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Erin E. Apperson
Assistant General Counsel

November 5, 2019

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") Reply 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** **REPLY COMMENTS**

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1. Introduction

In accordance with the Administrative Law Judge's (ALJ) scheduling memorandum issued September 10, 2019, Portland General Electric Company (PGE or the Company) submits these reply comments regarding PGE's 2019 Integrated Resource Plan (IRP). PGE also addresses comments and questions raised by parties and Commissioners at the October 31, 2019, Public Utility Commission of Oregon (Commission or OPUC) workshop.

Collaboration produces results that reflect the values of our customers and our community. PGE filed its 2019 IRP with the Commission on July 19, 2019. PGE appreciates the thoughtful and constructive Staff and stakeholder engagement around the 2019 IRP. Many of these parties participated in some or all of PGE's IRP public meetings and workshops conducted during the past two years. The development of the IRP benefits from stakeholder collaboration and feedback, particularly as the Company continues to assess increasingly complex resource planning issues. This stakeholder feedback helped strengthen PGE's analysis which directly improved the 2019 IRP and resulting Action Plan and provided the groundwork to inform future IRP processes and plans.

Nine parties submitted 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. Northwest Energy Coalition (NWEC);
5. Renewable Northwest (RNW);
6. Northwest and Intermountain Power Producers Coalition (NIPPC);
7. Renewable Energy Coalition (REC);
8. U.S. Endowment for Forestry and Communities (US EFC); and
9. Swan Lake North Hydro, LLC (Swan Lake).

Comments addressed a wide 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 requested additional information in areas of concern or interest. These comments are intended to provide PGE's perspective regarding recommendations from Parties and to provide additional information to help facilitate the continued review of PGE's plan.

1.1. We embrace the principles of integrated resource planning

Since initiating the 2019 IRP process, PGE has remained committed to developing a plan that increases the opportunity to meet our customers' needs with least-cost, least-risk, sustainable solutions. This IRP retains PGE's essential focus on safe, reliable, and affordable electricity while reflecting a future focused on more energy efficiency, demand response, and renewable resources, and fewer greenhouse gas emissions.

Oregon's method of resource planning relies on the balanced consideration of four substantive elements:[1]

1. Supply and demand resources;
2. Risk and uncertainty;
3. The best combination of costs and associated risks; and
4. Alignment with "the long-run public interest" provided in state and federal policies.

PGE relied on these principles and the current IRP guidelines to develop our 2019 IRP, construct the proposed Action Plan, and respond to parties' comments. PGE's IRP process involved thoughtful, reasoned, and studied analysis and discussions with Staff, stakeholders, consultants, and members of the general public.

In these reply comments, PGE provides responses to parties' concerns, additional information as requested, and in some cases, we propose modifications to the Action Plan. We also identify 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 response to Staff's comments and PGE's subsequent evaluation, PGE proposes two modifications to the Action Plan to ensure better alignment with the preferred portfolio and to provide more flexibility for long-lead-time resources to participate in the non-emitting Capacity request for proposals (RFP):
    - PGE proposes to add a condition to the Renewable Action that requires resources to be eligible for federal tax credits. This ensures that procured resources reflect the key attributes that contribute to the strong cost and risk performance of the preferred portfolio.
    - PGE also proposes to allow long-lead-time resources to participate in the non-emitting capacity RFP, provided that PGE can pair them with short-term contracts to meet capacity needs prior to the resource commercial operation date (COD).
- **Portfolio Analysis.** In response to several substantive questions regarding PGE's portfolio analysis from Staff, PGE conducted multiple additional analyses testing assumptions related to capacity factors, non-traditional scoring metrics, the weights applied to each future, and the treatment of banked and unbundled Renewable Energy Credits (REC). As further explained in these comments, these additional analyses support the selection of the preferred portfolio and recommendations of the Action Plan.

[1] *In the Matter of Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-022 at 2, (January 8, 2007), amended by Order No. 07-047.

