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Erin E. Apperson
Assistant General Counsel

January 17, 2020

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

Re: LC 73 – Portland General Electric Company's 2019 Integrated Resource Plan (IRP)

Dear Filing Center:

Enclosed for filing today in the above-referenced docket are Portland General Electric Company's ("PGE") Final Comments.

Thank you in advance for your assistance.

Sincerely,

Erin E. Apperson
Assistant General Counsel

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

DOCKET NO. LC 73

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY 2019 Integrated Resource Plan.	**PORTLAND GENERAL ELECTRIC COMPANY'S** **FINAL COMMENTS**

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1. Introduction

In accordance with the Administrative Law Judge's (ALJ) ruling issued November 22, 2019, Portland General Electric Company (PGE or the Company) submits these final comments regarding PGE's 2019 Integrated Resource Plan (IRP). PGE also addresses comments and questions raised by parties at the November 21, 2019, IRP roundtable meeting.

PGE appreciates the thoughtful and constructive Staff and stakeholder engagement around the 2019 IRP. Collaboration produces results that reflect the values of our customers and our community. The development of the IRP benefits from stakeholder collaboration and feedback, particularly as the Company continues to assess increasingly complex resource planning issues. Stakeholder feedback helped strengthen PGE's analysis which directly improved the 2019 IRP, resulting Action Plan, and provided the groundwork to inform future IRP processes and plans. PGE filed its 2019 IRP with the Commission on July 19, 2019.

Eight parties submitted final reply comments in this docket.

1. Public Utility Commission of Oregon Staff (Staff),
2. Oregon Citizens' Utility Board (CUB),
3. Alliance of Western Energy Consumers (AWEC),
4. NW Energy Coalition (NWEC),
5. Renewable Northwest (RNW),
6. Northwest and Intermountain Power Producers Coalition (NIPPC),
7. Renewable Energy Coalition (REC), and
8. Swan Lake North Hydro, LLC (Swan Lake).

Comments from stakeholders addressed a range of topics, including PGE's Action Plan and several of the components of PGE's IRP analysis. Some parties made recommendations regarding specific aspects of PGE's IRP, while others provided positions and perspectives on areas of concern or interest. In addition, Staff raised several topics for consideration in future planning cycles and regulatory proceedings. PGE appreciated Staff's interest in emerging planning challenges and looks forward to engaging with Staff and stakeholders to grapple with these topics in future planning cycles and other regulatory proceedings.

These final comments are intended to provide PGE's perspective regarding recommendations from parties and to provide additional information to help facilitate the acknowledgment of the Action Plan. In these final comments, PGE provides responses to parties' concerns, additional information as requested, and in some cases, we propose modifications to the Action Plan. PGE also identified opportunities for the Company to provide additional information both within this process and in future IRPs. Specifically, these comments address the following topics:

- **Action Plan**. In these final comments PGE proposes two modifications to the Action Plan to address Staff and stakeholder comments and to incorporate House Resolution 1865[1] which extended the federal Production Tax Credit (PTC) for wind.
  - Renewable Action. PGE modifies the timing of the Renewable Action, allowing resources to come online by the end of 2024 to align with PGE's capacity needs and the extended PTC availability afforded by House Resolution 1865.
  - Capacity Action. PGE modifies the process for pursuing dispatchable capacity resources, allowing for concurrent consideration of existing resources through bilateral negotiations and new non-emitting capacity resources through an RFP.
  - Additional Conditions. PGE proposes two additional conditions to ensure that concurrent procurement activities to pursue capacity from renewables, existing resources, and new non-emitting dispatchable resources align with PGE's resource needs.
- **Needs assessment.** PGE filed an update to its needs assessment in this docket on November 27, 2019, to incorporate more recent information as well as the new resource from PGE's Green Tariff program.
- **RFP design / Transmission.** PGE reiterates that the detailed RFP scoring related to the Interim Transmission Solution[2] is more appropriately addressed within an RFP docket, and responds to specific elements from parties' final comments on issues such as transmission products in the Interim Transmission Solution and PGE's transmission portfolio. PGE is responsive to the Commission's Competitive Bidding Rules and believes the RFP-related information contained in the 2019 IRP is complete and prepares all parties for a future RFP design proceeding focused on the approval of PGE's proposed renewable RFP design.
- **Additional items**
  - PGE provides updated analysis of two optimized portfolios, including the Mixed Full Clean portfolio, taking into account the PTC extension.
  - PGE provides updated analysis on Colstrip Units 3 and 4 based on the recently executed coal supply agreement and updated depreciation study information.
  - PGE provides responses to the questions in the December 11, 2019 AHD memo regarding long-lead time resources.
- **Staff recommendations**
  - PGE provides summary responses to Staff's recommendations in **Section 5.3**. In some cases, depending on the topic, Staff's recommendations are more thoroughly addressed in earlier sections.

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[1] H.R. 1865, Further Consolidated Appropriations Act, 2020, 116th Congress (2019-20).

[2] LC 73 PGE's 2019 IRP Addendum filed August 30, 2019.

2. Action Plan

2.1. Customer Resource Actions

Staff and stakeholders continue to support PGE's pursuit of customer resources, including energy efficiency and distributed flexibility. Staff and stakeholders also suggest that PGE may be able to secure more customer resources, particularly demand response, than are forecasted in the Reference Case. PGE responds to these comments in **Section 6.10**. PGE continues to believe that the Customer Resource Actions in the 2019 IRP are sufficiently flexible to allow the Company to acquire more customer resources than are forecasted in the Reference Case if they are cost-effective and reasonable. PGE therefore does not propose any modifications to the Customer Resource Actions originally filed as part of the Action Plan.

2.2. Renewable Action

Parties' Comments

In final comments, Staff continued to express concern regarding PGE's plan to conduct a Renewable RFP in 2020 and suggested that an RFP in 2020 should focus on securing resources to meet PGE's forecasted capacity needs in 2025, which could include renewables.[3] Staff also questioned PGE's approach to limiting the potential size of renewable additions based on forecasted market energy position and instead suggested that the traditional load-resource balance analysis may be more appropriate for constraining renewable resource additions in the Renewable Glide Path and the Action Plan. Further, Staff recommended that PGE not use the market energy position analysis to quantify resource need.[4]

CUB noted that the additional information provided by PGE in reply comments and the Updated Needs Assessment was instructive for consideration of the Renewable Action and recommended acknowledgment of the Renewable Action.[5] RNW and NWEC continued to express support for the Renewable Action as a low cost means to meet a portion of the Company's capacity, energy, and RPS needs,[6] and as part of a least-cost, least-risk strategy.[7] NIPPC expressed support for the Renewable Action, but proposed several conditions related to transmission requirements and the process for review of RFP design (see **Sections 4.1**. and **4.2**). AWEC continued to oppose the Renewable Action, suggesting that it does not meet a near-term resource need.[8]

New Information

Signed into law on December 20, 2019, House Resolution 1865 included an extension of the federal Production Tax Credit (PTC) for wind. Wind projects that commence construction by

[3] LC 73 Final Comments of Staff at 14–15.
[4] *Id.* at 15–19.
[5] LC 73 Final Comments of CUB at 6–7.
[6] LC 73 Final Comments of RNW at 9–10.
[7] LC 73 Final Comments of NWEC at 1.
[8] LC 73 Final Comments of AWEC at 6–10.

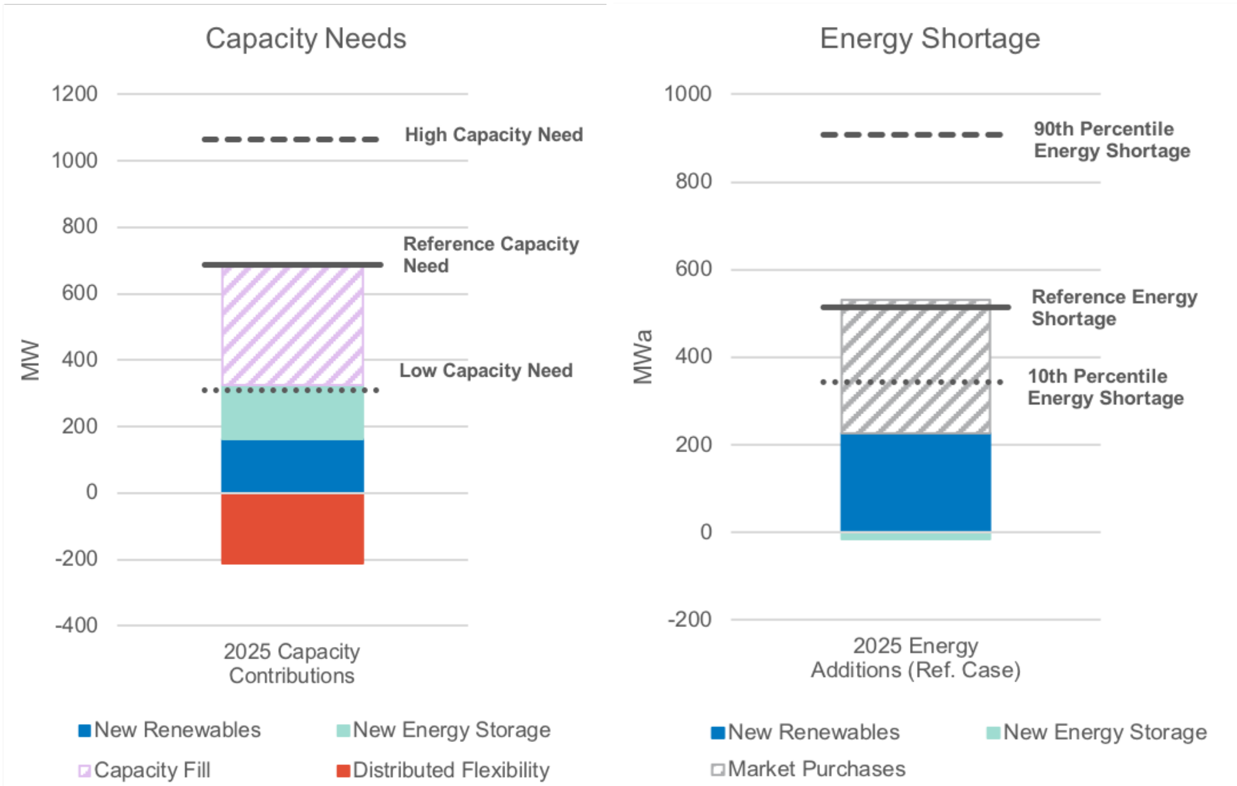
December 31, 2020, can now qualify for the 60% PTC. Application of the existing Safe Harbor guidance from the IRS suggests that qualifying resources must come online by December 31, 2024, to achieve the 60% PTC. At this time, there remains some uncertainty as to how the PTC extension will affect wind development plans, particularly for projects that have already qualified for PTCs under safe harbor, and whether the IRS will update its guidance on safe harbor in response to the PTC extension.

PGE Response

PGE conducted a limited set of additional analyses to understand whether the extension of the PTC affected the material findings regarding renewable resource economics in the 2019 IRP. This analysis, which can be found in **Section 5.1**, finds that the PTC extension results in renewable additions in 2024 and 2025 to both qualify for federal tax credits and contribute to meeting PGE's capacity needs as part of optimized portfolios. This analysis continues to demonstrate the economic value of near-term renewable additions, re-emphasizes the role that renewables play in contributing to meeting PGE's capacity needs, and indicates potential alignment between the economically optimal timing of 60% PTC-eligible renewable additions with the PTC extension and the timing of PGE's increased capacity needs.

PGE's portfolio analysis, as well as the supplemental analysis provided within this docket, consistently identify the near-term pursuit of renewable resources as critical to achieving strong outcomes for customers based on both cost and risk. Renewable resource additions not only provide low cost clean energy to PGE's portfolio, but as shown in Figure 7-17 in the 2019 IRP and replicated in **Figure 1** below, also help to meet PGE's capacity needs in the mid-2020s.

Figure 1. Mixed Full Clean portfolio contribution to 2025 resource needs [PGE's 2019 IRP Figure 7-17]



Concerns regarding PGE's Renewable Action have largely centered on timing and size. PGE proposed to pursue renewables to allow the Company to act in the near term to meet capacity needs and capture capacity value for customers while accommodating the timing constraints of those resources that could result in the most cost savings through leveraging federal tax credits. While PGE notes that a 2023 renewable addition would contribute to meeting the Company's near-term capacity needs, Staff and AWEC suggested that the Company's Renewable Action was out of alignment with PGE's resource needs.[9] The extension of the federal PTC, as PGE interprets it, removes this tension in the timing of the Renewable Action without impacting PGE's primary conclusions about the economic value of renewables and their ability to contribute to meeting PGE's growing resource needs. PGE therefore proposes to modify the Renewable Action to align the timing of renewable resource additions with the PTC extension and the timing of PGE's increasing capacity needs.

Regarding the size of the Renewable Action, PGE acknowledges that the selection of 150 MWa as an upper bound for near-term renewable additions required some degree of subjectivity, but PGE disagrees with Staff's assertions about how the Company has and should develop this constraint. PGE developed the constraint of 150 MWa of renewable additions not to justify the need for new

[9] LC 73 Final Comments of Staff at 10, 20; Final Comments of AWEC at 6-7.

resources (as Staff has suggested in Recommendation 4[10]), but to help prevent over-procurement of economic energy resources.[11,12] Without a constraint, PGE's portfolio optimization analysis continues to suggest that the near-term pursuit of significant quantities of renewables is expected to lower long-term costs.

Despite the quantitative finding that large quantities of near-term renewables could be economic, PGE notes that Integrated Resource Planning is not a strictly formulaic exercise. Thoughtful planning requires both quantitative and qualitative analysis. PGE developed the 150 MWa upper bound for the Preferred Portfolio based on a significant amount of data as well as qualitative considerations. The constraint was informed by PGE's forecast of the amount of energy that the Company would otherwise economically purchase from the market to meet load under 54 widely divergent market and need futures, which suggested a persistent market reliance of over 250 MWa in almost all futures and over 500 MWa in the Reference Case. The constraint was also informed by consideration of other uncertainties related to PGE's energy position, including voluntary renewable programs and the potential for longer-term contracts with existing resources to bring both capacity and energy.

Staff suggests that PGE's approach to designing this constraint was not adequately robust but proposes that PGE instead rely on a highly simplified analysis – the traditional energy load resource balance – to inform both procurement targets and the renewable glide path. PGE understands and appreciates the desire to rely on traditional and simplified methodologies to mitigate risks but finds this recommendation to be fundamentally at odds with Staff's insistence that a more robust analysis is required to establish an appropriate upper bound for renewable resource procurement. PGE described in the Company's reply comments the historical purpose of the energy load resource balance analysis and why it is not well-suited to the shifting energy dynamics in our industry.[13] As discussed further in **Section 3.4**, PGE continues to believe that the consideration of the shifting dispatch patterns of thermal resources is an important step forward in evolving long-term planning paradigms to account for both new market trends and broader decarbonization efforts in the West. Furthermore, the Company believes that leveraging the robust evaluation of future market positions to inform constraints on energy resource additions, as PGE has done in developing the 150 MWa constraint, is appropriate.

Modified Renewable Action

In response to both the extension of the federal PTC and the concern raised by Staff and AWEC that the Renewable Action should better align with PGE's capacity needs, PGE modifies the Renewable Action as follows:

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[10] LC 73 Final Comments of Staff at 30-31.
[11] LC 73 PGE's 2019 IRP at 194.
[12] LC 73 Reply Comments of PGE at 11.
[13] LC 73 Reply Comments of PGE at 53–54.

