BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. LC 73

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2019 Integrated Resource Plan.	Staff Final Comments

Contents

1. Executive Summary

The following are Staff of the Public Utility Commission of Oregon's (OPUC or Commission) Final Comments on Portland General Electric's (PGE or Company) 2019 Integrated Resource Plan (IRP or Plan). The goal of the final comments is to respond to PGE's reply comments, reflecting on Staff's remaining concerns and questions as we prepare to finalize our recommendations on acknowledgement.

Staff appreciates the Company's efforts to respond to a broad range of issues in its first round of Reply Comments, filed November 5, 2019, as well as, its updated needs assessment filed November 27, 2019, and multiple errata filings. In addition, Staff continues to applaud the openness and collaborative spirit PGE maintains throughout the IRP process. As mentioned in Staff's Opening Comments, this IRP presents significant complexity related to both the current planning environment and the range of new planning approaches that PGE introduced. The Company's willingness to work closely with Staff and stakeholders is critical in this process.

Similar to PGE's 2016 IRP, this Plan raises important questions about the application of least-cost, least-risk planning principles in a time of "rapid change due to a combination of customer, technological, market, and policy drivers."[1] PGE has proposed supply-side resource actions that, once again, surface issues related to the concept of need in the IRP, the appropriate justification for the timing and scale of resource procurements, and the appropriate sharing of risk between shareholders and customers.

In the Opening Comments, Staff identified four overarching concerns with PGE's IRP analysis and outcomes.

- The Action Plan is disconnected from portfolio analysis.
- Portfolio selection does not adequately reflect portfolio modeling.
- The projected resource need may be skewed by major omissions.
- A narrow approach to decarbonization clouds the analysis.

While PGE's reply comments provide a range of helpful analyses and adjustments related to the concerns above, Staff's main issue remains: the combination of the proposed Renewable Action and Capacity Actions are not justified by PGE's analysis.

Staff appreciates the Company's receptiveness to feedback from the 2016 IRP, but finds that the PGE should more thoughtfully apply past IRP concepts to the current planning environment. Staff does not find that past guidance justifies the pursuit of another, similarly large investment in renewable energy resources without more direct consideration for the Company's forecasted capacity needs.

Consequently, Staff cannot currently recommend acknowledgement of the Capacity Action item and Renewable Action item without modification. Specifically, Staff has concerns about the timing of the Capacity Action and cannot support the design of the Renewable Action without modification to concretely address the forecasted near-term capacity shortfall and align the

[1] LC 73 - In the Matter of Portland General Electric Company, 2019 Integrated Resource Plan, July 19, 2910, p. 71 (hereinto referred to as "2019 PGE IRP").

resource size with more reasonable justification. Should the Commission wish to consider these action items for acknowledgment, Staff offers a set of conditions to mitigate risk to customers.

2. Action Plan Summary

Per PGE's Reply Comments, the Company plans to continue to pursue the Action Plan items identified in its IRP, but has proposed two adjustments in response to Staff and stakeholder comments.[2] The table below summarizes the original Action Plan and the two modifications proposed in PGE's reply comments:

Table 1: Summary of 2019 IRP Action Items

Category	2019 IRP Action Items	PGE Modifications
Customer Resource Actions	Energy efficiency: 157 MWa	-
	Demand response: 141 MW (winter), 211 MW (summer)	-
	Dispatchable standby generation: 137 MW	-
	Dispatchable customer storage: 4.0 MW	-
Renewable Action	2020 Request for Proposals (RFP) for up to 150 MWa of Renewable Portfolio Standard (RPS)-eligible renewables online by the end of 2023	Resources must be eligible for federal tax incentives
Capacity Actions	First, pursue bilateral contracts for existing capacity	-
	At an unknown time prior to initiating an RFP for new capacity resources, provide an update on the status of efforts to acquire existing capacity	-
	2021 RFP for a to-be-determined amount of non-emitting capacity with a to-be-determined COD, if needs remain.	Allow resources with long lead times if PGE is able to pair them with contracts to meet interim needs

For its Customer Resource Actions, PGE provides forecasted acquisition levels, but notes that it will pursue all cost-effective energy efficiency, as well as, all cost-effective and reasonable demand response, dispatchable standby generation, and dispatchable customer storage. Staff appreciates PGE's efforts to pursue cost-effective demand side actions and it consideration for the role of customers in this action item.

For supply side resources, the Company has proposed to release one RFP specific to RPS-eligible renewable energy resources. However, dependent on the outcome of bilateral negotiations for existing capacity, the Company may issue an additional RFP for new, non-emitting capacity resources in 2021. PGE states that it has not made a determination about entering a benchmark resource for either RFP and would communicate that decision in the RFP process.

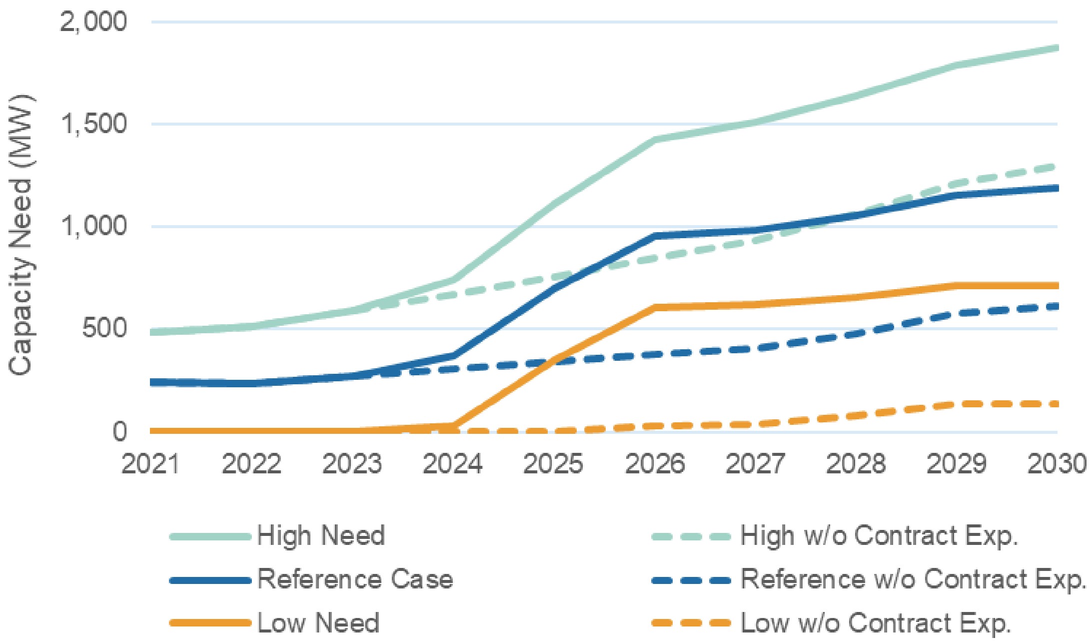
3. Capacity Action

PGE's Updated Needs Assessment forecasts a net increase in the Company's 2025 reference case capacity need from 685 MW to 697 MW, or from 326 MW to 340 MW if the need driven by expiring capacity contracts is not considered. This is due to the net effect of a 52 MW increase in the econometric load forecast and a 40 MW reduction driven by the addition of Green Tariff resources (subscribed only), Qualifying Facility (QF) contracts executed as of September 19,

[2] LC 73 – PGE Reply Comments, November 5, 2019, p. 5 ("PGE Reply Comments").

2019, and “additional miscellaneous resource and contract updates.”[3] PGE also provided updated high and low capacity need forecasts that account for changes in resources, but not the updated econometric load forecast. As illustrated in Figure 1, this creates a need that ranges from approximately 348 MW to 1,110 MW, or 0.4 MW to 753 MW if the need driven by expiring capacity contracts is not considered.[4]

Figure 1: Capacity need across Need Futures and impact of contract expirations[5]



As noted in Table 1, PGE plans to use a staged approach to meet this range of potential capacity needs. Under the staged approach, the Company will pursue bilateral agreements for existing capacity resources first. Then, it will reassess its capacity needs, update the Commission, and release a 2021 or later RFP for a to-be-determined amount of non-emitting capacity.

In Opening Comments, Staff expressed concerns that PGE's staged capacity strategy may be inconsistent with the urgency of its capacity needs and the feasibility of acquiring pumped storage—a major near-term resource in the Company's preferred portfolio.[6] Swan Lake North Hydro, LLC (Swan Lake) expressed similar concerns, while the Oregon Citizen's Utility Board

[3] PGE Updated Needs Assessment Addendum, November 27, 2019, pp. 4 – 5 (“Updated Needs Assessment”).
[4] Based on PGE Response to OPUC Staff Information Request (IR) No. 179, Attachments F and G.
[5] Updated Needs Assessment, p. 5.
[6] Staff Opening Comments, p. 7.

(CUB), Alliance of Western Energy Consumers (AWEC), and Renewable Northwest (RNW) expressed support or appreciation for the staged capacity approach.[7,8,9,10]

After considering the feedback from parties, PGE determined that a staged Capacity Action is in customers' interest, but offered to modify the future RFP to allow long lead time resources such as pumped storage to qualify.[11] Staff appreciates the Company's thoughtful discussion of the benefits of the staged approach. As noted in PGE's Reply Comments, the staged Capacity Action is designed to account for a range of uncertainties and is informed by Commission, Staff, and stakeholder feedback received in the 2016 IRP.[12]

Staff also agrees with PGE that it should carefully scrutinize the timing of new resource acquisitions against 1) the timing and certainty of its need; and 2) the risk that better options will be available in the future. However, Staff is concerned that the staged approach is:

- Not in line with the forecasted capacity need, portfolio modeling, and approach to the renewable action; and
- Limiting the Company's ability to secure cost-competitive and/or non-emitting resources to meet a near-term capacity shortfall.

For Staff to support the release of an RFP in 2020 it must adequately address the Company's demonstrated capacity need in 2025.

In the following sections, Staff takes another opportunity to explore the alignment of PGE's Capacity Actions with the forecasted capacity need and its preferred portfolio.

<u>3.1. Alignment with Capacity Need</u>

Staff's primary hesitation in recommending acknowledgement of the staged capacity action is not in the action itself. Rather, it is the inconsistency with the timing and scale of the Company's forecasted capacity need. Staff finds this particularly concerning against the backdrop of growing regional resource adequacy concerns referenced by many parties in this docket. Staff's review of the Company's capacity needs assessment suggests that the Company has accurately captured the range of potential future capacity needs and is likely to have an approximate 300 – 700 MW capacity shortfall in 2025—set against a decreasing likelihood of regional market capacity to mitigate this risk.

Staff's Opening Comments highlight the risks related to the staged approach, noting that the "extent of the reliability shortfall calls into question PGE's prioritization of near-term action items. The Company would appear to be more focused on acquiring renewables by 2023 than investigating zero-carbon approaches to meeting its potential capacity needs in 2025."

This section outlines Staff's support of PGE's capacity needs assessment and the risks associated with its staged approach.

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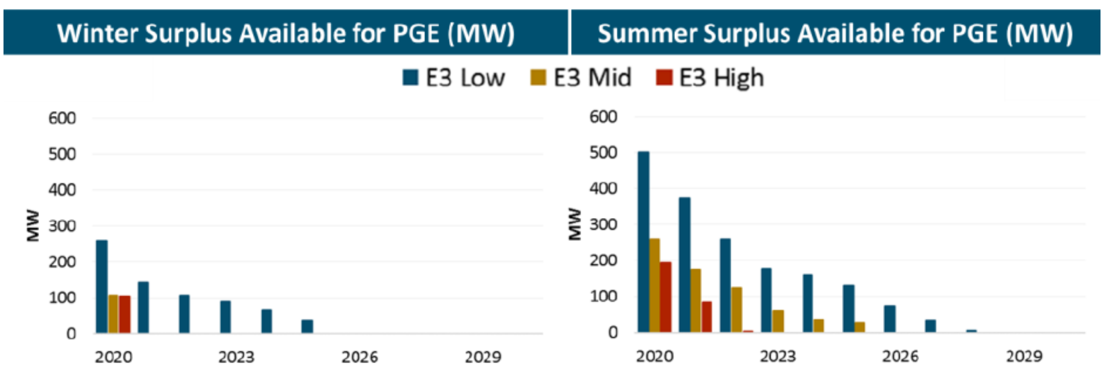
[7] Swan Lake Opening Comments, pp. 5 – 14.
[8] CUB Opening Comments, p. 14.
[9] AWEC Opening Comments, pp. 6 – 7.
[10] RNW Opening Comments, p. 7.
[11] PGE Reply Comments, pp. 14 – 16.
[12] Id., pp. 14.

Modeling Capacity Needs
PGE's 2019 IRP looks at capacity need in the open source model RECAP, using a capacity assessment study designed to achieve a Loss of Load Expectation of no more than 1 day in 10 years, or 2.4 hours per year.[13] Staff thanks PGE for its help in understanding the details of the Company's use of the RECAP model. Staff finds RECAP's overall approach to modeling capacity of variable energy resources reasonable; however, Staff notes one issue of interest raised by AWEC and considered by Staff in review of RECAP.[14]

PGE's modeling includes assumptions for the availability of regional capacity and imports from California and British Columbia. Staff notes that these amounts, supplied by E3, correspond with the assumption that no more regional generation resources will be built. Staff finds this an acceptable standard for now, so long as the assumption holds into the near future.

Staff plans to recommend an IRP acknowledgement condition that PGE monitor and report on this key assumption as part of any RFP and in the 2021 update to LC 73, as market conditions may encourage the building of more generation resources regionally.

Figure 2: E3 Market Capacity Assumptions Used to Model Capacity Need:[15]



Non-utility Actions
PGE provides helpful sensitivities to help characterize the potential impact of additional non-utility activities on its capacity needs. First, PGE provides sensitivity analysis of different QF development rates on its resource needs. The "low QF" sensitivity assumes that 50 percent fewer of the contracted but not operational QF generation comes online than the reference case. The "High QF" sensitivity assumes that all executed QF contracts become operational. PGE reports that a high or low QF adoption rate would lower or increase its capacity need by an estimated 16 MW respectively.[16]

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[13] 2019 PGE IRP, p. 104.
[14] AWEC Opening Comments, Attachment B, pp. 4 – 7.
[15] 2019 PGE IRP, External Study E p. 36, p. 647.
[16] PGE Updated Needs Assessment, p. 10, updated by PGE's December 11, 2019 errata filing.

Figure 3: PGE's QF Sensitivity[17]

	High QF	Base QF	Low QF
2025 Capacity Need (MW)	~~671~~681	~~685~~697	~~738~~713
2025 Energy Shortage (MWa)	~~135~~492	~~58~~527	~~28~~589
2030 RPS Physical Shortage (MWa)	~~228~~155	~~70~~190	~~42~~253

In its Reply Comments, PGE also provides a helpful discussion of the disadvantages of forecasting future QF adoption directly in its needs assessment. PGE explains that the IRP needs assessment is an important input for avoided cost rates and other QF development decisions. Incorporating a forecast of future QF development may skew this analysis. Staff appreciates this perspective and notes that the Commission opened Docket No. UM 2038 to address these types of questions. However, Staff still finds that an additional sensitivity of historic QF development rates would be helpful in understanding the range of future need.

Second, in addition to QFs, PGE's Updated Needs Assessment provides a sensitivity for increased participation in the Green Energy Affinity Rider program (GEAR or Green Tariff). This sensitivity assumes that the remaining capacity currently allowed under the program is subscribed. This analysis indicates that full subscription in the Green Tariff program could reduce the Company's capacity need by 28 MW. This only includes existing program size limits, not future expansion of the program offering.

Figure 4: PGEs Voluntary Program Sensitivity[18]

Program	Installed Capacity MW	Generation MWa	Capacity Contribution MW	2030 Avoided RPS MWa
Community Solar	93	12	15	4
Green Tariff (unsubscribed)	135	58	28	0
Total	228	70	42	4

In a high QF, high Green Tariff future, PGE's capacity need could be reduced by 44 MW. If all expiring contracts are renewed as well, these actions together would place the reference case 2025 capacity need at about 296 MW.

This analysis provides two helpful insights for Staff. First, PGE should consider these uncertainties when determining the scale of capacity resource procurements and continue to update its needs assessment to narrow in on the currently broad need future. On the other hand, these actions do not eliminate the 300 – 700 MW capacity deficit that the Company projects in 2025.

