BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. LC 80

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2023 Clean Energy Plan and Integrated Resource Plan.	OPUC Staff Round 2 Comments and Recommendations

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1. Executive Summary

The following are Staff of the Public Utility Commission of Oregon's (OPUC or Commission) Final Comments and Draft Recommendations for Portland General Electric's (PGE or Company) 2023 Integrated Resource Plan (IRP) and Clean Energy Plan (CEP). As many parties noted in Opening Comments, this IRP/CEP marks a major milestone in House Bill 2021 (HB 2021) implementation and a meaningful step forward in decarbonizing Oregon's electric sector in a manner that considers benefits and impacts for communities. Staff is grateful for the Round One comments provided by Alliance of Western Energy Consumers (AWEC), Columbia River Inter-Tribal Fish Commission (CRITFC), Oregon Citizens' Utility Board (CUB), Deep Blue Pacific Wind, Elizabeth Graser-Lindsey, Energy Advocates, Green Energy Institute (GEI), Grid United LLC, NewSun Energy LLC (NewSun), Oregon Solar + Storage Industries Association (OSSIA), Renewable Energy Coalition (REC), Renewable Northwest (RNW), and Swan Lake and Goldendale Energy Storage Projects. The first two rounds of comments in this process have been critical in understanding PGE's efforts to develop new planning approaches that capture the requirements of HB 2021 and highlighting areas where the Company needs to better demonstrate a credible path to a reliable, affordable, equitable and decarbonized system.

Staff's Final Comments assess PGE's responses to the questions and concerns raised in opening comments and offer a set of draft recommendations for acknowledgement of the Company's near-term action plan and consideration of the longer-term IRP/CEP strategy—with an emphasis on preparation for the state's 2030 emissions reduction target. Staff's comments also highlight a range of opportunities to improve the next IRP/CEP that PGE should be prepared to address in its plan development process and the investigation into the Commission's planning and procurement policies expected in 2024.

Based on analysis and discussions thus far, Staff has reached two preliminary conclusions. First, PGE has come very close to identifying the right combination of near-term actions to make meaningful progress toward its longer-term needs. Second, while some challenges and uncertainties are beyond the Company's capabilities and control, Staff remains concerned that the Company has not modeled its resource needs in 2030 and beyond well enough to have confidence in its long-term resource strategy.

PGE's analysis sheds light on the challenges posed by growing customer demand amidst shrinking generation from the Company's GHG emitting resources and the vast uncertainty around required transmission to integrate both Oregon-based and out-of-state renewable resources and the availability of clean emerging technologies. PGE's analysis makes a strong case for electricity markets and customer-owned resources to make up for any resource deficiency to meet its energy and capacity needs.

PGE's analysis traces out a clear emissions reduction path for the 2020s but fails to establish a firm path beyond that timeframe. Hence, while Staff feels comfortable with how the resources and emissions are going to shape out in the next few years, Staff is not ready to recommend acknowledgement for PGE's long-term IRP/CEP strategy.

Staff addresses the key issues in the IRP/CEP in the following sections:

Action Plan Review

Staff provides recommendations regarding PGE's planned actions for the next 2-4 years that would ultimately contribute toward meeting PGE's planning goals. Staff initially recommends acknowledgement of PGE's customer actions, community-based renewable energy (CBRE) actions, energy, and capacity actions subject to certain conditions.

Staff agrees that PGE should continue to explore its transmission expansion options and appreciates that this is the first time that the Company has taken on this level of transmissions analysis in the IRP. However, Staff does not believe that the proposed transmission action items are tangible enough for acknowledgement and requests that the Company provide a transmission study that thoroughly evaluates the Company's options to alleviate South of Allston and Cross Cascades South congestion by the IRP Update.

Long-term Resource Strategy Review

Staff evaluates PGE's long-term IRP/CEP strategy in the light of requirements set by HB 2021 and expectations developed by multiple Commissions Orders in the HB 2021 implementation process (Docket No. UM 2225). Staff is grateful to PGE for its efforts to retool its longstanding planning practices and to stakeholders for their engagement in this complex process. Staff has relied on a range of insights and suggestions to develop the recommendations related to the long-term strategy and identify a range of improvements for future IRP/CEPs.

Staff and stakeholders have expressed a general lack of confidence in the methods PGE has used to identify its procurement needs starting in the late 2020s. The key drivers of this concern are the Company's approach to modeling GHG emissions associated with its retail load and its reliance on overly optimistic proxy transmission resources. Staff believes that PGE made best efforts with the time and planning resources available, but these modeling issues leave Staff with too much uncertainty about what it will take for the Company to meet the 2030 targets reliably.

Staff's draft recommendation is that the Commission does not acknowledge PGE's long-term IRP/CEP strategy as presented unless PGE can supplement its current filing with the revisions outlined below. If PGE cannot make these revisions in time for review in this docket, Staff is not confident that it can recommend that the Commission acknowledge the longer-term IRP/CEP. Staff recommends in that case that the Commission direct the Company to make the following revisions and resubmit the revised plan before its IRP/CEP Update in 2025:

a. PGE shall present an hourly analysis of its GHG emissions associated with its retail electricity load.
b. 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.

Additional Issues

Staff recommends that the Company engage with stakeholders and develop community benefit indicators that would capture the economic and health impacts of specific resource actions and provide a comparison of community impacts of alternative portfolios in future CEPs. Staff also recommends the Company provide analysis on varying GHG implications associated with alternative portfolios in future CEPs. Further, based on Staff and stakeholder comments, Staff lays out suggestions for PGE to proactively work towards developing and effectively incorporate community engagement in critical decisions in the CEP.

Staff discusses issues raised by Energy Advocates around cost-effectiveness calculation for energy efficiency (EE) resources in the light of emissions reductions and its draft recommendation for PGE to work with Energy Trust of Oregon (Energy Trust) and Staff to update Energy Trust's implementation and budget strategies for EE acquisition. Staff had also noted a similar need and appreciates PGE's clear and forthcoming articulation of what it views as current Docket No. UM 1893 (EE Avoided Cost Calculation) shortcomings. Staff recommends the Commission not acknowledge the values shared to date, particularly the forward electricity prices.

HB 2021 requires an electric company to meet its renewables compliance by including small-scale renewable (SSR) resources to account for 10 percent of its total electrical capacity. PGE's SSR forecast shows two scenarios. Without counting customer-sited solar, PGE will lack 408 MW of SSR and thus has not presented a pathway to compliance. However, if all customer-sited solar is included, PGE could comfortably surpass the 10 percent requirement. If PGE anticipates pursuing a compliance strategy that includes net-metered resources, the Company must include a timeline and strategy for proposing appropriate administrative changes.

2. Action Plan Review

PGE's updated Action Plan ([LC 80 Addendum]) includes new projections for the energy and capacity RFPs in the light of revised system needs. Table 1 summarizes PGE's updated Action Plan that responds to increased system needs through increased energy and capacity projections in the RFPs.

Table 1: PGE's revised near-term Action Plan		
Customer Actions	Acquire all cost-effective energy efficiency.	150 MWa Cumulative 2024-2028
	Incorporate customer demand response.	211 MW Summer and 158 MW winter by 2028
CBRE Action	Issue RFP for all available and qualifying CBRE resources.	66 MW by 2026
Energy Action	Conduct one or more RFPs to acquire sufficient capacity to meet forecasted 2028 needs.	261 MWa (1307 MWa/5 total years) per year through 2028 (783 MWa in the Action Plan window)
Capacity Action	Conduct one or more RFPs to acquire sufficient capacity to meet forecasted 2028 needs.	944 MW summer and 827 MW winter
Transmission Actions	Pursue options to alleviate congestion on the South of Allston (SoA) flowgate.	n/a
	Explore options to upgrade the Bethel-Round Butte line (from 230 to 500kV).	n/a

2.1. Customer Action (Demand-side Resources)

Staff's greatest concern with PGE's Action Plan is the Company's energy efficiency (EE) target. Staff, CUB, and the Energy Advocates Opening Comments expressed concern that the Company did not include the full amount of EE selected in the least-cost portfolio in its EE acquisition target. CUB expressed an openness to a securitization proposal from PGE, which could help spread out the upfront cost of investing in EE. In reply, PGE did not revise its EE target, citing concerns about near-term rate impacts and suggesting that increases to Energy Trust's budget be delayed until there is clarity on new, non-ratepayer funding sources.

Staff agrees that controlling near-term costs is an important consideration and strongly encourages the Company to work collaboratively to leverage outside funding sources to meet or exceed its targets at a lower cost to ratepayers. Staff greatly appreciates CUB's recommendations to control rate impacts and believes that over the next few years, PGE must engage collaboratively in planning and budgeting efforts with Energy Trust of Oregon, as well as any cost recovery-focused investigations the Commission opens, to ensure that the reforms required for EE to serve the critical role that it should in decarbonizing the energy sector will be made. Staff also believes that PGE raises good points about co-delivery of EE and flexible loads and recommends that PGE work with Energy Trust to further consider these non-traditional forms of EE in the next IRP.

Staff is concerned with PGE's non-inclusion of optimal EE targets for several reasons. First, that the Company's response to a potential 44 percent increase in 2030 energy need and 51 percent increase in summer 2028 capacity need is to continue to resist the addition of EE that the portfolio analysis identified as optimal prior to revised load forecasts. While projecting electrification is difficult at this time, Staff believes that the Company's reaction is even more worrisome considering the pressures on the system from other sectors.

Second, PGE's community benefits indicators (CBIs) are not sophisticated enough to capture the relative community benefits of EE investments to other resource actions, such as health impacts and affordability. Staff is also concerned with the Company's reluctance to target higher levels of EE in light of this limitation in its portfolio analysis.

Finally, Staff is concerned that the Company's need for other resource actions will not be adequately informed if it does not base its targets on the right amount of EE for the system and the decarbonization strategy, not for a specific funding mechanism. In Reply Comments, PGE advocated for waiting to invest in Energy Trust until additional collaboration opportunities and information regarding external funding become available. Staff disagrees with PGE's request for an investment pause and notes that Energy Trust is already actively conducting what PGE seeks—collaboration with the external funding sources and programs to bring new, non-ratepayer funded EE to market. Staff views Energy Trust investments as proactive and reasonable. Energy Trust's 2024 draft budget demonstrates investments to prepare the market for accelerated EE acquisition, while still maintaining near-term cost effectiveness.

