forward once additional clarification has been provided by the Commission. Staff notes that it is committed to working with PGE to identify the appropriate REC analysis for future CEP/IRPs after the Commission order in Phase 1 of UM 2273 is released and that it does not plan to discuss REC disclosure, communications, and transparency policies before then.[50]

PGE agrees that subsequent rounds of the CEP/IRP will be the appropriate venue to explore REC generation and management going forward once further clarification has been provided by the Commission and looks forward to working with Staff on this topic.

Conclusion

PGE appreciates the significant work and feedback provided by Staff in this proceeding. In these comments, PGE has provided additional information and modifications to the Action Plan in response to Staff's recommendations. PGE looks forward to continued engagement by Staff and Stakeholders in this docket, and respectfully requests that the Commission acknowledge this IRP/CEP.

[48] Staff Round 2 Comments at 32
[49] Staff Round 2 Comments at 32
[50] Staff Round 2 Comments at 37