Timing and Risks of the Capacity Action

PGE's updated reference case shows a capacity need of about 240 MW beginning in 2021, increasing to about 270 MW in 2023 and reaching 697 MW as contracts begin expiring at the

[17] Id., p. 10, updated by PGE's December 11, 2019 errata filing.
[18] Id., p. 9.

end of the Action Plan window in 2025.[19] When accounting for the 40 MW reduction in capacity need due to Green Tariff elections, QF contracts, and other resource updates in the Updated Needs Assessment, PGE's 2023 capacity need would be roughly 5.8 percent of forecasted annual peak load in 2023 in the reference case.[20] Yet, PGE's plans to address this near-term need are not concrete, and Staff finds that PGE's choice to delay its proposed capacity RFP while pursuing renewable generation as an economic opportunity is concerning, especially in a time when regional capacity availability is uncertain.[21]

In addition, PGE has not yet provided modeling to show that its system will be reliable prior to 2025 if more capacity is not acquired.

The resources acquired through PGE's renewable action item would begin to contribute to meeting PGE's capacity need in 2024. However, the renewable RFP is not targeted to acquire a specific level of capacity and Staff finds the Company's estimation of the capacity contribution of wind resources in the IRP likely overstated and highly dependent upon the resource location and transmission capability.[22]

Figure 7-17 of PGE's IRP suggests that the 227 MWa of wind resources in the preferred portfolio provide a 161 MW contribution to the Company's capacity needs. As a note, this appears to be nearly comparable to the contribution of 237 MW of storage resources. Based on the capacity factors used in the 2019 IRP, 227 MWa could mean a 500 – 700 MW investment in wind resources by 2025. Given the ELCC figures provided in Table 6-6 of the IRP, Staff finds that the 161 MW contribution may be difficult to achieve outside of Montana resources.

Staff would appreciate additional discussion as to how a renewable-only RFP in 2020 for a 2023 date of operation can be an efficient means to contribute to the Company's forecasted capacity shortfall.

Table 2: Preferred Portfolio Contribution to 2025 Capacity Need[23]

Resource	**Estimated % of Need**
New Renewables	23%
New Energy Storage	24%
New Gas Generation	0%
Capacity Fill	52%

When asked to further clarify the risks associated with PGE's staged Capacity Action, PGE states that it was designed to reflect 2016 IRP feedback and mitigate the wide range of

[19] Based on PGE Response to OPUC IR No. 179, Attachment G.
[20] In the 2019 IRP, PGE's forecasted annual peak load is 3,524 MW in 2023 in the reference case (2019 PGE IRP, Appendix D. Table D-7, Page 268). PGE's Updated Needs Assessment did not provide an updated annual peak load. Therefore, Staff arrived at 5.8 percent by reducing the 246 MW capacity need in 2023 originally filed in the 2019 IRP (PGE Response to Staff IR No. 179, Attachment F) by the 40 MW reduction in capacity need due to updated resources that PGE reported in the Updated Needs Assessment, p. 5 (see December 11, 2019 errata filing for updated figures).
[21] 2019 PGE IRP, External Study E. Page 601.
[22] Staff Opening Comments, pp. 34 - 36.
[23] Based on PGE Response to NIPCC IR No. 022, Attachment O.

uncertainty in its capacity need, with load being the largest driver of uncertainty.[24] In the previous IRP, Staff recommended that PGE take specific actions to study its capacity need before pursuing a long-term capacity RFP. These recommendations included:

- Complete bilateral negotiations;
- Complete market depth/capacity study;
- Reevaluate capacity need; and
- Conduct an RFP for limited duration resources of less than 15 years to meet PGE's 2021 capacity needs.[25]

PGE has completed each of the above actions, with the exception of a limited-duration-resource RFP. Staff now finds it appropriate for PGE to begin looking to procure capacity in an RFP along with other resources as needed to achieve a portfolio with the best balance of cost and risk for customers.

Staff would note that PGE worked diligently in LC 66 and in UM 1892 to identify and negotiate bilateral contracts to meet a large portion of its near-term capacity need. In discovery, PGE provided the following insight related to its 2019 IRP:

> Throughout 2019, PGE has also engaged in commercial discussions with entities in the region to understand if, despite the potential regional challenges ahead, there may continue to be entities with excess capacity that could contribute to meeting PGE's needs. PGE's understanding is that there are multiple resources in the region that may be available to contribute to meeting PGE's capacity needs and that the bilateral negotiation process remains a critical step to ensuring that PGE has adequately explored these options before committing PGE customers to new resource development.[26]

Staff asks that PGE provide any additional information it can about the timing and availability of these resources and how they align with the Company's forecasted capacity needs between 2023 and 2025.

3.2 Alignment with Preferred Portfolio

In Opening Comments, Staff and Swan Lake commented on the misalignment of the pumped storage resources selected in the preferred portfolio and the timing of the non-emitting capacity RFP.[27] Specifically, these concerns relate to the ability of a long lead time resource to meet a requirement to come online in 2025 if an RFP is not released until 2021 or later.[28] PGE responds to these concerns with several points. Staff appreciates the discussion and provides its additional feedback below.

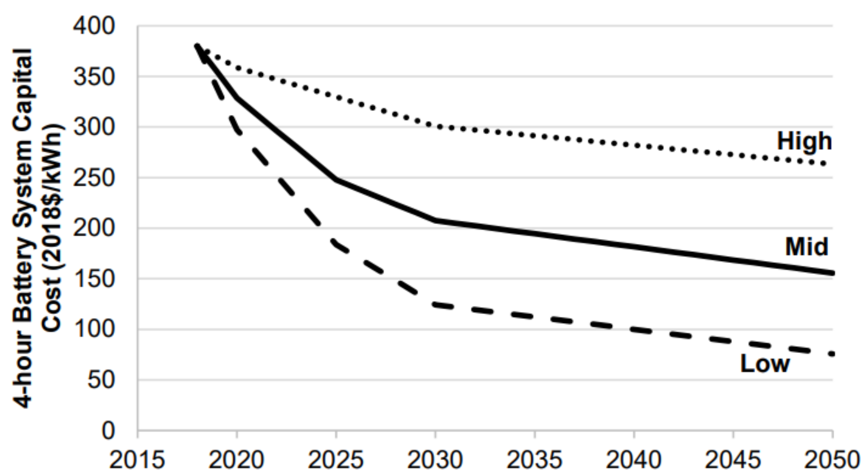
[24] PGE Reply Comments, pp. 18 – 23.
[25] LC 66, PGE 2016 IRP, Staff Final Comments, p. 20.
[26] Taken from PGE Response to OPUC IR No. 166.
[27] Staff Opening Comments, p. 7.
[28] Id., p.7.

Logistical Constraints for Long Lead Time Resources
The Company states that "accelerating the capacity RFP to 2020 and keeping the 2025 COD requirement would likely not mitigate the timing concerns expressed by Swan Lake."[29] Staff appreciates the Company's analysis of Swan Lake's development schedule and agrees that it is possible that a 2020 capacity RFP will not produce a qualifying bid from pumped storage. However, Staff disagrees that this is grounds to issue an RFP that is even more likely to preclude a resource selected in the preferred portfolio's Action Plan window from meeting the Company's capacity need it is intended to meet. There have been numerous past IRPs that have selected long-lead time items. *(See section 5.1.)*

Resource-specific Costs and Benefits
PGE suggests that modifying the timing of the RFP to be inclusive to pumped storage equates to targeting pumped storage and precluding "opportunities to meet resource needs at lower cost with battery storage."[30] This is based on PGE's IRP assumption that battery and pumped storage are currently on par, as well as, an expectation that battery technology will continue to improve rapidly in the near-term. Staff has several responses to this analysis.

Staff agrees that battery technology is likely to improve rapidly. In the time since PGE's 2019 IRP was filed, it has become apparent that battery costs are falling more rapidly than PGE's modeling assumptions have anticipated. A recent NREL paper published in 2019 shows that the mid-range of published storage cost projections expect battery storage costs to fall steeply from 2019 through 2021, and then fall an additional ~23% from 2021 through 2026. Even the high cost NREL scenario shows costs falling approximately 7% from 2021 to 2026.[31] This is compared to PGE's assumptions that battery costs fall less than 10% in the reference case from 2021 to 2026.

Figure 5: NREL Battery Cost Projections[32]



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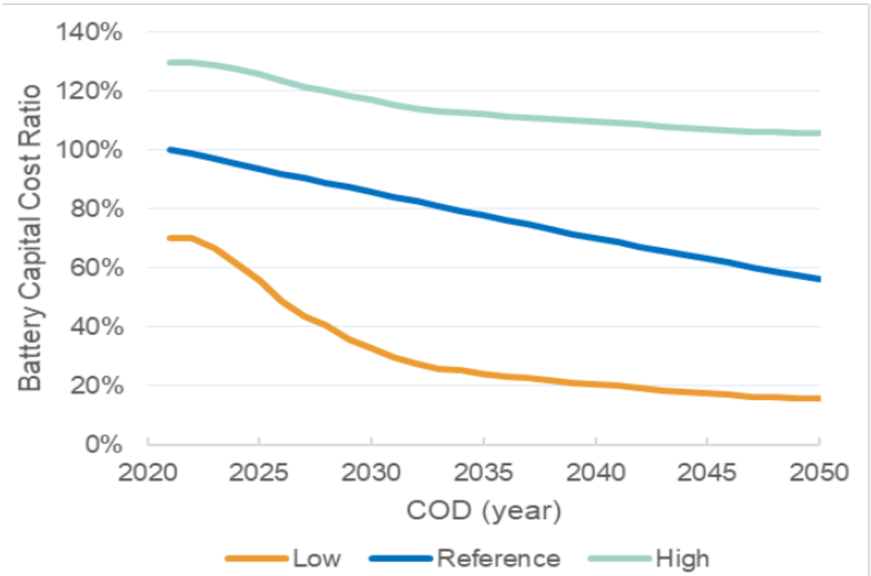
[29] PGE Response to OPUC IR No. 166.
[30] Id.
[31] Cole, Wesley, and A. Will Frazier. 2019. *Cost Projections for Utility-Scale Battery Storage*. p.iv. National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy19osti/73222.pdf.
[32] Id.

Figure 6: PGE Capital Cost Curves[33]



Staff also agrees with PGE that incremental or delayed procurement of large amounts of battery resources may make sense. Relying on batteries to be low-cost, modular, and flexible is likely an important part of a robust non-emitting capacity strategy. However, utilities across the country are still in early stages of learning how to operate large scale battery portfolios. A capacity action that waits for this technology to meet a near-term need may not be the appropriate balance of cost and risk.

Further, PGE's IRP includes assumptions for a wide range of possible battery storage cost curves. This range is considered in the portfolio modeling that resulted in the selection of both pumped storage and battery storage in the preferred portfolio during the Action Plan window. Staff understands that a mix of capacity resources, such as existing hydro contracts, pumped storage, and battery storage, may provide the best mix of cost and risk for meeting PGE's near-term capacity shortfall. PGE makes a similar point in its reply comments, stating that, "PGE agrees that the prospect of a regional capacity shortage in the mid-2020s is concerning and that pumped storage resources may be well-suited to meet a portion of the region's growing capacity needs."[34] If PGE's modeling already accounts a wide range of battery cost declines, and selects both pumped storage and battery technology in the Action Plan window, Staff questions what additional risks need to be accounted for with the RFP timing.

In discovery, PGE recognizes that, "in the long term, PGE's analysis suggests that capacity needs are expected to grow beyond 2025 if PGE takes no action. New resource additions that can come into PGE's portfolio after 2025 can help to meet this growing and persistent need."[35] Staff questions why this does not apply to batteries.

[33] 2019 PGE IRP, pp. 84 – 85.
[34] PGE Reply Comments, p. 14.
[35] Based on PGE Response to OPUC IR No. 166.

Finally, PGE explains in its 2019 IRP that "equipment costs for pumped hydro are less uncertain than for batteries; however, each project is unique in size and location, impacting construction costs and performance characteristics."[36] Staff finds that releasing the capacity RFP can only help PGE better understand the costs and risks of acquiring various amounts and types of resources to meet its state capacity needs. As PGE notes, releasing an RFP does not require the Company to purchase a resource if a good opportunity does not present itself.

Regional Insights

In its Opening Comments, Staff noted the risk that existing capacity resources may not be available in the same quantity as today because of additional fish recovery measures or a more lucrative California capacity market.[37] Staff expands on this risk to note that, in the event of a carbon-constrained regional capacity shortfall in the 2020s, competition for cost-competitive, non-emitting capacity resources may be high among Northwest utilities in a matter of years. This leads Staff to question how robustly PGE can evaluate existing capacity for cost-competitiveness without the pricing and performance data gathered through a concurrent RFP.

3.3. Consideration of Capacity in the 2020 RFP

Staff appreciates the Company's diligent efforts to explain the rationale behind its staged Capacity Action. It is clear that the Company is being thoughtful about risks and responsive to feedback, but Staff ultimately finds the Company's reasoning is contradictory and unsupported by the current circumstances. Absent demand response, PGE has not provided a concrete enough set of actions to meet its acute capacity shortfall by 2025. Staff is fully supportive of a plan that calls for the pursuit of cost-competitive existing capacity, but hopes that the Company can do more to position itself to be able to meet its future capacity needs with non-emitting resources.

If the Commission acknowledges the 2020 RFP, Staff recommends that acknowledgement be conditioned on specific consideration of the capacity need. For example, PGE could develop an all resource RFP for *up to* 100 MWa of energy (closer to the actual forecasted need in Action Plan window) and *up to* 340 MW of non-emitting capacity (2025 reference case capacity need not be driven by expiring contracts).

Staff also appreciated that PGE's goal for its Action Plan is to balance risks with flexibility, optionality, and cost containment. Staff finds that the principles underlying the Renewable Action can be applied to an RFP that also considers capacity more directly. Being more concrete about capacity in the RFP will help PGE make better informed decisions about the cost-effectiveness of existing capacity contracts, relieve some uncertainty surrounding storage technologies, incentivize non-emitting capacity providers to put forward competitive bids, and allow the Company to consider the relationship between different storage and renewable resources' capacity values.

For clarity, Staff proposes that the Company concurrently explore contracts for existing capacity and use the information available in both processes to inform its comprehensive resource procurement strategy.

[36] 2019 PGE IRP, p. 170.
[37] Staff Opening Comments, p. 7.

Recommendation #1: PGE's 2019 Action Plan has left substantial uncertainty as to how it will meet capacity needs in the near-term. Staff recommends that:

1. The Commission should acknowledge the Company's pursuit of bilateral contracts for existing capacity.
2. PGE should not release a 2020 RFP unless it specifically addresses the Company's capacity need and allows non-emitting capacity resources. The capacity need could be met in part or in whole by renewable energy.
3. PGE should provide updated analysis in the IRP that provides information on the types of resources that would be chosen by ROSE-E through a capacity and energy RFP in 2023.

3.4. Other Capacity Action Recommendations

Recommendation #2: To ensure future IRPs adequately account for future capacity needs:

- PGE should monitor and report on its market capacity assumptions as part of any RFP and in the 2021 update to LC 73, as market conditions may encourage the building of more generation resources regionally.
- PGE should provide additional explanation of the assumptions underlying the capacity contribution that the renewable-only procurement could provide.
- Given the modeling of multiple battery cost futures in the IRP, PGE should explain which additional risks need to be accounted for by delaying efforts to pursue the capacity resources in the preferred portfolio.
- Staff asks that PGE provide any additional information it can about the timing and availability of existing capacity resources and how they align with the Company's forecasted capacity needs between 2023 and 2025.

4. Renewable Action

As noted in Table 1, PGE proposes the addition of up to 150 MWa of unspecified RPS-eligible renewable resources by the end of 2023. While the top performing portfolios in the IRP select over 500 MWa of renewables in the Action Plan window, PGE constrained its preferred portfolio (Mixed Full Clean portfolio) to only add up to 150 MWa in 2023 and 2024. PGE indicates that this strategy aligns with Commission guidance in the 2016 IRP, which directs PGE to, "make a greater showing of how a proposed resource action aligns with needs, mitigates short-term rate impacts, and maintains long-term optionality."[38]

PGE proposes to acquire these resources through an RFP in 2020. This is designed to align the procurement with the deadline to secure remaining federal Production Tax Credits (PTCs). Staff's Opening Comments raise several concerns and questions about the risks associated with the Renewable Action. These concerns primarily relate to the timing of the action, but also relate to the process that identified the size of the procurement. On one hand, PGE's modeling suggests that PTC eligible wind is likely to be the cheapest resource available to meet its energy needs for decades. On the other hand, Staff, AWEC, and CUB point out that this procurement is not directly tied to an energy resource or RPS compliance need and identify a range of risks that may outweigh the forecasted benefits.

[38] PGE Reply Comments, p. 9.