Staff shares PGE's concern about near-term rate pressures but disagrees that the solution should be to shift the cost to future ratepayers. Staff recommends PGE address its concern of near-term rate impacts with a securitization proposal as opposed to an action plan that does not acquire the additional 53 aMW of cost-effective EE. The current Action Plan relies on increasing cost to future ratepayers, rather than reducing the cost and dealing with the timing of the impact. The Company provided productive consideration of securitization of EE investments in Reply Comments.

2.1.1. Energy Efficiency Implementation

Related to the EE Action Item, Staff appreciates the robust dialogue about the need to evolve a range of EE-related practices to achieve an optimal level of EE. In Opening Comments, Energy Advocates noted that HB 2021 requires a re-evaluation of prior practice, including how cost-effectiveness is determined. Energy Advocates found that PGE did not sufficiently address cost-effectiveness considering new planning requirements, though noting that the IRP/CEP is the right venue for that analysis. Energy Advocates suggested the Commission direct PGE to make cost-effectiveness analysis more robust within the plan then work with Energy Trust and OPUC Staff to determine how to incorporate the analysis in Energy Trust's implementation and budgeting practice.

PGE observed that Docket No. UM 1893, which is updated annually to set avoided costs for EE has not evolved with decarbonization policy. The Company highlighted two dynamics not currently captured in UM 1893. The first was that current avoided costs use a single value of capacity. That value does not capture the decreasing contribution of marginal resources over the planning horizon, nor does it capture the impact of transmission or other constraints to meet capacity needs. PGE also highlighted that using electricity prices to value energy is not compatible with portfolio analysis where the model has limited access to market purchases which are priced at the value of the electricity price forecast. The result is that additional energy need must be addressed with new resource additions to meet HB 2021 which come at a higher cost than is reflected in market prices.

Staff appreciates PGE's clear and forthcoming articulation of what it views as current Docket No. UM 1893 shortcomings. Staff agrees that the data reporting template needs updates but maintains its concern that values shared by PGE to date do not reflect the true avoided cost of pursuing EE. Staff is concerned because values from the most recently acknowledged IRP are used in Docket No. UM 1893 to set EE avoided costs. The values provided by PGE create the illusion that Energy Trust's investments are less cost effective than they actually are.

Therefore, Staff recommends the Commission not acknowledge the values shared to date unless the Company puts forward a proposal with a new method for accurately capturing avoided costs. On a directional, order-of-magnitude basis, Staff sees evidence that PGE's portfolio analysis suggests EE avoided costs may be at least 60 percent higher than current values and potentially significantly higher.[1] Staff reviewed several sources to contextualize anticipated increases in avoided costs.

First, Staff established that the additional 53 aMW of additional EE was composed of EE bins 1-3, based on Figure 60 in the IRP.[2] PGE organized the additional EE potential into five bins, sorted by levelized costs, that could be used in portfolio analysis. Since PGE identified that these 53 aMW are selected in the least cost portfolio, the levelized cost of the measures within EE bins 1-3 should provide some reference for the cost of avoided resources.

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[1] Staff presents a range of values in the discussion below. 60 percent represents an increase above a levelized cost of $0.097/kWh versus the net cost of energy for Nevada solar and transmission of $0.165/kWh. On a levelized-to-levelized basis, the increase to $0.27/kWh is an increase of 178 percent over $0.097/kWh.

[2] PGE IRP/CEP, p. 190.

Staff reviewed PGE's Response to Staff IR 77, Staff IR 077-Attach A, which included levelized costs of measures within each of the EE bins used in modeling.[3] Table 2 presents both the maximum levelized cost found within each bin and the bin's average levelized cost.

Table 2: Levelized Cost ($/kWh) of EE Measures Within Bins

EE Bin	Max of Levelized Cost	Average of Levelized Cost
1	$0.14	$0.09
2	$0.22	$0.18
3	$0.27	$0.24
4	$0.87	$0.52
5	$8.04	$2.06

It is noteworthy that PGE's portfolio analysis selects EE bins 1-3 considering their increased cost. Based on an Energy Trust supply curve, PGE's current Action Plan only includes EE up to $0.097/kWh in levelized cost, despite PGE's modeling results suggesting EE up to $0.27/kWh is cost-effective.[4]

Staff is aware that levelized cost alone is not a perfect representation of avoided costs for EE. Namely, it misses the energy and capacity value provided to the system. There are also interactive effects of when the efficiency occurs and its coincidence with peak demands. One method by which PGE contextualizes this cost is by computing a net cost of energy in dollars per Megawatt-hour ($/MWh). PGE's analysis, provided in response to Staff IR 200, explains and highlights this fact.

Resource needs in the medium term are primarily driven by energy needs. Thus, when we compare the net cost of capacity on a $/MWh basis, we see that EE bins 1-3 have a lower net cost of capacity to meet energy needs than the net cost of energy of the Nevada solar transmission expansion option and consequently the generic resources, resulting in selection of EE bins 1-3 when available.[5]

When converted to $/kWh, Staff IR 200-Attach A demonstrates that EE bins 1-3 have a maximum net cost of capacity for energy of $0.144/kWh compared to Nevada solar and transmission at $0.165/kWh.[6] These results provide another view into what the avoided resource in PGE's Preferred Portfolio is and illustrate an expectation that EE avoided costs must reflect these results.

PGE should propose a new method for calculating avoided costs that the Company views will resolve the shortcomings of the current Docket No. UM 1893 data template. Staff views the avoided energy cost represented by forward market prices to be unacceptable and will recommend against approval of data based on such costs in Docket No. UM 1893 if those values remain unchanged.

Staff notes that two actions are necessary for different purposes. One, Staff and stakeholders need PGE to propose a new method for updating avoided costs for later use in Docket No. UM 1893 that addresses the concerns outlined above. This may allow Staff to recommend acknowledgment if provided in a

[3] PGE's Response to OPUC Staff IR 77, OPUC Staff IR 077-Attach A

[4] PGE IRP/CEP, p. 671, *Energy Trust of Oregon: PGE Energy Efficiency 2023 Resource Assessment Model*, Figure 9, https://portlandgeneral.com/2023-energy-efficiency-resource-assessment-model.

[5] PGE Response to Staff IR No. 200.

[6] PGE Response to Staff IR No. 200, Staff IR No. 200-Attach A.

timely manner. It will also allow for accurate data collection in future processes. Two, Staff agrees with PGE that modernization of the data collection template to reflect HB 2021 dynamics is necessary and intends to propose updates in 2024 to avoided cost reporting within Docket No. UM 1893. This will help ensure avoided cost data reporting better conforms to HB 2021 requirements.

Draft Recommendation 1: 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/CEP 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.**

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.

2.2. Community-Based Renewable Resource (CBRE) Action

Staff appreciates the dialogue in Opening Comments regarding the costs and benefits of considering a higher or lower CBRE target. Energy Advocates emphasized the importance of CBRE for avoiding transmission, and asked PGE for a justification for determining 155 MW as the maximum amount of achievable CBRE and requested a model sensitivity with 125 percent of the maximum CBRE selected. NewSun also recommended directing PGE to model uncapped CBREs or up to 125 percent of CBRE potential, citing inadequate identification of technical achievable potential.

AWEC recommended that PGE's CBRE action item should not be acknowledged. AWEC takes the position that the CBRE action item is not least cost, and that the only statutory requirement is to meet 10 percent of aggregate electrical capacity with small-scale renewables by 2030. Based on the Company's response to AWEC IR 004, AWEC believes that PGE is on-track to meet the SSR requirement without its CBRE action item.[7] Finally, AWEC does not support spreading CBRE investments across the entire rate base. Instead, AWEC recommends that individual communities that benefit from CBRE should pay for those resources.

In Reply Comments, PGE referenced the community lens potential study as the Company's best assessment for arriving at the 155 MW of technical achievable potential. PGE acknowledged the

[7] AWEC Round 1 Comments, p.See *Opening Comments of the Alliance of Western Energy Consumers*, p. 15, https://edocs.puc.state.or.us/efdocs/HAC/lc80hac153940.pdf.

simplistic nature of its modeling of CBRE benefits but reiterates that the model selects CBRE because they provide benefits and disagrees with AWEC.

Staff remains supportive of PGE's CBRE targets. Staff agrees with PGE that given the simplistic modeling approach used for this first IRP/CEP, an increase in CBRE available to the model would result in selection of that resource. However, until the Company can enhance the sophistication of modeling CBREs and CBIs in portfolio analysis that Staff raised in Opening Comments, there is limited value in attempting to quantify the benefits of a higher or lower CBRE target. Given the uncertainty of how effectively the 155 MW can be acquired, Staff believes that the Company has identified a good starting point and expects future IRP analysis to be more robust and apply learnings from initial CBRE development activities.

Staff does not support AWEC's assumption that non-emitting resource investments that direct co-benefits toward communities, such as distributional equity, resilience, and bill reduction, are inappropriate for inclusion in the Preferred Portfolio or Action Plan. Staff reiterates that it is important for utilities to make room in their resource strategy for community focused projects and notes that the Commission's expectations for the first IRP/CEPs is that:

> [t]he primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers, the pace of greenhouse gas emissions reductions, and community impacts and benefits.[8]

Staff also notes that a top-down approach to studying CBRE potential is not the only option for future plans and believes that it is also acceptable, and perhaps preferrable, to study CBRE potential by working with local groups to assess CBRE potential to offset fossil fuel generation using a bottom-up approach. Staff appreciates PGE's work to integrate community feedback prior to conducting its CBRE potential study and believes that it is important to validate the CBRE potential forecasted by AdopDER[9] by meeting with community members in the areas identified to discuss the appetite, feasibility, and perceived local benefits of actual CBRE implementation.

Further Staff notes that PGE's Action Plan specifies a Request for Proposal (RFP) as the only mechanism of CBRE procurement. Several stakeholders have pointed out that an RFP may not be enough to facilitate small community-based resources due to their unique development challenges. PGE has expressed support for multiple mechanisms of CBRE procurement in its Round 0 Reply Comments[10] and Round 1 Reply Comments.[11] Staff agrees with PGE's proposal that the CBRE RFP is only the beginning of the process to meet the targets identified in the IRP/CEP and encourages the Company not to delay their efforts to, "move forward complementary processes to identify resources that may otherwise not choose to bid into an RFP-like structure."[12] Staff also supports PGE's commitment to leverage other federal, state, and local resources to support this kind of project. Staff wants to ensure that PGE is proactively pursuing and updating the Commission on the different strategies it is evaluating.