- **Needs Assessment.** PGE provides additional information on the load forecast and the treatment of electric vehicles, energy efficiency, direct access loads, the Green Tariff program, and PURPA qualifying facilities (QF). In addition, PGE commits to providing an update to the needs assessment in this docket in November 2019 to incorporate more recent information as well as new resources from PGE's Green Tariff program.
- **Resource Economics.** PGE provides additional information on technology costs, wind energy value, flexibility value, and risks associated with federal tax credits. In addition, PGE commits to host a discussion of the intergenerational equity analysis at the Company's next public roundtable meeting, on November 21, 2019.
- **Transmission.** PGE provides additional discussion related to transmission requirements for the renewables RFP (the Interim Transmission Solution[2]), provides clarifying information regarding the transmission products that PGE relies upon, and discusses plans to improve the treatment of transmission-related constraints in future IRP analyses.
- **Other items.**
  - While PGE does not have additional information related to Colstrip at this time, the Company commits to updating the Colstrip sensitivities when additional information becomes available.
  - PGE provides additional discussion related to the modeling of Boardman Biomass and refers interested Parties to PGE's Annual Boardman Decommissioning Update in UE 230.
  - PGE embraces Staff's recommendation to conduct a climate change adaption study to inform future planning exercises.

2. Action Plan

PGE appreciates parties' thoughtful comments on the Action Plan. PGE developed the Action Plan based on rigorous portfolio analysis that considered near-term needs and long-term value consistent with traditional IRP analysis, supplemented with a more thorough treatment of uncertainty and optionality as well as insights regarding near-term cost impacts. The Action Plan was designed to allow PGE to pursue resources with the key attributes of the preferred portfolio, while considering the market landscape and incorporating insights provided by stakeholders through the public roundtable process. The Action Plan is comprised of the following:

- Customer Resource Actions, which focus on meeting needs through customer-side resources, including all cost-effective energy efficiency and all cost-effective and reasonable distributed flexibility;
- A Renewable Action, which would allow PGE to pursue up to 150 MWa of low-cost renewable energy to come online by the end of 2023, with conditions to ensure strong outcomes for customers; and

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

- A staged Capacity Action, which would allow PGE to meet remaining capacity needs by leveraging existing capacity in the region and, if needed, new non-emitting technologies.

In the following sections, PGE summarizes parties' comments on each component of the Action Plan and provides responses. PGE also describes a set of Enabling Analyses that could support future IRPs and provides additional information on the treatment of risk in PGE's 2019 IRP.

2.1. Customer Resource Actions

Parties' Comments

Staff expressed support for PGE's proposed distributed flexibility actions and included additional recommendations related to demand response, [3] which are described in **Section 5.7**. CUB expressed support for PGE's Customer Resource Actions.[4] CUB also points to PGE's Smart Grid Test Bed as an innovative example of how customer resources may be leveraged to meet resource needs.[5]

NWEC expressed support for PGE's energy efficiency action item and suggested that the 157 MWa estimate by 2025 should be interpreted as a minimum target for energy efficiency.[6] NWEC strongly supports actions to increase the amount of distributed flexibility in PGE's portfolio and proposes a 20% additional stretch goal for distributed flexibility in the IRP[7] as well as modification of the Action Plan to include an "open-ended" request for distributed flexibility resources[8] and an item to improve customer interest in demand response.[9]

PGE Response

PGE appreciates the support expressed by parties for the continued reliance on customer resources to meet future needs. PGE would like to clarify that while the Action Plan references forecasts for energy efficiency and distributed flexibility resources, PGE does not interpret these forecasts as minimum or maximum targets. As both technology costs and resource value evolve over time, the amount of cost-effective customer resources will also change. PGE designed the Action Plan to be flexible enough to accommodate such changes, so that the company can pursue more customer resources than were identified in the 2019 IRP should they be cost-effective and reasonable. PGE's Low Need Future considers such a scenario, with expanded energy efficiency and distributed flexibility. PGE does not believe that a stretch goal is required for the Company to pursue cost effective customer resources in excess of those identified in the Reference Case.