Through Reply Comments, discovery, and supplemental filings, PGE has provided additional analysis that helps characterize the benefits and risks of the Renewable Action item. Staff greatly appreciates PGEs efforts to clarify the need driving this investment and quantify the risks about which Staff is most concerned.

In this section, Staff explains its continued hesitation to recommend acknowledgement due to the following risks:

- Alignment with Commission guidance,
- The Company's energy, capacity, and RPS need,
- The ability to secure and deliver the value of PTCs to ratepayers,
- The availability of low-cost renewable energy resources in a "High Tech Future",
- The performance of the selected resources,
- PGE's market price forecast, and
- Intergenerational equity.

PGE's analysis of sizing and other risks are not sufficient to recommend acknowledgement of the Renewable Action item. If the Commission acknowledges this item, Staff suggests conditions that may mitigate these risks. These conditions include better establishing the resource size, and ensuring that the RFP is structured to capture the potential difference in risk and rate impacts between a PPA versus a utility-owned resource.

4.1. Commission guidance

PGE's 2016 IRP presented similar issues related to the relationship between need and opportunity. In Order No. 17-386, the Commission provides a lengthy discussion of this difficult balance and outlines several principles on which an IRP must justify the size and timing of a resource procurement in the current landscape of complexity and uncertainty. First, the Commission suggests that full consideration of short-term impacts and long-term risks includes:

- Renewable resource portfolio diversity
- Alignment with near-term system needs
- Strategies for avoiding or mitigating front-loaded rate impacts, and
- Resource sizing that maintains long-term optionality.[39]

The Commission also advised that, "in reviewing an Action Plan, we will continue to look to see how individual action items fit into a comprehensive integrated strategy for meeting customer needs and whether the risks are appropriately shared between ratepayers and shareholders."[40]

Staff appreciates the Company's efforts to justify this RFP. However, Staff finds that PGE's has not yet demonstrated that the 2020 renewable RFP is designed to add a diverse set of resources, adequately aligns with the Company's near-term system needs; address the front-loaded rate impacts; provide a robust, quantitative justification for size of the procurement.

4.2. Energy Need

In Opening Comments, Staff, CUB, and AWEC raised questions about PGE's characterization of its energy need. These concerns relate to the underlying econometric load forecast,

[39] Commission Order No. 17-386, p. 3.
[40] Commission Order No. 17-386, p. 14.

consideration for industrial load and non-utility action such as Direct Access, and the use of the market energy position to characterize energy need in long-term planning. Staff appreciates the analysis provided in the Updated Needs Assessment, Reply Comments, and discovery. PGE has answered several questions about the econometric load forecast and non-utility actions. Staff also appreciates the Company's openness to answering Staff's technical questions about the load forecasting methodology.

In Section 6.3 of these comments, Staff explains in detail that PGE's load forecast methodology appears to be reasonable and that a review of the Updated Needs Assessment is under review. In this section, Staff's outlines how the proposed Renewable Action is not in alignment with the Company's forecasted energy need.

Market Energy Position and Energy Need

In Opening Comments, Staff commented that PGE's Market Energy Position (MEP) analysis should not be viewed as a measure of how much energy PGE needs to acquire through an RFP, since it only represents the quantity of energy PGE should purchase on the market in a given future, and not a need to acquire new resources.

In Reply Comments, PGE wrote that the MEP has "advanced the consideration of energy need by examining the changing energy position across need and market energy price futures…" PGE explained that it has historically used the energy load resource balance (energy LRB) as a simplified proxy to estimate energy need, and that the MEP is an updated way to provide "greater insight into the uncertainties of the existing portfolio's future energy position and potential exposure to variability risk."[41]

Staff continues to disagree with PGE that the MEP is a useful tool for measuring the need for new energy resources. The MEP is based on economic dispatch instead of a true energy shortage. The MEP is simply a measure of how much energy PGE would choose to purchase on the market in a given economic scenario. It does not seem appropriate to simultaneously use it to represent the amount of energy PGE should procure from an RFP in the same future.

PGE's MEP analysis shows that when market prices are lower than the cost of operating PGE's system, PGE will go to the market for energy. This is not necessarily an indication that PGE needs to build new resources, only a commentary on how economic PGE's existing assets happen to be. It may simply indicate that market price forecasts are low and PGE does not need to run its existing dispatchable energy resources to meet load. The model may be choosing to back down existing PGE generators that could easily ramp up again if market prices increased. Further, the difficulty of forecasting dispatch may increase as regional markets evolve.

PGE should purchase energy generation resources when they are part of a least cost, least risk portfolio. This includes consideration of the resources that are already in rate base. The Company's expected market energy position is simply not a good metric for deciding how much energy or capacity the company should procure in an RFP.

Finally, if this approach to analyzing need is to be adopted, Staff would like to have a discussion with all stakeholders before the next IRP about other areas where an MEP type of analysis could be applied. For example: this analysis could be applied to evaluate executing a long-term

[41] PGE Reply Comments, p. 53.

purchase of RECs from Oregon-based QFs for 100% of RPS compliance needs versus rate-basing the construction of new renewable resources.

PGE should not use the market energy position to quantify the need for new resources.

Load Resource Balance and Energy Need
While the MEP can be a meaningful tool in assessing the value of a Company's assets in a more integrated market, Staff finds that the traditional load-resource balance (LRB) remains a more meaningful IRP tool to ultimately characterize the need to invest in new resources. As noted above, Staff continues to evaluate the updated needs assessment for accuracy. Staff's review aside, the updated LRB does not provide a compelling rationale to invest in renewable resources that are online in 2023.

Figure 7**Error! Reference source not found.** indicates that the Company may need to meet a 121 MWa energy deficit in 2025 with market purchases or new resources. In the low and high need futures, the Company identifies an energy need that could range from a 147 MWa energy surplus to a 255 MWa deficit. While PGE may have an energy need in 2025, Staff notes that being 121 MWa short to market in 2025 is not a clear justification for acquiring 150 MWa of resources in 2023.[42]

Therefore, Staff does not find that the Renewable Action item is driven by energy need.

[42] Based on PGE Response to OPUC IR No. 179, Attachment M.

Figure 7: Updated Load Resource Balance[43]

Energy Load-Resource Balance based on the Need Update Addendum

Please Section G.3 of the 2019 IRP for a description for the methodology for constructing the energy LRB.

Reference Need

	2021	2022	2023	2024	2025	2030	2035	2040	2045	2050
Gas	945	945	945	946	945	945	945	946	945	945
Coal	262	262	262	262	262	262	0	0	0	0
Hydro	439	438	437	435	341	272	259	260	259	259
Wind+Solar	472	559	559	559	558	548	485	342	334	333
Other contracts	31	31	31	31	31	26	8	0	0	0
Energy Efficiency	41	70	97	124	150	280	400	515	629	742
Total Resources	2190	2305	2332	2357	2288	2334	2097	2063	2167	2280
Load	2193	2247	2302	2355	2408	2658	2910	3169	3437	3705
Energy Deficit / (Surplus)	3	(58)	(30)	(1)	121	324	813	1105	1270	1425

Low Need

	2021	2022	2023	2024	2025	2030	2035	2040	2045	2050
Gas	945	945	945	946	945	945	945	946	945	945
Coal	262	262	262	262	262	262	0	0	0	0
Hydro	439	438	437	435	341	272	259	260	259	259
Wind+Solar	472	559	559	559	558	548	485	342	334	333
Other contracts	31	31	31	31	31	26	8	0	0	0
Energy Efficiency	41	70	99	129	159	305	449	593	736	879
Total Resources	2190	2305	2333	2362	2296	2359	2147	2142	2274	2417
Load	2054	2079	2108	2130	2150	2256	2360	2465	2574	2680
Energy Deficit / (Surplus)	(136)	(226)	(225)	(232)	(147)	(102)	213	323	299	263

High Need

	2021	2022	2023	2024	2025	2030	2035	2040	2045	2050
Gas	945	945	945	946	945	945	945	946	945	945
Coal	262	262	262	262	262	262	0	0	0	0
Hydro	439	438	437	435	341	272	259	260	259	259
Wind+Solar	472	559	559	559	558	548	485	342	334	333
Other contracts	31	31	31	31	31	26	8	0	0	0
Energy Efficiency	41	70	97	124	150	280	400	515	629	742
Total Resources	2190	2305	2332	2357	2288	2334	2097	2063	2167	2280
Load	2248	2317	2394	2466	2542	2934	3310	3687	4070	4447
Energy Deficit / (Surplus)	59	12	63	110	255	600	1213	1623	1902	2166

[43] Ibid.

4.3. Capacity Need

PGE notes in its Reply Comments that "these renewable additions serve to provide both low cost energy to the portfolios and avoid the need for additional capacity resources."[44] As noted in Section 3.1, PGE assumes that procuring the renewables in its preferred portfolio will provide up to 161 MW of capacity contribution online before the end of 2025; however, this is based on assumptions that Staff finds are likely to overstate the capacity contribution and be largely dependent on the location of the resource and availability of transmission during peak hours. These risks are further discussed in Section 4.5 below.

While Staff agrees that the Company faces a likely capacity shortfall in 2023, it is unclear how a renewable-only procurement without a specific capacity target will address this. As noted in Section 3, Staff asks that PGE clarify how the 2023 renewable procurement specifically helps meet the Company's capacity need.

Without further clarification, Staff does not find that this procurement is driven by the Company's capacity need.

4.4. RPS Need

In the 2019 IRP, PGE's RPS need varies, based on the 810 futures, non-utility actions, and objective function selected in portfolio modeling. As a baseline, if PGE does not execute the Renewables RFP as currently called for the in the IRP and relies on existing resources and its REC bank, PGE will not have an RPS need until the mid-to-late 2030s.[45] Regarding RPS need, the Company provided two sensitivities which help clarify that requiring use of 20 percent unbundled RECs and removing the RPS obligation altogether do not materially impact the selection of resources or the performance of the preferred portfolio.[46]

Staff appreciates the sensitivities and agrees that the IRP's selection of near-term renewable energy is driven by economic opportunity.

To account for this, PGE suggests that it will return the value of these RECs to customers prior to 2030, which is the year PGE suggests it will have a physical RPS deficiency.[47] This approach is consistent with the condition approved by the Commission in the 2016 IRP.[48] In comments during the 2016 IRP docket and in a recent filing on December 3, 2019, in Docket UE 370, PGE describes the available options for monetizing RECs as including 1) a sale of RECs in the wholesale market, 2) a sale of RECs to PGE's retail subscribers of renewable portfolio option programs, or 3) the evaluation of REC value toward future alternative policy compliance.[49] Consideration of potential mechanisms to returning value to customers is ongoing; however, Staff requests that PGE identify the strategies it has or will consider to return the value of these RECs, and share any analysis as to how the mechanism impacts the overall value returned to customers relative to RPS compliance, and mitigation of the lack of RPS need for its Renewable Action in the 2019 IRP.

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[44] PGE Reply Comments, p. 26.

[45] Based on PGE Response to OPUC IR No. 022, Attachment A. Staff notes that this is based on analysis performed prior to the Updated Needs Assessment.

[46] PGE Reply Comments, pp. 49 – 53.

[47] 2019 PGE IRP, pp. 216 – 217.

[48] Commission Order No. 18-044, p. 2.

[49] Order 18-044 at 3; Docket UE 370, Exhibit PGE/100, Armstrong – Batzler at 18.

4.5. Renewable Resource Risks

While Staff does not find that PGE has a compelling energy, capacity, or RPS need to add 150 MWa of renewable energy resources in 2023, its analysis suggests that PTCs make near-term wind acquisition a promising economic opportunity for customers. The Commission recognizes that incremental and near-term action to address longer-term renewable energy obligations may be appropriate.[50] However, this guidance is rooted in the existing IRP principles, meaning the investment appropriately balances near-and-long-term cost and risk. Staff reiterates from Section 3.1 that the greatest risk associated with this action is that it does not sufficiently address the Company's important capacity needs.[51] This section outlines additional risks specific to the early procurement of a renewable resource.

Securing Production Tax Credits

Renewable size and timing analysis provided in PGE's Reply Comments further indicate that the benefits of the preferred portfolio is largely dependent on the modeling of federal PTCs. In PGE's analysis, the net difference between a wind acquisition in a PTC eligible year, versus delaying to the following year is only half as high as the benefit provided by the PTC. In other words, early action is only beneficial with PTCs.[52]

Figure 8: PGE Reply Comments Renewable Size and Timing Comparison[53]

Table 1: Differences in Renewable Size & Timing Portfolios, 2023 versus 2024

MWa Addition	COD2024-2023 NPVRR (millions $2020)	Approximate Difference of PTC Value (millions $2020)	Percent of Value Difference Attributable to PTCs
50	16	25~~13~~	155.5%~~83.4%~~
100	31	49~~26~~	161.5%~~86.6%~~
150	45	73~~39~~	162.5%~~87.1%~~
200	59	98~~52~~	164.5%~~88.2%~~
250	73	122~~65~~	167.3%~~89.7%~~

Based on the PTC, PGE's analysis of the levelized cost of energy (LCOE analysis) forecasts that the value of wind will not be as good again until as early as 2036 in the low future and after 2050 in the high future. Staff provides additional comments on the learning rates underlying PGE's LCOE analysis in the next section, Cost in High Tech Future.

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[50] Commission Order No. 17-386 p. 2.

[51] It should be noted that PGE's near-term capacity need is partially driven by an assumption of limited market supply, not solely a lack of PGE resources. Specifically, PGE can rely on 100 MW – 250 MW of winter market surplus in 2020 depending on load growth in the region and availability of market imports from California. For the summer, PGE can rely on 100 MW – 500 MW of market surplus through 2021 and a smaller amount thereafter depending on load growth and imports availability. This is driven by resource availability, not the import capability of the physical system. *See* 2019 PGE IRP, External Study E Market Capacity Study, p. 37.

[52] PGE Reply Comments, p. 32, updated with PGE errata filing, December 5, 2019.

[53] Id.

Table 3: PGE Assumptions for Wind Price Over Time			
Wind Resource	Year in which LCOE is at or below LCOE of 40% PTC eligible resource (2024)		
	Ref	Low	High
New_Wind_Gorge	2046	2041	After 2050
New_Wind_Ione (Oregon)	2041	2037	After 2050
New_Wind_MT	2047	2043	After 2050
New_Wind_WA	2047	2043	After 2050

Recognizing the strong relationship between the PTC and its preferred portfolio, the Company offers to modify its renewable RFP to require that resources are eligible for available federal tax credits. Staff appreciates and supports this recommendation (without supporting the RFP itself.)

Staff also recommends PGE specify which federal tax incentives, such as PTCs and Investment Tax Credits (ITCs) are required for eligibility as this could be as broad as accelerated depreciation.

In Opening Comments, Staff also noted the risk that projects may fail to provide the forecasted benefits due to cost overruns and construction delays. In its Reply Comments, PGE indicates that it manages this risk through non-price scoring criteria for project readiness and "contractual terms that would, in a PPA, set fixed prices that assume PTC, and, in an ownership model, through liquidated damages provisions."[54] Staff appreciates this helpful response and underscores the importance of fully vetting non-price scoring metrics in the RFP approval docket, to the extent not fully articulated in the IRP.

PGE also explains that, "ultimately, the Commission has the authority to weigh whether PGE took appropriate steps of behalf of customers to mitigate these risks in a future ratemaking proceeding." Staff appreciates the Company's response, but considers the IRP process as a critical input into the Commission's review of prudence.

Therefore, Staff recommends that if the Commission acknowledges a 2020 renewable RFP, the Company should be required to return the full forecasted value of the PTC and ITC to customers.

Cost in a High Tech Future

PGE's Renewable Action relies on the likelihood that conditions in the future will not be so favorable for renewable buildout that a near-term investment is unfavorable. PGE's modeling is designed to recognize this risk with the non-tradition scoring metric for Cost in High Tech Future. This metric measures the, "NPVRR through 2050 in a future with High Renewable WECC-wide Buildout, Low Solar and Battery Costs, and Reference Case Needs. This metric examines the risk of regret in a future with rapid advancement and deployment of clean technologies."[55]

[54] PGE Reply Comments, p. 68.
[55] 2019 PGE IRP, p. 187.