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[8] Commission Order No. 23-060.
[9] PGE IRP/CEP filing, p. 161.
[10] PGE Round 0 Reply Comments, p.31-32.
[11] PGE Round 1 Reply Comments, p. 84-85.
[12] Id., p. 84.

Staff expects PGE to take ownership for the success of its CBRE action item, which means being proactive about:

- 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.

Staff is committed to carrying these expectations into the 2024 planning and procurement policy investigation. If PGE is proactive about this responsibility, Staff will be happy to review Company proposals to fill gaps in the existing CBRE development landscape and overcome barriers to controlling costs and facilitating CBRE success.

<u>Draft Recommendation 3</u>: 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.

2.3. Energy and Capacity Actions

PGE's forecasts continue to project increasing energy and capacity needs on its system. Additionally, the HB 2021 emissions reduction targets will require PGE to procure significant amounts of non-emitting resources. Staff agrees that despite modeling deficiencies, growing system needs from load growth and electrification demand coupled with HB 2021 targets will necessitate procurement of non-emitting resources. Staff also realizes that procurement targets will depend on the Company's set targets for demand-side resources. Staff expects PGE to use an accurate estimate of energy efficiency resources to determine its Request for Proposal (RFP) targets for both energy and capacity resources as described in the Action Plan.

Regarding the Company's cost and risk analysis of different RFP sizes and associated timing, PGE explained that "results from the RFP size and pacing and supply chain analyses provide insights into the costs and risks of alternative procurement cadences but do not contain exact quantitative recommendations for annual procurement quantities."[13] Staff appreciates PGE's acknowledgment that the RFP size and cadence should be adapted to updated needs assessments, but does not have a clear understanding whether the Company would consider procurement levels that are responsive to the evolving market depth and availability of competitive projects rather than having them capped at the annual levels identified in the IRP/CEP without providing sufficient near-term cost impact analysis.

Staff notes that static annual procurement targets may not be responsive to the development of other resource types, including long lead time resources, EE, and CBRE, and the role that they could play in meeting needs pre-and-post 2030.

Staff sought more information around PGE's proposed RFP framework and alternative actions to address underperformance of RFPs in its Opening Comments. The Company directed Staff to the additional bid windows proposed in its planning and procurement forecast filed in UM 2274 intended to address RFP under performance. PGE further explained that if underperformance persisted over time, future

[13] PGE Round 1 Reply Comments, p.86.

planning could show a greater reliance on demand-side resources or specific non-RFP procurement actions.

Staff believes the framework the Company provided in UM 2274 is a valuable starting point for the accelerated procurement strategy, but finds PGE's response lacking the detail it sought regarding needs assessment updates, potential offramps, and how it proposes to consider the closure of a procurement round. Further, the Company's response did not clarify how market intelligence from RFPs might inform demand side resource valuation or procurement strategies for resources not participating in bidding opportunities. 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 modeling inputs and assumptions that influence capacity and energy need, avoided costs, and project capacity, energy, and/or flexibility valuation. The Company should identify inputs and assumptions it would anticipate updating prior to issuing future RFPs as well as those it assumes would only change as part of a new IRP filing or IRP Update.

2.3.1. CBIs in RFP Scoring

Energy Advocates commented that the scoring criteria for RFPs should include CBIs or other non-price factors to maximize benefits for environmental justice communities. PGE states it will work with stakeholders on scoring in future RFPs, including the consideration of non-price scoring elements. Staff supports the engagement with stakeholders and notes that PGE's 2023 RFP, as drafted, does not include non-price scoring elements, and that while the competitive bidding rules afford space for the inclusion of non-price scoring, they include specific direction regarding their inclusion.[14]

PGE's CBIs are not sophisticated enough to meet the non-price scoring criteria at this time but, moving forward, CBIs present an opportunity to better capture the state's policy preferences in weighing options and making resource decisions. Staff appreciates PGE's commitment to the inclusion of CBIs in bid scoring in its next RFP docket and will consider the need for additional policy direction in the Commission's reexamination of planning and procurement policies in 2024.

2.3.2. Long Lead Time Resource Procurement

RNW raised three points regarding long lead time (LLT) resources: 1) developers of a LLT resource need appropriate market signals earlier in the development process than current RFP practices provide, 2) current RFPs do not adequately consider and evaluate LLT resources and would need to be changed if they were to be leveraged for LLT resource acquisitions, and 3) a near-term LLT Resource RFP would provide certainty to developers to invest in offshore wind in Oregon. RNW explains "the current RFP rules and processes and the specific RFP designs have not been and are not sufficient to properly value long-lead time resources"[15] and recommends the Commission direct PGE to either issue an RFP for long lead-time resources in late 2025 or develop and issue an RFP that "fairly and accurately compares long-lead time resources to shorter-term resources."[16] PGE has instead proposed to issue an RFI for long-lead time resources in 2023.

[14] OAR 860-089-0400 (2).
[15] RNW Round 1 Comments, p.43.
[16] RNW Round 1 Comments, p.43.

Figure 1. PGE Request for Information Proposal

	2023 RFPs	2023 Requests for Information (through end of decade)
All-Source	Will align with the IRP, once acknowledged. Based on IRP as filed, will seek: • 181 MWa of non-emitting energy resources per year • Capacity sufficient to meet any remaining 2026 need, adjusted for bilateral acquisition, EE/DR, contract renewals, or other actions.	Seeks information on project development technologies and locations through the end of the decade. Will prepare PGE and stakeholders for enabling actions needed to maximize resource value (such as additional transmission, regional RA evolution, etc.)
CBRE	Will seek to procure up to 66 MW of resources with a 2026 COD. Nimble process to be co-developed with customers.	Highlights technologies and funding mechanisms not currently transactable that may hold potential in the future Will help to inform the remaining CBRE acquisition target through 2030 Response may help direct PGE program development
Bilateral acquisition and contract renewals will inform RFP/RFI volumes and timing		

In discovery, RNW responded that it did not have explicit recommendations for adapting current RFP scoring and modeling practices to better evaluate LLT resources alongside non-LLT resources and indicated that stakeholders need time to consider what changes might be necessary. RNW offered ways RFPs have attempted to accommodate LLT resources including:

> having a longer commercial operation date requirement for long-lead time resources, form contracts for long-lead time resources, sufficient time from bid submission to initial shortlist for due diligence in evaluating a long-lead time resource, allowing a long-lead time resource to submit a reasonable transmission plan instead of requiring firm transmission at time of bid, developing modeling and evaluation tools that ensure long-lead time resources are evaluated fairly, and ensuring scoring is fair among all resources…[17]

PGE revised its Preferred Portfolio to include LLT resources before 2030 that are not well suited to the RFP approach currently used. RNW's responses reinforce that more discussion is needed to ensure these resources remain a viable option while establishing appropriate valuation and risk mitigation practices. Because determinations of prudence are based on the Company's decision to contract with a resource, there is a lot that needs to be understood prior to a utility contracting with a selected LLT resource in early stages of development.

Given the need for further exploration, Staff suggests PGE begin its RFI process by filing comments and soliciting feedback on design in this docket. After receiving feedback from stakeholders, PGE can choose the most appropriate method by which to issue an RFI. In terms of timing, Staff would expect the results of an RFI to be concluded prior to the Company's next RFP for any type of utility-scale resource.

[17] RNW Response to OPUC Staff IR No. 5.

Staff believes this RFI should study offshore wind, pumped hydro storage, advanced geothermal, and any other resources identified by the Company or by stakeholders. In addition to thorough consideration of ratepayer risks, Staff will seek to understand following:

1. How much time should be allotted between RFP issuance, the signing of a contract, and the commercial operation date for LLTs?
2. Can a traditional RFP resource valuation accommodate LLT resources and, if so, what should be changed to account for unique benefits provided by various LLT technologies to ensure they can compete fairly against more traditional resources? If not, what other procurement approaches provide adequate market signals, activity, and competition; appropriate cost recovery pathways; and necessary customer protections?
3. How should transmission requirements be altered with respect to LLTs bidding into an RFP, whether that RFP is for all resources or specifically for LLTs?
4. What aspects of a LLT project should be considered as within the control of the project, and what aspects should be considered outside of its control?

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 and reactions to the RFI.**

2.4 Transmission Action

PGE plans to pursue ways to upgrade the South of Allston (SoA) transmission line that would add up to 400 MW of capacity to its portfolio. According to PGE, any effort to move energy to PGE's system from anywhere in the Western Interconnection would impact power flows on the South of Allston flowgate. Hence, some amounts of almost all off-system resources in the Preferred Portfolio would require the transmission upgrade.[18] Staff understands PGE's conclusion that upgrading the SoA can alleviate this issue; however, PGE's transmission action is vague when it comes to understanding what these upgrades look like, why 400 MW of additional capacity would be sufficient in addressing the congestion at the SoA flowgate, and whether the Company had considered multiple options (both in terms of transmission strategies and consideration of off-system resources) before narrowing down on a particular upgrade strategy. PGE ascertained that since on-system resources like energy efficiency, demand response, CBRE resources and on-system storage are not subject to transmission constraints, their existence in the Preferred Portfolio does not impact the amount of transmission available to other off system resources. Moreover, PGE states that the projected deficit on the SoA path congestion far outweigh the capacity that could be added by potential on-system resources.[19]

In response to Staff's information requests about the upgrade options PGE plans to pursue, the Company clarifies that the SoA upgrade "options" consist of a study to evaluate the feasibility and cost-

[18] PGE Response to Staff IR No. [18] PGE Response to OPUC Staff IR No. 83 and LC 80: PGE Round 1 Reply Comments.
[19] PGE Response to Staff IR No. [19] PGE Response to OPUC Staff IR No. 186.

effectiveness of building a new Trojan-Harborton 230kV line.[20] Staff does not undermine the need for transmission resources in general, but believes that additional analysis is needed to evaluate potential value of on-system distributed energy resources, alternative transmission strategies, and a clear description of options that PGE says it will pursue for the SoA line. PGE also points out that the availability of the 400 MW of capacity from SoA in 2030 is dependent on work beginning immediately on this line.[21] Given this urgency and the fact that transmission is a long lead time resource, Staff hoped to see a more rigorous analysis along the lines described above rather than what PGE has presented as its planned near-term action for the SoA line.