Original Renewable Action

Action 2. Conduct a Renewables Request for Proposals (RFP) in 2020, seeking up to approximately 150 MWa of RPS-eligible resources to enter PGE's portfolio by the end of 2023.

Conditions:

- Open to all RPS-eligible resources
- Resources must pass the cost-containment screen
- The value of RECs generated prior to 2030 must be returned to customers
- Resources must meet the transmission requirements for variable renewables described in PGE's Addendum Filing

Modified Renewable Action

Action 2. Conduct a Renewables Request for Proposals (RFP) seeking up to approximately 150 MWa of new RPS-eligible resources that contribute to meeting PGE's capacity needs by the end of 2024.

Conditions:

- Resources must qualify for the federal Production Tax Credit (PTC) or the federal Investment Tax Credit (ITC);
- Resources must pass the cost-containment screen;
- The value of RECs generated prior to 2030 must be returned to customers; and
- Resources must meet the transmission requirements for variable renewables described in PGE's Addendum Filing.

The modified Renewable Action incorporates three changes from the original Renewable Action. The modified Renewable Action:

1. Requires renewable additions to contribute to meeting PGE's capacity need and better aligns the timing of the renewable resource action to the timing of PGE's increasing capacity needs;
2. Requires that resources qualify for the federal PTC or federal ITC, consistent with Staff Recommendation 3;[14] and
3. Removes the specificity in the timing of the Renewable RFP to allow the Company to leverage the flexibility afforded by the PTC extension. The Company still anticipates that a timely initiation of an RFP would yield positive outcomes for customers but acknowledges that the near-term urgency for an RFP may no longer be foundational to pursuing resources with the attributes identified in the Preferred Portfolio.

PGE's modified Action Plan also clarifies that the RPS-eligible resources must be new resources.

[14] LC 73 Final Comments of Staff at 30.

2.3. Capacity Actions

Parties' Comments

Staff recommend that the Commission acknowledge PGE's plan to pursue capacity from existing resources in the region via bilateral negotiations and that PGE focus procurement activities in 2020 on meeting capacity needs, rather than acquiring renewable energy.[15] CUB and RNW expressed openness to a more accelerated consideration of new non-emitting capacity resources.[16,17] Swan Lake continued to argue that a staged Capacity Action would not allow a long-lead time resource to compete against other technologies to meet PGE's capacity needs in the mid-2020s.[18] Several parties express support for the pursuit of new non-emitting resources in the Capacity RFP.

PGE's Response

PGE appreciates the continued interest from Staff and stakeholders in PGE's bilateral negotiation process and non-emitting Capacity RFP. PGE designed the staged Capacity Action to help facilitate the procurement of new non-emitting capacity resources to meet PGE's needs, while also ensuring that the Company had the opportunity to pursue potentially lower cost existing capacity resources in the region. PGE outlined several risks that were considered in designing the staged Capacity Action in the Company's reply comments.[19] While PGE views the staging of procurement activities as a straightforward way to mitigate the identified risks and to ensure that procured resources align with the Company's most recent understanding of resource needs, PGE also acknowledges that these objectives could be met through appropriately designed concurrent processes. Specifically, concurrent processes must be designed to ensure that the combined procurement across the processes aligns with resource needs.

In response to feedback from Staff and stakeholders and with consideration of the risks that PGE designed the Capacity Action to address, PGE proposes to modify the Capacity Action to allow for concurrent, rather than sequential, processes and to introduce additional cross-cutting conditions to ensure alignment between the concurrent procurement activities and PGE's resource needs.

Modified Capacity Action

PGE modifies the Capacity Action as follows:

[15] LC 73 Final Comments of Staff at 15.
[16] LC 73 Final Comments of CUB at 7–8.
[17] LC 73 Final Comments of RNW at 7.
[18] LC 73 Final Comments of Swan Lake at 2–4.
[19] LC 73 Reply Comments of PGE at 19-23.

Original Capacity Action

Action 3A. Pursue cost-competitive agreements for existing capacity in the region.

Action 3B. Update the Commission and stakeholders on the status of PGE's bilateral negotiations and any resulting impacts on capacity needs.

Action 3C. Conduct an RFP for non-emitting resources to meet remaining capacity needs.

Modified Capacity Action

Pursue dispatchable capacity through the following concurrent processes:

Action 3A. Pursue cost-competitive agreements for existing capacity in the region.

Action 3B. Conduct an RFP for non-emitting dispatchable resources that contribute to meeting PGE's capacity needs.

The modified Capacity Action incorporates three changes from the original Capacity Action. The modified Capacity Action:

1. Calls for concurrent, rather than sequential, consideration of existing and new capacity resources. This allows the Company to initiate the non-emitting Capacity RFP while bilateral negotiations may still be underway.
2. Removes the explicit stage between the bilateral negotiation process and the RFP in which PGE updates the Commission and stakeholders on resource needs. PGE would still plan to update the Commission and stakeholders on resource needs as part of the procurement activities.
3. Focuses the capacity action on dispatchable capacity resources to differentiate the resources pursued through this action from those non-dispatchable non-emitting resources that would also contribute capacity to the system through the Renewable Action but would not meet PGE's needs for dispatchable and flexible resources.

The modified Capacity Action also retains the flexibility for PGE to adjust as information is gained about the market through the bilateral negotiation and RFP processes and to procure long-lead time resources in the non-emitting Capacity RFP if the Company can pair them with short-term contracts to meet interim capacity needs. While PGE does not have a minimum target for procurement across the bilateral negotiation process and the Capacity RFP, the Company estimates an indicative lower bound of approximately 250 MW of capacity contribution from these combined activities based on the capacity need in the Low Need Future and the anticipated contribution of renewables.

2.4. Additional Conditions

To accommodate the redesign of PGE's Renewable and Capacity Actions as concurrent rather than sequential processes, PGE proposes the following additional conditions to ensure that procurement activities remain aligned with the Company's resource needs and reflect the findings of PGE's portfolio analysis:

Additional Conditions

The combined capacity contribution of all procured dispatchable capacity resources (Modified Actions 3A and 3B) and all new renewable resources (Modified Action 2) will not exceed PGE's identified 2025 capacity need, currently forecasted to be 697 MW.

The combined energy additions from new non-emitting dispatchable capacity resources (Modified Action 3B) and new renewable resources (Modified Action 2) will not exceed approximately 150 MWa.

2.5. Enabling Analyses

Over the course of this docket, Staff and stakeholders have raised important issues to be addressed in future IRPs or in other decision-making processes. PGE proposes the following Enabling Analyses:

Enabling Analyses

Transmission-Related Constraints to incorporate transmission-related constraints into IRP analysis.[20]

Climate Adaption Study to investigate the potential impacts of climate change on PGE's loads and resources.[21]

Solar Integration Cost Drivers to further investigate the drivers of PGE's findings regarding solar integration costs, with a specific focus on identifying the relative importance of sub hourly variability versus the timing of morning and evening solar ramps.[22]

Colstrip Customer Impacts to investigate the potential customer rate impacts of options related to Colstrip Units 3 and 4, including, but not limited to, modified depreciation schedules.[23]

3. Needs Assessment

In this section, PGE addresses the comments from stakeholders regarding the load forecast, electric vehicles, energy efficiency, the Updated Needs Assessment, regional markets, and PURPA qualifying facilities (QFs). PGE appreciates the thoughtful feedback provided by stakeholders.

3.1. Load Forecast and Direct Access

Parties Comments

Staff stated that PGE's top-down load forecast is "reasonable"[24] from its review thus far. Nevertheless, Staff, CUB, and AWEC questioned PGE's assumptions with respect to direct access, implying that the cost-of-service portion of the load forecast may be skewed high due to the possibility of customers opting for long-term direct access (LTDA) in future years.

[20] See PGE's Reply Comments at 17, Section 2.4, and at 70, Section 6.3, for additional information.
[21] See PGE's Reply Comments at 17, Section 2.4 and at 90, Section 8.2, for additional information.
[22] See PGE's Reply Comments at 17, Sections 2.4 and at 69, Section 5.5, for additional information.
[23] See PGE's Reply Comments at 65, Section 5.2, for additional information.
[24] LC 73 Final Comments of Staff at 46.

Staff recommended that PGE "Provide analysis that helps parties consider the impact future LTDA elections would have on its forecasted needs."[25] Additionally, CUB suggested specific sensitivity analyses for the industrial sector load forecast would better capture risks[26] and requested analyses of the industrial forecast using alternative economic drivers to the US GDP driver currently used.[27]

PGE's Response

PGE understands Staff's and stakeholders' interest in adequately considering future LTDA elections within the needs assessment. PGE would like to clarify how LTDA loads are currently considered in the econometric forecast. PGE conducts its top-down econometric forecast at the net system level, which encompasses both cost-of-service and LTDA energy deliveries. Afterward, PGE forecasts a growth rate for the embedded LTDA energy deliveries. The delta between the net system forecast and the LTDA forecast becomes the cost-of-service forecast, which is then used in IRP modeling. Although PGE has not speculated on future individual customer decisions to elect LTDA as part of its forecast of the LTDA growth rate, PGE has forecasted an increase in the level of LTDA energy deliveries. In the 2019 IRP Update, PGE's long-term forecast includes 1.6 percent average annual growth of the LTDA energy deliveries within the total industrial forecast, a rate that is estimated based on growth rates for those specific customers who participate in LTDA.

PGE reiterates that customer interest in the LTDA program fluctuates with many factors. While there have been years when customer interest in LTDA has grown, there have been years when new interest in LTDA does not materialize; in the most recent 2019 election window, no new customers opted for LTDA.[28] Additionally, a forecast needs to consider the risk of customers closing businesses or reducing loads in the LTDA forecast in addition to the possibility of growth. PGE has anchored its LTDA and cost-of-service forecasts in the current information available, aiming to achieve an unbiased estimate of need.

PGE has an obligation to plan for all cost-of-service supply customers, regardless of customer class or eligibility for Direct Access. If sensitivities are designed to examine the portion of PGE's needs that are associated with customers who are eligible for, but do not participate in, Direct Access, PGE strongly believes that these sensitivities should not factor into resource planning decisions.

With respect to CUB's interest in specific sensitivity analyses and alternative economic drivers for the industrial sector load forecast, PGE is open to discussing these concerns in more detail with CUB and other interested stakeholders in future planning cycles.

[25] LC 73 Final Comments of Staff at 49.
[26] LC 73 Final Comments of CUB at 2.
[27] LC 73 Final Comments of CUB at 5.
[28] Six service points for existing LTDA customers opted for LTDA during this window.

3.2. EV Forecast

Parties' Comments

Staff's final comments express concerns that the additional load associated with electric vehicle adoption may be too high, potentially causing PGE to "overstate its near-term capacity needs."[29] Staff recommends that instead of using low, reference, and high EV adoption forecasts in the Need Futures, PGE "use the base case of EV adoption under *all* IRP load forecasts" based on Staff's opinion that high adoption would be quickly mitigated by load shifting measures.[30] Staff also raised concerns with the methodology and assumptions used to forecast EV penetration. Their concerns comprised the following arguments:

- PGE's response to opening comments from Staff included further description provided by Navigant regarding the EV modeling approach, which characterized the underlying mathematical algorithm for their VAST™ forecasting tool as an enhanced Bass diffusion model.[31] In final comments, Staff noted a concern that "enhancements may be pushing the Bass model beyond what is reasonable."[32]
- Staff asserted that PGE tailored the Bass diffusion model in the high EV scenario to include unrealistic assumptions related to vehicle substitution and drivers of consumer choice.[33] Staff elaborated on this, stating that the powertrains included from manufacturer press releases do not exist and that modeling their entry into the market creates an overestimation of EV sales in both quantity and timing.[34]
- Staff expressed concern that Navigant's use of the total cost of ownership (TCO) metric to estimate market competitiveness of EVs may "overlook important non-cost related barriers to EV adoption such as vehicle range and charger availability."[35]

RNW acknowledged uncertainty in EV forecasting, and included analysis on market trends, which "suggest that Staff's concerns about possible exaggeration of EV load are likely unfounded."[36] RNW concluded that Navigant applied a "sophisticated forecasting methodology" and that "PGE has done a thoughtful and reasonable job forecasting EV load."[37]

NWEC expressed support for the advancements in EV forecasting and further voiced the need for flexible demand programs to accommodate the growth of EV load.

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[29] LC 73 Final Comments of Staff at 47–48.
[30] LC 73 Final Comments of Staff at 48, emphasis in original.
[31] LC 73 Reply Comments of PGE at 42.
[32] LC 73 Final Comments of Staff at 47.
[33] *Id.*
[34] LC 73 Final Comments of Staff at 48.
[35] *Id.*
[36] LC 73 Final Comments of RNW at 8.
[37] *Id.*

PGE's Response

PGE appreciates the interest in EV forecasting methodologies within the context of long-term planning and looks forward to working with Staff and stakeholders in future planning cycles to further refine models of both EV adoption and measures to flexibly manage these new loads. In the subsections below, PGE addresses Staff's concern with Navigant's EV forecasting methodology and the Company's incorporation of EV forecast scenarios into the Need Futures.

Near-term EV Load

In the near-term, the forecast of EV load[38] in the Reference Case in the 2019 IRP is a small portion of the peak load. In the year 2025, Reference Case EV load comprises approximately 2.7 percent of the peak IRP load, which is further reduced to 2.2 percent when accounting for the load-shifting forecast from direct load control programs for EV load (EV DLC). PGE understands Staff's recognition that in the High Need Future, the increased forecast of EV adoption contributes to greater uncertainty in capacity need. However, PGE does not propose to procure capacity according to the High Need Future. PGE utilizes this scenario to understand the risk associated with uncertainty. PGE will be continually reassessing these forecasts and will adjust the resulting need outlook as is appropriate in future IRPs.

EV Adoption Forecast for Need Futures

PGE respectfully disagrees with Staff's recommendation to "use the base case of EV adoption under all IRP load futures." The Company notes that Staff's suggestion that EV adoption would be accompanied by complementary load shifting measures was included in Navigant's analysis through the EV DLC potential study, which provided an EV DLC forecast for each of the three EV adoption forecasts. Further, the presence of load-shifting capability, while useful for mitigating capacity impacts, does not reduce overall energy needs. Examining uncertainty in future energy need is an important component of long-term planning risk assessment and in developing the renewable glide path.

Due to the potential for non-linear growth in the uptake of the technology and the uncertainty in timing of mass adoption, PGE does not find it appropriate to adopt the reference EV forecast for the Low and High Need Futures for long-term planning analysis applied. PGE will continue to update its EV adoption and EV load-shifting potential studies as new market information becomes available.

Navigant's Use of the Bass Diffusion Model

The Bass diffusion model is a well-established and widely used first-order differential equation that calculates the pace of consumer adoption of new technologies. In its base form, the Bass diffusion model presents a mathematical framework that represents the proportion of a population that will adopt a new technology as a measure of the levels of innovation and imitation within that population. Enhancements to the Bass diffusion model were introduced by thought leaders in the

[38] As discussed in the 2019 IRP at 96, Section 4.1.3.1, the IRP EV load forecast is for light-duty EVs only.

field of diffusion modeling in the early 1990s to account for parameters such as technology turn-over, the interaction between various products, and granular analysis of adoption per individual in a population.[39] These enhancements have precedent and are commonplace in present-day diffusion models. PGE clarifies that Navigant did not create novel enhancements to push capabilities of the Bass diffusion model further. They utilized an existing well-established enhanced form of the model to account for customer attributes and competing products specific to the PGE service territory.