For example, in the reference case, the preferred portfolio NPVRR performs $885 million better than the Delay Renewables portfolio. However, in the High Tech Future, delaying renewables performs $921 million better.[56]

Table 4: Comparison of High Tech Future Risk – Delay Renewables									
	Traditional Metrics			Non-Traditional Metrics					
Portfolio	Cost	Variability	Severity	GHG-Constrained Cost	GHG Emissions	Near Term Cost	Incremental Criteria Pollutants	High Tech Future Cost	2025 Energy Additions
Mixed Full Clean (preferred portfolio)	25,740	3,614	31,004	25,694	100.5	6,098	0	15,341	213
Delay Renewables	26,625	3,835	32,065	26,671	107.3	6,161	0	14,421	-42
Difference	(885)	(221)	(1,061)	(977)	(7)	(63)	0	920	255

Staff notes that the preferred portfolio and Delay Renewables portfolios are constrained differently. It is possible that not adding renewables in the Action Plan window is not the only driver for these differences. In discovery, PGE provided a portfolio which it considers to be a more direct portfolio comparison with the preferred portfolio.[57] Comparison of this new portfolio, Mixed Full Clean, No Resource Acquisition (NO RA), produces interesting results which warrant further exploration.

Table 5: Comparison of High Tech Future Risk – Mixed Full Clean, No RA									
	Traditional Metrics			Non-Traditional Metrics					
Portfolio	Cost	Variability	Severity	GHG-Constrained Cost	GHG Emissions	Near Term Cost	Incremental Criteria Pollutants	High Tech Future Cost	2025 Energy Additions
Mixed Full Clean (preferred portfolio)	25,740	3,614	31,004	25,694	100.5	6,098	0	15,341	213
Mixed Full Clean, No RA	26,369	3,824	31,829	26,453	105.0	6,140	0	15,324	34
Difference	(629)	(210)	(825)	(759)	-4.5	(42)	0	17	179

Staff seeks clarity about the stark differences in metrics between the Delay Renewables and Mixed Full Clean, No RA. Staff requests that PGE discuss the differences between these two portfolios and what may be driving the very different metrics of two portfolios designed to enable comparison of near-term renewables. This may provide helpful insights into 1) the costs and risks associated with different investment, and 2) the nuances within PGE's new, sophisticated modeling tool.

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56 Id., p. 190.

57 PGE Response to OPUC IR No. 181.

Further, Staff asks that PGE explain how this non-traditional metric will be present in the scoring of the RFP.

In addition to noting the risk of a highly favorable future for renewables, Staff raised concerns about PGE's methodology for forecasting future renewable resource prices. In Opening Comments, Staff raised questions about PGE's use of different approaches to forecasting wind and solar learning rates and requested further explanation.[58] PGE's Reply Comments suggest that its reason for choosing a learning rate from Bloomberg NEF (BNEF) for solar is that the EIA's rate was too low, but the EIA had a high enough learning rate for wind, so BNEF wasn't used.[59] Staff is concerned the same argument PGE made for rejecting EIA projections for solar might also apply to wind. The gap between the two wind learning rates may not be as large as it was for solar, but the existence of a gap might be material to assessing the value of the PTC against future costs of wind resources.

PGE should provide additional explanation to demonstrate these choices were not arbitrary and expected to impact the risk of a more favorable future for delayed renewable resource acquisition.

Resource Performance

The location and type of renewable resource plays an important role in the amount and time at which a resource will generate. The amount of energy a wind resource generates over the course of a year (capacity factor) will impact the amount of PTCs it generates and the ability to reduce the Company's market exposure. The amount and time at which this generation occurs throughout the year (generation profile) dictates the value of the resource in meeting PGE's specific capacity needs.

PGE's modeling specifies a capacity factor and generation profile at four proxy wind locations. Each proxy location corresponds differently with the Company's needs. In Opening Comments, Staff raised questions about the capacity factor and generation profiles of the wind resources selected in the preferred portfolio. For example, Montana and Southern Washington proxy resources are modeled with higher capacity factors and correspond better with the Company's winter peaks. Oregon and Columbia Gorge resources have lower capacity factors and correspond more with the Company's August peak.

Capacity factor sensitivities provided in PGE's Reply Comments indicate that the wind acquisition in the preferred portfolio still represents a $400 - $600 million benefit to ratepayers over the Delayed Renewable resource acquisition, even with a capacity factor as low as 24 – 32 percent.[60] At the same time, Staff notes that the preferred portfolio loses roughly $1,330 million in benefits when the capacity factors are adjusted to this level. Staff assumes this risk is driven by reduced PTC benefits, lower LCOE, and higher exposure to the market.[61]

Staff notes again that PGE's decision not to specify a capacity level or location for the 2020 Renewable RFP exposes ratepayers to the risk that the resource selected will not meaningfully contribute to the Company's capacity need.

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[58] Staff Opening Comments, pp. 37 – 38.
[59] PGE Reply Comments, p. 65.
[60] Based on PGE Response to OPUC IR No. 174.
[61] Ibid.

If the Commission is to approve any renewable RFP from this IRP, Staff believes it is important to direct the company to weight those resources with a higher capacity factor or generation profile that best aligns with PGE's capacity needs (e.g., Montana or Southern WA wind versus Gorge wind).

Market Price Forecast
In Staff's understanding of PGE's portfolio modeling, the market price assumptions are an important factor in the calculation of costs and risks of resource procurement, such as near-term wind. At the highest level, Staff finds that the market price in a given future will impact ROSE-E's decision to fill an energy shortage with a new resource or a market purchase, and the extent to which ROSE-E estimates a new resource can generate benefits by selling energy to the market. Staff is concerned that PGE's Aurora electricity market price forecast does not fully consider the impact of a potential Oregon carbon price to the region, and as a result the forecast may be unrealistically high.

A future Oregon carbon price would change the composition of generation resources in the regional market over time. For example, if a carbon price were enacted in Oregon in 2020, it would send a price signal to developers which would result in development of fewer emitting resources in the years going forward. However, PGE's Aurora market price forecast is based on resource buildout assumptions provided by Wood Mackenzie that do not appear to include a carbon price comparable to PGE's forecasted Oregon carbon price.

The result of using resources developed in a world without a comparable Oregon carbon price would be a substantial increase in electricity market prices. In this unrealistic world, developers would just keep building the same emitting resources, even in the presence of a carbon price. This is unrealistic because a carbon price should have the effect of influencing developers to build less emitting generation in order to avoid paying the price of emitting.

It is difficult to speculate about the extent to which PGE's market price forecast may be over-estimated due to this effect, or how fixing the issue would impact portfolio selection. Probably, lowering the market price forecast would result in new energy resources looking less economic. This is because of two effects. 1) The new energy resource would have to compete with lower market prices in order to be cost-effective, and 2) sales from the new energy resources would be less lucrative at lower market prices.

In order to get an accurate market price forecast, PGE could use a resource buildout scenario developed for a world with an Oregon carbon price. PGE should pursue this improvement in its next IRP. And, any market price forecast should be based on a future resource buildout portfolio developed using an Oregon carbon price comparable to those PGE is considering in its portfolio analysis.

In Opening Comments, Staff also questioned whether PGE's modeling captured the dynamic relationship between the shape of wind generation in the region and wholesale market prices.[62] In its Reply Comments, PGE provided helpful analysis that eased some of Staff's initial concerns and indicated that PGE's calculation of the historical energy value of the Tucannon

[62] Staff Opening Comments, p. 36.

wind farm comes in close to Staff's estimate, which used Platt's Day-Ahead prices. However, Staff has a few remaining questions about this analysis.

Staff notes that it is unclear which price data PGE used and would also like PGE to explain how a historical value of $19.98 MWh falls so far below the bottom range of the 2019 IRP's estimate of the levelized energy value of Washington wind resources.[63]

Staff expects this historical price to fall below the reference wholesale price future, but Staff would like to know how it fell below the bottom range of price futures. In Final Reply Comments, Staff would like the Company to confirm that the $32.35 for Washington wind in Table 6-4 on page 162 of the 2019 IRP is derived from the H,L,L,H price future. This was the Company's lowest price future which had little escalation out to 2050. It would be helpful to understand why even that levelized energy value is significantly higher than the Company's own estimate of the recent historical energy value of the Tucannon wind farm's generation.

One explanation Staff has considered is that PGE's Aurora modeling is dispatching wind generation with prices that average a low wholesale price when the wind blows and a high wholesale price when the wind does not blow. Staff tested the ability of the Company's Aurora modeling to capture this dynamic effect between wind generation and wholesale prices by regressing historical hourly Mid-C prices onto historical hourly wind generation and historical PGE hourly load, comparing this model with the same data simulated by Aurora. Staff found the two sets of data display similar results, and PGE's modeling in Aurora reasonably captures the effect regional wind generation has on Mid-C prices.

Regardless, Staff is concerned that PGE's modeling may be overstating the value of bringing on new wind resources.

Intergenerational Equity Analysis
As noted in Opening Comments, Staff appreciates PGE's inclusion of an intergenerational equity analysis in its 2019 IRP. This is a meaningful improvement from the 2016 IRP. Overall, Staff appreciates that the difference between a 2023 and 2026 energy resource acquisition may be on the smaller side. What Staff finds particularly interesting is that there is a noticeable difference between the ratepayer impacts of a PPA and a utility-owned resource. If the Company does move forward with a 2020 RFP for renewable resources, the Company should carefully structure its RFP to weight bids to capture these differences.

The intergenerational equity analysis as included in section 7.3 of the 2019 IRP compares the rate effects of acquiring a PTC-eligible wind project in 2023 versus a non-PTC-eligible wind project of the same size in 2026. PGE's analysis shows that both projects would save customers money in the long run, but increase costs in the near-term. The 2023 project would cause a rate increase three years sooner, increasing rates by approximately .04 cents/kWh from 2023-2026, and reducing rates beginning in 2027. The 2026 wind acquisition would lead to a rate increase of about .05 cents/kWh from 2026-2030, and would result in a rate reduction by 2031.

Staff's Opening Comments pointed out that the ultimate effect a new resource will have on rates depends on many factors, including resource cost and performance, future market conditions,

[63] PGE Reply Comments, p. 66.

and customer demand. As such, Staff recommended PGE assist stakeholders in gaining an in-depth understanding of the intergenerational equity analysis by holding a workshop. [64]

In PGE's Reply Comments, it noted that it would be open to holding a workshop related to its intergeneration equity, stating it would add intergenerational equity to its November 21, 2019 roundtable agenda. [65]

At the November 21, 2019, roundtable PGE provided background and more information regarding the intergenerational equity analysis, including assumptions and methodology.[66] Among the presented information was the fact that the intergenerational equity analysis in 7.3 assumes a Purchased Power Agreement (PPA) structure, meaning that the wind resource was not modeled as a PGE owned resource, and that the Company had selected the year 2026 as its comparator as it is the first year outside of the action plan timeframe.

As a follow-up to the roundtable meeting, Staff requested additional information from the Company, asking them to perform the analysis as if the wind resource was a PGE resource. As a PPA structure allows the costs to be fixed (levelized or equal) over the life of the project, this can cause the acquisition to look more attractive in the near-term than a utility owned resource that would have front-loaded costs that decrease over time. This was confirmed in PGE's response to Staff.

PGE's response indicated that the Company additionally modeled an alternative intergenerational equity analysis scenario in which two modifications from the filed scenario are made:

1. Fixed costs in each year reflect annual revenue requirements for fixed costs of a proxy PGE-owned resource; and
2. PTC value flows to customers contemporaneously with PTC generation, rather than levelized over the life of the project.

The result of this scenario is that the 2023 renewable addition results in a net increase in costs between 2023 and 2026, averaging 0.12 cents per kWh, and net costs decreasing beginning in 2027. The 2026 renewable addition results in increased costs between 2026 and 2032, with an average increase of 0.15 cents per kWh, and net costs decreasing beginning in 2033.[67,68]

As evidenced by the results, in either ownership scenario, the differential in the rate impact is rather small when comparing apples to apples, i.e. a PPA structure in in 2023 vs 2026 and PGE owned in 2023 vs 2026. However, the rate impact, and therefore the intergenerational equity impact is substantially different when comparing one to the other. For example, when comparing the alternative analysis in 2023 to a PPA structured acquisition in 2026, the near-term (2023)

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[64] Staff Opening Comments, p. 5.
[65] PGE Reply Comments, p. 67.
[66] Integrated Resource Planning Roundtable Meeting #19-3, Slides 17-20. https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning/irp-public-meetings.
[67] PGE Response to OPUC IR No. 176.
[68] Staff notes that PGE's alternative analysis does not include potential impacts associated with PTC carryforward, which the Company notes are accounted for in evaluating potential PGE-owned resources within the RFP.

result is 0.12 cents per kWh for the alternative, but the 2026 PPA acquisition has a near-term rate increase of just 0.05 cents per kWh. This is to say, that when considering intergenerational equity issues, it is important to consider ownership structure and review all possible outcomes to future ratepayers before determining whether a particular set of outcomes is, in fact, equitable.

Staff notes that PGE's section in the IRP on utility ownership does not currently include this analysis.

Staff is also concerned that the Company's choice of years (2023 and 2026) may be unduly arbitrary, and as the Company has performed no sensitivity analysis around the choice of acquisitions (i.e. comparing a 2023 acquisition with a 2025 or 2027 acquisition). While Staff understands the Company's choice to choose 2026 for its estimate, as it is the first year outside of its Action Plan, Staff would have liked to see analysis that corresponded with the Company's projected energy need in 2025. Staff cannot definitively confirm whether or not the rate impacts as presented in Section 7.3 of the IRP broadly hold, or are only applicable in this particular case.

Staff finds that PGE should include more discussion of its conclusion surrounding this topic when justifying a resource acquisition solely on economic opportunity. Rather than simply include graphs showing the rate impact, PGE needs to include a description of why it is equitable to shift these costs forward, how choices around timing and ownership impact net costs on a $/kWh basis, and how the Company is mitigating this risk. Staff also notes that reiterating that 150 MWa is smaller than 500 MWa and selling RECs to its own green power customers is not sufficient.

4.6. Renewable RFP Size

In Opening Comments, Staff expressed concerns that the Action Plan was too disconnected from the portfolio modeling and that the construction and selection of the preferred portfolio was a blunt exercise detached from the rigorous portfolio modeling. As many of these issues drive the Company's determination of an "up to" size for its Renewable Action item, Staff finds this approach to sizing is too subjective to sufficiently balance costs and risks.

In Reply Comments, PGE repeatedly states that concerns about size and timing are inconsequential due to the 150 MWa constraint that the Company used to identify the renewable RFP size. Staff finds PGE's response unsatisfactory from a methodological standpoint and remiss of the fact that acknowledgement of an IRP is not isolated to the Action Plan. Portfolio modeling flaws cannot be overlooked simply because the procurement size is smaller than what the best performing portfolio selected. Nor can waiting a year to perform a capacity procurement justify the misalignment of the 2020 RFP with the Company's needs assessment and regional adequacy concerns.

In PGE's 2016 IRP, the Company proposed 175 MWa of renewable energy procurement. The Commission determined that this procurement size did not adequately balance near-term costs and long-term risks and, "was not well explained and justified, except on the basis that projected NPVRR benefits increased with the size of the resource, up to a point."[69] As a result, the Company returned with a revised 100 MWa procurement that was acknowledged with additional

[69] Commission Order No. 17-386, p. 15.

conditions.[70] In the 2019 IRP, PGE has proposed nearly as large of an “up to” procurement size as the 175 MWa that the Commission failed to acknowledge in 2016, despite lower PTC values available to resources in the 2019 RFP. Regardless of modeling, Staff finds this concerning.

In terms of modeling, Staff does not find adequate analysis supporting the “up to” size. Already knowing that PGE’s model will select more than 500 MWa of wind in 2023 without constraints, the Company placed a 150 MWa constraint on 2023 and 2024 resources in its preferred portfolio. Then, when the model selects the entire 150 MWa allowed in 2023, the Company seems to suggest that means that it is the appropriate size.[71]

The Company has introduced a range of new analytical tools in this IRP. Staff finds it surprising that the Company did not consider a more methodical approach to determining the appropriate size.