Regarding exploring the Bethel Round Butte upgrade, Staff's primary concern is the appearance of this action item in the near-term Action Plan without any contemplation in the portfolio analysis. PGE discusses the importance of this upgrade in enabling integration of renewable resources from Central and Southern Oregon but does not provide supporting analysis or allow this action item to inform its Preferred Portfolio. PGE was unable to point out resources in PGE's Preferred Portfolio that the Bethel Round Butte would be connecting. The IRP is a platform to present analysis that Staff and stakeholders should be able to evaluate prior to recommending an action plan emerging from such analysis. In the absence of that analysis Staff and stakeholders cannot conclude if this is an acknowledgeable action to take on behalf of customers.

On October 18, 2023, PGE announced that the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS) was awarded federal funding for enhancements to the 230 kV Bethel-Round Butte transmission line in partnership with PGE.[22] Staff congratulates CTWS and PGE on this great accomplishment. Staff has not had sufficient time to evaluate the impact of this award on PGE's Action Plan or long-term strategy but notes that this reinforces the need to better articulate this action item and account for the award in its IRP/CEP analysis and the rest of the Action Plan.

Staff also recognizes the comments put forward by AWEC regarding PGE's transmission action items. AWEC points out that the SoA upgrade is not sufficient to connect all of PGE's proxy resources and that the transmission actions as presented in the IRP/CEP are vague and cannot be acknowledged.

Staff agrees that PGE should continue to explore its transmission expansion options and appreciates that this is the first time that the Company has taken on this level of transmissions analysis in the IRP. However, Staff does not believe that the proposed transmission action items are tangible enough for acknowledgement and requests that the Company provide this analysis as soon as practicable.

<u>Draft Recommendation 5</u>: 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.

3. Long-term IRP/CEP Strategy Acknowledgement

PGE's 2023 IRP is also the Company's first CEP following the passage of HB 2021. Staff and stakeholders have reviewed and provided substantial comments on multiple issues that the Commission might factor

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[20] PGE Response to Staff IR No. [20] PGE Response to OPUC Staff IR No. 91.

[21] PGE Response to Staff IR No. [21] PGE Response to OPUC Staff IR No. 187.

[22] See PGE Press Release, October 18. 2023, accessed at: https://portlandgeneral.com/news/2023-10-18-us-doe-grants-usd250m-to-confederated-tribes-of-warm-springs-in.

in when making decisions on acknowledgement of its strategy to meet its long-term needs—with an emphasis on readiness for the 2030 emissions reduction target. Staff understands that there is added complexity in planning for a clean energy future amidst growing electricity load, market and technological uncertainties, and a range of broader policy requirements. Staff appreciates PGE's efforts to prepare a reasonable plan while navigating through these challenges and believes that PGE has the tools to better evaluate the alternative paths to HB 2021 compliance, the strategies to deal with failures and acknowledge and minimize negative outcomes of its actions for its customers. However, the current plan lacks clarity around many of these issues. PGE's IRP/CEP is a step in the right direction, but does not provide Staff with the confidence that the Company has identified the full amount of resource actions needed to enable them to achieve the HB 2021 targets. Or, in other words, Staff continues to question whether PGE's analysis is sufficient to demonstrate that the Preferred Portfolio will be able to reduce emissions in line with the 2030 target. The work needed to model this is substantive, as the Company itself realizes.

Staff realizes that a lot of these improvements will happen over time and therefore distinguishes between key modeling changes to capture the actions that need to be taken to reach 2030 goals versus uncertainties outside of the Company's control or areas that can captured over future iterations of the plan.

The following subsections summarize the major areas where Staff is still concerned about the Company's resource strategy beyond the Action Plan. Staff understands that PGE made a "best efforts" attempt to adapt its IRP framework to the post-HB 2021 planning context and appreciates the Company's hard work. Staff continues to investigate interim solutions to ensure that remaining issues in the post-Action Plan resource strategy will not impact on the near-term Action Plan e.g., RFP scoring, avoided cost calculations, and other valuation of DERs. Staff's greatest concern at this time is the ability to monitor continual progress, reliability, affordability, and critical junctures without a more realistic understanding of what is needed to reach the HB 2021 targets.

<u>Draft Recommendation 6</u>: 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.**

3.1. GHG Emissions Modeling

In opening comments, Staff questioned whether PGE's emissions modeling approach accounts for practical operational constraints when estimating emissions reductions and presented a draft analysis that estimated PGE's GHG emissions with consideration of hourly dispatch and balancing challenges under a range of different assumptions. Staff estimated PGE's GHG emissions to fall between ~2.4 and

~3.5 mmtCO2e in 2030, compared to PGE's 2030 target of 1.62 mmtCO2e. Based on this analysis, Staff expressed concern that PGE's approach may be overly optimistic and may under-account for portfolio GHG emissions and noted that additional resources may be needed for PGE to achieve its 2030 GHG target. These additional resources may include complementary resources like energy efficiency and energy storage. Staff urged PGE to conduct its own hourly analysis of the Preferred Portfolio in 2030 using its PZM model to determine whether Staff's concerns were warranted.

RNW raises a similar concern in addition to several questions regarding the allocation of emitting resource dispatch, emissions, and costs to PGE customers and argues that the unspecified emissions rate could increase over time as utilities preferentially specify purchases of non-emitting energy.

Energy Advocates point out the importance of PGE's day to day operational decisions in decarbonizing the system, despite systems operations being excluded from traditional resource planning and recommend PGE use social cost of carbon in economic dispatch calculations to account for health and economic impacts of PGE's fossil fuel plants on local communities. Both Energy Advocates and NewSun call out the need to reduce emissions related to market sales of PGE's fossil fuel generation for purposes of earning revenue as it ignores impacts on communities located near these power plants.

PGE acknowledges these vulnerabilities in its GHG analysis and notes that the Company plans to improve this analysis in future planning processes. PGE also agrees with Staff's proposed near-term solution:

> PGE agrees with Staff that evaluating the resources included in the Preferred Portfolio in the PZM model (conducted in Aurora) could provide useful insight into both the feasibility of our plan and opportunities for modeling improvements going forward.[23]

Nevertheless, PGE raises several issues with conducting hourly analysis, including: PGE disputes that an hourly timestep is necessarily the best timestep for this analysis; PGE suggests that the differences in resource GHG emissions intensities between IRP modeling and DEQ accounting would cause inconsistencies if the Company were to use the PZM results to inform its GHG forecasts; and PGE expresses concern with the accuracy of the hourly load shapes if they were to be used in such an analysis. PGE suggests that these issues should be resolved before addressing hourly modeling of its GHG emissions within the IRP/CEP.

Staff is not compelled by PGE's rationale for delaying hourly analysis. Hourly modeling is the standard analysis for understanding how a portfolio might interact within a broader electricity market. Staff agrees that sub hourly modeling would also be instructive, but sees no reason to delay hourly analysis when PGE is already capable of doing it. Staff does not view the different GHG emissions intensities between IRP modeling and the DEQ reporting as a problem. PGE could simply take the total generation delivered to load from the PZM model over the course of each year and multiply that generation by the DEQ emissions intensities to estimate its DEQ reported emissions for that year. Staff agrees that PGE's hourly load shape probably warrants further attention if PGE is concerned about its accuracy but does not view imperfect input data as an excuse to defer insightful analysis.

Staff is grateful that, despite concerns, PGE conducted hourly dispatch analysis of the Preferred Portfolio in 2030 and presented some results from this analysis in its Reply Comments. However, PGE's new analysis does not provide insight into how the Company might balance the portfolio on an hourly basis,

[23] PGE Round 1 Reply Comments, p. 52.

because PGE applied run constraints to its emitting resources in order to match the outputs from its Intermediary GHG Model. Because PGE forced the model to match the Intermediary GHG Model outputs, the analysis cannot be used to better understand the extent to which economic dispatch in 2030 aligns with the Intermediary GHG Model outputs. Furthermore, PGE did not provide accompanying analysis into how the balancing challenges in its hourly analysis might impact annual GHG emissions. Nevertheless, PGE's analysis does offer some important insights if one accepts the caveat that the analysis excludes a significant portion of their thermal generation.

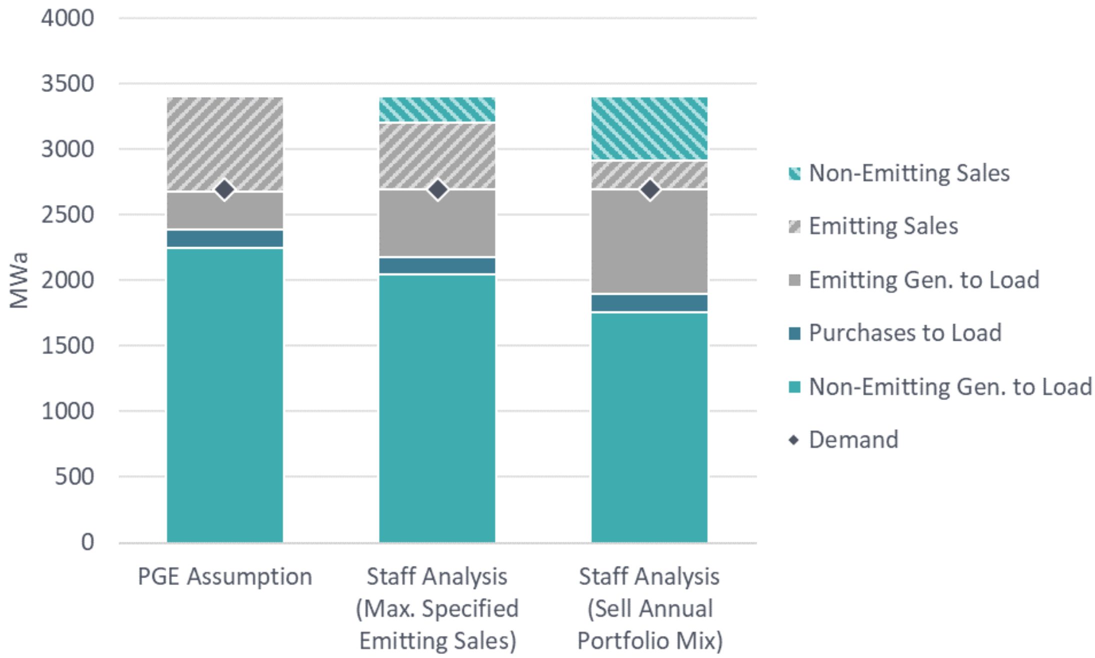
Figure 7 in PGE's Reply Comments shows the timing of purchases and sales across months and across hours of the day in 2030. It shows that PGE's portfolio is generally long during the Spring and in the middle of the day from March through September and is short during other hours, especially evening hours in the summer and winter. In short, the portfolio is long when the region has significant hydro and/or solar output and short when the region does not. The periods when it is purchasing from the market are the same periods when the region is expected to have less non-emitting generation available. Yet the analysis assumes that there will be a market for clean energy during the periods of length and that there will be clean energy available (with no cost premium) when it is short.