PGE also notes that while cost-effectiveness is crucial for customer resources, deployment ultimately hinges on customer decisions. PGE understands that some customers have a negative perception of the term "demand response" but not necessarily the customer benefits of participating in demand

[3] LC 73 Opening Comments of Staff at 45.
[4] LC 73 Opening Comments of CUB at 13.
[5] *Id*.
[6] LC 73 Opening Comments of NWEC at 3.
[7] *Id*.
[8] *Id*.
[9] *Id.* at 3-4.

response programs. Customer interest and the customer experience are central areas of focus for PGE's Smart Grid Test Bed. PGE is working within the Smart Grid Test Bed to understand, design and test a series of customer value propositions associated with customer participation in demand response programs. The Demand Response Review Committee of which Staff and NWEC are members have helped design and guide this activity. PGE looks forward to incorporating the learnings from the Smart Grid Test Bed in future planning processes.

Regarding processes to acquire demand response, PGE plans to provide a more thorough proposal of plans to acquire these resources within the Company's Flexible Load Plan, to be filed with the Commission in 2020. PGE looks forward to engaging with the Commission and stakeholders on the substance of that plan so that the Company can thoughtfully scale demand response and flexible load deployment in a way that provides the best value to customers. PGE provides additional discussion of energy efficiency in **Section 4.3** and demand response in **Section 5.7**.

2.2. Renewable Action

Parties' Comments

Parties expressed mixed reactions to PGE's Renewable Action. NWEC, RNW, and NIPPC expressed general support for the Renewable Action,[10,11,12] though each included comments related to transmission, which are discussed in **Section 6**. NWEC and RNW emphasized the contribution of the Renewable Action to meeting resource needs.[13,14] RNW further noted that the design of the Renewable Action "…incorporates learnings from the 2016 IRP…" as well as feedback from PGE's public roundtable process.[15] NWEC expressed some concern that the analysis of renewable cost and performance may not fully capture the benefits of wind and solar and noted that this "under-represent[ation]" may result in lower cost outcomes in an RFP than are anticipated based on IRP assumptions.[16] NWEC also expressed support for PGE's proposal to return the value of RECs to customers.[17]

AWEC expressed opposition to the Renewable Action, citing similar concerns to those that they expressed in Docket No. LC 66 regarding the 2016 IRP. AWEC further suggested that the arguments for near-term renewables have weakened since the 2016 IRP due to the step-down of the Production Tax Credit (PTC) and the reduced need for RECs due to actions taken since the 2016 IRP.[18] AWEC

[10] *Id.* at 4.
[11] LC 73 Opening Comments of RNW at 6.
[12] LC 73 Opening Comments of NIPPC at 2.
[13] LC 73 Opening Comments of NWEC at 4.
[14] LC 73 Opening Comments of RNW at 6.
[15] *Id*.
[16] LC 73 Opening Comments of NWEC at 4-5.
[17] *Id.* at 4.
[18] LC 73 Opening Comments of AWEC at 4-5.

suggested that PGE delay acquisition of renewables by leveraging banked RECs and future unbundled REC purchases for RPS compliance.[19]

Staff and CUB expressed concerns, but did not appear to take definitive positions regarding the Renewable Action at this time, both pointing to the need for additional information at this stage in the process.[20,21] CUB questioned whether the Renewable Action is aligned with an accurate forecast of future resource needs.[22] Staff expressed concerns that the Renewable Action may not adequately align with portfolio analysis and questioned whether "specifying the MWa, commercial operating year, and RPS eligibility" of the resources adequately captures the attributes of the preferred portfolio per IRP Guideline 4.[23] Staff pointed to tax credit eligibility as an example of a driver of value in the preferred portfolio that is not specified as part of the Renewable Action.[24] Staff expressed additional concerns about the RPS analysis supporting the Renewable Action, in particular the treatment of banked and unbundled RECs,[25] which is discussed in **Section 4.5**.

PGE's Response

In considering near-term renewable resource options in the 2019 IRP, PGE followed the guidance provided by the Commission in Order Nos. 17-386 and 18-044 as well as the feedback provided by stakeholders in the public roundtable process. The Commission summarized their guidance to PGE in Order No. 18-044, noting that they had urged PGE to "make a greater showing of how a proposed resource action aligns with needs, mitigates short-term rate impacts, and maintains long-term optionality," in proposing an alternative Renewable Action within the 2016 IRP.[26] PGE followed this guidance with the Revised Renewable Action in the 2016 IRP, which was ultimately acknowledged by the Commission.[27]