Assumptions of Future Product Lines

PGE clarifies that the powertrains included in Navigant's model of future market offerings do exist. They are presently in production and are being prepared for market release. Manufacturers are likely highly motivated to deliver on their stated product release commitments because they stand to lose major investments in new product lines if they do not realize anticipated sales of those products at the cost recovery timelines in their financial plans. PGE acknowledges the uncertainty in predicting nascent markets but asserts that ignoring signals of new product offerings from public statements made by manufacturers would create a less reasonable forecast and would not improve long-term planning.

Total Cost of Ownership Methodology

PGE appreciates Staff's concern over the non-cost barriers to EV adoption, as applied to the total cost of ownership (TCO) methodology. The Company clarifies that Navigant did include both vehicle range and charger availability within their TCO calculation. The methodology for Navigant's TCO analysis was provided to Staff in Confidential Attachment A of PGE's response to LC 73 OPUC Data Request No. 157.

3.3. Energy Efficiency

Parties' Comments

For future planning, Staff recommended that PGE coordinate with Energy Trust to develop additional energy efficiency scenarios and Staff expressed the opinion that energy efficiency scenarios should be "consistent with the future that these scenarios represent."[40] Staff also recommended that for the next IRP, PGE and stakeholders consider if energy efficiency can be selected as a resource in portfolio construction.[41] NWEC noted concern "about the reduction of anticipated energy efficiency potential from the revised Energy Trust of Oregon analysis" provided in

[39] Frank M. Bass, (2004) Comments on "A New Product Growth for Model Consumer Durables The Bass Model". Management Science 50(12_supplement):1833-1840. Available at: https://doi.org/10.1287/mnsc.1040.0300.
[40] LC 73 Final Comments of Staff at 40.
[41] *Id.*

PGE's reply comments and indicated that NWEC would like additional details about the updated near-term forecast.[42]

PGE's Response

PGE is coordinating with the Energy Trust to develop two energy efficiency forecasts in addition to the Reference Case for the next long-term energy efficiency forecasts. PGE appreciates Staff's recommendation for consistency between energy efficiency scenarios and IRP scenarios, however PGE continues to respectfully disagree with Staff regarding the structuring of the high and low need futures. PGE also notes that energy efficiency forecasts are impacted by many inputs other than the load scenario, for example, wholesale market prices, generation capacity costs, energy efficiency measure costs, the assumption that the conservation adder remains at 10 percent, codes and standards, and customer adoption assumptions.

PGE is open to hosting discussions with Staff and other interested stakeholders regarding Staff's suggestion to consider if and how IRP portfolio analysis could include the selection of additional energy efficiency measures beyond those found to be cost-effective.

PGE appreciates NWEC's interest in additional information about the recent near-term forecast from Energy Trust and notes that Energy Trust's final 2020 budget information is now available online.[43]

3.4. Needs Assessment Update

Parties' Comments

In final comments, Staff concluded that PGE's capacity needs assessment was accurate and found "RECAP's overall approach to modeling capacity of variable energy resources reasonable."[44] Staff did express concern for the potential for future announcements of regional resource additions to impact the market capacity assumptions, however, Staff found the current assumptions to be reasonable for now.[45] Swan Lake recommended Commission acknowledgment of PGE's capacity need.[46] CUB noted its appreciation for the Updated Needs Assessment and commented that the update addressed CUB's earlier concerns regarding Community Solar and Green Tariff Programs.[47]

AWEC recommended that PGE assume greater quantities of market capacity in its capacity need assessment and suggested that this was a reasonable assumption because other utilities "rely on market purchases to satisfy material portions of their respective capacity requirements."[48] AWEC also provided a recommendation for the modeling of market capacity in RECAP.[49]

[42] LC 73 Final Comments of NWEC at 3.
[43] See: https://www.energytrust.org/wp-content/uploads/2019/12/2020_Apprpoved_Binder_WEB.pdf.
[44] LC 73 Final Comments of Staff at 8.
[45] *Id.*
[46] LC 73 Final Comments of Swan Lake at 11.
[47] LC 73 Final Comments of CUB at 4-5.
[48] LC 73 Final Comments of AWEC, Attachment A at 5.
[49] *Id.* at 7.

Additionally, AWEC asserted that customers should not pay for transmission rights to market hubs if the rights do not bring capacity benefits.[50] AWEC's comments regarding assumptions for resource adequacy benefits from potential participation in a day-ahead market are discussed in **Section 3.5**.

Staff continued to express the opinion that the market energy position should not be used to determine the quantity of energy needed in an RFP.[51] Staff also continues to find the traditional energy load-resource balance (LRB) to be a "more meaningful IRP tool to ultimately characterize the need to invest in new resources."[52] RNW presented a different opinion, noting that "market reliance can bring both costs and risks" and "reiterate[d] its support for PGE's efforts to model energy need in an evolving and increasingly complex operational paradigm."[53]

Regarding the impact of the Green Tariff resource, AWEC expressed the opinion that the Green Tariff resource should reduce PGE's RPS obligation.[54]

PGE's Response

PGE appreciates the careful review and thoughtful questions provided by stakeholders of the Updated Needs Assessment filed on November 27, 2019.

Capacity Need

PGE disagrees with AWEC's recommendations regarding market capacity assumptions and does not find that market capacity assumptions made by other utilities are useful indicators that PGE should increase its own assumptions, particularly in a period of reduced regional capacity. PGE continues to believe that a holistic evaluation of regional loads and resources, as was performed within the Market Capacity Study,[55] provides a reasonable assumption for market access under constrained conditions for the purposes of long-term planning.

Regarding the market capacity modeling in RECAP, PGE notes that AWEC's suggestion is based on a misinterpretation of the current modeling of market capacity in RECAP.[56] AWEC's description of varied hour-to-hour quantities misinterpreted the treatment of the resource in the model. PGE clarifies that for each regional capacity scenario (low, reference, and high), market capacity is modeled as four on-peak segments (winter, summer, spring, fall) and one off-peak segment.[57] While these segments are listed on the "Variable Generation" worksheet in RECAP, their profiles

[50] LC 73 Final Comments of AWEC, Attachment A at 6.
[51] LC 73 Final Comments of Staff at 18.
[52] *Id.*
[53] LC 73 Final Comments of RNW at 9.
[54] LC 73 Final Comments of AWEC, Attachment A at 4.
[55] See 2019 IRP at 65, Section 2.4.2.1 and at 601, External Study E.
[56] LC 73 Final Comments of AWEC, Attachment A at 6.
[57] PGE's response to AWEC Data Request No. 003, Attachment C, "RECAP_2019IRP_CONF.xlsm", worksheet "VarInput", columns BS-CG.

contain factors of "1" for all hours appropriate for each segment (e.g., all on-peak hours of January, December, and February for the winter on-peak segment) and do not vary as suggested by AWEC.[58]

PGE disagrees with AWEC's assertions regarding costs associated with transmission rights and notes that ratemaking issues are outside the scope of this docket. As discussed in Section 4.4 of PGE's reply comments, transmission rights may provide the opportunity to access resources to support capacity adequacy needs, but these rights by themselves do not provide capacity contributions. Transmission rights also bring other values to customers beyond the opportunity to access capacity resources. PGE reiterates that the comprehensive assessment of the Market Capacity Study is the appropriate methodology for estimating market capacity for long-term planning.

Energy Need

PGE clarifies that the Company has not used the market energy position analysis to quantify a need for new resources. PGE has instead used the market energy position analysis to establish an upper bound for new renewable additions, limiting the contribution that new resources may have (relative to market purchases) to meeting PGE's energy needs.

PGE continues to disagree with Staff about the usefulness of the traditional energy LRB in IRP planning. PGE notes that the traditional energy LRB is not a measure of "true energy shortage"[59] as it disregards energy capability from natural gas resources with high heat rates. As described within PGE's reply comments, the energy load resource balance serves as a simplified proxy for market exposure.[60] PGE appreciates the complexity of considering energy need and market exposure and plans to host discussions with Staff and stakeholders in the next IRP cycle to consider opportunities to improve the terminology and reporting of information related to energy in future IRPs.

RPS Need

PGE continues to disagree with AWEC's opinion that the Green Tariff resource reduces PGE's RPS obligation and refers to PGE's response in Section 4.8 of PGE's reply comments. Further, while PGE does not opine on AWEC's interpretation of ORS 469A.060(1)(a), PGE notes that the Company does not forecast that the RPS standard will require PGE to acquire electricity in excess of its projected calendar year load during the term of the Green Tariff resource.

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[58] PGE's response to AWEC Data Request No. 003, Attachment C, folder "profiles_CONF", files "RegionalCap_WinterOnPeak_CONF.csv", "RegionalCap_SummerOnPeak_CONF.csv", "RegionalCap_SpringOnPeak_CONF.csv", "RegionalCap_FallOnPeak_CONF.csv", "RegionalCap_OffPeak_CONF.csv".
[59] LC 73 Final Comments of Staff at 17.
[60] LC 73 Reply Comments of PGE at 53-54.

3.5. Regional Markets

Parties' Comments

CUB expressed appreciation for PGE's reply comments regarding resource sufficiency and economic benefits, but requested that additional information and analysis about potential regional markets be included in future IRPs to "contribute to the knowledge base necessary to evaluate regional market decisions."[61] In comments regarding regional markets and potential market enhancements, NIPPC stated that "it is too early – and there is too much uncertainty around the final form of those market enhancements – to expect PGE to provide any detailed analysis of the benefits that will flow from those market reforms, especially with regard to transmission."[62] Mr. Mullins, commenting on behalf of AWEC, recommended that PGE include assumptions of resource adequacy benefits from potential participation in the Extended Day-Ahead Market (EDAM).[63]

PGE's Response

PGE will reach out to CUB and other stakeholders to discuss what information would be useful to provide about potential regional markets and what docket would be most appropriate to provide the information.

PGE disagrees with AWEC regarding including an assumption of resource adequacy benefits from potential participation in the EDAM. PGE notes that the EDAM stakeholder process has just started, and that the first stakeholder workshop is scheduled in February. Additionally, PGE notes that the EDAM would operate in a day-ahead timeframe, and as a result, would not facilitate resource adequacy for participating entities. AWEC commented that "there will likely be mechanisms that will allow market participants to rely on resources of other balancing authorities for meeting the resource sufficiency tests."[64] However, PGE notes that resource sufficiency tests in markets like the EIM or also potentially in the EDAM are separate and distinct requirements from longer-term resource adequacy requirements. PGE continues to believe that a holistic evaluation of regional loads and resources, as was performed within the Market Capacity study,[65] provides a reasonable assumption for market access under constrained conditions for the purposes of long-term planning.

3.6. PURPA Qualifying Facilities

Parties' Comments

Staff found that PGE's reply comments provided "a helpful discussion of the disadvantages of forecasting future QF adoption directly in its needs assessment."[66] Staff also expressed the opinion

[61] LC 73 Final Comments of CUB at 6.
[62] LC 73 Final Comments of NIPPC at 7-8.
[63] LC 73 Final Comments of AWEC, Attachment A at 7.
[64] *Id.*
[65] See 2019 IRP at 65, Section 2.4.2.1 and at 601, External Study E.
[66] LC 73 Final Comments of Staff at 9.

that a "sensitivity about historical QF development rates would be helpful."[67] As in REC's initial Comments, REC continued to disagree with the PURPA qualifying facility (QF) treatment in PGE's needs assessments and sensitivities.[68]

PGE's Response

PGE appreciates Staff's comments regarding the discussion of QFs in Section 4.9 of PGE's reply comments. PGE understands Staff's interest in a sensitivity regarding historical QF completion rates and believes that Docket No. UM 2038 (which will address the treatment of QFs in the IRP process[69]) may be the best place to consider this question.

PGE continues to disagree with REC's position regarding QF forecasting. PGE provided extensive responses to REC's recommendations for forecasting QFs in Section 4.9 of PGE's reply comments. REC's reply comments again included comments related to PGE's QF procurement and interconnection process that are outside the scope of this docket and are in some cases inaccurate or misleading.

4. RFP Design

4.1. Transmission Interim Solution

Parties' Comments

Staff provided a detailed review of the parties' positions and a thorough assessment of the issues relating to transmission including RFP design details, availability of BPA's conditional firm products and long-term firm transmission, and the interplay between curtailment and capacity contribution. Staff concludes its testimony by providing a recommendation consisting of five parts.[70]

NIPPC provides multiple critiques and comments pertaining to the use of non-firm transmission, PGE's transmission rights, deferred transmission service, regional markets, coal retirements, and resource diversity.[71]

RNW's final comments mainly focus on the incorporation of non-firm transmission products into the Interim Transmission Solution and the impact of reduced long-term transmission on a resource's capacity contribution. Additionally, similar to NIPPC, RNW also encourages PGE to further explore use of PGE's transmission rights by bidders. RNW states that it is sensitive to PGE's concerns and recommends that PGE explore contractual mechanisms to minimize the associated risks.[72]

[67] LC 73 Final Comments of Staff at 9.
[68] LC 73 Final Comments of REC at 2-5.
[69] See UM 2000, Order No. 19-254, Staff's Recommendation Adopted as Modified, Appendix A at 1.
[70] LC 73 Final Comments of Staff at 39.
[71] LC 73 Final Comments of NIPPC at 2-10.
[72] LC 73 Final Comments of RNW at 5.

NWEC is generally supportive of PGE's approach in the Interim Transmission Solution and provides several points of focus to guide future discussions.[73] Referencing PGE's reply comments, NWEC raises the point regarding the potential need for additional analysis of the BPA system to determine impacts on future renewable resource procurement.[74]

NWEC, NIPPC, and Staff each identify the potential value for resource diversity, both for overall procurement and specific to transmission.

PGE's Response

PGE thanks stakeholders for their comments on the Company's Interim Transmission Solution and their openness while working with PGE and each other to review and further advance the deployment of the Interim Transmission Solution. All parties have identified transmission as an important issue for renewable procurement and all agree that the transmission paradigm in the Northwest is in a dynamic state. As stated in our reply comments, a primary purpose of the Interim Transmission Solution is learning and as the Company gains experience, it plans to adjust its methodologies accordingly.[75] PGE looks forward to continued work with stakeholders to as the Interim Transmission Proposal is operationalized.

RFP Design

As summarized above, some Parties have requested more detailed scoring information or requested the Commission instruct PGE to make specific changes to the Interim Transmission Solution as proposed in the 2019 IRP Addendum.[76,77,78] As detailed in **Section 4.2**, PGE believes the level of detail provided in the IRP docket is sufficient. Parties' comments appear to support the position that the 2019 IRP Addendum, discovery, and subsequent workshop(s) have provided sufficient information for parties to understand the mechanics and application of the Interim Transmission Solution. PGE understands and appreciates an RFP-specific application of the Interim Transmission Solution is new and the Company is committed to addressing requests for further scoring details and supporting information, including the questions raised by the Commission at the October 31 public meeting, in an RFP docket. However, PGE does want to address two specific comments raised in Parties' final comments in order to provide clarification.