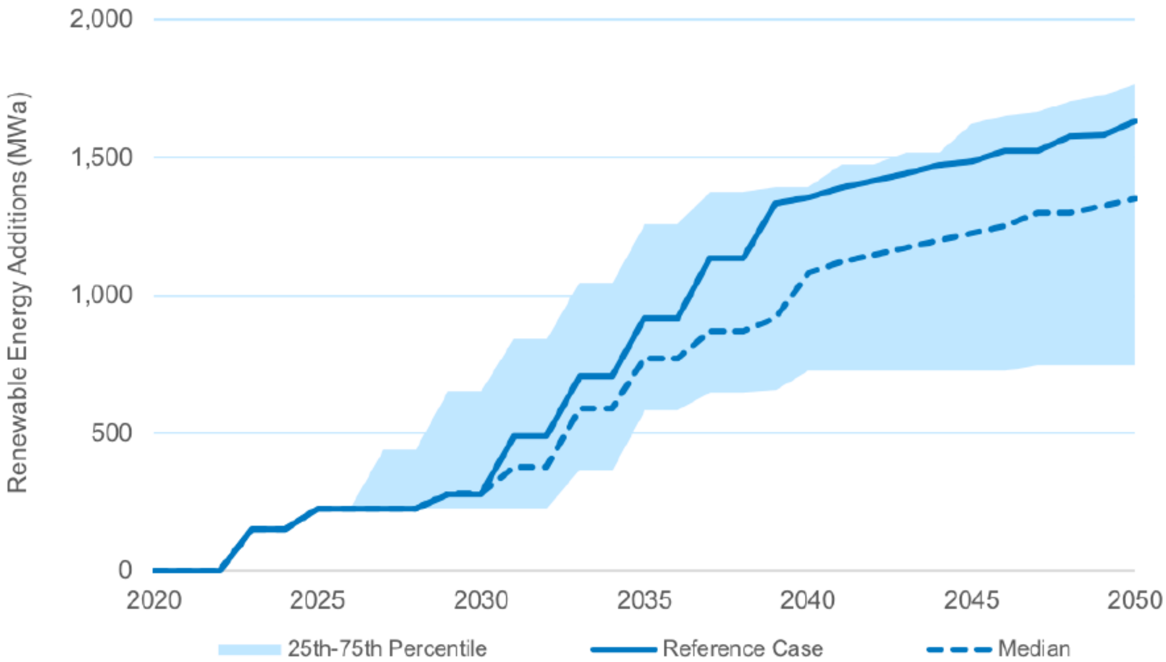
Finally, the Company performed a renewable glide path analysis on the preferred portfolio. Staff appreciates this important analysis, which shows that the preferred portfolio falls beneath its market energy position and above its RPS need. PGE finds that this is a good check that the sizing appropriately balances risk and optionality. Staff finds that it is a start, but has two concerns:

- PGE should not use its market energy position to quantify the bounds of resource procurement.
- In the reference case, the Company will purchase over 200 MWa in the Action Plan window, and will not make another purchase until 2029.

Without additional explanation, Staff finds it difficult to find a concrete justification for why the Renewable Action is the appropriate size. Staff cannot recommend acknowledgement of this item until presented with an approach that aligns more clearly with the IRP’s cost and risk assessment.

[70] Commission Order No. 18-044.
[71] PGE Response to OPUC IR No. 171.

Figure 9: PGE's Renewable Glide Path for the Preferred Portfolio[72]



4.7. Conditions for the Renewable Action

As established in this section, the 2023 renewable RFP is solely driven by an economic opportunity to acquire wind when the Company expects it to be most economic. The Company has not provided a strong justification for the 150 MWa size and there are still several risks associated with, as PGE describes a pumped storage investment, a "large irreversible commitment." That said, capturing the PTC for customers does lower the cost of wind significantly and could provide substantial benefits to ratepayers. Below is a summary of the conditions that Staff finds could help mitigate the risks associated with the 2020 RFP.

Recommendation #3: PGE has not sufficiently demonstrated its Renewable Action provides full consideration of short-term impacts and long-term risks. The following conditions will help balance the costs and risks of the 2020 Renewable RFP:

- Establish a procurement size that is rooted in more robust analysis and use the load resource balance as the upper bound of the glide path.
- As recommended by PGE, require renewable resources to qualify for federal tax incentives. PGE should also specify which incentives are eligible.
- Require the Company to return the forecasted value of PTCs to customers.
- Adequately evaluate bids for the impact of the ownership model on rate impacts.

4.8. Other Renewable Action Recommendations

Recommendation #4: To ensure renewable action items adequately balance costs and risks:

- PGE should not use the market energy position to quantify the need for new resources.

[72] 2019 PGE IRP, p. 203.

- Staff requests that PGE confirm whether it is considering a similar strategy to mitigate the lack of RPS need for its Renewable Action in the 2019 IRP as it is for Wheatridge.
- PGE should discuss the differences between the Delay Renewables and Mixed Full Clean, No RA portfolios and the drivers behind the stark variation in scoring metrics.
- Staff asks that PGE explain how the Cost in High Tech Future non-traditional metric will be present in the scoring of the RFP.
- PGE Should compare the difference between BNEF and the EIA's learning rates for wind and explain why that difference would be inconsequential in assessing the intergenerational equity of the Renewable Action.
- Any market price forecast should be based on a future resource buildout portfolio developed using an Oregon carbon price comparable to those PGE is considering in its portfolio analysis.
- In future IRPs, PGE should provide more discussion of its conclusions surrounding intergeneration equity analysis, including a description of why it is equitable to shift these costs forward how the Company is mitigating the risk. This analysis should include:
    - Sensitivity analysis surrounding its choice of years of estimating intergenerational equity analysis.
    - Sensitivity analysis surrounding ownership models.
- A description of PGE's conclusions related to its intergenerational equity analysis.
- Any RFP for renewable resources should include a non-price screen for intergenerational equity, taking into account timing and ownership, on a dollar per kWh basis.

5. Sufficiency of Request for Proposal

PGE's 2019 IRP is the first IRP since the Commission adopted its competitive bidding rules for electric companies on August 30, 2018.[73] As this is the first use, engagement on this issue has been substantial. Staff appreciates PGE's and stakeholders' efforts to discuss PGE's use of the new requirements. This exercise will provide meaningful benefits for this and future IRPs.

The rules seek to bridge the IRP and RFP processes. Utilities are required to file a draft RFP for Commission approval that reflects the scoring, methodology, and associated modeling described in the Commission-acknowledged IRP.[74] The draft RFP must also address a resource need that aligns with an acknowledged IRP. This need can be updated if good cause is shown.[75] If the RFP does not reflect the design, scoring methodology, and associated modeling process that were included as part of the Commission-acknowledged IRP, the electric company must, prior to preparing a draft RFP, develop and file a proposal for scoring and any associated modeling in the IE selection docket, prior to filing a draft RFP for approval.[76]

Staff finds that these rules require a comprehensive review of the design, scoring and modeling elements of an RFP in an IRP, and if that information is not part of the IRP, a separate process that provides for the same sort of notice and review as the IRP must be conducted in the IE

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[73] Order No. 18-324 adopted Oregon Administrative Rules (OAR) Chapter 860, Division 89 Resource Procurement For Electric Companies.
[74] OAR 860-089-0250(1), (2).
[75] OAR 860-089-0250(2) (g).
[76] OAR 860-089-0250(2) (a).

selection docket.[77] Evaluation of such information in the IRP or IE selection proceedings allows for meaningful review and in-depth discussion by stakeholders and ensures the review is sufficient to effect the purpose of the competitive bidding rules, which is to “establish a fair, objective, and transparent competitive bidding process, without unduly restricting electric companies from acquiring new resources and negotiating mutually beneficial terms”[78] This allows for a more efficient process for review of the draft RFP.[79]

While the competitive bidding rules do not require RFP information to be provided in the IRP, Staff observes that the IRP generally is the docket in which a significant number of stakeholders participate in an in-depth review of the utility’s modeling and RFP design. When a utility intends to issue an RFP within a year of IRP acknowledgment, and likely has the necessary information regarding the RFP, the most efficient and effective process available for review of the RFP elements is the IRP docket.

Staff notes that when a utility includes RFP design, modeling and scoring information in the IRP, changes may result, depending on the Commission’s decision on acknowledgment that may affect the content of the RFP elements. And, this year, with the first IRPs filed since the competitive bidding rule was adopted, there appears to be some uncertainty as to the practical application of the rule. As a result, an IRP may contain some, but not all of the design modeling and scoring information required for the RFP. In such instances, Staff requests the Commission consider the extent to which a supplemental filing in the IRP or review of selected elements in the RFP docket may be appropriate.

Staff has discussed its position that a 2020 RFP must more directly address its capacity needs and that the 150 MWa up to amount is not adequately justified in previous sections. Therefore, this section focuses on additional RFP information that PGE should provide either in IRP comments or prior to filing a draft RFP in a separate docket.

5.1. Solar Integration Costs

In Opening Comments, RNW expressed concern that, “PGE’s methodology to determine solar integration costs may be overstating the variability of solar that PGE is likely to integrate and therefore overstating the actual cost of integrating that solar.”[80] Further, RNW Staff raised similar concerns in Opening Comments and continues to agree with Renewable Northwest’s comments on this topic. Further, Staff supports PGE’s commitment to study this further in the next IRP.[81] However, Staff requests a clarification as to why PGE does not believe they need to work on this important topic prior to the release of any RFP.

[77] Order No. 18-324 p. 8. “If a utility chooses to deviate from the scoring proposed in the RFP (sic), the same sort of notice and review should be available to all stakeholders.”
[78] OAR 860-089-0010(1).
[79] OAR 860-089-0250(5), (6).
[80] RNW Opening Comments, pp. 10 - 11.
[81] PGE Reply Comments, p.

Recommendation #5: PGE should continue to work to refine its solar integration cost methodology with Stakeholders and clarify why it does not need to wok to refine its solar integration cost methodology prior to issuing a 2020 RFP.

5.2. Response to RFP Memorandum

On December 11, 2019, the Administrative Hearings Division (AHD) issued a memo requesting stakeholders and PGE to address two detailed questions on the application of the OPUC's new rules for resource procurement by PGE. These questions explore the nexus between PGE's IRP and the Action's planned RFPs. Staff offers the responses below, noting these are only preliminary and Staff may further address resource procurement issues or in Staff's final memorandum on February 7, 2020.

Question 1 asked:

Regarding a RFP for RPS-eligible resources:

a) *Do PGE's IRP filings contain RFP design, scoring methodology, and associated modeling process as described in OAR 860-089-0250(2)(a) such that further RFP design information may be filed in the RFP approval docket?*
b) *Please explain if specific RFP design items should be re-stated or further explained in PGE's IE selection docket, such as non-price criteria.*

Based on the information available in the docket at this time, Staff does find that the IRP contains sufficiently detailed information on RFP design, scoring and modeling that PGE may proceed to an RFP approval docket, without further process in the IRP docket or IE selection docket. Staff notes that **if** the RFP accurately reflects the portfolio design and modeling processes that can be found in LC 73, a few additional items may need to be re-stated or further explained. This could occur in either in the final round of comments in the IRP or in the IE selection docket. At this time they include:

- Non-price scoring criteria and their relationship to factors used to develop the preferred portfolios;
- Transmission scoring and weighting (see Section 5.3 below);
- Identification of all minimum threshold issues;
- More background data on solar integration costs;
- Cost-containment screen.

Staff believes guidance on other issues, related to Question 1, could be helpful to PGE and the stakeholders. They are:

- Should a single docket contain a summation of all of key RFP design, scoring, and modeling information? Or can the key information be shared, vetted, and tracked across multiple dockets? May modeling and design elements be included in the IRP, but scoring elements reviewed in the IE selection docket?
- Is the IRP the preferred process for review of RFP elements?

- When the IE selection docket is used to review RFP elements, what exactly does the Commission mean by its direction to use, "the same sort of notice and review"?[82] Should the same timeline and discovery process as the IRP be available?
- Do the expectations for "notice and review" increase in scale as the information in the IE selection docket deviates further from what was found in the acknowledged IRP?

In terms of RFP process, Staff would note that the final acknowledged IRP Action Items are still taking shape. PGE or the Commission may agree with any number of stakeholder comments, which would subsequently reshape the final Action Plan and require more information to be developed and/or shared with stakeholders as part of any further process in this docket or in the IE docket review process.

Question 2 asked:

Regarding regulatory barriers for long-lead time resources:

> a. *Does the Commission need to address a long-lead time resource within this IRP proceeding?*
> b. *Is it important whether the Commission acknowledges a resource need, or a specific resource type, in this IRP proceeding?*
> c. *If the Commission does not address a long-lead time resource within this IRP, how could or would PGE pursue such a resource?*
>   i. *Would a long-lead time resource be able to participate in a future capacity procurement?*
>   ii. *Are there bridging strategies available to PGE?*

Staff does not believe that, "…regulatory barriers to long-lead time resources," actually exist. The IRP process encourages action within the Action Plan time horizon, but it does not preclude long-lead time resource acquisition with steps taken over the course of one or more action plans.

In fact, there have been numerous instances of long-lead time resources being acknowledged in IRP action plans since the establishment of the Competitive Bidding Guidelines in 2006.[83] Staff does not believe there were any substantive changes in the assessment and acknowledgement of long-lead time resources in the IRP or RFP from when the Commission transitioned from competitive bidding guidelines to a rule in 2018. Examples of acknowledged IRPs and subsequent RFPs with long-lead time resources include:

- PAC, All-Resource RFP, LC 47: Resource identified in 2008 IRP for online dates between 2012 and 2016.
- PGE, Carty, LC 48 and UM 1535: The resource was identified in the 2009 IRP with operation slated for 2015.
- Idaho Power, Boardman-to-Hemmingway, LC 63: Resource identified in 2015 IRP for operation in 2025, and in subsequent IRPs.

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[82] Order No. 18-324, pg. 8.
[83] *See* UM 1182, Order No. 06-446, Aug. 10, 2006.

The iterative IRP process allows for continual updates of important information for the ongoing justification of long-lead time action items. With all this in mind, Staff believes there may be little for the Commission to address on this issue.

With regard to the question of acknowledging need for a specific resource, Staff believes it is vitally important to acknowledge a need for a resource with the key attributes as specified in portfolio testing for at least two reasons.

- *Need drives capacity and renewable values; and*
- *Need forms a key element in future prudency reviews.*

Further, as the Commission recently observed in Idaho Power Company's 2017 IRP docket:[84]

> An important part of the IRP process is an action plan. Where new resources are needed to meet system needs, the action plan will include these resource additions. The action plan identifies the preferred portfolio of supply-side and demand-side resources to meet this need and identifies the steps the company will take within the next four years to deliver needed resources. Different resources require different steps to move forward with procurement, Transmission in particular requires more development lead time than other supply-side resources.

With regard to non-approval of a long-lead time resource in this IRP, Staff notes that PGE may consider proposing an alternative acquisition process to pursue such a resource and seek Commission acknowledgment in a future IRP, under OAR 860-089-0100(3)(c). Under this rule, an electric company is not required to comply with the competitive bidding rule when an "alternative acquisition method was proposed by the electric company in the IRP and explicitly acknowledged by the Commission."

Recommendation #6: In response to the Commission's questions related to PGE's implementation of new competitive bidding rules in its 2019 IRP, Staff finds the following:

- PGE's 2019 IRP does not contain sufficiently detailed information on RFP design, scoring and modeling such that PGE may proceed to an RFP approval docket, without further process in the IRP docket or IE selection docket.
- The IRP process does not preclude long-lead time resource acquisition.
- It is vitally important to acknowledge a need for a resource with the key attributes as specified in portfolio testing for at least two reasons.
- An electric company is not required to comply with the competitive bidding rule when an alternative acquisition method was proposed by the electric company in the IRP and explicitly acknowledged by the Commission.

5.3. Transmission

The majority of RFP discussion in Opening Comments is related to the transmission requirements and Interim Transmission Solution, filed as an addendum to the 2019 IRP on August 30, 2019. Staff finds this logical for several reasons. First, transmission was a central

[84] Docket LC 68, Order No. 18-176 (May 23, 2018).

point of conflict in PGE's last competitive procurement. Second, Staff notes in its Opening Comments that PGE does not model transmission in its portfolio analysis aside from assigning the cost of a BPA wheel to resources and a custom transmission rate for Montana Wind. Under this approach, the RFP is the only vehicle with which PGE genuinely considers the cost and risks of transmission of specific resources in its procurement cycle. And, third, the Company's Interim Transmission Solutions provided a new approach for PGE's competitive resource procurement process.

Given the amount of highly charged engagement in this IRP and in previous procurements, this section provides a detailed summary of parties' comments, PGE's response, and Staff's final concerns surrounding 1) the sufficiency of detail regarding transmission in the RFP that PGE has provided in the IRP; and 2) the efficacy of the Interim Transmission Solution to establish a fair, objective, and transparent competitive bidding process that brings least cost, least risk resources online.

Parties' Comments

Staff's Opening Comments expressed concerns with PGE's approach to modeling transmission in the IRP. While Staff appreciates that the Company introduced a proposal that broadens the diversity of transmission products it is willing to accept as part of an RFP bid, the Company's proposal contained limited information about the basis on which it will score bids in the RFP. Despite the fact that the Company will allow for up to 80 percent of a bid to include eligible firm service, and 20 percent otherwise, the limited detail on the scoring methodology made it unclear as to how PGE would rank bids with one type of transmission against others. Staff provided a list of requests for PGE to address, including discussion of tradeoffs of types of resources, transmission paths to be utilized, and net contributions of blended wind regimes.