Staff used information from PGE's hourly dispatch analysis and additional information regarding the hourly economic dispatch of the Company's thermal fleet without run constraints to update Staff's analysis of PGE's 2030 GHG emissions.[24] Staff's updated analysis examines the Preferred Portfolio's expected position relative to the market in 2030 under Reference Case assumptions. In hours in which the Company is long, Staff tests two strategies: an optimistic emissions strategy, in which the Company is able to specify its sales and preferentially sell emitting generation into the market ("Maximize Specified Emitting Sales"); and a more technology-agnostic strategy, in which sales are not specified and are therefore assigned an emissions intensity based on the utility's resource mix for the year per DEQ rules ("Sell Annual Portfolio Mix"). In both scenarios, market purchases are assigned the flat unspecified emissions rate.[25] Figure shows how hourly constraints might affect the share of load that PGE can feasibly meet with emitting versus non-emitting generation under each strategy and compares this to PGE's assumptions.

[24] This underlying information was provided in PGE's highly confidential responses to Staff IR No. 179 and Staff IR No. 206.

[25] Staff's draft analysis showed an alternative approach in which purchases were assigned an emissions rate based on the estimated market heat rate in each hour to approximate the potential availability of non-emitting generation from the market during periods with a regional excess of renewables. This was not found to be a significant driver of PGE's total GHG emissions because of the timing and relatively small volume of its purchases.

Figure 2. Addendum Preferred Portfolio Annual Position (2030)



Staff finds that PGE's approach overestimates both the Company's ability to deliver non-emitting generation to load and its ability to sell emitting generation into the market, resulting in underestimation of its DEQ reported emissions. If PGE does not specify its sales, Staff's analysis suggests that 485 MWa of the annual sales in 2030 would be assigned a zero emissions rate and 221 MWa would be assigned emissions rates associated with PGE's natural gas generation for the year, per DEQ accounting rules. If PGE is able to specify the sales and maximize sales of emitting generation into the market, Staff's hourly analysis identifies a physical limit to how much emitting generation can be sold in 2030 while still meeting load under typical weather conditions. Staff estimates that in this scenario, 507 MWa of PGE's sales would be specified natural gas sales and the remaining 199 MWa of sales would be specified non-emitting. In contrast, PGE's GHG calculations assume that all non-emitting generation is delivered to load and all sales are therefore specified emitting generation. Staff finds PGE's assumption to be infeasible with the Preferred Portfolio in 2030.

Moreover, PGE's assumptions regarding market sales in its GHG emissions accounting do not align with its historical operations or its own simulations of future operations. PGE reported sales of 140-157 MWa of bundled renewable energy in its 2017-2021 RPS Compliance Reports,[26] compared to PGE's assumption of 0 MWa and Staff's estimated range of 199-485 MWa in 2030. In the CEP Data Template, PGE reports that 22 percent of the generation from emitting resources was sold in 2020, compared to PGE's assumption of 72 percent and Staff's estimated range of 22-50 percent in 2030.

The net effect of PGE's assumptions is an overestimation of DEQ reported emissions. **Table *3*** compares PGE's forecasted 2030 GHG emissions with GHG emissions estimates based on Staff's updated analysis. Staff continues to estimate that the GHG emissions associated with PGE's Preferred Portfolio may fall

[26] Note that this excludes sales of non-RPS-eligible hydropower.

between ~2.4 and ~3.5 mmtCO2e in 2030, missing the 1.62 mmtCO2e target set forth by HB 2021. Rather than reducing GHG emissions to 80 percent below baseline levels by 2030, Staff is concerned that the Preferred Portfolio may only achieve a 57-70 percent reduction from the baseline by 2030 unless PGE modifies its Preferred Portfolio.

Table 3. Comparison of 2030 emissions projections under emissions modeling approaches

	PGE CEP/IRP Addendum	Staff Updated Analysis (Maximize Specified Emitting Sales)	Staff Updated Analysis (Sell Annual Portfolio Mix)
Emitting resource GHGs in 2030 (mmtCO2e)	1.07	1.90	2.95
Unspecified purchase GHGs in 2030 (mmtCO2e)	0.55	0.51	0.51
Total 2030 GHG emissions (mmtCO2e)	**1.62**	**2.41**	**3.46**

PGE has suggested that markets for clean energy may help enable it to achieve the HB 2021 GHG targets without procuring incremental resources. Staff does not dispute this, but raises two important issues with this argument: 1) **Table *3*** shows that even if market purchases had no associated GHG emissions, PGE would still not hit the 2030 GHG target in 2030 without further action; and 2) Staff expects that a market for non-emitting energy would bring with it a cost premium over conventional market purchases and that this premium should, at equilibrium, align with the additional costs of adding clean resources to the utility's portfolio to meet policy constraints.

PGE does not agree with the Energy Advocates' position that economic dispatch in long term planning should consider health impacts and the social cost of carbon and disagrees with the position expressed by both the Energy Advocates and NewSun Energy that emissions from thermal generation that is sold should be reduced in addition to the emissions from thermal generation delivered to PGE loads. PGE points to guidance from OPUC Staff in justifying its use of economic dispatch modeling to estimate generation from the Company's thermal fleet.

Staff clarifies that the Docket No. UM 2225 expectations require generation and associated emissions information in the IRP/CEP to align with the Company's strategy for operating its thermal fleet going into the future. From Staff's perspective, this provides transparency into PGE's strategy for operating the thermal fleet and allows for more honest evaluation of whether the Company's plans are likely to achieve GHG targets, and how. If PGE needs to adopt an alternative operating strategy to economic dispatch in order to meet the targets (e.g., applying run constraints, GHG constraints, or GHG bid adders to dispatch decisions), then the Company should be transparent about how its plan depends on those planned operational changes and how/when it intends to operationalize those changes.

Staff continues to recommend that PGE 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 the extent that the Preferred Portfolio cannot achieve PGE's 2030 GHG target after taking into consideration hourly constraints, Staff recommends that PGE modify the Preferred Portfolio as needed. Staff understands that PGE may not currently have the modeling capabilities to bring these considerations into the portfolio optimization model and suggests that in the near term the Company use its analytical expertise and professional judgement to develop a portfolio that achieves the target in a manner that is, at a minimum, informed by portfolio optimization principles. Staff suggests that the Company specifically consider the potential roles of additional energy efficiency, complementary renewables, and energy storage to help mitigate any hourly balancing challenges that threaten the Company's ability to achieve the 2030 GHG target.

3.2. Transmission Modeling

In addition to the concerns around PGE's near-term transmission actions, Staff and stakeholders questioned PGE's long-term transmission strategy to reach HB 2021 goals. Staff's calculation showed that PGE's modeling assumptions project incremental firm transmission rights of 15,000 MW to deliver incremental resources to PGE in 2040. Staff questioned whether this approach resulted in overestimation of firm transmission rights that PGE would need realistically.

PGE does not dispute Staff's calculation and suggests that these rights will be needed for WRAP compliance because "as part of WRAP compliance obligations, PGE is expected in the day of operations to have 100 percent energy delivered to load on firm transmission."[27] PGE explains that non-firm and short-term firm transmission service increases the risk of resource curtailment and could affect reliability if those resource curtailments align with periods of high resource adequacy risk. Staff is not comfortable accepting this assertion without seeing this curtailment risk described quantitatively and or understating why 15,000 MW of additional long term firm transmission rights into PGE's system would be needed to deliver 100 percent energy to the peak load of 6,362 MW in 2040 on firm transmission rights within the day.

Moreover, it is not clear whether "the day of operations" need or the forward showing obligations is the correct metric to estimate transmission requirements for resources that will be acquired over a period of 20 years. For instance, WRAP's Forward Showing obligations are that "seven months in advance of each WRAP Winter and Summer Season, that they have sufficient capacity to meet a required planning reserve margin and have reserved at least 75 percent of the transmission (firm or conditional firm) necessary to deliver energy from that capacity to their load." Also, WRAP includes both firm and conditional firm transmission products for both operational and forward showing obligations.

RNW and Grid Strategies characterize PGE's assumption around curtailment rates of conditional firm transmission to be too conservative and ask for a more refined analysis on conditional firm transmission. This, they say, can be done by including conditions under which BPA's conditional firm transmission product might be curtailed. Grid Strategies analysis suggest that PGE assume zero hours of curtailment corresponding with peak hours for purposes of capacity accreditation, and that PGE perform power flow analysis.

PGE objects to RNW's position that PGE should assume zero curtailment hours for resources with conditional firm transmission rights. The Company argues that the assumptions behind the RNW/Grid Strategies study (including load growth, battery storage deployment, and South of Allston upgrades) are not appropriate for a long-term planning analysis.

[27] PGE Round 1 Reply Comments, p. 19.

Staff believes that a refined analysis of PGE's transmission product assumptions and a more rigorous analysis of transmission needs using power flow models are necessary steps for PGE to adopt as they engage in transmission planning. Staff agrees that PGE's assumptions about curtailment rates for resources with conditional firm transmission maybe too conservative, however, Staff does not support the use of a zero-curtailment assumption for these resources. Staff understands that the IRP typically does not include power flow analysis; however, PGE can include a supplemental study or refer to such studies that it did outside of the IRP, in the context of long-term transmission planning.