Staff requests that PGE should explain how it will weigh tradeoffs between resource quality and transmission capacity.[79] Within a competitive solicitation, PGE will evaluate non-quantifiable project risks, including transmission quality risks, through non-price scoring. Evaluation of resource quality will generally be accomplished by forecasting project value and cost and will be included in a

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[73] LC 73 Final Comments of NWEC at 5-6.
[74] *Id.*
[75] LC 73 PGE's Reply Comments at 85-86.
[76] LC 73 Final Comments of Staff at 38.
[77] LC 73 Final Comments of NWEC at 5.
[78] LC 73 Final Comments of NIPPC at 10.
[79] LC 73 Final Comments of Staff at 38.

resource's price score. Those projects with the highest price and non-price scores will be considered for procurement as is described in Appendix J. As noted below in **Section 4.2**, PGE's IRP does not include comprehensive detail on non-price scoring elements as such information is appropriately reviewed within the context of an RFP approval proceeding. While Staff's comment appears to be more broadly addressing detailed RFP scoring, PGE wishes to clarify that the Company intends to design an RFP process with appropriate consideration given to BPA's TSEP process. Aligning the RFP with BPA's TSEP will enable the Company to better evaluate the tradeoff between resource quality and transmission availability. Further, RFP bidders providing the results of interconnection studies, including upgrade timing and cost, will enhance our evaluation in this regard.

NIPPC's final comments imply that PGE is seeking acknowledgment of "its transmission plan." [80] As detailed in **Section 4.2** below, PGE has complied with the Competitive Bidding Rules and sought to provide its Interim Transmission Solution proposal within the IRP to allow stakeholders additional time to review and comment. PGE is not seeking specific acknowledgment of the Interim Transmission Solution nor should the IRP acknowledgment be specifically tied to the Interim Transmission Solution. Instead, the components of the Interim Transmission Solution will be incorporated into subsequent RFP design and scoring, which will be reviewed and commented on by Staff and stakeholders in the appropriate docket, and ultimately referred to the Commission for approval.

Conditional Firm

Staff notes that it has concerns regarding the potential for the RFP scoring to "materially impact the ability of selected resources to help meet the Company's capacity needs…"[81] when evaluating the tradeoff between conditional firm and long-term firm at various levels (e.g. 80% vs 100%). Similarly, RNW encouraged PGE to consider lower levels of long-term transmission within an upcoming or subsequent renewable RFP and base its assessment on historical curtailment activity.[82] The Interim Transmission Solution was designed with the intent that it evolves over time. PGE has proposed a reduced level of 80 percent long-term products and plans to evaluate the impacts, both costs and risks, to PGE operations and customers.[83] As more is learned and performance under the Interim Transmission Solution is analyzed during the interim period of 2019 through 2024[84], PGE plans to revisit the specific elements of its proposal and determine appropriate changes in a subsequent IRP and/or RFP. Any changes proposed will be subject to input by Staff, stakeholders, and the Commission. With respect to curtailment and its incorporation into PGE's scoring analysis, PGE agrees with Staff that historical curtailment patterns may not be suitable predictors of future curtailment given the changing transmission and regional landscapes.[85] This further supports the need to monitor and report during the initial implementation of the Interim Transmission Solution.

[80] LC 73 Final Comments of NIPPC at 10.
[81] LC 73 Final Comments of Staff at 38.
[82] LC 73 Final Comments of RNW at 5.
[83] LC 73 PGE's 2019 IRP Addendum at 5.
[84] *Id.*
[85] LC 73 Final Comments of Staff at 37.

BPA's 'number of hours' conditional firm product provides a method to monitor and report, as there is a clearly defined limit to curtailment. Conversely, BPA's 'system conditions' conditional firm product does not allow the same clarity for evaluation purposes.

Staff also expresses concerns that the 'number of hours' conditional firm reassessment service may not be offered by BPA.[86] PGE believes the information Staff is relying on from BPA refers to a specific technical limitation for BPA that has now remedied.[87] It is not PGE's intent to have transmission requirements in its RFP that do not align with the transmission products offered by BPA. If during the interim period of 2019 through 2024 BPA either removes, significantly alters, or adds transmission products, PGE will evaluate and evolve its transmission requirements accordingly and make those changes available to interested stakeholders. PGE still contends that the 'number of hours' option is appropriate because it allows for a defined limit in curtailment hours instead of broad system conditions and allows for more robust scoring in an RFP; however, PGE notes that under current BPA practices the transmission customer may request an offer of both number of hours and system conditions.[88]

As NWEC and RNW indicate in their comments, PGE will continue to explore further refinements of its analytical methods applying curtailment and transmission availability limitations to resource valuation. PGE looks forward to deeper discussion of these methods and their application within a future renewable RFP docket.

<u>Non-Firm Transmission</u>

Both RNW and NIPPC reiterate their recommendation that PGE's renewable RFP requirements allow for non-firm transmission usage at or above the 20 percent level of nameplate that is not required to be a long-term product.[89,90] PGE provided reply comments in response to both RNW and NIPPC's recommendation and maintain our position on this issue.[91] Relative to short-term firm transmission, non-firm transmission products introduce significant risks beyond curtailment. While some parties have argued that these impacts are minimal or economic in nature, they have real-time impacts to the system that go beyond financial outcomes. Staff appropriately identifies this in its final comments by agreeing that accommodating flexibility should not subject the system to adverse reliability impacts.[92]

RNW also raises a concern regarding the availability of short-term firm and recommends that PGE at least accept deliveries over non-firm in the event that short-term firm is unavailable.[93]

[86] LC 73 Final Comments of Staff at 38.
[87] BPA Presentation at 4, 14. BPA Transmission Service Options for Delivery to PGE, dated October 31, 2019. Available at: https://oregonpuc.granicus.com/MetaViewer.php?view_id=2&clip_id=435&meta_id=23341.
[88] *Id.* at 16.
[89] LC 73 Final Comments of RNW at 2.
[90] LC 73 Final Comments of NIPPC at 3.
[91] LC 73 PGE Reply Comments at 74-76.
[92] LC 73 Final Comments of Staff at 37.
[93] LC 73 Final Comments of RNW at 3.

Generally, this has not been a significant issue with past procurement due to PGE's previous transmission requirement of long-term firm. However, the concern RNW raises may be more likely to exist under the Interim Transmission Solution framework and goes beyond resource evaluation and contracting, manifesting in near real-time operations. As PGE indicated in the Interim Transmission Solution, "Because the proposed transmission requirements introduce new risks for project deliverability, the RFP will reflect modifications to contract requirements to ensure these risks are addressed. The Company recognizes that certain events, curtailment or otherwise, may be outside the control of the parties and a contract must be flexible enough to address such events."[94] PGE believes that it is important that both the RFP and any resulting agreements create the clear obligation to procure and provide the necessary transmission service that aligns with the bid. PGE also understands and appreciates the need for resource contracts to contain provisions that address unexpected or infrequent occurrences. It is PGE's position that the specific situation RNW raises is best addressed within an RFP docket.

<u>Transmission Availability Assessment</u>

As part of its recommendation, Staff requested the Company assess transmission impacts, specifically that the Company detail how it will weigh specific transmission paths and average flowgate impacts of projects bids.[95] PGE clarifies that a request for transmission service to BPA results in a unique impact to BPA's flowgates. Consideration of average flowgate impacts in an RFP would be inappropriate as it would not provide resource-specific information. PGE further clarifies that a transmission provider, likely BPA, is responsible for calculating the transmission impacts associated with requests for specific projects. However, BPA, as well as most transmission providers, have tools and information available to estimate these resource-specific impacts. While these tools and information can provide guidance, they do not provide indicative results. Ultimately, the transmission provider is the entity responsible for determining available transmission service. PGE is not in a position to speculate on resource impacts to other transmission systems and does not believe such an exercise would lead to improved accuracy. However, PGE notes that transmission providers, specifically BPA, have been willing to provide impact estimates to developers and PGE to better inform the feasibility of resource transmission plans. To the extent that Staff is recommending the Company incorporate consideration of which paths or specific flowgates are impacted by a bid's transmission arrangements into PGE's renewable RFP non-price scoring framework, PGE will plan to work with Staff to better understand its proposed approach and application.

<u>PGE's Transmission Rights</u>

NIPPC expresses concerns that "given the uncertainty associated with how transmission will be treated in these rapidly evolving markets, there is too much uncertain to require PGE ratepayers to make commitments to new long-term firm PTP contracts…"[96] Instead NIPPC recommends that

[94] LC 73 PGE's 2019 IRP Addendum at 6.
[95] LC 73 Final Comments of Staff at 39.
[96] LC 73 Final Comments of NIPPC at 8.

PGE's renewable procurement rely on transmission rights associated with Boardman or that have been deferred. NIPPC again fails to recognize that its proposal shifts all the uncertainty and costs associated with maintaining these rights, for potentially up to five years, on to PGE and customers for the benefit of speculative developers/projects. As PGE stated in its reply comments, there are financial risks, redirect risks, and renewal risks that would be unnecessarily placed on PGE and its customers.[97] The Company's reply comments further elaborate on these risks, specifically redirects.[98] Based on discussion at the October 31 public meeting, PGE understands that the Commission and some stakeholders desire to see additional analysis supporting PGE's characterization of redirects and PGE is committed to providing such analyses in an RFP-specific docket.

While NIPPC acknowledges there is risk with transmission, it continues to suggest that those risks should not be borne by developers and that the Commission should determine a risk tolerance through a similar lens.[99] PGE agrees there is risk with transmission but disagrees with NIPPC's approach. The specifics of RFP eligibility and scoring should be debated in an RFP-specific docket where the Commission should appropriately consider both costs and risks to customers as well as PGE. Moreover, determinations regarding cost recovery are reserved for prudency evaluations in ratemaking proceedings, not an IRP docket. NIPPC asks the Commission to order PGE to perform additional analyses[100], but is essentially asking for the analysis PGE has already provided in the form of the Interim Transmission Solution and supporting materials provided through discovery and workshops.

<u>Resource Diversity</u>

Most parties identify the value of resource diversity and support an RFP framework that allows and accounts for resource diversity.[101,102,103] PGE agrees with parties that diverse resources provide value in many ways, including usage of transmission. Staff requests that the Company should discuss how it will score net contribution made by blending diverse regime wind profiles.[104] NIPPC claims that there is insufficient information to determine how the diversity of resources is accounted for with regard to transmission and further suggests a paradigm whereby PGE should assess diversity benefits across bids, not just within a single bid with multiple resources.[105]

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[97] LC 73 PGE's Reply Comments at 78.
[98] PGE's transmission rights, both active and deferred, are not broadly redirectable to any part of the BPA system and the viability of a redirect is highly dependent on impacted flowgates, ATC, location, timing of request, and duration. In the last two years, PGE has had multiple redirects not granted due to lack of ATC or granted in part for a limited term with no associated renewal rights.
[99] LC 73 Final Comments of NIPPC at 3.
[100] *Id.*
[101] LC 73 Final Comments of NIPPC at 4.
[102] LC 73 Final Comments of Staff at 39.
[103] LC 73 Final Comments of NIPPC at 9.
[104] LC 73 Final Comments of Staff at 39.
[105] *Id.*

PGE noted in its reply comments, "The assessment of the benefits provided will depend on the specific characteristics of the generating resources and transmission service. For example, complementary facilities like wind and solar may not require additive transmission service or a facility paired with energy storage can reduce its transmission need."[106] There are several possible ways in which a bidder could propose to capture a diversity benefit through usage of the transmission associated with the bid(s). Because of this, PGE cannot provide a specific scoring rubric for every possible approach. Instead, PGE's analytical tools used for scoring are sufficiently capable of accounting for the cost, energy, and capacity impacts associated with potential transmission proposals and the technical details of these tools will be reiterated throughout the RFP process.[107] Additionally, similar to the IRP, PGE makes use of a portfolio analysis approach within an RFP to assess costs and benefits across various combinations of resources. Appendix J to PGE's 2019 IRP provides an overview of these portfolio modeling methods, and Staff, stakeholders, and the Commission will evaluate these methods in detail in the RFP docket.

PGE appreciates NIPPC's and Staff's request for further details regarding the evaluation of resource diversity within the RFP. PGE also appreciates NIPPC's creative proposal regarding resource diversity and transmission usage across bids and looks forward to working with NIPPC in a subsequent RFP docket to better understand NIPPC's proposal.

4.2. Competitive Bidding Rules

Parties' Comments

On December 11, 2019 the Administrative Hearings Division (AHD) issued a memo requesting that parties address how PGE's IRP and included RFP information aligns with the OPUC Competitive Bidding Rules. The memo seeks comments on whether PGE's IRP filing contains the RFP information described in OAR 860-089-0250(2)(a). Additionally, the memo requested additional information exploring how long-lead time resources could integrate into PGE's planning and procurement processes, which is addressed in **Section 5.3**.

Parties were responsive to the AHD memo in their final comments. Staff[108] and NIPPC[109] argue that the level of detail included in PGE's RFP design Appendix J is inadequate to meet the requirements of OAR 860-089-0250(2)(a) and would require additional process to evaluate the RFP design prior to the RFP approval process. AWEC does not oppose the structure of Appendix J, arguing that the level of detail included in Appendix J is generally appropriate with the understanding that the RFP design is not acknowledged in the IRP proceeding, but rather offered for informational purposes prior to an

[106] LC 73 PGE's Reply Comments at 77.
[107] PGE notes that these analytical tools are the same described in detail throughout the IRP docket.
[108] LC 73 Final Comments of Staff at 33.
[109] LC 73 Final Comments of NIPCC at 14.

RFP approval process.[110] AWEC does believe that it would be appropriate for Appendix J to include additional non-price scoring detail.

PGE's Response

PGE's 2019 IRP is responsive to the Commission's Competitive Bidding Rules ('Rules'). The information contained in PGE's IRP has led to productive discussions regarding PGE's future renewable RFP design, particularly with respect to off-system transmission availability. PGE believes that the RFP-related information contained in the 2019 IRP is complete and prepares all parties for a future RFP design proceeding focused on the approval of PGE's proposed renewable RFP design.

As an initial matter, PGE's 2019 IRP only includes RFP related information for a renewable RFP. The filing does not include analogue material for a capacity RFP. To satisfy the competitive bidding requirements for a capacity procurement, PGE plans to open an IE RFP design docket in 2020 for capacity resources following acknowledgment of the IRP. PGE may also choose to use the IE process to change renewable RFP design components. As is described below, PGE believes that the IRP filing is sufficiently detailed to allow for direct review of a complete final draft RFP should PGE choose to advance a renewable RFP design consistent with the IRP filing.

Differences of opinion regarding the completeness of PGE's RFP information reflect differences of interpretation of the Rules that refer to RFP elements. OAR 860-089-0250(2) requires that future requests for proposals (RFPs) reflect the elements, scoring methodology, and associated modeling described in the Commission-acknowledged IRP. PGE's appendix makes clear reference to the scoring methodology and models to be used in analysis. Disagreement regarding the adequacy of PGE's Appendix J appears to focus on the appropriate interpretation of RFP design elements that are to be included in the IRP. "Design elements" is not a defined term in the Rules, but in PGE's view an RFP element is a characteristic or essential RFP design feature. Such characteristic features include a description of the staged analytical process, the plan to assess non-quantifiable risks through discrete categories of 'non-price scores', the methods by which PGE would compare projects of unequal size or term, portfolio construction techniques, and sensitivity analyses to be deployed. Parties have argued for a more expansive interpretation of RFP design elements to possibly include a level of detail that includes every individual scoring decision and explicit identification of all inputs. PGE disagrees that the level of detail called for by Staff and NIPPC's final comments is appropriate.