NIPPC's Opening Comments addressed similar concerns as Staff, but NIPPC provided more stringent recommendations than Staff, including that the Commission not acknowledge PGE's Interim Proposal or IRP. NIPPC wrote a great deal about how PGE failed to adequately address proper transmission cost and risk. According to NIPPC, PGE assumed that "all resources are one wheel away from PGE and that the transmission cost is set at the BPA rate,"[85] and that PGE failed to justify its need for additional transmission to support acquisition of new renewable generation. NIPPC proposed several recommendations to the Commission, including a suggestion that the Commission decline to acknowledge PGE's IRP until it incorporates an analysis of transmission cost and risk.

RNW expressed positive comments about PGE's transmission proposal, stating that PGE was moving in the right direction, but that the Company had also omitted important details traditionally addressed in an RFP proceeding, such as contract clauses and bid scoring details, that would more fully allow for evaluation of the interim proposal. RNW, like NIPPC, recommended that RFP price scoring should be based on historical curtailments.

NWEC's comments were generally positive and supported the views submitted by RNW. NWEC stated that PGE's approach will "expedite the buildout of clean supply resources" and that

[85] NIPPC Opening Comments. p. 37.

“[r]emoving barriers will accelerate renewable uptake, decrease costs for all sides and provide tangible benefits for customers.”[86]

Overall, parties expressed a general sentiment that though the interim solution is positive, additional details are needed to assess the effectiveness of what PGE is actually proposing.

PGE’s Comments

PGE responded to parties largely by maintaining its positions in the IRP and interim proposal. It sought to refute the recommendation to make its transmission rights available to third parties by stating that it is unreasonable to expose PGE’s customers to the financial burden and risks associated with managing transmission service for a third party, and also that if third-party beneficiaries fail to energize their facilities or honor their transmission agreements, PGE’s customers will be subject to those risks.[87] PGE also disagreed with the recommendation to allow for non-firm service because of its higher risk of curtailment, thereby shifting risk onto its customers for the benefit of resource developers.[88] PGE maintained the view that firm transmission products are the only way to ensure that renewable resources have sufficient transmission to deliver output to PGE’s customer load and avoid reducing output or shutting off.[89]

Staff’s Response and Recommendations for Future Consideration

All parties raised nontrivial points about PGE’s transmission-related considerations in the 2019 IRP and Interim Proposal. At its core, several points must be highlighted in order to make appropriate recommendations moving forward. First, as several parties note, PGE has additional transmission capacity available on its system. Several parties argued that PGE should be leveraging this additional capacity, with NIPPC and RNW going so far as to say that PGE should make its own capacity available for third-party usage.

Second, PGE as a load serving entity must prioritize reliable service for its customers. Despite Staff’s frustrations with the lack of information presented in the Interim Proposal, and PGE’s subsequent desire to redirect substantive details to the RFP proceeding, Staff can agree that accommodating flexibility should not subject the system to adverse reliability impacts. NIPPC and RNW both recommend that the conditional firm number-of-hours product should be scored based on historical curtailment and not the maximum threshold curtailment. While Staff can see some reasonableness in this approach, Staff notes that if more renewable resources come online, historical curtailment patterns may not suffice as acceptable predictors of future curtailment. The Pacific Northwest has yet to see the impacts of anticipated coal retirements and additional GW of renewables coming online, and what this will do to power flows, curtailments, reliability, and costs. BPA is also slated to join EIM in 2021, so it is unclear what impact this will have on transmission capacity availability.

PGE has not explored these ideas in the IRP beyond its analysis justifying 150 MWa of RPS-eligible capacity to prepare for alleged resource adequacy shortfalls. While coal plant retirements will free up additional MW of transmission capacity, replacement of that capacity with intermittent renewables may require transmission availability beyond what exists in the

[86] NWEC Opening Comments, p. 8.
[87] PGE Reply Comments, p. 78.
[88] Ibid., p. 75.
[89] Ibid., p. 74.

current paradigm. This does not take into consideration the need for new transmission buildout to get to more diverse resources, which comes with long-lead times and is subject to considerable regulatory oversight and public involvement.

Third, while a conservative approach to anticipated transmission need has merit, there is still room for improvement for PGE's current tools and Interim Transmission Solution. Indeed, under the current interim proposal, PGE has decided not to accept the conditional firm, system conditions option as an eligible product for a project's associated transmission service. At the Commission workshop on October 31, 2019, BPA confirmed that it does not always offer the conditional firm reassessment, number of hours product, and that even last year BPA did not offer it. Thus, even though PGE has proposed to accept a bid including up to 80 percent of associated transmission service as conditional firm, number of hours, if BPA chooses not to offer this product, this could render PGE's interim transmission proposal useless for bids relying on BPA to make the number-of-hours product available.

Fourth, PGE has refused to provide additional details on the RFP scoring methodology and has opted to push these details into the RFP proceeding. It is possible that even if a bid includes a bundle of 80 percent eligible conditional firm service and the remainder as long-term firm service, a bid into the RFP with 100 percent long-term firm will still be chosen, regardless of cost or contribution to the Company's capacity needs, because it will be considered superior to other projects with lower-quality transmission service. As it currently stands, the Company's framework suggests that a bid with 100 percent long-term firm transmission will outrank other bids with lower quality transmission, despite the fact that they may technically meet PGE's RFP criteria. Thus, it is entirely possible that several projects may make it to the short list with non-traditional transmission products, but may ultimately be rejected because of discounted scoring related to transmission service. Depending on the generating profile where these resources are located, this could materially impact the ability of selected resources to help meet the Company's capacity needs, regardless of PTC benefits.

Flexibility must be appropriately balanced with reliability risk. In Opening Comments, Staff made a series of recommendations to the Company to understand how it intends to weigh these two forces in the RFP. These were briefly addressed in its Reply Comments, but ultimately PGE did not provide additional details about how it intends to score bids, and this did not alleviate Staff's concerns.

PGE is correct that if the system is stressed, BPA will prioritize and curtail accordingly. In the October 31 workshop, BPA made it abundantly clear that South of Alston is a frequent bottleneck, but other contingencies can occur singly or simultaneously. That said, if a fully comprehending end user can accept a type of conditional firm product and understands they may be curtailed, and if an independent power producer can provide that generation pattern, then it makes sense to look at transmission that can also meet those end-customer needs.

Some of this might not be as attractive to the transmission provider as the ability to cut a certain amount of hours anytime with minimum notice–but it could allow for greater grid utilization and flexibility. It is also possible that there may be other contractual “system conditions” outside of the South of Alston bottleneck. It is Staff's understanding that a contract for conditional firm can incorporate any agreed upon framework. Staff may ultimately recommend that the Commission consider requiring PGE to make available the system conditions conditional firm product as part of the Interim Proposal.

In summary, PGE has refused to provide additional detail in its Reply Comments about RFP scoring and argues that these details should be addressed in the RFP. The Company states that it is complicated to know the full breadth of transmission rights available because some of it could be held by third parties and/or bought and sold among market participants. PGE states that it believes that an RFP is the best way to achieve price discovery and understand available options.[90] However, if any information related to RFP scoring is available now, it should be provided at this time.

While exact details about third parties may not be known, Staff does not see any reason why the Company cannot clarify additional RFP design considerations now. If PGE intends to postpone additional details in this proceeding, Staff will recommend that the Commission place more rigorous guidelines in its Acknowledgement Order requiring that the Company outline robust RFP scoring criteria in its initial RFP application in the 2020 RFP.

Recommendation #7: As several parties note, this is the first IRP formally filed since the new competitive bidding rule was adopted. Staff thus responds accordingly by expanding upon recommendations from Opening Comments:

- The Company must explain how it intends to score transmission service in the IRP or the Independent Evaluator docket. This includes qualitative and quantitative weighing. The Company must outline its rubric and explain how it will score transmission products. Exact values/formulas should be provided. The discussion should be supported by an appendix explaining what PGE relied on in making its cost and risk projections, and how those calculations were specifically made. PGE should make straightforward, lay-audience explanations in the initial application on what it is trying to achieve and how and why it has confidence in particular resources or sub-regional sourcing of resources. This should be backed up with an appendix that gets more technical and detailed. The application should include how the methodology will align with BPA's TSEP process.
- The Company should explain how it will inevitably weigh tradeoffs between resource quality and transmission capacity, including ATC. This discussion should include but not be limited to explaining how it will score tradeoffs of lower quality wind (or other resources) with existing ATC vs. higher quality resources with incremental transmission capacity build.
- The Company should discuss how it will score net contribution made by blending diverse regime wind profiles.
- The Company should discuss how it will score partnerships or partial share of larger wind projects that can lower cost and risk for PGE ratepayers. If partnerships will not be considered, the Company should provide an explanation as to why it will not be considering partnerships in its RFP.
- The Company should discuss how it will weigh specific transmission paths and average flow gate impacts of project bids. This discussion should explain how PGE has or would acquire each needed transmission resource or right.

[90] Id., p. 76.

6. General IRP comments

<u>6.1 Customer Actions</u>

Energy Efficiency

Staff appreciates PGE's responsiveness to changes in Energy Trust's energy efficiency forecasts and PGE's plans to pursue studying the implications of these changes on future planning.

Staff understands PGE's intent to produce three scenarios that would represent a range of needs. Staff maintains that inputs are consistent with the future that these scenarios represent. Some variables may naturally move in a different direction from an overall need, creating a dampening or buffering effect, so that their contributions towards uncertainty may be overstated through this method. Regardless of the directionality of energy efficiency drivers, Staff recommends working directly with Energy Trust to produce energy efficiency scenarios that are consistent with the scenarios that will use these inputs. The aforementioned recent change in energy efficiency forecasts indicates there is notable uncertainty in forecasts that could be used in future scenarios. Staff maintains PGE should work with Energy Trust to produce the most appropriate inputs for their modeling needs.

Further, Staff would like to explore before the next IRP the potential for PGE's models to independently select more energy efficiency, beyond Energy Trust's baseline forecast. Specifically, could the model be allowed to select energy efficiency up to the point of the levelized cost of the generic fill?

Recommendation #8: In future IRPs, collaborate with Energy Trust to produce distinct energy efficiency forecasts that are consistent with key scenarios used in the IRP. Also, work with stakeholders before the next IRP to determine if and how PGE's models could select additional, least-cost energy efficiency resources beyond the Energy Trust base forecast.

Flexible Load Plan

In Opening Comments, Staff presented recommendations to improve the modeling of demand response, to provide transparency on how distributed resources will be planned for and implemented, to consider Dynamic Peak Pricing and to study the valuation of customer-owned dispatchable battery storage.

In its Reply Comments, PGE noted that it is, "assembling a cross-functional team to develop a Flexible Load Plan will be submitted to the Commission in 2020." PGE explains that the, "plan will address current and future implementation practices, as well as program cost effectiveness." In discovery, PGE provided a significant amount of additional detail that suggest this plan will be particularly useful.[91] Staff appreciates PGE's efforts to produce and share a "Flexible Load Plan" as it will provide a broader view of demand-side activities together. Staff looks forward to reviewing and discussing these plans. Ideally, the Flexible Load Plan will address all items Staff requested in Opening Comments and include information about the feedback loop between IRP resource planning and the Company's plan to implement its suite of flexible load programs.

[91] PGE Response to OPUC IR No. 161.

Recommendation #9: The Flexible Load Plan should address the flexible load items Staff requested in Opening Comments. It should also include information about the feedback loop between IRP resource planning and the Company's plan to implement its suite of flexible load programs.

Demand Response and Capacity Need

When considering the alignment of PGE's Action Plan with its capacity need, Staff also notes that its demand response projections may be under-developed to meet the urgency of the capacity need. Table 7-7 in PGE's 2019 IRP shows that the difference in capacity need between the reference-need case and the low-need case can be attributed largely to different assumptions about demand response.[92] For example, there are 139 fewer MW of summer demand response in the reference case than the low-need case:

Figure 10: Cumulative Demand Response in Preferred Portfolio[93]

	Reference Case			Low Need			High Need		
	2023	2024	2025	2023	2024	2025	2023	2024	2025
Energy Efficiency (MWa)*	108	133	157	111	140	167	108	133	157
Demand Response†									
Summer DR (MW)	190	202	211	329	359	383	104	106	108
Winter DR (MW)	129	136	141	263	282	297	72	73	73
Dispatchable Standby Generation (MW)	136	137	137	136	137	137	136	137	137
Dispatchable Customer Storage (MW)	2.2	3.0	4.0	7.3	9.1	11.2	1.1	1.6	2.2

*Energy efficiency savings reflect the forecast of deployment by the end of the year and are at the meter.
†Distributed Flexibility values are at the meter. [94]

PGE has a robust growth plan that enables the organization to learn from "doing." The testbed and PGE's many DR pilots should provide the foundation for PGE to scale DR more aggressively. Unless PGE plans to undermine the avoided cost value of DR or make a half-hearted attempt to scale its learnings across all customers, which we do not expect, PGE's goals may be too conservative, especially given the near-term capacity need in PGE's system and the region and the cost-effectiveness of DR as a capacity resource for ratepayers.

Staff appreciates PGE's work to include demand response resources in its RECAP capacity and reliability analysis. Demand response has the potential to provide the near-term capacity shown in RECAP to be needed in the near-term. In PGE's modeling, and in the study commissioned from Navigant, Residential Direct Load Control is a large portion of forecast demand response in the near-term:

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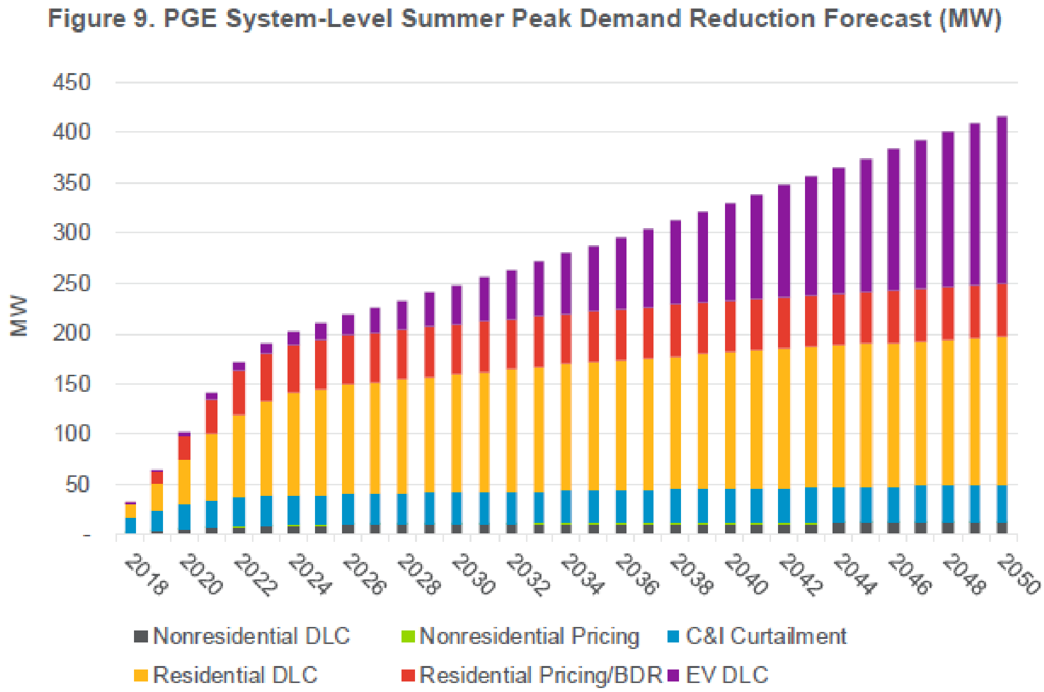
[92] 2019 PGE IRP, p. 189.
[93]Ibid.
[94] Id. p. 195.

Figure 11: Navigant Study Summer Peak Demand Reduction Forecast[95]



Source: Navigant

Staff appreciates the growth embodied in the forecast above. However, it falls short of expectations of growth for DR and may signal a troubling turn in PGE's commitment to DR from the 2016 IRP. The potential shown above is (a) well below a national benchmark average for peak impact from DR, and (b) marks a large decrease from the DR potential found in the previous IRP. First, 2017 research from ACEEE found that most utilities, on average, can reduce peak demand by approximately 10 percent. PGE's 2024 forecast for DR is approximately 6 percent of forecasted peak. Second, the Brattle Group study used in PGE's previous IRP identified between 261 - 278 MW of cost-effective, 2021 summer-peak DR from *only* direct load control programs (DLC) *without* any customer program crossover. The graphic above shows PGE achieving less than one-half of that amount of DLC by 2025.