NewSun and Energy Advocates point out the need to adequately weigh CBREs as resources that can avoid transmission in PGE's portfolio analysis. NewSun states that PGE's plan relies on unrealistic transmission assumptions which prevents inclusion of additional CBREs and DERs as potential resources and indicates that PGE will not be able to meet the 2030 goals. They point out that WY and NV proxy transmission projects in the Preferred Portfolio are not economically and technically feasible in the timeline suggested by the IRP. NewSun argues that PGE's treatment of BPA TSR as available transmission is inappropriate and that the projected BPA transmission upgrades will take much longer than what is portrayed in the IRP. Both NewSun and Energy Advocates recommend the Commission host a workshop on transmission. Grid Strategies suggest that PGE should consider more proxy transmission resources in its portfolio. RNW argues that the artificially set limits of 400 MW of SoA, WY, and NV transmissions prevent selection of emerging resources and show that if the model was not restricted to transmission availability, the Preferred Portfolio would select offshore wind resources and recommend that PGE include at least 1 GW of offshore wind in the Preferred Portfolio.

Regarding proxy transmission resources, PGE asserts that its "Action Plan assumes that the company can and will explore all options to add incremental rights, including acquisition of rights on existing regional systems, and/or potential participation in new inter-regional transmission builds that are already underway and scheduled to come online before 2029."[28] PGE also argues that the transmission action item is driven by congestion issues and hence will be largely unchanged even if other on system or emerging resources become available.

Staff believes that stakeholders raised valid concerns which all point to risks of PGE not able to meet its 2030 targets given the heavy dependence of its Preferred Portfolio on proxy transmission resources and the absence of any alternative analysis in the event these transmission resources do not materialize. Staff understands that exploring transmission options will be a long-term endeavor and encourages the Company to initiate efforts in this regard sooner than later.

In the near-term, Staff believes that PGE needs to perform its portfolio analysis without overly optimistic assumptions about the deliverability of resources throughout the region.

For its next IRP/CEP, Staff believes that PGE should build on the progress it has made in its transmission modeling to include the following:

- 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.

[28] PGE Round 1 Reply Comments, p. 18.

- Include 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.

3.3. Portfolio Analysis

Portfolio analysis provides an opportunity for quantitative evaluation of cost and risks associated with the utility's resource strategy. Going into this IRP/CEP, Staff expected the Company to estimate the costs, risks, emissions, and community impacts (positive and negative) with alternative resource strategies that would allow comparison of the tradeoffs of strategies to reach the HB 2021 emissions goals and understand why PGE's chosen strategy is the most reasonable.

PGE introduced emissions reduction pathways and community benefit indicators associated with the resources and portfolios as enhancements to its portfolio analysis in order to address requirements in HB 2021 and Docket No. UM 2225 expectations. Staff understands the new planning requirements have made the already complex exercise even more challenging and appreciates PGE's efforts to include these new elements in its portfolio analysis.

Staff commented in Round 1 that PGE's approach of isolating groups of portfolios under different categories with different sets of assumptions prevents a direct comparison of portfolio risks and costs. PGE restricts emissions pathways comparison to a select group of portfolios that prevent understanding of emissions implications across all its portfolios. PGE uses cost, risk, and community benefits as portfolio scoring metrics, yet rejects a high performing portfolio on the basis of near-term cost impacts. Staff raised concerns with this inconsistent treatment of portfolios and the non-comparability of PGE's Preferred Portfolio with alternatives, which prevents a full understanding of the Preferred Portfolio being economically, technically and community impacts wise the most reasonable strategy to meet emissions reduction goals that are fast approaching. RNW raises similar concerns.

Staff also expressed concern with the dependence of the Preferred Portfolio on proxy transmission resources and the generic VER and capacity resources in PGE's Preferred Portfolio that prevents any visibility into the type of technologies the Company may need to reach its 2030 and 2040 emissions reduction goals, the costs associated with these transmission resources and technologies and the risks of these transmission or new technologies not materializing in the timeframe PGE is planning for. Both AWEC and RNW share the concerns around inclusion of generic resources. Concerns around proxy transmission availability have been discussed earlier.

PGE responded that its approach to portfolio analysis was aimed at answering a specific set of questions, which it did by gaining insights from the different categories of portfolios and then hand-designing the Preferred Portfolio to reflect the best outcomes from each category. They also point out that the 2019 IRP used a similar approach, and that comparability of the Preferred Portfolio is not a requirement within IRP guidelines. PGE also defends that the application of scoring criteria beyond cost and risk is based on the Company's judgement of factors that must be addressed while considering a particular resource type.

In response to Staff's comments on the absence of comparability of the Preferred Portfolio (Portfolio 40) with other portfolios (Portfolios 1 -39), PGE states, "…. That the comparability of the Preferred Portfolio to other portfolios is neither an IRP guideline nor requirement". Staff reminds PGE 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. The IRP Guidelines begin with the expectation that all resources will be evaluated on a consistent and comparable basis with portfolio risk modeling used to enable this comparison of different resources and other relevant factors over the planning period. Staff believes that this is basic information that Staff and stakeholders must have to draw even some high-level conclusions irrespective of whether a need for such portfolio comparisons is expressed in detail in the existing IRP guidelines.

PGE, nevertheless, responded to Staff's request to remove transmission proxy resources of 800 MW from the Preferred Portfolio to examine the resource alternatives the portfolio might select in the event these transmission resources do not materialize. PGE shows that the removal of transmission resources results in earlier and greater additions of generic variable energy resources (VERs) and generic capacity resources, the net impact being a $4.2 billion increase in net present value of revenue requirement in portfolio cost compared to the Addendum Preferred Portfolio. Staff notes that PGE did not provide this analysis for the most recent Preferred Portfolio that is included in its Reply Comments.

PGE also points out that Staff's suggested scoring criteria of pace of GHG reductions and community impacts across portfolios is overly prescriptive and that portfolio comparisons are not necessarily best understood using uniform scoring criteria.

Finally, in the Reply Comments, PGE made available 1,000 MW of offshore wind resources in its analysis and the Preferred Portfolio selects offshore wind beginning in 2032. Staff appreciates PGE responding to RNW comments in this regard.

Staff appreciates PGE's responses to Staff's suggestions to remove the 800 MW of transmission from the Preferred Portfolio. Staff's intention was to understand how this modified portfolio would compare to the other portfolios in PGE's analysis that did not rely on these proxy transmission additions. Making these proxy transmission resources available only to the Preferred Portfolio puts it in a different universe relative to the other portfolios PGE evaluated, making it impossible to understand the tradeoffs between the Preferred Portfolio and other alternatives.

The increased reliance on generic resources highlights the absence of any viable alternative in the event the WY and NV proxy transmissions were unavailable. Without these transmission additions, generic VERs now get added in 2029 (before it was 2030) and generic capacity gets added in 2031 (before it was 2034). PGE needs to consider these results seriously and explore alternative pathways to meet 2030, 2035, and 2040 goals.

Further, Staff differs with PGE on its comments regarding the use of GHG emissions reduction pace and community impact criteria across all portfolios. Staff realizes that traditionally IRP analysis has used cost and risk criteria uniformly across portfolios for comparison purpose. HB 2021 adds a new purpose to utility resource planning by requiring the utilities to plan for specific GHG reduction targets and accounting for impacts (both positive and negative) their actions would have on communities. The Commission needs visibility into these tradeoffs to evaluate its reasonableness. PGE must address the additional requirements 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. This is a key expectation of Staff going into the investigation into planning and procurement policies and PGE's next IRP/CEP development.

3.4. Reliability and Resilience

Staff raised concerns that the resource adequacy metrics of loss-of-load hour (LOLH) of 2.4 hours per season used by PGE is less stringent compared to traditional metrics. Staff requested for a comparison of the LOLH metric with loss of load expectations (LOLE) for its Preferred Portfolio.

RNW argues that reliance on the LOLH in need determination obscures other important information about loss of load risk, in particular the size, duration, frequency, and timing of loss of load events. They recommend that PGE adopt multiple RA metrics in their needs assessment, that they consider outage events, rather than outage hours, in determining resource needs, and that they identify an economically efficient resource adequacy target, rather than using the 1-in-10 standard. RNW argues that PGE should adopt more granular hourly import assumptions in their RA analysis to recognize regional diversity benefits, especially during summer heavy-load periods (6am-10pm).

Finally, both AWEC and RNW point out that PGE's current modeling of ELCCs of resources on an individual basis ignores portfolio effects of resources that could be either competing (e.g., two solar resources generating at the same hours lowers the combined ELCC) or complementary (e.g., solar and storage will increase the combined ELCC). If portfolio effects are present but ignored the resulting portfolio could be resource deficient or project resource overbuild. RNW recommends that PGE enhance future ELCC modeling to better capture portfolio effects and the impacts of the changing load and resource portfolio over future years. RNW also recommends that PGE conduct round-trip modeling to ensure that final portfolios achieve the RA target.

Staff agrees with both RNW and AWEC. Staff suggested that PGE rerun the Preferred Portfolio through their RA model Sequoia and verify if the reliability metrics are met. Staff believes this would largely address the concerns around under or over projection of resources in the Preferred Portfolio. Regarding refinement of RA metrics to capture the multidimensional effects of an outage event, Staff realizes this is an area of ongoing research and PGE should be able to adopt these evolving techniques going forward.

CUB asks for further details on how the IRP/CEP actions affect the reliability and resiliency of the electric system.

PGE expresses openness to RNW's suggestions to consider more RA metrics and to improve the granularity of market availability assumptions in future planning analyses. With regard to WRAP, PGE lists a number of questions regarding the interactions between WRAP and PGE's long term resource planning analysis and expresses the desire to continue the dialogue around those questions with WRAP and stakeholders. Staff appreciates PGE's willingness to explore and improve on its current reliability analysis.

PGE notes that CUB's concerns regarding the reliability and resilience impacts of PGE's actions are captured in the development of informational Community Benefits Indicators (iCBI). While reliability analysis is performed for resource portfolios, the breadth of issues related to resilience might prevent direct modeling of the benefits. PGE suggests that the development of iCBIs in the CEP captured resilience impacts of PGE's actions. Staff addresses this issue in Community Benefits.

PGE responded to Staff's request to provide the LOLH and LOLE of the Preferred Portfolio. PGE calculated and provided this information for the originally filed Preferred Portfolio and the revised Preferred Portfolio from their Addendum filing in select years. PGE did not provide this information for the updated Preferred Portfolio that they described in Section 6.2.4 of PGE's Reply Comments. Table 4 lists the RA metric provided by PGE for the revised Preferred Portfolio from their Addendum filing.

Table 4. RA Metrics for revised Preferred Portfolio[29]

Year	LOLH (hours per year)	LOLE (event days per year)
2026	1.994	0.260
2027	1.945	0.264
2028	1.531	0.191
2029	0.051	0.014
2030	0.051	0.020
2036	0.313	0.068
2043	0.385	0.020

Staff appreciates PGE's transparency in providing this additional information. PGE's analysis demonstrates a few key findings, which are described below.