In addition to the traditional evaluation based on cost and risk, PGE also provided the following information in the 2019 IRP to be responsive to the Commission's specific guidance:

- A summary of the contribution of each category of resources in the preferred portfolio to meeting near-term energy and capacity needs, which can be found in Section 7.3.2 of the 2019 IRP. This analysis showed that the renewable additions in the preferred portfolio met approximately 160 MW of the identified capacity needs in 2025.[28]
- An intergenerational equity analysis, which can be found in Section 7.3.1 of the 2019 IRP. This analysis demonstrates that while renewable resources are expected to have near-term rate

[19] *Id.* at 8.
[20] LC 73 Opening Comments of Staff at 5 and 47.
[21] LC 73 Opening Comments of CUB at 13-14.
[22] *Id.* at 13.
[23] LC 73 Opening Comments of Staff at 5-7.
[24] *Id.* at 6.
[25] *Id.* at 12-14.
[26] Order No. 18-044 at 6.
[27] Order No. 18-044.
[28] This includes the impacts of both the 2023 renewable addition and the 2025 renewable addition in the preferred portfolio. Only the 2023 renewable addition is reflected in the Renewable Action.

impacts, those impacts are relatively small and can be lessened by pursuing renewable resources that qualify for federal tax credits. PGE also incorporated a non-traditional scoring metric focused on near-term cost impacts, described in Section 7.2.1 of the 2019 IRP, to screen out the portfolios with the greatest expected impacts on near-term costs.

- A renewable glide path analysis, which can be found in Section 7.3.3 of the 2019 IRP. The renewable glide path analysis was an outcome of a fundamental change in the way that PGE designed and scored portfolios to directly account for optionality and to more holistically consider the impact of future uncertainties in resource needs on the value of and risks associated with near-term resource additions.

PGE appreciates that conditions have changed since the 2016 IRP and takes seriously the concerns raised by Staff and some stakeholders regarding the Renewable Action. PGE provides responses to the concerns regarding compliance with the IRP Guidelines and alignment with resource needs in the following sections.

Alignment with Resource Needs

One common area of concern among Staff, CUB, and AWEC is that the Renewable Action may not align to PGE's resource needs. PGE notes that AWEC misrepresented PGE's approach to accounting for RECs from Wheatridge in the RPS needs assessment and incorrectly implied that PGE's treatment led to a "misleading" forecast of future RPS needs.[29] In accordance with PGE's 2016 IRP Revised Renewable Action Plan,[30] PGE assumed that RECs generated from Wheatridge prior to 2025 would be monetized on behalf of customers and therefore would not be available for RPS compliance.

PGE acknowledges that the Renewable Action would bring renewable energy into PGE's portfolio in advance of the need for additional RECs to comply with Oregon's Renewable Portfolio Standard. However, the 2019 IRP portfolio analysis suggests, and the additional analysis provided in **Section 4.5** of these comments confirms, that RPS obligations are not a key driver for the Renewable Action. As discussed more thoroughly in **Section 4.5**, the 2019 IRP portfolio analysis identifies near-term renewable resource additions as foundational to achieving low cost and low risk outcomes, even if the physical RPS constraint is removed and full utilization of unbundled RECs is assumed into the future at zero cost—the most extreme possible interpretation of AWEC's suggestion. The analysis in **Section 4.5** further demonstrates that near-term Renewable Action is least-cost, least-risk even if RPS obligations are fully removed. This finding is a consequence of the confluence of a low-cost environment for renewable technologies and the continued availability of federal tax credits. It also reflects the contribution of renewable resources to meeting PGE's near-term resource needs, as the renewable additions in the preferred portfolio avoid approximately 160 MW of capacity needs by 2025.[31]

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[29] LC 73 Opening Comments of AWEC at 5.

[30] As a condition of the 2016 IRP Revised Renewable Action Plan, the Company stated: "PGE also commits to return to customers the value associated with RECs procured prior to 2025 through this Revised Renewable Action Plan." LC 63, Revised Addendum to the 2016 IRP at 4.

[31] See PGE's 2019 IRP at 200, Figure 7-17.