There is a clear difference between the RFP information contained within the IRP and the final draft RFP that is included in the application for RFP approval. If the Rule's intent was to require that a draft of the RFP should be filed along with the IRP, the Rules would plainly state this intent. Instead, the Rules discuss the type of information that should be included in an IRP as to avoid an expansion of review process associated with the IE selection docket. The differences between the IRP and RFP filings are differentiated in the Rules and recognize the important differences between the purpose of the IRP's planning objectives and the much narrower purpose of the RFP design's

[110] LC 73 Final Comments of AWEC at 16.

commercial evaluation. Staff and NIPPC's suggestion that comprehensive scoring detail be included in the IRP is analogous to filing a complete draft of the RFP scoring material. As is discussed below, not only would such a filing be contrary to the intent of the IRP but it would require the utility to unrealistically adopt a comprehensive scoring design far in advance of application without the benefit of Stakeholder and Commission feedback on the broad issues of need and risk, without the benefit of IE review, and without the mechanisms to remain flexible to change the scoring design ahead of application.

The level of detail present in PGE's filing is appropriate and correct. Additional detail may be unknowable at the time of publication of the draft IRP which can realistically occur nearly two years prior to receipt of bids in a competitive solicitation. Furthermore, the level of detail should not be so specific to be rendered unacceptable by change in policy or circumstance that may occur after filing of the draft IRP. PGE does not believe that it is in customers' best interest to be required to detail a complete scoring rubric well ahead of commercial application.

4.3. Non-traditional Analysis

Parties' Comments

Staff recommends that PGE incorporate non-traditional analysis from the 2019 IRP into RFP scoring. Specifically, Staff recommends that PGE "evaluate bids for the impact of the ownership model on rate impacts,"[111] "include a non-price screen for intergenerational equity,"[112] and "explain how the Cost in High Tech Future non-traditional metric will be present"[113] within the Renewables RFP.

PGE's Response

PGE disagrees with Staff's recommendations to introduce aspects of PGE's near-term cost impact analysis and non-traditional scoring metrics as scoring criteria or screens within the Renewables RFP. PGE's near-term cost impact analysis presented in Section 7.3.1 of the 2019 IRP and discussed at the workshop at IRP Roundtable #19-3 was presented as informational and was not used to identify the Preferred Portfolio or to determine key attributes of the Preferred Portfolio that should be reflected in the Action Plan. While PGE believes that high level information about potential near-term cost impacts can help to contextualize long-term plans, it should not be used to prescribe resource actions or procurement outcomes.

Regarding the non-traditional scoring metrics, these metrics were designed to help PGE weigh the various implications of potential resource plans, specifically with respect to values, priorities, or risks not captured by traditional scoring metrics. PGE utilized insights from the non-traditional scoring metrics to select a Preferred Portfolio and to design an Action Plan that achieves multiple objectives for our customers. Because the Action Plan captures the key attributes of resources within the Preferred Portfolio, PGE believes that individual resources that are procured in a manner consistent

[111] LC 73 Final Comments of Staff at 30.
[112] *Id.* at 31.
[113] *Id.*

with the Action Plan will adequately align with the values and priorities encompassed by the non-traditional scoring metrics. The goal of the RFP is not to establish a plan, but to select the best resources that are consistent with a plan. As such, PGE does not intend to specifically incorporate the non-traditional scoring metrics from the IRP into RFP scoring.

As discussed in Appendix J, PGE's RFP evaluation will use the IRP wholesale market price futures to evaluate resource and portfolio risks. Accordingly, this evaluation will consider the wholesale market price futures with High WECC-wide Renewable Buildout, which is one component of the High Tech Future.

5. Additional Items

PGE appreciates the opportunity to provide additional relevant information to the IRP in the following sections.

5.1. PTC Extension

As PGE noted in our reply comments, eligibility for federal tax credits, including the PTC was a key attribute of the resource additions in the Preferred Portfolio that resulted in the best balance of cost and risk.[114] In response to the passage of House Resolution 1865, as described in **Section 2.2**, PGE undertook additional analysis to understand whether the extension of the PTC materially impacts the primary findings of PGE's portfolio analysis, namely that PTC eligibility is a key driver for near-term renewable action. To do so, PGE re-optimized key portfolios with a modified assumption of PTC eligibility: all wind resources that achieve COD between January 1, 2022 and December 31, 2024 are assumed to be eligible for the 60% PTC.[115] All other input data aligns with the originally filed portfolio analysis. Note that for comparability, this analysis does not incorporate the Updated Needs Assessment filed on November 27, 2019. PGE does not expect that the relatively small updates to PGE's needs filed in that update would materially affect the high-level findings of this supplemental analysis.

To test whether the PTC extension affects PGE's finding that energy-unconstrained optimization leads to very large near-term renewable resource additions, PGE evaluated the composition and performance of the Min LT Avg Cost, All Clean portfolio, which is unconstrained in resource size or type, save for the exclusion of thermal resources. Results of this portfolio analysis, presented below in **Figure 2**, show ROSE-E's cost minimization achieving the same quantity of renewable energy additions through 2025, but shifting near-term renewable additions by one year and staging renewable additions between 2024 and 2025. Despite the availability of the PTCs in 2025, ROSE-E elects to add renewables in 2024 to contribute to meeting capacity needs.

[114] LC 73 PGE Reply Comments at 30.
[115] This assumes that projects achieved safe harbor for 60% PTC eligibility in 2018 or that they do so in 2020.

Figure 2. Min Avg LT Cost, All Clean Portfolio with PTC Extension

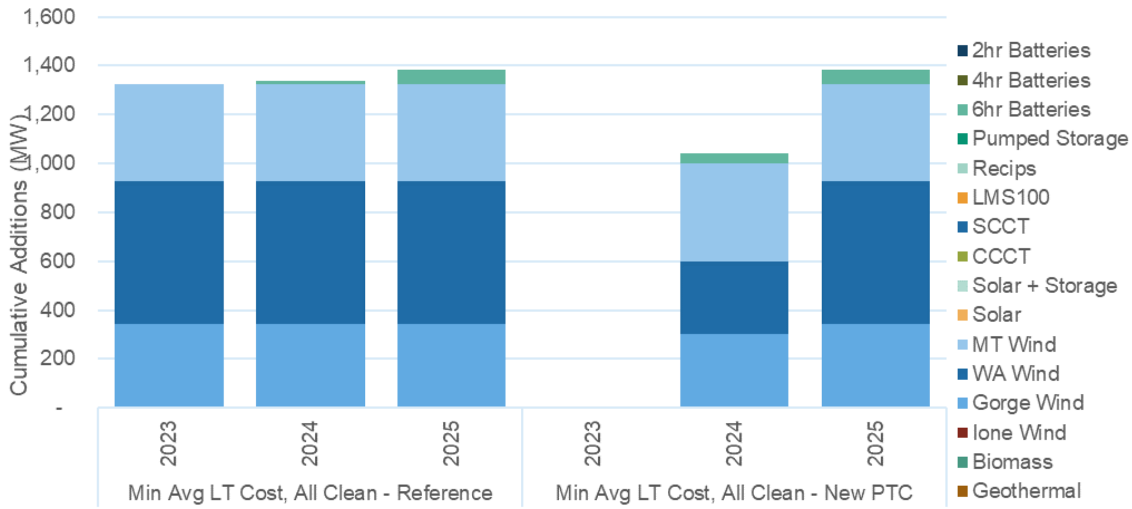


Table 1 shows the impact of the PTC extension on the scoring metrics for this portfolio. Notably, the PTC extension and corresponding re-optimization of resource additions reduces the portfolio cost by $86 million. There are only two metrics that do not see improved performance with the PTC extension: Variability and Reference Case Greenhouse Gas (GHG) Emissions, which both see slight increases due to the change in timing of the renewable additions. This finding continues to support PGE's high-level conclusion that there is a strong economic signal to pursue near-term renewable additions while federal tax credits remain available. It also reinforces the value of renewable resources that can contribute to meeting near-term capacity needs.

Table 1. Min Avg LT Cost, All Clean Portfolio Scoring Metrics with PTC Extension[116]

	Reference	New PTC	Difference
Cost ($ millions)	25,220	25,134	-86
Variability ($ millions)	3,307	3,315	7
Severity ($ millions)	30,088	30,013	-75
GHG-Const Cost ($ millions)	25,144	25,058	-86
Near Term Cost ($ millions)	6,133	6,071	-62
High-Tech Cost ($ millions)	15,321	15,229	-92
Ref. Case GHG Emissions (MMtCO2)	88	89	2
Inc. Criteria Pollutants (short tons)	0	0	0
2025 Energy Additions (MWa)	554	554	0

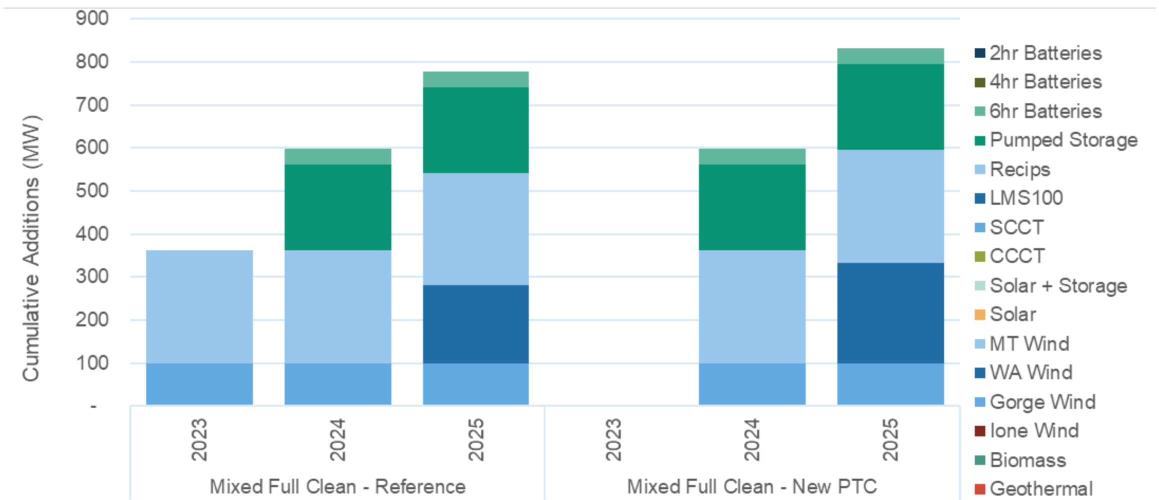
PGE also evaluated the Mixed Full Clean portfolio with the effects of the PTC extension. To ensure that the Mixed Full Clean portfolio continued to reflect the common attributes of the top performing portfolios, PGE introduced one additional constraint to the formulation – that renewable additions through 2025 not exceed 250 MWa. This constraint was not required in the original

[116] All values in tables 1 and 2 are expressed in 2020 dollars

formulation of the Mixed Full Clean portfolio because the stricter 150 MWa energy constraint was applied through 2024 and PTCs were not available in 2025. As a result, renewable additions through 2025 in the original Mixed Full Clean portfolio naturally met the 250 MWa screen without an explicit constraint.

Like the Min Avg LT Cost, All Clean portfolio, re-optimization of the Mixed Full Clean portfolio also results in a shift of renewable additions from 2023 to 2024 and additional renewables in 2025, as shown in **Figure 3** below. The renewable additions in the Mixed Clean portfolio now all qualify for federal PTCs and contribute to meeting PGE's capacity needs in 2024 and 2025. The balance of PGE's capacity needs continues to be met through a combination of 6-hr battery storage and pumped storage.

Figure 3. Mixed Full Clean Portfolio with PTC Extension



The scoring metrics for the Mixed Full Clean portfolios are presented in **Table 2**. Measured with both traditional and non-traditional metrics, each cost metric shows improvement with the incorporation of the new PTC information. Similar to the Min Avg LT Cost, All Clean portfolio results, there is a slight increase in the Variability metric due to the small differences in near term resource additions.

Table 2. Mixed Full Clean Portfolio Scoring Metrics

	Reference	New PTC	Difference
Cost ($ millions)	25,740	25,617	-123
Variability ($ millions)	3,614	3,623	8
Severity ($ millions)	31,004	30,851	-152
GHG-Const Cost ($ millions)	25,694	25,571	-123
Near Term Cost ($ millions)	6,098	6,081	-17
High-Tech Cost ($ millions)	15,341	15,227	-114
Ref. Case GHG Emissions (MMtCO2)	100	101	0
Inc. Criteria Pollutants (short tons)	0	0	0
2025 Energy Additions (MWa)	213	236	23

5.2. Colstrip

Parties' Comments

Staff noted developments related to Colstrip that have occurred since filing Opening Comments, including an executed fuel supply contract that is in effect between January 1, 2020, and the end of 2025; NorthWestern Energy (NWE)'s proposed purchase of Puget Sound Energy (PSE)'s 25 percent share in Colstrip Unit 4; and Avista and PacifiCorp's filed plans relating to their Colstrip ownership in a rate case and integrated resource plan; respectively. Staff agreed that uncertainties related to Colstrip continue to create challenges for assessing cost and risk associated with Colstrip decision-making but are important drivers for continued exploration of actions. Staff requested an update from PGE regarding Colstrip actions, including rate impact analysis, and noted NWEC's recommendation for future analysis of Montana wind with storage resources.[117,118] RNW supported additional evaluation of costs and risks associated with Colstrip ownership and potential benefits of early retirement of Colstrip Units.[119]

PGE's Response

In the 2019 IRP, PGE provided Colstrip Sensitivity A and B described below:[120]

- **Sensitivity A.** Colstrip is fully depreciated and exits PGE's portfolio by the end of 2027. All replacement energy and capacity required as a result of Colstrip's exit is solved for by the portfolio optimization.
- **Sensitivity B.** Colstrip is fully depreciated and exits PGE's portfolio by the end of 2027. Beginning in 2028, the portfolio incorporates a 296-MW Montana Wind resource to replace a portion of the capacity and energy associated with Colstrip's exit. Any replacement energy and capacity that is required beyond the Montana Wind replacement resource is solved for by the portfolio optimization.

[117] LC 73 Final Comments of Staff at 49–50.
[118] LC 73 Final Comments of NWEC at 7.
[119] LC 73 Final Comments of RNW at 11.
[120] PGE 2019 IRP at 208, Section 7.4.2.

Portfolio analysis results indicated that preferred portfolio Reference Case cost could be lowered if Colstrip exited the portfolio at the end of 2027 instead of end of 2034 in Sensitivity A, while risk could be increased. Sensitivity B indicated that portfolio Reference Case costs increase, but variability would be lowered, relative to the strategy of replacing energy and capacity in a cost optimal manner. Though the analysis suggested potential economic benefits to Colstrip exiting PGE's portfolio before the end of 2034, specific options and costs related to Colstrip are subject to continued uncertainty.

Since filing the 2019 IRP, additional updates related to Colstrip have materialized. A contract with Westmoreland Rosebud Mining, LLC to supply fuel for Colstrip Units 3 and 4 has been signed by utility owners of Colstrip. PGE's fuel supply contract took effect at the beginning of 2020 and continues through the end of 2025. In addition, estimates of Colstrip fixed cost were updated following a consultant update to estimates of accelerated depreciation of production plant and updated cost estimates of decommissioning and remediation costs in compliance with federal coal combustion residuals (CCRs) and state regulations. Any updates to depreciation estimates will be discussed in future rate-making proceedings.

Given the developments described above, PGE updated the Colstrip sensitivity analysis based on this updated information. All other input data aligns with the originally filed portfolio analysis. These developments do not change PGE's capacity need arising from Colstrip exiting PGE's portfolio by the end of 2027 as the years in which Colstrip exits PGE's portfolio remain consistent with the original sensitivities.[121] However, the updated fuel supply contract results in changes to Colstrip's modeled economic dispatch and GHG emissions for both sensitivities.