The Preferred Portfolio meets a 2.4 hour per year LOLH standard in the years provided. While Staff agrees with AWEC's concern that using 1-D ELCC curves of very similar resource types could overestimate the capacity contribution of those resources, it appears that this has not resulted in inadequate portfolios when considering their chosen RA metric. This could be in part because PGE's 1-D ELCC curve approach also underestimates portfolio effects and the benefits of combining complementary resources.

The Preferred Portfolio does not meet a 1 day in 10 years LOLE standard (or 0.1 days per year) in the near term. In years 2026-2028, the LOLE is closer to 2-3 days every 10 years. Staff is concerned that PGE's plans may not be adequate to meet the requirements of Oregon's RA program or the WRAP program. Because both of these programs are currently in development, Staff is not recommending that PGE adopt a 1 day in 10 years RA standard for planning at this time but poses this as an important question for the next planning cycle.

The Preferred Portfolio appears to be long on capacity beginning in 2029, with an LOLE of 1-2 days every 100 years in 2029 and 2030. In their Reply Comments and discoveryresponse to Staff IR 207, PGE explains that this finding is a direct result of the Preferred Portfolio's reliance on Wyoming Wind and Nevada Solar to help achieve the 2030 GHG target.[30] These resources are assumed to be brought to PGE via proxy transmission that also provides access to markets in the West. PGE assumes this market access allows the proxy transmission additions to provide perfect capacity to the portfolio. In other words, the NV and WY proxy resources effectively bring 100 percent capacity contributions. As a result of this assumption, the energy acquisitions prior to 2030 in the Preferred Portfolio bring more capacity than is needed to meet PGE's RA requirements. Staff does not believe that PGE's assumptions regarding the capacity provided by proxy transmission to NV and WY are reasonable and therefore does not consider the RA metrics reported by PGE to meaningfully reflect the Company's expected RA position in 2030. In their response to Staff IR 208, PGE largely agreed, stating with respect to the NV and WY resources and

[29] PGE Round 1 Reply Comments, p.39, Table 4.
[30] PGE response to OPUC Staff IR 207.

their associated transmission: "the Company believes that the market access assumption is creating an inappropriate over-crediting of capacity to these resources."

PGE's IRP/CEP Addendum found that, without taking action, the Company's summer capacity needs in 2030 are expected to exceed 1,500 MW.[31] The Preferred Portfolio assumes that over half of this need, 800 MW, will be met by perfect capacity from NV and WY proxy resources and their associated transmission. PGE admits that this is an unreasonable assumption, but does not provide an alternative assumption to use. Staff is left wondering whether the Preferred Portfolio would leave some portion of capacity needs unmet if the Company were to adopt more reasonable assumptions and how large these unmet needs might be in 2030. At a high level, Staff is concerned that the IRP/CEP does not provide enough meaningful information to understand whether the Preferred Portfolio would ensure resource adequacy in 2030.

In the near-term, PGE should 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 should update the Preferred Portfolio accordingly before Staff makes its final recommendation on acknowledgment.

For its next IRP/CEP, Staff believes that PGE should evolve its 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. PGE should also consider portfolio effects of similar or complementary resources in ELCC calculations of its resource portfolios in its next IRP/CEP.

4. Additional Issues

4.1. Small-scale Renewable Energy

Staff requested PGE detail its SSR compliance strategy and position. PGE's response included a table that details the SSR resources anticipated on the system by 2030.

Table 5: PGE's Small-Scale Renewables Forecast[32]

Resource Type	Current Capacity per 2023 CEP/IRP	2030 Forecast as updated in CEP/IRP Addendum
Community Solar Program	27 MW	93 MW
PURPA QF < 20 MW	271 MW	281 MW
CBRE	0 MW	155 MW
Customer DERs (AdopDER forecast)	183 MW (not SSR-eligible per Order 21-464)	739 MW of solar 121 MW of storage[193]
TOTAL SSR ELIGIBLE CAPACITY	**298 MW**	**529 - 1,268 MW**

PGE noted in the IRP that customer DERs, specifically net metered resources, do not currently count toward the 10 percent SSR requirement from ORS 469A.210. This fact traces to OAR 860-091-000 through 860-091-0040, which establish additional parameters for utility compliance with the SSR

[31] Figure 7, PGE IRP/CEP Addendum.

[32] PGE Round 1 Reply Comments, p. 88, Table 9.

requirement. However, Table 5 shows that the majority of small-scale renewables on PGE's system in 2030 are expected to be customer-sited solar.

Staff and the public's ability to understand PGE's compliance position relies on both the SSR forecast provided in Table 5 and what the Company's "aggregate electrical capacity" is expected to be in 2030. PGE discusses this in Staff IR 197 and cites three values in calculating this value for 2030:

1. 5,085 MW: A Staff-derived value of existing owned and contracted resources
2. 3,550 MW: PGE's anticipated resource buildout by 2030 (Table 5 of PGE's Reply Comments)
3. 739 MW: PGE's anticipated customer solar, seen in Table 5 above.[33]

These three values add up to 9,374 MW as a best estimate of PGE's "aggregate electrical capacity" in 2030. Ten percent of this value is 937 MW. Therefore, PGE's SSR forecast shows two scenarios. Without counting customer sited solar, PGE will lack 408 MW of SSR and thus has not presented a pathway to compliance. However, if all customer sited solar is included, PGE could comfortably surpass the 10 percent requirement.

To this end, PGE notes in Reply Comments that the Company's success is contingent on, "progress in integrating customer-sited resources into our virtual power plant. Increased ability to manage customer solar as a capacity resource in planning and operations will be a key development toward SSR eligibility of some or all customer DERs".[34] PGE's strategy relates to the Commission's openness to revisit the inclusion of net-metered resources made in Docket No. AR 622, Order No. 21-464, adopting the SSR administrative rules. Despite not including customer-owned resources, the Commission expressed willingness to, "revisit the determination upon a demonstration that this paradigm has changed in ways that make customer-owned resources part of a utility's supply portfolio."[35]

Staff recognizes the compliance and cost saving potential of integrating customer solar into a VPP. However, significant questions remain about the pathway to that outcome. Does the Company anticipate all net-metered resources could become eligible as SSR and if not, what percentage could realistically be considered? How would customer solar be managed in the VPP such that it operates akin to supply options and when does PGE expect to demonstrate that ability?

Due to the uncertainty and nascent development stages of the VPP, Staff highlight the importance of nameplate capacity achieved via CBRE. Closing the SSR gap with additional PURPA qualifying facilities less than 20 MW and CBRE resources may be a prudent compliance strategy.

Draft Recommendation 7: The Commission should direct PGE in the next 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.

[33] PGE Response to OPUC Staff IR 197.
[34] PGE Round 1 Reply Comments, p. 88.
[35] See Docket AR 622, Order no. 21-464. https://apps.puc.state.or.us/orders/2021ords/21-464.pdf.

4.2. Community Engagement

PGE demonstrates a sincere effort to align with the requirements and guidance of both HB 2021 and Commission Order No. 22-390 regarding community engagement. The Company has provided a robust capture of engagement dates, venues, attendees, and input in addition to creating dedicated webpages, hosting accessible community meetings, and providing materials in user-friendly formats. PGE has also demonstrated responsiveness to feedback with regard to engagement by adjusting its platforms and methods based on stakeholder input. That said, Staff finds that there are still discernible gaps between the Company's interpretation of effective engagement and stakeholder priorities and expectations, particularly with regard to community-centered transparency, accessibility, and accountability in the CEP. For example, PGE's documentation on community engagement is extensive, yet it lacks authenticity because it does not provide clear explanation of how of how or why input was used to inform the plan.

Stakeholders, including Energy Advocates, RNW, and CUB have articulated a number of concerns that emphasize a lack of responsive revisions to the IRP/CEP. Stakeholders, including RNW and Energy Advocates, have also urged for more emphatic inclusion of environmental and energy justice principles in PGE's Action Plan.

Stakeholders urge PGE to commit to proactive advancement of CBIs with the incorporation of specific, strategic actions in the CEP to enhance outcomes related to these indicators and also elevate the lack of tribal engagement and inputs in the CEP. Comments include recommendations for a more direct, meaningful, and engaged interaction process with tribal entities to ensure that the planning process is genuine inclusive and reflective of both the intersections and divergences between communities impacted by the CEP.

PGE has expressed a commitment to enhancing its planning processes, particularly in embedding environmental justice principles within the CEP. The Company acknowledges the need for improvement and is willing to take steps to align its plan more closely with community expectations. This includes efforts to increase the accessibility of the CEP for non-experts, establish transparent feedback loops, and improve engagement with tribal communities. PGE has recently hired a dedicated tribal liaison to assist with this lingering deficiency in planning.

Recognizing this proactive stance, Staff believes it is a priority to develop clear, actionable expectations for engagement in future IRP/CEP development and review. Staff recommends the establishment of a working group that can operate in coordination with the broader investigation into the Commission's planning and procurement policies in 2024. Staff is committed to working with the Company to facilitate a constructive dialogue between the utility and representatives of communities where shared understanding and expectations can lead to actionable insights to improve the next IRP/CEP process. Staff also hopes that the working group will support or drive development of improvements to the Commissions IRP guidelines related to engagement.

The working group should consider what constitutes successful engagement by identifying standards, metrics, and benchmarks for transparency, accessibility, and accountability. It should explore and articulate standards and guidelines that can be considered for codification and/or provide a structured framework for community engagement and consider where change in current processes or regulatory frameworks may be necessary to achieve the desired outcomes. To this end, objectives of the working group may include:

- Define successful community engagement:
    - Develop consensus on clear definitions and standards of what constitutes 'successful' community engagement in the context of the CEP.
    - Develop a shared understanding on these standards across represented groups.
- Develop codifiable standards and guidelines:
    - Explore and identify elements of community engagement that can be standardized and codified into rules or guidelines for future IRP/CEPs.
    - Standards should be adaptable and reflective of community priorities and needs.
- Enhance understanding of community expectations
    - Assist utilities in better understanding and acknowledging the diverse expectations, needs, and priorities of community stakeholders.
    - Facilitate the utilities' efforts to incorporate this understanding and environmental justice considerations into the development of a more responsive and inclusive IRP/CEP.
- Propose improvements for future IRP/CEPs:
    - Based on the definitions, standards, and understanding developed, propose concrete and actionable recommendations for improving transparency, accessibility, and accountability in future IRP/CEP processes.
    - Ensure that these recommendations are geared towards environmental justice and HB 2021 objectives.