PGE's explanation for this dramatic reduction in the 2019 IRP is lacking. Given PGE's near-term capacity need, the much reduced Navigant forecast for DR potential found in this IRP, and PGE's on-going, multi-million dollar pilot efforts to refine and improve their DR offerings PGE needs to better explain this reduction in potential at such a critical time.

Further, PGE should redouble efforts to actively pursue direct load control in the near-term, as well as performing an evaluation of the effectiveness of its current Time of Use rate in shifting load from peak hours.

[95] Id., External Study C. Distributed Energy Resource Study, p. 16.

Recommendation #10: Staff requests an explanation in the change of modeling assumptions for DR potential between the IRPs, what field learnings have resulted in a downward revision of assumptions of DR potential, and what additional steps would be needed for PGE to achieve a DR capacity to reduce 10 percent of peak demand by 2024.

6.2 Portfolio Analysis

Staff appreciates PGE's responsiveness to questions and concerns related to PGE's portfolio analysis. Portfolio analysis is foundational to least-cost, least-risk planning and adherence to the Commission's IRP Guidelines. While PGE insinuates in its Reply Comments that acknowledgement is specific only to the Action Plan, Staff notes that, unless otherwise specified, all elements of the plan need to be evaluated for acknowledgement. The action plan implementing the preferred portfolio over the short-term, is the culmination of the other elements. Acknowledgment of an IRP "means that the Commission finds that the utility's preferred portfolio is reasonable at the time of acknowledgement."[96] This section provides feedback on remaining concerns related to the use of probabilities and non-traditional metrics in portfolio analysis. It also discusses concerns related to the RPS compliance strategy used in modeling.

Probabilities

In Opening Comments, Staff recommended PGE adjust its modeling inputs and assumptions to more accurately represent the probability of each of the approximately 810 futures considered in the 2019 IRP. PGE explained through Reply Comments, workshops, and phone conversations that ROSE-E is not capable of capacity expansion informed by such granular probabilities, and can only look at the probabilities of low, reference, or high cases of the need, price, and technology futures. However, PGE expressed openness to performing a sensitivity on the preferred portfolio that weights the NPVRR *results* of each future by an estimate of that future's probability. PGE notes that this will only inform the variability and severity scores, not the NPVRR cost metric of portfolios.

PGE has provided a sensitivity analysis in its Reply Comments that gives the reference case a 100 percent probability in the preferred portfolio and Delay Renewables portfolio. Staff finds that more analysis should be done to fully assess the effects of probability in PGE's portfolio modeling. It will be important for Staff to continue to work with PGE and stakeholders to develop the treatment of probabilities in future PGE IRPs.

Non-traditional Screens

In Opening Comments, Staff asked PGE to report on PGE's 2019 IRP portfolios without the use of its non-traditional screens, so that the impacts of applying these screens before traditional costs and risks analysis can be better understood.[97] PGE's Reply Comments provide some helpful explanation of how the metrics were developed and how portfolios perform without non-traditional scoring.[98] Staff finds that this discussion, while appreciated, falls short of the more quantitative analysis envisioned. As mentioned in Section 4.5 and Section 5.1, Staff would also

[96] No. 18-176 (May 23, 2018).

[97] Staff Opening Comments, pp. 8 – 9.

[98] PGE Reply Comments, p. 27.

like to better understand how these non-traditional screens will be reflected as non-price scoring metrics in the proposed RFPs.

Staff reiterates that PGE did a good job developing its non-traditional metrics collaboratively with stakeholders. These metrics have proven helpful for evaluating important trade-offs between the portfolios that are not as easily captured in traditional cost and risk metrics. These include risks of near-term resource procurement and consideration for the environmental impacts of portfolios. Staff reiterates that its concerns related to non-traditional metrics focus on the blunt manner with which the Company used this new tool. In its IRP analysis, PGE eliminated portfolios based on non-traditional metrics without any discussion of their traditional cost and risk metrics. PGE also eliminated portfolios in an oversimplified manner by excluding portfolios based on a deviation from the mean in any of the metrics and if they added more than 250 MWa before 2025. In doing so, the Company eliminated all but one of its optimized portfolios and a total of 12 of the top 15 performing portfolios on reference case NPVRR.[99]

Staff finds that non-traditional metrics should be used to enhance the comparison of the costs and risks of portfolios after scoring for traditional metrics. For example, PGE identified seven portfolios as top performing on traditional cost and risk metrics in Reply Comments.[100] All of the top performing portfolios contain more than 500 MWa of renewable energy resource acquisition in the Action Plan window, despite a lack of energy need in that timeframe. Consequently, these portfolios rank between 25th and 39th out of 43 for "High Tech Future Cost," meaning they perform relatively poorly in a future where near-term renewable resource procurement is least beneficial. While five of the seven portfolios rank between 23rd and 29th for near-term cost, two of the portfolios score in the top six. However, those two portfolios are ranked 41st and 42nd for cumulative greenhouse gas emissions and perform worse on traditional cost and risk than the portfolios with relatively lower environmental impacts.

Further, the non-traditional metrics allow a quantitative discussion of these tradeoffs. For example, the Company looked at several "Renewable Size and Timing" portfolios. These portfolios consider additions of various sizes and in various years of the Action Plan window up to the 250 MWa threshold that PGE determined to allow, "the potential to fill approximately half of the Reference Case shortage while minimizing the chance of being energy long under other conditions."[101] While modeling limitations related to pumped storage may skew resource selection, these portfolios allow a comparison of the top performing portfolios for traditional cost and risk to ones that place limits on near-term acquisition risk.

Table 6 compiled from PGE data allows a comparison of the optimized portfolio Staff considers top performing across traditional metrics against the best performing renewable size and timing portfolio across traditional metrics.[102] This comparison suggests that limiting renewable additions in 2023 increases the NPVRR in the reference case by $400 million, but would avoid

[99] Based on scoring results provided in Table 7-4 of the 2019 PGE IRP, p. 190.
[100] PGE Reply Comments, p. 26.
[101] PGE Response to OPUC IR No. 169.
[102] While Min. Avg LT Cost is the 3rd best performing portfolio for reference case NPVRR, the other two top portfolios are optimized to minimize the reference case NPVRR. Staff finds that, when looking at the reference case NPVRR, a portfolio that takes into account performance in all futures is more informative.

$311 million of additional costs in the future where near-term procurement is least beneficial. Further, restricting renewable procurement saves ratepayers $36 million in the near-term.

Table 6: Comparison of Optimized and Renewable Constrained Portfolios									
	Traditional Metrics			**Non-Traditional Metrics**					
Portfolio	**Cost**	**Variability**	**Severity**	**GHG-Constrained Cost**	**GHG Emissions**	**Near Term Cost**	**Incremental Criteria Pollutants**	**High Tech Future Cost**	**2025 Energy Additions**
Min Avg LT Cost	25,220	3,299	30,087	25,144	87.6	6,133	0	15,320	554
250 MWa in 2023	25,620	3,605	30,807	25,577	96.8	6,097	0	15,009	236
Difference	(400)	(306)	(721)	(433)	-9.3	36	0	311	317

Finally, the non-traditional metrics allow a more robust comparison of the preferred portfolio against a comparable portfolio that does not allow near-term renewable energy additions. As discussion in Section 4.5, there are outstanding questions about PGE's portfolio modeling that limit discussion of the differences between Mixed Full Clean and Mixed Full Clean, No RA; however, in theory, the non-traditional metrics would allow better comparison of the reference case NPVRR to the Cost in High Future; as well as, the difference in Near Term Cost.

Staff encourages PGE to continue to utilize and refine non-traditional metrics with stakeholders in future IRPs. However, Staff reiterates its recommendation that PGE may not screen portfolios for non-traditional metrics prior consideration of traditional metrics.

RPS Analysis

Staff understands that the renewable resource additions in the preferred portfolio are not driven by RPS compliance need, but the economic performance of the PTC-eligible wind resources modeled. That does not alleviate Staff's concern with the overarching RPS compliance strategy that the Commission would be acknowledging as part of this IRP. Staff does not support an RPS compliance strategy that ignores the ability to use unbundled RECs to mitigate risk and could result in the Company never utilizing the large bank of RECs that customers have already paid while continuing to add future resources. As mentioned previously in these comments, PGE should not assume that IRP acknowledgement is solely focused on the Action Plan. In acknowledging this IRP, the Commission is considering the RPS compliance strategy underlying the analysis, regardless of any direct mention in the Action Plan items.

In its Opening Comments, AWEC notes that it, "has not seen an analysis yet that optimizes the use of the REC Bank for the benefit of ratepayers" and describes the risk of an RPS strategy that ignores the REC bank as follows:[103]

> PGE's RPS need is also misleading because it does not utilize any of its substantial REC bank. As Dr. Marc Hellman shows, the REC bank is a valuable customer asset that becomes worthless to customers through PGE's IRP.[104]

[103] AWEC Opening Comments, Attachment A, p. 7.
[104] Id., p. 6.

Staff agrees that the Company needs to address this risk, and finds that PGE can either provide a meaningful strategy to utilize its REC bank in its IRP analysis or propose a ratemaking mechanism, such as the Regulatory Value and Market Value concepts discussed in AWEC's comments, in a ratemaking proceeding.

Further, the benefit of any sale of RECs from PGE's REC bank should be assessed against the cost to acquire RECs from new resources procured as part of PGE's physical compliance strategy. This will allow ratepayers to understand the relative cost and benefits of PGE's shift away from use of its currently banked RECs.

Portfolio Analysis Recommendations

Recommendation #11: Staff provides the following recommendations to ensure robust portfolio analysis in future IRPs:

- PGE should work with Staff and stakeholders to develop the treatment of probabilities in future PGE IRPs.
- Non-traditional screens cannot be used to screen portfolios prior to considerations of traditional cost and risk. PGE should continue to refine the non-traditional metrics with Staff and stakeholders so that they can be used to enhance discussion of the trade-offs between portfolios.
- To ensure equitable and least cost, least risk compliance with the RPS:
  - PGE should make it a standard IRP practice to model the use of a reasonable amount of unbundled RECs.
  - PGE should either provide a meaningful strategy to utilize its REC bank in IRP planning or propose a ratemaking mechanism.
  - The benefit of any sale of RECs from PGE's REC bank should be assessed against the cost to acquire RECs from new resources procured as part of PGE's physical compliance strategy.

6.3. Load Forecast

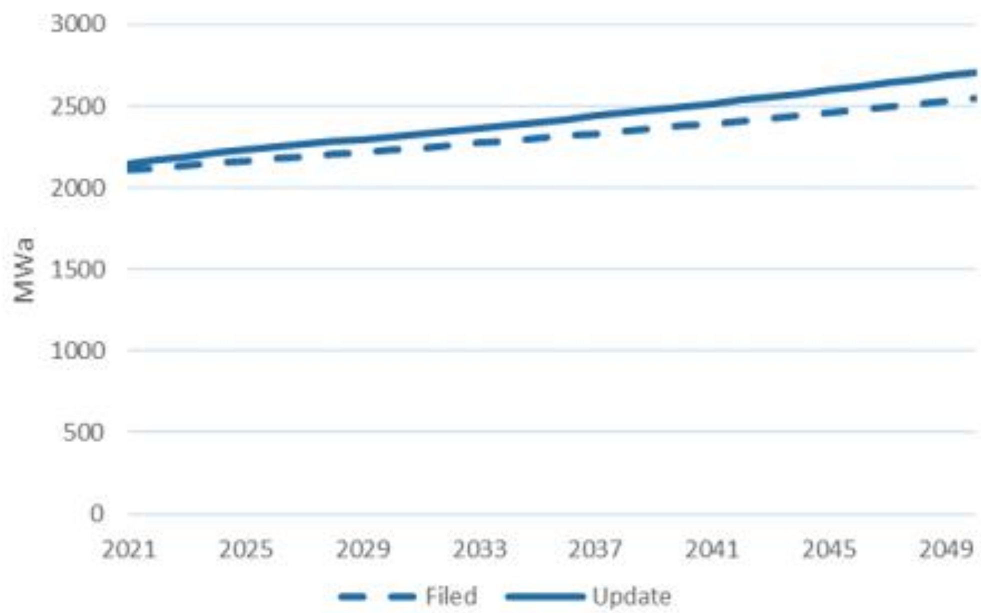
Econometric Load Forecast

In Opening Comments, Staff indicated that it was working with PGE to reproduce the econometric load forecast and looking into the use of different and additional variables, such as, unemployment. In addition, Staff is evaluating PGE's use of historical data that includes the 1990s.[105] After reproducing PGE's econometric estimates, Staff found no evidence excluding the 1990s or including other variables improved the energy models. Excluding the 1990s and (or) adding a co-variable for unemployment did slightly improve the fit of the peak capacity model, but these alternative specifications did not materially change the estimated results. Staff finds PGE's top-down load forecast reasonable.

On November 27, 2019, PGE filed an updated needs assessment that includes a roughly 3 percent increase in the econometric load forecast in 2025 from what was filed in the 2019 IRP. Staff received underlying data for this forecast on December 9th and 10th and continues to review the modeling and assumptions behind the load forecast increase. Staff will file supplemental comments if this review provides meaningful findings.

[105] Staff's Opening Comments, p. 21.

Figure 12: Updated Needs Assessment Reference Case Econometric Load Forecast[106]



Electric Vehicle Load

Staff's Opening Comments raised a concern that the Company's assumptions about the availability of certain electric vehicle (EV) models in its EV forecast may be causing PGE to overstate its near-term capacity needs.[107] In the Company's reply comments and discovery, PGE offered more information about the methodology underlying the EV adoption forecast. Specifically, they addressed Staff's questions about the model for technology adoption, called the Bass Diffusion Model. PGE explained that it used an enhanced Bass Diffusion Model for EV adoption.[108] Staff appreciates the explanation PGE provided, but cautions that the enhancements may be pushing the Bass model beyond what is reasonable.

Staff finds that there is a risk that, while the EV forecast is on trend with historical EV adoption across all light-duty vehicles, the impact of vehicle type availability at certain levels of adoption may be causing the forecast to overstate the Company's load forecast. Staff finds that there are two weaknesses in how PGE approached tailoring the Bass Diffusion model for the IRP to represent the high adoption scenario. The first is an assumption around vehicle substitution. The second is around drivers of consumer choice.

The PGE 2019 Transportation Electrification Plan notes that electric vehicles, as a technology, currently lack in model type diversity and functionality.[109] PGE explains that within this model:

> Larger light duty vehicles, like pickup trucks and SUVs, compete with LDVs that can offer similar benefits, but the inventory of trucks available in the model is low in the near-term compared to sedans or other more mature EV models. This

[106] PGE's Updated Needs Assessment, p. 3.
[107] Staff Opening Comments, p. 21.
[108] PGE Response to OPUC IR No. 160.
[109] Docket No. UM 1811, PGE's Transportation Electrification Plan, September 30, 2019, pp. 26-28.

> approximates the currently existing and anticipated future industry share per vehicle type.[110]

PGE described Navigant's method of overcoming the problem on non-availability as follows:

> To calibrate the share of each vehicle type within the population, Navigant surveyed LDV powertrains currently available in the PGE service area along with their historical sales, then incorporated information from manufacturer press releases on product lines to approximate foreseeable growth in vehicle availability within the model.[111]

Staff does not find either explanation compelling, and that the implied assumption in the Bass Diffusion Model regarding vehicle substitution is unaddressed: the product exists. As Staff mentioned in Opening Comments, most of the light duty vehicles that consumers prefer are not available with an electric alternative.[112] Using the Bass Diffusion Model on products that don't yet exist creates two analytic vulnerabilities. The VAST Model will overestimate EV adoption if it overestimates the market share of smaller vehicles or underestimates the time it will take to have electric SUVs, vans, and light-duty trucks that can compete with existing internal combustion vehicle models.

Second, the comparison the Navigant Study uses to measure competitiveness—and drive consumer choice—is the total cost of ownership (TCO). However, this method may overlook important non-cost related barriers to EV adoption such as vehicle range and charger availability. As an example, PGE cites range and the associated charger availability as a concern in the TE Plan.[113] Improvements to TCO overstate PGE's ability in the Bass Diffusion Model to address other types of fundamental market barriers. In addition, the competitiveness of buying new electric vehicles must then also be compared with the TCO of buying used internal combustion engines.

While Staff is supportive of PGE's transportation electrification efforts, the forecasted level of EV adoption–and subsequent impact to peak load–is most likely optimistic. Further, if EV adoption does begin to grow more than anticipated, Staff believes that PGE and the Commission would act quickly to take commensurate steps (e.g., time of use rates) to shift the peak impacts of the very flexible load curves associated with residential EV charging. As a result of this Staff would recommend only using the base case of EV adoption under *all* IRP load forecast scenarios and thus peak load forecasts should be adjusted accordingly.