The findings of the 2019 IRP analysis are clear with respect to near term Renewable Action—that pursuing renewable resources in the near term reduces both cost and risk. However, there remains some subjectivity in determining the most appropriate size of a near-term Renewable Action to capture value for customers while maintaining optionality and flexibility for the future. This was a central question at the heart of the Commission order directing PGE to conduct a renewable glide path analysis.[32] PGE responded to this question by fundamentally improving the Company's approach to portfolio design and scoring in the 2019 IRP to directly account for optionality and to more holistically consider the impact of future uncertainties in resource needs on the value of and risks associated with near-term resource additions. The resulting renewable glide path analysis as described in Section 7.3.3 of the 2019 IRP is instructive. It finds that the optimal trajectory of renewable additions over time is expected to fall above the Company's RPS obligations and below the Company's forecasted open market energy position. The exact trajectory varies widely depending on technology costs, resource needs, and market conditions, but the 150 MWa near-term addition in the Preferred Portfolio provides adequate flexibility to ensure low cost outcomes for customers across a wide range of potential futures.

PGE notes that the renewable glide paths strongly depend on the forecasted market energy position, particularly in the outer years. As such, PGE takes seriously the concerns expressed by stakeholders regarding the energy needs assessment and the input assumptions that drive it. PGE responds to these concerns in **Section 4**. PGE also plans to supplement the needs assessment based on updated information in November 2019.

PGE also acknowledges that there is no guarantee that the market will bring renewable bids that provide comparable value as those modeled in the IRP. PGE designed the Renewable Action to provide for additional flexibility in right-sizing renewable acquisitions both by establishing approximately 150 MWa as a maximum procurement size (with no minimum) and by applying a cost-containment screen. This design explicitly allows the Company to procure less than 150 MWa if bids do not provide adequate value for customers based on information obtained through the RFP. This is discussed further, specifically as it relates to risks associated with federal tax credit benefits, in **Section 5.4**.

Compliance with IRP Guideline 4

PGE interprets Staff's concerns with PGE's compliance with Guideline 4 as focused on the alignment of the Renewable Action with the key attributes of resources in the preferred portfolio. Before discussing this issue, PGE would like to clarify the sizes of the resource additions in the preferred portfolio. In describing the preferred portfolio, Staff refers to the cumulative additions listed in Table 7-8 and Table 7-9 in the IRP as additions that are made "per year" and states that

[32] Order No. 17-386 at 14. In Order No. 18-044, the Commission ordered PGE to "use a glide path analysis in future IRPs and subsequent RPIPs. The glide path analysis has been a helpful foundation upon which to build and further refine an understanding of the pacing of PGE's procurement plans, showing a forecast of the company's long-term compliance strategy and the incremental steps to get there." Order No. 18-044 at 5.

resource additions in the preferred portfolio include "…527 MWa of wind resource additions between 2023 through 2025."[33] For clarification, the numbers listed in Table 7-8 and Table 7-9 refer to cumulative additions through each of the specified years, not incremental additions made in each year. Per Table 7-8 and Table 7-9, the preferred portfolio includes: 41 MWa of Gorge Wind and 109 MWa of Montana Wind added in 2023; 37 MW of 6-hour batteries and 200 MW of pumped storage added in 2024; and 77 MWa of WA Wind added in 2025. Cumulative wind additions between 2023 and 2025 equal 227 MWa, not 527 MWa. PGE notes that the Action Plan addresses the 2023 renewable addition in the preferred portfolio but does not include an action to pursue the 2025 renewable addition in the preferred portfolio. PGE plans to re-evaluate renewable additions in the 2025 timeframe in the next IRP.

In response to Staff's comments regarding compliance with the IRP guidelines, PGE acknowledges that there is subjectivity in designing an Action Plan consistent with the Preferred Portfolio in accordance with Guideline 4(n). Guideline 4(n) states that the IRP must include "[a]n action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing." [34]

At one extreme, the Company might interpret the resource additions in the Preferred Portfolio very specifically and seek to acquire the exact technologically-, locationally-, and size-specific resources included in the Preferred Portfolio. This interpretation of Guideline 4 could result in poor outcomes for customers if, for example, resource bid cost, performance, or availability does not exactly align with the proxy resources investigated in the IRP. Such narrowing of the specifications for an RFP would limit opportunities for the identification of the most valuable and cost-competitive resources for customers. Taking such a narrow interpretation of this guideline is also contrary to Commission guidance. Specifically, the Commission provided the following guidance on this interpretation in Order 07-002: "To keep the IRP process separate from the procurement process, we prefer to acknowledge general, not specific resources, in the IRP process."[35]