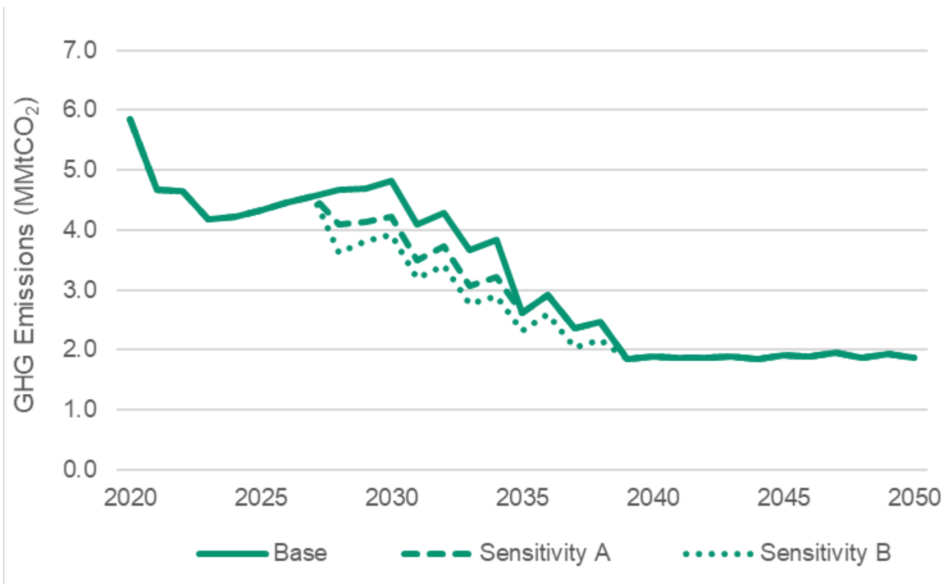
The updated traditional cost and risk metrics of the preferred portfolio across both Colstrip sensitivities are shown in **Table 3**. The results continue to suggest that acceleration of Colstrip's exit from PGE's portfolio to 2027 from the end of 2034 could lower the preferred portfolio Reference Case cost in both sensitivities. Sensitivity A continues to increase the risk while Sensitivity B reduces the risk as described by the variability metric relative to the Base Case. Updated GHG emissions from the Colstrip sensitivities are included in **Figure 4**. Under Reference Case conditions, an early exit of Colstrip from PGE's portfolio continues to result in a reduction of GHG emissions relative to the Base Case.

[121] PGE 2019 IRP at 209, Section 7.4.2, Figure 7-26.

Table 3: Updated portfolio scoring metrics for Colstrip sensitivities

	Scoring Metric (million 2020$)		
	Cost	Variability	Severity
Base Case	25,779	3,619	31,061
Colstrip Sensitivity A 2027 Exit	25,529	3,666	30,862
Colstrip Sensitivity B 2027 Exit w/ MT Wind	25,564	3,614	30,788

Figure 4: Updated GHG emissions in Colstrip sensitivities



Despite the developments related to Colstrip described above, there remain ongoing uncertainties. These uncertainties include:

- **Carbon regulation in Oregon**. Adoption of carbon regulation in Oregon continues to have consequential impacts on the near-term economics of Colstrip Units 3 and 4. The 2019 IRP included a reference assumption that Oregon adopts carbon regulations starting in 2021. There continues to be uncertainty surrounding the specific format and timing of carbon regulation in Oregon, which would have implications for the near-term customer rate impacts of options related to Colstrip Units 3 and 4.
- **Operating Uncertainty.** Due to the structure of the ownership agreements between the co-owners of Colstrip Units 3 and 4, PGE has limited ability to pursue actions related to Colstrip in a unilateral manner. The Colstrip co-owners' diversity in ownership, business practice, regulatory processes and mandates, and emissions goals continues to have uncertain implications on potential options related to Colstrip Units 3 and 4. As discussed above, in December 2019, NWE announced the purchase of PSE's 25 percent share in Colstrip Unit 4 to

be completed in the fourth quarter of 2020 subject to approval by the Montana Public Service Commission, Washington Utilities and Transportation Commission and the Federal Energy Regulatory Commission.

Additional analysis for examining options relating to Colstrip Units 3 and 4 is important, as stakeholders have also noted. As PGE examines options related to Colstrip Units 3 and 4, it will be important to continue considering potential long-term planning implications, as explored within the IRP process. Analysis and consideration of resource additions continue to fall within the long-term planning process.

It is also necessary to investigate the more immediate potential impacts to customers. Toward this end, PGE proposes to conduct an enabling analysis into the potential customer rate impacts of options related to Colstrip Units 3 and 4, including, but not limited to, modified depreciation schedules.

5.3. Long-lead Time Resources

Parties' Comments

In addition to questions regarding Competitive Bidding Rules compliance, the December 11, 2019 AHD memo asked five questions related to regulatory barriers for long-lead time resources. Swan Lake's final comments recommend that PGE address long-lead time resources by issuing a solicitation for capacity as soon as practicable or to file a waiver to the Competitive Bidding Rules to procure the Swan Lake facility outside of a competitive bidding process. Additionally, Swan Lake asks the Commission to provide additional guidance to PGE and stakeholders on how to interpret a waiver request made before a resource acquisition.[122] Staff does not agree that any policy or practice change is necessary to allow long-lead time resources to be procured through established planning and procurement practices.[123]

PGE's Response

PGE responds to each of the subparts of Question 2 in the AHD memo below.

Q. Does the Commission need to address a long-lead time resource within this IRP proceeding?

PGE agrees with Staff that no change in planning and procurement practices are necessary to accommodate long-lead time resources. In the 2019 IRP, PGE's portfolio analysis suggests that pumped storage, a long-lead time resource, may contribute to meeting capacity needs in a manner that best balances cost and risk. However, there are a limited number of viable pumped storage projects in the region and each project faces unique development circumstances, costs, and operational constraints, PGE has not designed the Action Plan to specifically seek out a certain type of resource such as pumped storage. Instead, the Company has designed an Action Plan that will

[122] LC 73 Final Comments of Swan Lake at 10.
[123] LC 73 Final Comments of Staff at 34.

allow for consideration of pumped storage alongside other non-emitting dispatchable capacity options to ensure the opportunity to procure the best resources for customers within an RFP. PGE does not believe that the Commission needs to address any specific long-lead time resources within this IRP, but anticipates that the Commission will weigh whether the Capacity Action provides adequate flexibility for the Company to consider long-lead time resources within the RFP.

Q. Is it important whether the Commission acknowledges a resource need, or a specific resource type, in this IRP proceeding?

PGE believes that it is appropriate and consistent with past practice for the Commission to acknowledge resource actions within an IRP as well as the key methodologies and findings that support those resource actions which will then support determinations in other dockets. The needs assessment is one such key component of the IRP, as it informs procurement decisions. PGE therefore believes that it is important that the Commission acknowledge the needs identified within an IRP.

With regard to resource actions, PGE believes that the Commission may acknowledge the pursuit of a specific resource type within an action plan if the utility adequately justifies it on the basis of cost and risk, but that the Commission may also acknowledge resource actions that outline key attributes of the resources that the utility plans to pursue without reference to a specific resource type. The Commission addressed this question in Order No. 07-002:

> "To keep the IRP process separate from the procurement process, we prefer to acknowledge general, not specific resources, in the IRP process. We note, however, that circumstances might arise to justify acknowledgement of a specific resource. For example, in Order No. 06-446, we stated that a utility may request, in an IRP, that the Commission acknowledge an exception to the RFP requirement for a Major Resource."[124]

PGE's approach in the 2019 IRP aligns with the Commission's guidance regarding general, rather than specific resources. The actions are designed to allow the Company to pursue resources of various types that meet specified criteria that are consistent with the needs assessment and the findings of the Company's portfolio analysis.

Q. If the Commission does not address a long-lead time resource within this IRP, how could or would PGE pursue such a resource?

Consistent with PGE's Action Plan, the Company could pursue a long-lead time resource within the non-emitting Capacity RFP even if the Commission has not specifically addressed a long-lead time resource within the IRP.

[124] See UM 1056, Order No. 07-002 at 25.

Q. Would a long-lead time resource be able to participate in a future capacity procurement?

PGE's Action Plan would not disqualify a long-lead time resource from participating in the non-emitting Capacity RFP based on its online date, provided that the Company can secure near-term contracts to meet capacity needs in the interim. As with all potential resource bids, long-lead time resources will be required to meet other standards to participate or to be selected in an RFP. PGE cannot guarantee that a long-lead time resource will necessarily be able to meet all requirements for participation in an RFP. This project-specific uncertainty is one of many reasons that the Capacity Action does not target a specific resource or technology.

Q. Are there bridging strategies available to PGE?

If a long-lead time resource participates in the non-emitting Capacity RFP, PGE will consider opportunities to leverage existing resources in the region to meet capacity needs that would otherwise be unmet prior to the resource reaching COD. While PGE anticipates that short-term contracts may be available, the Company cannot speculate as to the terms, availability, or price of those options at this time.

6. Staff Recommendations

Staff provided a range of recommendations which PGE is committed to address in the following sections. In some cases, Staff recommendations are addressed in other sections, in which case the section references are listed below.

6.1. Staff Recommendation 1

Recommendation: "The Commission should acknowledge the Company's pursuit of bilateral contracts for existing capacity."[125]

> **PGE Response:** PGE agrees with Staff's recommendation. Further discussion can be found in **Section 2.2**.

Recommendation: "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."[126]

> **PGE Response:** PGE agrees that a renewable RFP should in part address PGE's capacity needs but does not necessarily agree that dispatchable capacity and variable renewable resources are best pursued through a single RFP due to potential differences in resource requirements. As described in **Section 2.2**, PGE's modified Action Plan would allow the Company to conduct concurrent and coordinated processes to pursue renewable and dispatchable capacity resources, both of which would contribute to meeting PGE's capacity needs.

[125] LC 73 Final Comments of Staff at 52.
[126] *Id.*

Recommendation: "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."[127]

PGE Response: PGE cannot simulate the potential outcome of a procurement process using ROSE-E for several reasons, including lack of information on the availability, price, and terms of potential bids. However, PGE can design portfolios by constraining resource additions in ways similar to the potential design of an RFP, for example by establishing a procurement target or constraint and solving for the resource additions that fill that target or satisfy that constraint. The Mixed Full Clean portfolio was designed in such a way: 1) by allowing the optimization model to select renewable resources, if economic, up to the 150 MWa constraint; and 2) by constraining new resource additions to non-emitting resources. PGE provides additional analysis on the Mixed Full Clean portfolio that reflects the PTC extension in **Section 5.1**.

6.2. Staff Recommendation 2

Recommendation: "Monitor and report on its market capacity 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."[128]

PGE Response: While this recommendation from Staff focuses on the potential impact from new resource additions, PGE notes that in Staff's reply comments, in discussing PGE's capacity need, Staff also stated that there is "a decreasing likelihood of regional market capacity to mitigate this risk."[129] PGE agrees that there is uncertainty in the future availability of market capacity and has designed the Action Plan to be flexible as regional conditions evolve.

PGE will report on the market capacity assumptions used in the capacity modeling for the subsequent RFP and IRP Update. PGE will continue to monitor regional resource adequacy conditions, whether impacted by committed new generation, announced retirements, load forecast updates, energy efficiency forecast updates, or other material changes. PGE will periodically refresh its market capacity study to capture the impacts of regional changes.

Recommendation: "Provide additional explanation of the assumptions underlying the capacity contribution that the renewable-only procurement could provide."[130]

PGE Response: PGE understands Staff's request to specifically refer to variable renewable resources.

Adding additional variable renewable resources to PGE's resource portfolio can reduce the capacity need. The quantity of capacity contribution depends both on the specific resource

[127] LC 73 Final Comments of Staff at 52.
[128] *Id.*
[129] LC 73 Final Comments of Staff at 7.
[130] LC 73 Final Comments of Staff at 52.

added and PGE's system needs. In IRP analysis, PGE used the RECAP model to examine the capacity contribution of four proxy wind resources, one proxy solar resource, and one proxy solar plus storage resource. Each resource was characterized in RECAP by an hourly generation profile based on historical wind or solar irradiance data and assumptions regarding the wind, solar, and storage technologies. Resources with a higher probability of high levels of generation during times of need have a greater capacity contribution than those with a lower probability. The results of the RECAP analysis are provided in Section 6.2.3 of the 2019 IRP.

In IRP portfolio analysis, the capacity contribution of additional renewable resources reduced the need to include other resources to meet the capacity adequacy target. For example, in the preferred portfolio, the 150 MWa of wind resources provide approximately 120 MW of capacity contribution in 2025. In other words, if the wind resources were not included in the portfolio, an additional 120 MW of capacity contribution from other resources would be needed to meet the capacity adequacy target in 2025.

The capacity contribution of the winning bid or bids from the Renewable RFP will depend on the specific combination of technologies and locations of the winning bids. The capacity contribution may be greater than or less than the proxy resources from the preferred portfolio. In the Renewable RFP scoring, the RECAP model will be used to examine the capacity contribution of each bid submitted. Bids will be characterized by multiple years of hourly generation reflecting the specific technology and location of each bid, along with any necessary transmission limitation adjustments described in the Interim Transmission Solution. The capacity contribution of a bid will be translated to a capacity value based on the IRP cost of capacity. The capacity value is one component of the price score of each bid. Bids with generation profiles that have a greater probability of providing generation during times of need will tend to have higher capacity values, which will be reflected in their price scores. RECAP will also be used to examine the capacity contribution of combinations of bids, capturing the potential diversity benefits from combining one or more bids with different technologies or locations. The capacity contribution from the winning bids will reduce the amount of other resources necessary to fill PGE's capacity need.

Recommendation: "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."

PGE Response: PGE discussed risks associated with technology-specific procurement targets amidst the current environment of rapid technological change and significant price uncertainty in Section 2.5 of the Company's reply comments. PGE's reply comments included discussion of the quantitative and qualitative approaches that the IRP included to mitigate these risks. While portfolio analysis provided a quantitative approach to mitigating some of these risks, PGE continues to believe that qualitative approaches to mitigate risks through the design of the Action Plan are important to ensure the best outcomes for customers. PGE does not believe that it is appropriate to interpret the generic resources in the Preferred Portfolio as prescriptive guidance for the procurement outcomes that are necessarily best for customers when information about actual resource availability, cost, and performance can be obtained through an RFP. The best procurement outcomes for customers will depend on the availability, pricing, and terms for actual projects that participate in an RFP. PGE therefore believes that customers benefits from an RFP design that allows multiple resource types to meaningfully participate and to allow flexibility for the procurement outcome to deviate from the resources in the Preferred Portfolio based on information obtained through the RFP. This flexibility is important regardless of the timing of the RFP.

With respect to timing, as described in **Section 2.2**, PGE has determined that concurrent consideration of new non-emitting dispatchable resources and existing dispatchable capacity resources can be pursued in a way to limit PGE's exposure to the risks associated with both current and future storage prices. Specifically, the Capacity Action and accompanying additional conditions establish a maximum amount of capacity that the Company may procure for 2025 through the Renewable and Capacity Actions but retain the flexibility for PGE to adjust the scale and pace of capacity procurement as information is gained from the market. The modified Capacity Action would provide PGE with the opportunity to pursue long-lead time resources, like pumped storage, in the near-term if they are available and competitively priced. It would also allow PGE to consider the scale and pacing of procurement of shorter lead-time resources, like battery storage, thoughtfully based on the latest information from the market.

PGE believes that the design of the Modified Capacity Action continues to mitigate the risks that PGE described in the Company's reply comments while allowing the Company the opportunity to bring new non-emitting dispatchable capacity to the region in a manner consistent with the interests of PGE customers.