Direct Access Load

In Opening Comments, Staff, CUB, and AWEC questioned whether PGE's forecast may be overstating need due to the possibility of new long-term direct access (LTDA) elections.[114],[115],[116]

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110 PGE Response to OPUC IR NO. 160.

111 Ibid.

112 Staff Opening Comments, p. 21.

113 "37 percent of of current EV/PHEV owners mention some difficulty locating charging stations when needed." See Docket No. UM 1811, PGE's Transportation Electrification Plan, September 30, 2019, p. 28.

114 Staff Opening Comments, p. 28.

115 CUB Opening Comments, pp. 4 - 5.

116 AWEC Opening Comments, Attachment A, pp. 2 – 3.

PGE responded that this may be too speculative and, "[s]everal factors might motivate an individual customer to select LTDA, and PGE does not have direct insights into these motivations or access to information about terms being offered by ESSs that would help inform such decisions."[117] Staff finds that this program has been around for 20 years and there may be sufficient historical data to characterize what a high direct access future could look like. Regardless, Staff finds that the Company's characterization of industrial load growth should be considered with the likelihood that it could be overstated due to future Direct Access elections.

Load Forecast Recommendations

Recommendation #12: When developing load forecasts for future IRPs, PGE should:

- Use the base case of EV adoption under all IRP load forecasts.
- Provide analysis that helps parties consider the impact future LTDA elections would have on its forecasted needs.

6.4. Colstrip

In its Opening Comments, Staff expressed appreciation for PGE's sensitivity that accelerated exit from Colstrip Units 3 and 4 from 2034 to 2027. Staff noted that PGE's analysis suggests sizeable benefits, and requested additional explanation of risk metrics and rate impacts. Staff also encouraged the Company to continue to examine early exit and to keep participants in the 2019 IRP process updated as new information becomes available. This included a specific request for any updated information on the variable costs of generation at Colstrip. RNW and NWEC also encouraged the Company to continue to evaluate Colstrip, with NWEC recommending "analysis of Montana wind plus pumped storage and/or battery resources to provide a better match to system load and more efficient use of transmission resources."[118,119]

In its reply comments, the Company expressed support for continued evaluation, provided a helpful explanation that increased market exposure impacts the risk metrics in the Colstrip early retirement sensitivity, and renewed its commitment to updating the Commission regarding the Colstrip sensitivity analysis when additional information becomes available.[120]

Once again, Staff appreciates PGE's commitment to continued evaluation of early exit from Colstrip. Staff agrees that the uncertainties and quickly moving pieces make long-term cost and risk assessment more challenging. On the other hand, Staff finds that this complexity is an important reason to continue to monitor accelerated retirement. Otherwise, PGE customers may bear an unreasonable level of risk for decisions that are dependent on a wide range of actors and conditions.

Staff also notes that several developments have occurred since its Opening Comments, which are summarized below. These include specific developments about the fuel supply contract Staff mentioned in its Opening Comments.

[117] PGE Reply Comments, p. 57.
[118] RNW Opening Comments, pp. 10 - 11.
[119] NWEC Opening Comments, p. 7.
[120] PGE Reply Comments, pp. 37 – 38.

- PacifiCorp filed its 2019 IRP on October 18, 2019. The Action Plan includes 2027 retirement of PacifiCorp's 10 percent share of Colstrip Units 3 and 4.[121]
- In a November 21, 2019 rate case settlement, Avista Corp agreed to be financially ready to exit its 15 percent share of Colstrip Units 3 and 4 by 2025.[122]
- On December 5, 2019, Westmoreland Mining, LLC announced that the joint owners of Colstrip Units 3 and executed a new Coal Supply Agreement (CSA) with its Rosebud Mine.[123] This fuel supply contract take effect on January 1, 2020, and is reported to continue through at least the end of 2025.
- On December 10, 2019, NorthWestern Energy announced its purchase of Puget Sound Energy's 25 percent share in Colstrip Unit 4 for $1. According to NorthWestern Energy, "If the sale is approved, NorthWestern Energy will own 55% of Colstrip Unit 4 and will have greater influence over its operations."[124]

These events would leave PGE among the last three of six joint owners in Colstrip Units 3 and 4 (and the last two of the five regulated utility owners). While PGE's reply comments suggest that no relevant new information was available, Staff finds that the events listed above could be meaningful and warrant an update from PGE.

Further, it appears that PGE did not respond to directly to Staff's request for rate impact analysis or NWEC's considerations for future analysis.

Recommendation #13: Staff requests that PGE's next round of comments include a summary of any other relevant updates and a discussion of how Staff and PGE's list of updates may affect the 2019 IRP analysis. Staff also requests that PGE include a rate impact assessment and consider NWECs suggestions.

6.5. Boardman Biomass

The US Endowment for Forestry and Communities (the Endowment) recommended in its Opening Comments that the Commission authorize fuel cost recovery for a continued evaluation of biomass potential at PGE's Boardman plant. The Endowment reports that it has funded a torrefaction plant in John Day, Oregon to support the State of Oregon and US Forest Service in efforts to manage forests, and that the plant, which is designed to produce 100,000 tons of torrefied biomass annually, is now accumulating small diameter and diseased tree stems for use in former coal plants. The Endowment finds that the 5,000 tons of fuel consumed in the previous Boardman combustion tests was not adequate to fully assess plant behavior, and that longer-run tests should be authorized.

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[121] See Docket No. LC 70, PacifiCorp's 2019 IRP, October 18, 2019, p. 13.

[122]Washington Utilities and Transportation Commission (UTC), **S**ettlement reached in Avista rate case, November 21, 2019. https://www.utc.wa.gov/aboutUs/Lists/News/DispForm.aspx?ID=636.

[123] Westmorland Mining, LLC, Westmoreland Rosebud Mining LLC announces new Coal Supply Agreement for Colstrip Units 3&4, December 5, 2019, https://westmoreland.com/2019/12/westmoreland-rosebud-mining-llc-announces-new-coal-supply-agreement-for-colstrip-units-34/.

[124] NorthWestern Energy, NorthWestern Energy to acquire 25% share of Colstrip; plans to reduce carbon by 90%, December 10, 2019, http://www.northwesternenergy.com/our-company/media-center/current/news-article/2019/12/10/NorthWestern-Energy-to-acquire-25-share-of-Colstrip-Unit-4-from-Puget-Sound-Energy.

Recommendation #14: Staff recommends PGE perform a study on the costs and benefits to ratepayers of using biomass at the Boardman plant for further testing. PGE should also study whether the testing could be performed using fuel from forest management practices and not from wood harvested solely to be turned into fuel.

6.6. Emissions Forecast

Staff greatly appreciates the emissions forecast of the preferred portfolio PGE provides in Section 7.3.4 of the 2019 IRP.[125] Given the design of 2019's House Bill 2020, this forecast could be the basis for implementing any carbon policies that pass before the next IRP. Staff finds that PGE's general methodology for developing the forecast is acceptable for this IRP. Staff also notes that this analysis is very likely to change in the near-term. First, Staff agrees with PGE that the Company's actual procurement activities could vary quite a bit from the proxy resources selected in the preferred portfolio. In addition, the Company's needs assessment and the future of resources such as Colstrip and Boardman are uncertain.

Therefore, Staff recommends that the Company update their emissions forecast when a better sense of the Action Plan window conditions is known. This update should not be restricted to resource acquisition, and can include updated needs assessments, carbon pricing, resource retirements, regional market participation, QF forecasts, voluntary programs, distributed resource forecasts, and other elements as appropriate.

Further, Staff believes that emission forecast modeling based on hourly market dispatch of PGE resources might be more appropriate for the next IRP, especially if Oregon considers Cap and Invest legislation again. Staff looks forward to working with PGE and parties to refine emissions forecasting for the next IRP.

Recommendation #15: PGE should file an updated emissions forecast in the 2019 IRP docket after the Renewable Action and Capacity Action implementation commences.

7. Conclusion

Staff reiterates its appreciation for PGE's extensive analysis and willingness to work closely with parties throughout this process. Despite these efforts, Staff still finds that the proposed Renewable Action and Capacity Actions are not justified by PGE's analysis. Staff's primary concern is that the Action Plan is focused on capturing economic opportunity, rather than positioning the Company to address the forecasted capacity shortfall in the Action Plan timeframe. Consequently, Staff cannot recommend acknowledgement of a 2020 RFP without conditions that more directly address Company's capacity need and better demonstrate a balance of near and long-term costs and risks. In these Final Comments, Staff recommends the following actions and additional requirements:

[125] 2019 PGE IRP, pp. 205 – 208.

Related to the Acknowledgement of PGE's Action Items

1. Due to concerns about the timing of the Capacity Actions, Staff recommends that:
   - The Commission should acknowledge the Company's pursuit of bilateral contracts for existing capacity.
   - PGE should not release a 2020 RFP unless it specifically addresses the Company's capacity need and allows non-emitting capacity resources. The capacity need could be met in part or in whole by renewable energy.
   - PGE should provide updated analysis in the IRP that provides information on the types of resources that would be chosen by ROSE-E through a capacity and energy RFP in 2023.
2. To ensure future IRPs adequately account for future capacity needs, Staff asks that PGE:
   - Monitor and report on its market capacity assumptions as part of any RFP and in the 2021 update to LC 73, as market conditions may encourage the building of more generation resources regionally.
   - Provide additional explanation of the assumptions underlying the capacity contribution that the renewable-only procurement could provide.
   - Given the modeling of multiple battery cost futures in the IRP, PGE should explain which additional risks need to be accounted for by delaying efforts to pursue the capacity resources in the preferred portfolio.
   - Provide any additional information it can about the timing and availability of existing capacity resources and how they align with the Company's forecasted capacity needs between 2023 and 2025.

3. Due to the risks associated with the timing, focus, and size of the 2020 Renewable RFP, Staff recommends that PGE:
   - Establish a procurement size that is rooted in more robust analysis and use the load resource balance as the upper bound of the glide path.
   - Require renewable resources to qualify for federal tax incentives. PGE should also specify which incentives are eligible.
   - Be required to return the forecasted value of PTCs to customers.
   - Adequately evaluate bids for the impact of the ownership model on rate impacts.

4. To ensure the Renewable Action items adequately balance costs and risks, Staff also asks that PGE:
   - Not use the market energy position to quantify the need for new resources.
   - Confirm whether it is considering a similar strategy to mitigate the lack of RPS need for its Renewable Action in the 2019 IRP as it is for Wheatridge.
   - Discuss the differences between the Delay Renewables and Mixed Full Clean, No RA portfolios and the drivers behind the stark variation in scoring metrics.
   - Explain how the Cost in High Tech Future non-traditional metric will be present in the scoring of the RFP.
   - Compare the difference between BNEF and the EIA's learning rates for wind and explain why that difference would be inconsequential in assessing the intergenerational equity of the Renewable Action.

- Base any future resource buildout portfolio developed using an Oregon carbon price comparable to those PGE is considering in its portfolio analysis.
- In future IRPs, provide more discussion of its conclusions surrounding intergeneration equity analysis, including a description of why it is equitable to shift these costs forward how the Company is mitigating the risk. This analysis should include:
    - Sensitivity analysis surrounding its choice of years of estimating intergenerational equity analysis.
    - Sensitivity analysis surrounding ownership models.
- A description of PGE's conclusions related to its intergenerational equity analysis.
- Any RFP for renewable resources should include a non-price screen for intergenerational equity, taking into account timing and ownership, on a dollar per kWh basis.

Regarding the Sufficiency of Information Related to PGE's 2020 Renewable RFP

5. PGE should continue to work to refine its solar integration cost methodology with Stakeholders and clarify why it does not need to wok to refine its solar integration cost methodology prior to issuing a 2020 RFP.

6. In response to the Commission's questions related to PGE's implementation of new competitive bidding rules in its 2019 IRP, Staff finds the following:
    - PGE's 2019 IRP does not contain sufficiently detailed information on RFP design, scoring and modeling such that PGE may proceed to an RFP approval docket, without further process in the IRP docket or IE selection docket.
    - The IRP process does not preclude long-lead time resource acquisition.
    - It is vitally important to acknowledge a need for a resource with the key attributes as specified in portfolio testing for at least two reasons.
    - An electric company is not required to comply with the competitive bidding rule when an alternative acquisition method was proposed by the electric company in the IRP and explicitly acknowledged by the Commission.

7. In response to the transmission-related components of PGE's RFP, Staff requests that PGE:
    - Explain how it intends to score transmission service in the IRP or the Independent Evaluator docket. This includes qualitative and quantitative weighing. The Company must outline its rubric and explain how it will score transmission products. Exact values/formulas should be provided. The discussion should be supported by an appendix explaining what PGE relied on in making its cost and risk projections, and how those calculations were specifically made. PGE should make straightforward, lay-audience explanations in the initial application on what it is trying to achieve and how and why it has confidence in particular resources or sub-regional sourcing of resources. This should be backed up with an appendix that gets more technical and detailed. The application should include how the methodology will align with BPA's TSEP process.
    - Explain how it will inevitably weigh tradeoffs between resource quality and transmission capacity, including ATC. This discussion should include but not be limited to explaining how it will score tradeoffs of lower quality wind (or other resources) with existing ATC vs. higher quality resources with incremental transmission capacity build.
    - Discuss how it will score net contribution made by blending diverse regime wind profiles.

- Discuss how it will score partnerships or partial share of larger wind projects that can lower cost and risk for PGE ratepayers. If partnerships will not be considered, the Company should provide an explanation as to why it will not be considering partnerships in its RFP.
- Discuss how it will weigh specific transmission paths and average flow gate impacts of project bids. This discussion should explain how PGE has or would acquire each needed transmission resource or right.

Additional Recommendations Related to PGE's 2019 IRP Analysis and Future IRPs

8. *Energy Efficiency*: In future IRPs, collaborate with Energy Trust to produce distinct energy efficiency forecasts that are consistent with key scenarios used in the IRP. Also, work with stakeholders before the next IRP to determine if and how PGE's models could select additional, least-cost energy efficiency resources beyond the Energy Trust base forecast.

9. *Flexible Load Plan*: The Flexible Load Plan should address the flexible load items Staff requested in Opening Comments. It should also include information about the feedback loop between IRP resource planning and the Company's plan to implement its suite of flexible load programs.

10. *Modeling Demand Response*: Staff requests an explanation in the change of modeling assumptions for DR potential between the IRPs, what field learnings have resulted in a downward revision of assumptions of DR potential, and what additional steps would be needed for PGE to achieve a DR capacity to reduce 10 percent of peak demand by 2024.

11. *Portfolio Analysis*: For future IRP's PGE should adopt the standards for portfolio analysis:
    - PGE should work with Staff and stakeholders to develop the treatment of probabilities in future PGE IRPs.
    - Non-traditional screens cannot be used to screen portfolios prior to considerations of traditional cost and risk. PGE should continue to refine the non-traditional metrics with Staff and stakeholders so that they can be used to enhance discussion of the trade-offs between portfolios.
    - To ensure equitable and least cost, least risk compliance with the RPS:
        - PGE should make it a standard IRP practice to model the use of a reasonable amount of unbundled RECs.
        - PGE should either provide a meaningful strategy to utilize its REC bank in IRP planning or propose a ratemaking mechanism.
        - The benefit of any sale of RECs from PGE's REC bank should be assessed against the cost to acquire RECs from new resources procured as part of PGE's physical compliance strategy.

12. *Load Forecast: When developing load forecasts for future IRPs, PGE should:*
    - Use the base case of EV adoption under all IRP load forecasts.
    - Provide analysis that helps parties consider the impact future LTDA elections would have on its forecasted needs.

13. *Colstrip*: Staff requests that PGE's next round of comments include a summary of any other relevant Colstrip updates and a discussion of how Staff and PGE's list of updates may affect the 2019 IRP analysis. Staff also requests that PGE include a rate impact assessment and consider NWECs suggestions.

14. *Boardman*: Staff recommends PGE perform a study on the costs and benefits to ratepayers of using biomass at the Boardman plant for further testing. PGE should also study whether the testing could be performed using fuel from forest management practices and not from wood harvested solely to be turned into fuel.

15. *Emissions Forecast:* PGE should file an updated emissions forecast in the 2019 IRP docket after Renewable Action and Capacity Action implementation commences.

This concludes Staff's final comments.

Dated at Salem, Oregon, this 17th day of December, 2019

Caroline Moore

Senior Utility Analyst

Energy Resources and Planning Division