<u>Draft Recommendation 8</u>: 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. 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.

4.3. Community Benefits

In opening comments, Staff indicated that PGE's initial CBIs represent the beginning of a journey to develop meaningful metrics to inform portfolio analysis and track ongoing benefits and impacts of the Company's resource actions. The current CBIs provide limited insights and it is a priority that the Company invest in improving them for use in the IRP Update, the next IRP/CEP, and additional uses such as future RFPs.

Renewable Northwest (RNW) requests that PGE provide more information about how the baseline values for energy, equity, health and community wellbeing, and economic CBIs will be determined. RNW also requests that PGE differentiate the benefits from the CEP from other PGE efforts. RNW also reaffirms its recommendation that PGE create additional environmental CBIs, perhaps in coordination with Tribal partners.[36]

Much like Staff, CUB expressed interest in learning more about how community engagement factored into PGE's CBI development.[37] While CUB does not necessarily frame these two issues as purely CBI-

[36] RNW Round 1 Comments, pp. 52-53.
[37] CUB's Round 1 Comments, p. 3.

related issues, CUB requests that PGE clarify health, community, environmental, resiliency, and reliability benefits that arise from the PGE's IRP/CEP filing.[38]

The Energy Advocates recommend that PGE include additional environmental CBIs, such as tracking air quality, because the current approach leaves out important insights into the tradeoffs of the Company's HB 2021 implementation options.[39] Much like RNW, the Energy Advocates also recommend that PGE includes CBIs related to Tribal priorities and in consultation with Tribal partners.[40] The Energy Advocates conclude their discussion by imploring PGE to address the evolution of CBIs as part of its action plan and integrating CBIs into its RFPs for large scale resources.[41]

Throughout its Reply Comments, PGE reiterates that the CBIs included in this CEP are a first attempt. PGE states that it does not currently have the capacity to engage with communities to develop more specific tribal or environmental iCBIs but plans on reporting on the progress in those areas in the next IRP/CEP.[42] Rather than develop CBIs that capture localized health and environmental benefits as was suggested by stakeholders, PGE proposes to use its current rCBI and pCBI approach to proxy for these benefits.[43] PGE also suggests creating a process with stakeholders and a third-party consultant to develop more robust pCBIs.[44]

Staff supports PGE's proposal to prioritize the development of more functional CBIs and agrees with RNW and the Energy Advocates that more transparency and a clearer timeline is needed when developing more permanent iCBIs, baseline values, and pCBIs.

Staff agrees that implementing a new pCBI is not feasible in this IRP/CEP cycle and recognizes that this is PGE's first attempt at incorporating CBIs into its resource planning. However, Staff recommends that the Company improve upon its current pCBI and incorporate feedback from Staff and stakeholders for the next IRP/CEP cycle. A key part of HB 2021 is ensuring that the clean energy transition does not leave systemically underserved communities behind, and Staff still believes that PGE's current approach fails to provide any tangible information in portfolio evaluation or provide any sort of timeline by which the metrics will be improved. Staff is supportive of the Company's suggestion to hold a process to further develop pCBIs with the help of a third party and recommends that the Company provide a more detailed description of what this process would look like.

Further, Staff plans to consider minimum expectations for CBI development and use in portfolio modeling in the Commission's reexamination of planning and procurement policies in 2024. Staff believes that it will be important for PGE to take the lead in developing its CBIs with its communities and stakeholders, but it will be important that this effort remains connected to any expectations that will be established Staff-led investigation.

<u>Draft Recommendation 9</u>: 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

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[38] CUB's Round 1 comments, p. 6.
[39] Energy Advocates' Round 1 comments, p. 13.
[40] Id., p. 14.
[41] <u>Id.</u>, p. 15.
[42] PGE's Round 1 <u>Reply</u> Comments, p. 62.
[43] Id.
[44] PGE's Round 1 Comments, p. 67.

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.

4.4. Federal Incentives

The Infrastructure Investment and Jobs Act (IIJA) passed in 2021 and the Inflation Reduction Act (IRA) passed in 2022 provide various federal incentives in the form of new and extension of existing tax credits for both supply side generation and transmission resources, distributed energy resources (DER), and demand side energy efficiency measures. It is important that PGE reasonably account for these incentives in its long-term resource planning to accurately determine cost and benefits associated with various investment decisions. Staff and stakeholders appreciate PGE's inclusion of IIJA and IRA incentives, at least partially, in the updated DER forecasting in the Addendum. CUB asks that PGE provide timely updates about its analyses and strategies to utilizing available federal funds and how they plan to ensure that 40 percent of benefits flow to disadvantaged communities (resulting from the Justice40 initiative of the Federal government).

PGE responds that they have taken initiatives to develop measures toward building the needed equitable and inclusive workforce for the clean energy transition through the creation of the Oregon Clean Energy Workforce Coalition in 2022 and applied for grants that would be partly used to conduct market studies to evaluate workforce needs in the state. PGE is also willing to "provide updates to interested parties on its strategies to accomplish workforce and Justice40 goals as grants are awarded and implemented".[45]

Staff appreciates PGE's consideration of federal incentives in its DER forecasts and realizes that PGE has tried to consider these incentives in annual portfolio cost calculations as well. Staff believes there is room for more robust analysis of federal incentives as greater certainty develops around the availability of these funds to PGE. Therefore, it is a priority for the Company to take ownership over the successful implementation of federal incentives and provide updates about the impact on its current strategy as information becomes available.

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 next IRP/CEP Update.

4.5. Renewable Energy Credits (RECs)

In opening comments, Staff and GEI advocated for more transparency relating to PGE's RECs due to HB 2021. Staff's focus is understanding the Company's plan for use of RECs in excess of the Company's Renewable Portfolio Standard requirements, while GEI provided helpful reminders about PGE's responsibility in communicating its use of renewable energy when RECs are not retired.

In response to Staff, PGE explained that the Preferred Portfolio is forecasted to produce an excess of 263,245,829 RECs over the planning horizon, but the strategy for their treatment is more appropriate for discussion in the Renewable Portfolio Standard Implementation Plan (RPIP).[46] While REC valuation has been a difficult task in Commission proceedings over the years, this may represent hundreds of millions, if not billions, of dollars over the planning horizon.

[45] PGE Round 1 Reply Comments, p.94.
[46] PGE Round 1 Reply Comments, pp.89-90.

Staff believes that the IRP/CEP is the appropriate place to understand the REC position resulting from the Preferred Portfolio. Since Round 1 Comments, the Commission has clarified that the IRP/CEP will be the main forum for understanding the Company's REC position and management strategy.[47] Now that Staff understands the potential magnitude of the Company's excess RECs—which are a ratepayer asset—Staff believes that it is a priority to ensure the Company is focusing on customer value in managing RECs in excess of its compliance needs. The Commission is addressing certain stakeholders' questions related to HB 2021 REC policy in Docket No. UM 2273 and subsequent phases may investigate planning and asset treatment policy. Otherwise, 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.

In response to GEI, PGE agrees with GEI, "that full transparency is needed when communicating statements about its emissions accounting and forecasting, especially with the Company's use of RECs."[48] Staff also agrees and believes that this topic will be easier to discuss in detail following the Commission's order in Phase 1 of UM 2273.

5. Conclusion

Staff is appreciative of all the work that went into the development of the IRP and CEP by the Company and the thorough review of the plan by stakeholders. Staff has considered the fact that this is PGE's first CEP and hence a work in progress. Staff, with the help of stakeholders has presented an analysis of the plan and appropriate recommendations regarding PGE's near-term actions and long-term plan improvement. Staff hopes the CEP/IRP will continue to evolve in a collaborative manner and PGE will continue to make progress towards meeting the HB 2021 goals.

Staff has summarized its draft recommendation to the Commission on the acknowledgement of this IRP/CEP in Section 6: Summary of Recommendations and its other expectations for future IRP/CEPs in Section 7: Staff Expectations for Future IRP/CEPs. Staff looks forward to Stakeholders' and PGE's feedback on additions, corrections, or modifications to these recommendations in Round 2 Reply Comments. This includes suggestions to move expectations from Section 7 to actionable Commission recommendations in this docket or vice versa.

6. Summary of Recommendations

<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

[47] See Commission Order No. 23-360 issued in Docket No. AR 662.
[48] PGE Round 1 Reply Comments, p. 90.

securitization of EE, and a 2024 effort to update avoided cost methods to include the full value of HB 2021 compliance and avoided transmission.

<u>Draft Recommendation 2</u>: 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**.**

<u>Draft Recommendation 3</u>: 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.

<u>Draft Recommendation 4</u>: 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.

<u>Draft Recommendation 5</u>: 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.

<u>Draft Recommendation 6</u>: 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.

<u>Draft Recommendation 7</u>: 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.

<u>Draft Recommendation 8</u>: 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.

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.

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.

7. Staff Expectations for Future IRP/CEPs

In these Comments, Staff has identified the following expectations for future IRP/CEPs that will be carried through to the Commission's investigation into planning and procurement policies and/or PGE's development of its next IRP/CEP.

Customer Actions

- Include all EE identified as optimal in the Preferred Portfolio in the Action Plan, regardless of funding source. Ensure that other resource actions are informed by the overall target/optimal EE level.

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.

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 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.

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 for its next IRP/CEP.

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 will 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.

Portfolio Analysis

- Provide portfolio analysis that allows more direct comparison of tradeoffs of different resource strategies e.g., more precisely capture the CBIs of portfolios beyond the inclusion of CBREs i.e., allow comparison of the CBIs of the entire portfolio of actions and allowing GHG emissions to vary across portfolios.

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.
- 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.
- Rerun the preferred portfolio through the Company's RA model (e.g. Sequoia) and verify if the portfolio meets RA standards.
- Consider portfolio effects of similar or complementary resources in ELCC calculations of its resource portfolios in its next IRP/CEP.
- 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 compliance position and actions that it plans to take to acquire the needed resources.

- 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.

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.

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.

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.

Dated at Salem, Oregon, this October 24, 2023.

Sudeshna Pal

Sudeshna Pal
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