Recommendation: "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."[131]

PGE Response: PGE plans to provide additional information to the Commission about existing resources that could contribute to meeting PGE's capacity needs within the bilateral negotiation process.

6.3. Staff Recommendation 3

Recommendation: "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."[132]

PGE Response: PGE disagrees with Staff's recommendation for relying on the traditional energy load resource balance to size procurement efforts and believes that the Company's investigation

[131] LC 73 Final Comments of Staff at 52.
[132] *Id.*

of a wide range of market conditions and resource needs provides robust analysis to inform near-term energy resource sizing decisions. PGE discusses this further in **Section 2.2**, **Section 3.4**, and in the Company's reply comments.[133]

Recommendation: "Require renewable resources to qualify for federal tax incentives. PGE should also specify which incentives are eligible."[134]

PGE Response: PGE agrees with Staff's recommendation and clarifies in **Section 2.2** that the Renewable Action seeks resources that are eligible for the federal Production Tax Credit or the federal Investment Tax Credit.

Recommendation: "Be required to return the forecasted value of PTCs to customers."[135]

PGE Response: PGE interprets this recommendation to be focused on the mitigation of risks associated with project performance in rate setting. PGE believes that year-to-year performance risks are already mitigated as part of PGE's determination of customer rates and that recommendations on this topic are out of scope for the Company's IRP.

Recommendation: "Adequately evaluate bids for the impact of the ownership model on rate impacts."[136]

PGE Response: PGE's evaluation of bids within a competitive solicitation will recognize the specific commercial structure proposed by the bidder, and the cost of the structure will be accurately evaluated. PGE disagrees that the commercial structure and procurement outcomes should be determined within PGE's long-term planning and provides additional discussion on this topic in **Section 4.3** and **Section 6.4**.

6.4. Staff Recommendation 4

Recommendation: "Not use the market energy position to quantify the need for new resources."[137]

PGE Response: PGE clarifies that the Company has not used the market energy position analysis to quantify a need for new resources. PGE has instead used the market energy position analysis to establish an upper bound for new renewable additions, limiting the contribution that new resources may have (relative to market purchases) to meeting PGE's energy needs. The need assessment identifies a near-term capacity need and portfolio analysis suggests that filling a portion of this need with resources that bring both capacity and energy provides for the best balance of cost and risk.

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[133] LC 73 Reply Comments of PGE at 53-54.
[134] *Id.*
[135] LC 73 Final Comments of Staff at 52.
[136] *Id.*
[137] *Id.*

Recommendation: "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."[138]

PGE Response: PGE has proposed two conditions as part of the Renewable Action that are similar to the conditions imposed on the 2016 Revised Renewable Action that led to the procurement of the Wheatridge Energy Facility. Specifically, PGE proposes to once again utilize a cost-containment screen in the RFP and to return the value of the RECs generated prior to the physical RPS deficiency year (now forecasted to be 2030) directly to customers.

Recommendation: "Discuss the differences between the Delay Renewables and Mixed Full Clean, No RA portfolios and the drivers behind the stark variation in scoring metrics."[139]

PGE Response: For clarification, in the Company's reply comments PGE provided several sensitivity analyses testing various assumptions in its portfolio modeling, where the results of the preferred Mixed Full Clean portfolio were compared with the Delay Renewables portfolio. In Part C of OPUC Data Request No. 174, Staff asked what amount of the difference between the two portfolios was attributable to the different capacity options available to each portfolio. In response, PGE provided a new portfolio, Mixed Full Clean, No RA,[140] which estimated this difference requested by Staff. The scoring metrics of both portfolios are presented below in **Table 4**:

Table 4: Scoring Metrics of Delay Renewables and Mixed Full Clean, No RA portfolios

	Delay Renewables	Mixed Full Clean, No RA	Difference
Cost ($ millions)	26,625	26,369	-256
Variability ($ millions)	3,835	3,824	-11
Severity ($ millions)	32,065	31,829	-236
GHG-Const Cost ($ millions)	26,671	26,453	-218
Near Term Cost ($ millions)	6,161	6,140	-21
High-Tech Cost ($ millions)	14,421	15,324	904
Reference Case GHG Emissions (MMtCO2)	107	105	-2
Incremental Criteria Pollutants (short tons)	0	0	0
2025 Energy Additions (MWa)	-42	34	76

The Delay Renewables and Mixed Full Clean, No RA portfolios vary in two ways. While the Delay Renewables portfolio is constrained to add renewables only after 2026, the Mixed Full Clean, No RA portfolio can add renewables in 2025, which ROSE-E elects to do by adding 52 and 100 MW

[138] LC 73 Final Comments of Staff at 52.
[139] *Id.*
[140] No Renewable Acquisition.

of Washington and Montana wind that year. Further, the capacity resources available are different between portfolios: the Mixed Full Clean, No RA portfolio has the ability to select battery storage of 2- and 4-hour durations and pumped hydro resources between 2023 and 2025, while the Delay Renewables only has the ability to select 6-hour batteries to meet capacity need in that timeframe.[141,142] Without the option of meeting any portion of near-term capacity needs with renewables, both portfolios select a large addition of storage resources. The Delay Renewables portfolio adds 611 and 109 MW of 6-hour duration batteries in 2024 and 2025, while the Mixed Full Clean, No RA portfolio adds 500 MW of pumped storage and 12 MW of 6-hour batteries in 2024.

The differences in scoring metric performance between the two portfolios are driven by the allowance of renewables and pumped storage to contribute to meeting capacity needs in 2025 in the Mixed Full Clean, No RA portfolio. Allowing a portion of the capacity needs to be filled by renewables has the effect of lowering both cost and risk, as is seen across most of the scoring metrics. However, the inclusion of pumped storage results in an increase in Cost in a High Tech Future metric. Recall that this metric considers portfolio costs in a future with more rapid deployment of renewables in the West and more rapid declines in solar and battery costs. The poor performance of the Mixed Full Clean, No RA portfolio in this future reflects the risk that a commitment to a large pumped storage resource in the near-term may result in higher cost outcomes for customers should battery storage costs decline more quickly than in the Reference Case. This finding supports PGE's design of the Capacity Action to be technology-agnostic between non-emitting capacity resources and to allow for flexibility to adapt as information is gained about energy storage pricing through an RFP.

Recommendation: "Explain how the Cost in High Tech Future non-traditional scoring metric will be present in the scoring of the RFP."[143]

PGE Response: PGE addresses this recommendation in **Section 4.3**.

Recommendation: "Compare the difference between BNEF and the EIA's learning rates for wind and explain why that difference would be inconsequential in assessing the intergeneration equity of the Renewable Action."[144]

PGE Response: For clarification, the intergenerational equity analysis in the 2019 IRP uses Reference technology cost for wind, which is based on the capital costs provided in HDR's Supply Side Options study (External Study D of PGE's 2019 IRP). According to the study, HDR explains the learning rate for wind is based on the EIA's National Energy Modeling System

[141] This point was made in PGE's response to OPUC Data Request No. 174.
[142] Both portfolios have the option between 2023-2025 to meet capacity needs using biomass and/or geothermal generation, however neither are selected by ROSE-E's cost minimization in these or any other portfolios without being required.
[143] LC 73 Final Comments of Staff at 52.
[144] *Id.*

(NEMS). PGE's understanding is that the EIA utilizes a learning rate of 5 percent for onshore wind. PGE also designed a Low Cost Wind future for consideration within the risk analysis, which utilized a learning rate of 20 percent. This future did not factor into the analysis referred to by Staff in this recommendation. The BNEF learning rate for wind (11 percent) was not used in the 2019 IRP analysis, but falls between the EIA learning rate and the learning rate used to develop the Low Cost Wind future. As such, the Low Cost Wind future may be instructive for bounding the impact that using the BNEF learning rate might have on near-term cost impacts. In the Reference Case, the levelized cost of Washington Wind increases from $41/MWh with COD 2023 to $50/MWh with COD 2026, indicating a $9/MWh cost impact that reflects the loss of PTC benefits net of capital cost declines associated with learning. In the Low Cost Wind future, the levelized cost increases from $31/MWh with COD 2023 to $39/MWh with COD 2026, indicating an $8/MWh cost impact that reflects the loss of PTC benefits net of capital cost declines associated with learning. While the Low Cost Wind future considers both lower initial capital costs and more rapid capital cost declines associated with learning, the capital cost declines between 2023 and 2026 in the Low Cost Wind future continue to be small relative to the cost savings associated with the PTC, even in the Low Cost Wind future. PGE expects that this finding would also translate to the intergenerational equity analysis if it were conducted under a scenario with the BNEF learning rate rather than the Reference Case assumption. More specifically, PGE expects that a more rapid learning rate for wind, consistent with the BNEF assumption of 11 percent would reduce the near-term cost impact of the COD 2026 wind resource but would not outweigh the reduction in near-term costs associated with the PTC benefit.

Recommendation: "Base any future resource buildout portfolio developed using an Oregon carbon price comparable to those PGE is considering in its portfolio analysis."[145]

PGE Response: PGE agrees that the composition of the resource buildout can affect market prices. Accordingly, PGE included in its analysis the High Renewable WECC future, which envisions a future where renewables are built in exceedance of current expectations across the West.[146] Relative to the Reference Case, the High Renewable WECC future exhibits lower prices but higher volatility, shown in IRP Figure 3-5. In estimating the traditional risk metrics variability and severity, half of all futures considered have this high renewable buildout. PGE notes that the resource additions in these futures encompass a much broader geography and set of entities than would be affected by carbon regulation in the state of Oregon. PGE therefore expects that any effects of carbon regulation on resource additions in the West and associated impacts on pricing would fall well within the bounds of uncertainty investigated in the IRP. In future IRPs, PGE is open to further refinements to its long-term market price forecasts, and will continue to work with Staff, stakeholders, and potential third-party vendors in this effort.

[145] LC 73 Final Comments of Staff at 53.
[146] See 2019 IRP at 76, Section 3.2.3 – High Renewable WECC Buildout for more detail.

Recommendation: "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."[147]

PGE Response: PGE is open to including analysis in the next IRP that estimates near-term price impacts but does not believe that such analysis provides a complete picture of intergenerational equity issues. Specifically, the analysis that Staff recommends ignores the benefits that today's customers are afforded from the investments made by past customers. It also ignores the harm that could be experienced by future customers if today's customers do not invest in clean technologies. The IRP Guidelines already provide guidance on how to weigh near-term versus long-term impacts to customers through the utilization of a discount rate in determining portfolio cost and risk performance. PGE suggests that intergenerational equity issues could be explored in a manner more consistent with IRP methodologies by testing sensitivities to the discount rate applied in portfolio scoring.

Recommendation: "A description of PGE's conclusions related to its intergenerational equity analysis."[148]

PGE Response: PGE described the quantitative findings of the analysis into potential near-term cost impacts of 150 MWa of additional renewables in Section 7.3.1 of the 2019 IRP. At a high level, this analysis suggested that a renewable addition could result in net increases in power prices beginning in the first year of operation, regardless of when the resource comes online, but that the net effect on power prices may become negative within 5-6 years, depending on resource costs. Furthermore, the analysis suggested that the magnitude of the impacts in the initial years are expected to be relatively small (averaging 0.04-0.05 cents/kWh) and that opportunities to secure resources at lower costs through, for example, federal tax credits, also work to lower net power price impacts in those years.

The analysis filed in the IRP assumed that fixed costs and PTC benefits were levelized over the life of the project, resulting in a fixed real price over time. After PGE presented this analysis at a workshop as part of Roundtable #19-3, Staff requested that PGE repeat the analysis assuming utility-ownership. PGE conducted additional analysis to be responsive to Staff's request, in which annual fixed costs reflected PGE's revenue requirement for an owned resource rather than a fixed real price. This analysis also reflected the requirement that PGE flow federal PTC benefits directly to customers contemporaneously in each year. It did not account for the potential impacts of PTC carryforwards. This analysis suggests that initial net price impacts are also expected to be relatively small under a utility-ownership scenario and that the availability of PTCs is even more important for reducing near-term price impacts under utility ownership

[147] LC 73 Final Comments of Staff at 53.
[148] *Id.*

because they flow to customers during the first 10 years, when the revenue requirement would otherwise be the highest.

Importantly, this analysis was not designed, nor was it presented to inform a decision around the potential ownership structure of resources procured as a result of this IRP. Under current practice, it is well-established that utility ownership results in a more front-loaded revenue requirement for fixed costs than a fixed price contract, assuming the resources have the same levelized fixed costs over their lifetimes. This has not been, nor should it be, the primary determining factor in comparing utility-owned versus contracted resources. Consistent with past IRPs, PGE has developed both the IRP portfolio analysis and IRP Action Plan to be ownership-agnostic and has not made a recommendation on the ownership structure of the resource additions that could be pursued through the Action Plan. The ownership structure of procured resources will depend on the specific characteristics and pricing of bids in an RFP.

Recommendation: "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."[149]

PGE Response: PGE disagrees with this recommendation and provides additional discussion in **Section 4.3**.

6.5. Staff Recommendation 5

Recommendation: "PGE should continue to work to refine its solar integration cost methodology with Stakeholders and clarify why it does not need to wo[r]k to refine its solar integration cost methodology prior to issuing a 2020 RFP."[150]

Other Parties' Comments: NWEC continues to express concerns about the integration costs and notes that they are an important factor in solar resource development.[151]

PGE Response: PGE agrees that understanding the primary drivers of integration cost estimates as increasing levels of renewables enter the system is an important topic. However, the Company disagrees with the presumption that solar integration costs should necessarily be lower than wind integration costs and that PGE's findings necessarily indicate an issue with PGE's methodology. PGE proposes to provide analysis aimed at determining key drivers of solar integration cost for feedback and discussion with stakeholders prior to the next IRP. PGE includes this as an enabling analysis in **Section 2.5**.

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[149] LC 73 Final Comments of Staff at 53.
[150] *Id.*
[151] LC 73 Final Comments of NWEC at 4.

6.6. Staff Recommendation 6

Recommendation: "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."[152]

> **PGE Response:** PGE disagrees with Staff's assessment of the completeness of the RFP-related information contained in the IRP. PGE does not believe that the Competitive Bidding Rules call for the filing of final draft RFP within the IRP. PGE interprets the Competitive Bidding Rules to call for a description of the scoring, methods, models, and central design features. Consistent with this interpretation of the Rules, PGE has included a thorough, but not exhaustive, description of the PGE's expected RFP design with the intention to file a draft RFP within an RFP approval proceeding. PGE provides additional discussion on this topic in **Section 4.2**.

Recommendation: "The IRP process does not preclude long-lead time resource acquisition."[153]

> **PGE Response:** PGE agrees with Staff's assessment and provides additional discussion in **Section 5.3**.

Recommendation: "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."[154]

> **PGE Response:** PGE agrees that Commission review can and should broadly acknowledge resource need. Commission acknowledgment need not be limited to consideration of specific resource or technology procurements. Additional discussion can be found in **Section 5.3**.

Recommendation: "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."[155]

> **PGE Response:** PGE agrees.

6.7. Staff Recommendation 7

Recommendation: "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.

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[152] LC 73 Final Comments of Staff at 53.
[153] *Id.*
[154] *Id.*
[155] *Id.*

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."[156]

> **PGE Response:** PGE disagrees on the appropriateness of including detailed transmission related non-price scoring criteria within PGE's IRP. Additional discussion can be found in **Section 4.2**.

Recommendation: "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."[157]

> **PGE Response:** Within a competitive solicitation, PGE will evaluate bids' competitiveness through price scoring and non-price scoring. Non-price scoring assesses non-quantifiable project risks, including transmission quality risks. Those projects with the highest price and non-price scores will be considered for procurement as is described in Appendix J of the 2019 IRP. As noted above and in **Section 4.2**, PGE's IRP does not include comprehensive detail on non-price scoring elements as such information is appropriately reviewed within the context of an RFP approval proceeding.

Recommendation: "Discuss how it will score net contribution made by blending diverse wind profiles."[158]

> **PGE Response:** Within a competitive solicitation, PGE evaluates the complementary performance of resources with diverse wind or renewable profiles within its portfolio model which is described in Section J.4.2 of Appendix J in the 2019 IRP.

Recommendation: "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."[159]

> **PGE Response:** PGE will consider partnerships or partial shares of resources within a competitive solicitation. Partnerships can provide for the opportunity to lower customer costs through cost and risk sharing across multiple counterparties. All partnership offers will be subject to the same requirements and scoring methods as is applied to all other offers.

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[156] LC 73 Final Comments of Staff at 53.
[157] *Id.*
[158] *Id.*
[159] LC 73 Final Comments of Staff at 54.

Recommendation: "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."[160]

> **PGE Response:** As is discussed in **Section 4.1**, PGE will rely upon transmission providers to estimate flowgate impacts of project bids. PGE's renewable RFP will require bidders to bring forth a transmission service plan. PGE will not acquire transmission resources or rights on bidders' behalf.

6.8. Staff Recommendation 8

Recommendation: "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 beyond the Energy Trust base forecast."[161]

> **PGE Response:** PGE is coordinating with the Energy Trust to develop two energy efficiency forecasts in addition to the Reference Case for the next long-term energy efficiency forecasts. PGE is open to hosting discussions with Staff and other interested stakeholders regarding Staff's suggestion to consider if and how IRP portfolio analysis could include the selection of additional energy efficiency measures beyond those found to be cost-effective. Please also see the discussion in **Section 3.3**.

6.9. Staff Recommendation 9

Recommendation: "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."[162]

> **PGE Response:** PGE intends to address the items requested by Staff in opening and final comments regarding contents of the forthcoming Flexible Load Plan. The Flexible Load Plan will give the Commission a review of the flexible load activity present and immediately planned for by PGE. This will include EV direct load control and customer sited energy storage. PGE plans to submit a Time of Use rate for Commission review in late spring 2020. We are open to discussions about further dynamic rate structure development. The Flexible Load Plan will also review our current cost-effectiveness practice in a separate section of the Flexible Load Plan.

6.10. Staff Recommendation 10

Recommendation: "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

[160] LC 73 Final Comments of Staff at 54.
[161] *Id.*
[162] *Id.*

assumptions for 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."[163]

PGE Response: PGE clarifies that the trajectories established in the Brattle study for the 2016 IRP assessed the development potential of various demand response programs but did not include analysis on the likelihood of customers to participate. As described in Section 5.1 of PGE's 2019 IRP, "PGE leveraged the robust analysis in the [Brattle] Demand Response Potential Evaluation and worked with Navigant to improve the consideration of customer adoption drivers, interactive effects between programs, the adoption of new technologies such as electric vehicles, and forecast uncertainty."

It is also important to note that the Brattle Study was a meta-study of possible demand response programs which could be deployed in PGE's service territory. There are two points of clarification regarding this study: first, Brattle did not conduct a true bottom up potential study specific to the PGE service territory. Second, much of the Brattle study-identified-savings were the result of default opt-out demand response programs including a default time-of-use program. PGE explored with the Demand Response Review Committee the option of a default opt-out time of use rate for the Test Bed, but the Committee decided against the measure because of concerns about unintended higher bill impacts for low income families.

As PGE matures in its development of demand response programs, we need also to refine our understanding of the likelihood of customers to adopt various demand response offerings under base conditions, as well as under varied incentive structures. PGE chose to include this modeling enhancement in the 2019 IRP to gain further understanding of the drivers of customer participation in preparation for upcoming development activities in the Smart Grid Testbed and through the Flexible Load Plan. Additionally, the work being conducted with the PGE Smart Grid Test Bed targets two learning, engagement and participation rates associated with various communication and engagement approaches for multiple different types of customers. The information acquired through this activity will help inform PGE in our efforts to create a participation model.

PGE notes that the National average demand response penetration may not be appropriate as a comparator against which to benchmark our progress on demand response development. A large portion of demand response contribution within the national average is provided by industrial loads. Many of the large industrial loads and national accounts in the PGE service territory that would be optimal demand response participants are direct access customers that do not purchase power from PGE. PGE also notes that our programs are structured differently. PGE chose to build demand response programs with long-term evolution in mind such that the programs could be used for multiple services as costs decline. PGE built these programs so that we need not undergo costly initial build and deployment for a program more than once.

[163] LC 73 Final Comments of Staff at 54.

Emergency demand response programs are generally cost-effective because they pay very little and are built to be called only during grid emergencies. Though effective during the energy crisis, California regulators in 2007 began migrating emergency demand response programs to more dynamic program offerings in order to create a more valuable system resource.[164]

PGE agrees with Staff that time of use (TOU) rates and direct load control (DLC) should be further developed. We are piloting new applications of these demand response options in the Smart Grid Testbed and will provide updates to the Commission on the results.

Although PGE intentionally structured the 2019 IRP Action Plan to acquire all cost-effective and reasonable demand response, in order to avoid imposing any limitation on demand response growth, PGE does acknowledge that we must work collaboratively with Staff, stakeholders, customers, and the Commission to enable more efficient development of demand response programs. As part of the proposed practices in the forthcoming Flexible Load Plan we will being resurrecting the Demand Response Advisory Group and scheduling meetings at a regular cadence.

We find the most appropriate preliminary steps to enable greater penetration levels of demand response is to include an improved structure to assess cost-effectiveness and cost recovery, a cost-benefit methodology that accounts for early learning stages where programs are not yet benefiting from economies of scale, as well as a methodology to account for the dual-peaking nature of PGE's load. PGE also acknowledges that we have faced challenges with scaling demand response programs, many of which have stemmed from aggressive goal setting and the need to ramp programs at a fast pace. We envision the solution for this challenge as a process of multi-year goal setting and the ability to work within a portfolio, without the administrative burden of filing each individual element with the Commission as it develops. We plan to open a discussion with the Commission on these topics through the Flexible Load Plan.

6.11. Staff Recommendation 11

Staff made several recommendations for analyses conducted in future IRPs.

Recommendation: Staff recommended that PGE work with Staff and stakeholders to improve the treatment of the probabilities assigned to individual futures.[165]

PGE Response: For clarification, this recommendation refers to the evaluation of individual portfolios across a range of 810 futures. Staff highlighted that some combinations of futures are

[164] California Public Utility Commission Rulemaking 07-01-041, Decision filed January 25, 2007, available at: http://docs.cpuc.ca.gov/PublishedDocs/EFILE/RULINGS/79323.PDF
[165] LC 73 Final Comments of Staff at 54, Staff recommendation 11, part a.

less likely than others, whereas currently ROSE-E both optimizes and scores portfolios equally.[166] This issue was raised in Staff's Initial Comments and in PGE's reply comments.[167]

PGE introduced several innovations in the 2019 IRP to better quantify uncertainty and risk. PGE looks forward to working with Staff and stakeholders in the next IRP to continue to improve the Company's methodologies and assumptions, including the consideration of the weights applied to various futures.

Recommendation: While acknowledging some value in their continued use, Staff raised concerns about the use of non-traditional metrics to screen out portfolios**.** "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."[168]

PGE Response: PGE believes it appropriate to use non-traditional metrics to screen out portfolios for consideration in designing the Action Plan. IRP portfolio construction has always required that the utility prioritize those portfolios that are most informative to long-term planning decisions. PGE's introduction of the non-traditional metric screens provided a quantitative justification for what has traditionally been a purely qualitative exercise. In working with both Staff and stakeholders, PGE developed the non-traditional metrics to help avoid undesirable outcomes not captured by a strict application of the traditional cost and risk metrics. In future IRPs, PGE will necessarily need to exclude some portfolios from consideration, whether explicitly and quantitatively through screens, or implicitly and qualitatively through other portfolio construction decisions. PGE will continue to seek feedback from Staff and stakeholders in both portfolio construction and in the application of non-traditional metrics in future IRPs.

Recommendation: In its final comments, Staff recommended that "PGE should make it a standard IRP practice to model the use of a reasonable amount of unbundled RECs."[169]

PGE Response: PGE does not believe it is appropriate to plan for the inclusion of the retirement of unbundled RECs to meet RPS obligations. Forward unbundled REC forecasts are not reliable predictors of the cost of unbundled RECs, as the market is both illiquid and non-transparent. Uncertainty and unpredictability of policy at the state, regional, and federal levels further reduce the value of a forecast. Without reliable price information, PGE cannot be certain that the use of unbundled RECs on a forward basis will be beneficial to customers or the company. For example, in cases where RPS-eligible resources are also the lowest cost energy resources, paying separately for energy to serve load and unbundled RECs to meet RPS requirements

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[166] Unless otherwise specified, which was done with some optimized portfolios.
[167] See Staff Initial Comments at 24 and PGE Reply Comments at 34-35.
[168] LC 73 Final Comments of Staff at 54.
[169] *Id.*

rather than procuring renewable energy resources that provide both may increase costs for customers in the long term. Accordingly, PGE does not believe it to be sound long-term planning practice to forecast the use of unbundled RECs in the IRP.

Recommendation: Staff recommended that "PGE should either provide a meaningful strategy to utilize its REC bank in IRP planning or propose a ratemaking mechanism."[170]

PGE Response: For clarification, PGE notes that in portfolio analysis, ROSE-E has the ability to select the retirement of RECs in its bank to meet its RPS obligations. The model evaluates the cost of this option relative to the cost of renewable procurement and chooses the option that minimizes its objective function (generally minimizing cost). PGE is open to exploring strategies to utilize its REC bank on behalf of customers. However, PGE believes that proposing a ratemaking mechanism as suggested by Staff is outside the scope of an IRP docket.

Recommendation: Staff recommended that 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."[171]

PGE Response: As noted above, PGE does not forecast REC sales in the IRP, as the market for RECs is both illiquid and non-transparent. PGE is open to exploring strategies to utilize its REC bank on behalf of customers. However, PGE believes that proposing specific conditions for such utilization is outside the scope of an IRP docket.

6.12. Staff Recommendation 12

For load forecasts in future IRPs:

Recommendation: "Use the base case of EV adoption under all IRP load forecasts."[172]

PGE Response: PGE respectfully disagrees with Staff's recommendation and provides additional discussion in **Section 3.2**.

Recommendation: "Provide analysis that helps parties consider the impact future LTDA elections would have on its forecasted needs."[173]

PGE Response: PGE understands Staff's and parties' interest in adequately considering future LTDA elections within the needs assessment. In the 2019 IRP, PGE has a balanced approach; PGE has considered growth within the current LTDA elections without speculating on future customer decisions to opt for LTDA.

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[170] LC 73 Final Comments of Staff at 54.
[171] *Id.*
[172] *Id.*
[173] *Id*.

PGE has an obligation to plan for all cost-of-service supply customers, regardless of customer class or eligibility for Direct Access. If sensitivities are designed to examine the portion of PGE's needs that are associated with customers who are eligible for, but do not participate in, Direct Access, PGE strongly believes that these sensitivities should not factor into resource planning decisions. Additional discussion is provided in **Section 3.1**.

6.13. Staff Recommendation 13

Recommendation: "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 NWEC's suggestions."[174]

PGE Response: PGE discusses this recommendation in **Section 5.2**.

6.14. Staff Recommendation 14

Recommendation: "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."[175]

PGE Response: PGE is currently exploring if there is value, once coal-fired operations have ceased, for the potential beneficial reuse of Boardman plant equipment. PGE is beginning conversations with potential research partners to gauge interest and value on whether the remaining plant infrastructure could operate as a "test-bed" facility to evaluate potential dispatchable, non-greenhouse gas (GHG) emitting energy or capacity technologies and/or grid services. PGE intends to follow this outreach with the development and release of a request for information (RFI). Further information on this proposal can be found in PGE's Annual Boardman Decommissioning Update in Docket No. UE 230.

6.15. Staff Recommendation 15

Recommendation: "PGE should file an updated emission forecast in the 2019 IRP docket after Renewable Action and Capacity Action implementation commences."[176]

PGE Response: PGE agrees with this recommendation and plans to file an updated emission forecast as part of a 2019 IRP Update.

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[174] LC 73 Final Comments of Staff at 55.
[175] *Id.*
[176] *Id.*

7. Conclusion

In these final comments, PGE has provided additional information and modifications to the Action Plan to be responsive to the feedback received from Parties throughout the docket and in alignment with the Company's core findings in this IRP. PGE also addressed the implications of House Resolution 1865, which extends the federal PTC for wind within the Company's Action Plan window. PGE continues to find that the core findings of the 2019 IRP analysis are robust – that pursuing a combination of customer resources, renewable resources, and dispatchable capacity resources will allow the Company to meet near-term needs through the best balance of cost and risk. The extension of the PTC strengthened the role of tax credit-eligible resources in meeting PGE's near-term capacity needs, as it has aligned the optimal timing of a new renewable addition that qualifies for the 60% PTC with the timing of PGE's increasing capacity needs. As such, while PGE has incorporated modifications to the Action Plan in this filing, the Company has not changed the target sizes or characteristics of the resources that PGE plans to pursue through the Action Plan.

The modifications to the Action Plan included in this filing focus on process and timing, ensuring that the Company maintains the opportunity to act in the near term to meet capacity needs and to capture value for customers, while preserving the flexibility to respond as conditions evolve and market realities come into focus. The modified Action Plan allows for the concurrent consideration of additional capacity from existing dispatchable resources, new non-emitting dispatchable capacity resources, and renewable resources. The Action Plan modifications address the same risks that the Company identified in the 2019 IRP and the Company's reply comments, but address them with additional cross-cutting conditions, rather than through sequential processes. The modified Action Plan allows the Company to consider long-lead time resources, like pumped storage, if they are cost competitive, while also allowing the Company the flexibility to pursue short lead-time resources, like battery storage, more incrementally over time based on information from the market.

The modified Action Plan and these filed comments do not answer all procedural questions that will necessarily need to be addressed as PGE pursues these actions, which will occur in the forthcoming RFP approval dockets. But, consistent with the purpose of the IRP process, the Action Plan sets forth the Company's intention to pursue those actions and provides a clear indication of the types and quantities of resources that may result from the actions.

The modifications to the Action Plan, while being responsive to stakeholder feedback, are also consistent with the priorities that PGE established for the 2019 IRP. The concurrent activities in the Action Plan and proposed cross-cutting conditions continue to allow PGE to pursue resources in a manner that is incremental and flexible as more information is gained about the rapidly shifting market, technology, and regional landscapes. Moreover, the Action Plan continues to allow PGE the opportunity to pursue new, clean, technologies to meet customer needs in a manner that is consistent with the traditional least cost, least risk planning framework and with the values of the Company.

PGE appreciates the contributions and feedback provided by Parties within this docket and throughout the informal public process supporting the 2019 IRP. As described in the IRP and these comments, the 2019 IRP satisfies the procedural and substantive requirements of Oregon's IRP Guidelines. As such, PGE respectfully requests that the Commission acknowledge the 2019 IRP at its February 20, 2020 public meeting.

DATED this 17th day of January, 2020.

Respectfully submitted,

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