At the other extreme, the Action Plan could be designed to meet the needs identified in the IRP with few constraints related to resource type based on the findings of IRP portfolio analysis to provide for the broadest possible competitive solicitation. Such an interpretation would provide little in the way of guidance to the Commission, stakeholders, and the development community as to the resource attributes that the Company expects to be best aligned to customer needs at the best value. PGE's approach in the 2019 IRP seeks to find a middle ground between these two extremes. The portfolio analysis and design of the preferred portfolio provides insight into those resource attributes that are likely to meet customer needs while providing for the best balance of cost and risk, and the Action Plan is designed to allow PGE to thoughtfully pursue resources with those attributes while allowing for the flexibility to adjust to market realities.

[33] LC 73 Opening Comments of Staff at 5.
[34] Order No. 07-002 at 12 (Jan. 8, 2007) amended by Order No. 07-047.
[35] *Id.* at 25.

Specifically, the portfolios that provide the best balance of cost and risk in the 2019 IRP leverage a combination of renewable resources that are eligible for federal tax credits and energy storage resources to meet near-term capacity needs that remain after accounting for other actions. The resource-specific analysis in Chapter 6 of the IRP suggests that the cost and performance differences between various wind resources and between various energy storage resources (specifically 6-hour batteries and 8-hour pumped storage) are small relative to the associated uncertainties.

For this reason, PGE does not believe that a more technologically or location-specific treatment within the Action Plan will provide for the best outcomes for customers, nor does PGE agree that such specificity is required by the IRP guidelines. PGE believes that more value can be derived for customers by allowing bids for resources across multiple locations and leveraging various technologies to participate within a competitive solicitation.

While PGE does not believe that a more technologically- or location-specific Action Plan is warranted at this time, PGE is considering the extent to which other key attributes of the resources in the preferred portfolio are reflected in the Action Plan. Specifically, all renewable resources in the preferred portfolio that are reflected in the Action Plan are eligible for federal tax credits, but this attribute is not directly referenced in the Action Plan. As PGE states in the 2019 IRP and Staff references in their opening comments,[36] PGE's cost containment screen provides some assurance that procured resources demonstrate similar benefit to customers as the proxy resources modeled in portfolio analysis. However, PGE understands Staff's concern with this outcomes-focused approach, particularly with respect to adherence to IRP Guideline 4(n). To address this concern, PGE proposes the following additional condition for the Renewable Action.

- **Proposed Condition for Action Item 2:** Resources must be eligible for federal tax credits.

PGE believes that this condition will help ensure that procured resources align with the Preferred Portfolio and the findings of IRP analysis while providing adequate flexibility for the RFP to identify the best resources to meet customer needs.

2.3. Capacity Actions

Parties' Comments

Parties' comments regarding PGE's staged Capacity Action were also mixed. CUB, AWEC, and NWEC supported the staged approach to securing capacity, which prioritizes meeting capacity needs first with bilateral agreements for existing capacity in the region.[37,38,39] AWEC further suggested that PGE should consider contract options beginning in 2024 and with terms as short as three years within the

[36] LC 73 Opening Comments of Staff at 6.
[37] LC 73 Opening Comments of CUB at 14.
[38] LC 73 Opening Comments of AWEC at 6-7, Attachment B.
[39] LC 73 Opening Comments of NWEC at 6.

bilateral process, due in part to the status of BPA's Regional Dialogue contracts, which currently extend through September 30, 2028.[40] Staff and Swan Lake expressed concern with the staged approach, both suggesting that there may be value in pursuing new capacity resources concurrently with existing resources in 2020.[41,42] Staff's concerns focused on the urgency of PGE's capacity needs, the potential resource adequacy challenges in the region, and the long lead times for potential new capacity resources like pumped storage.[43] Swan Lake suggested that a capacity RFP in 2021 would result in a 2026 or 2027 COD for the Swan Lake pumped storage project if it were selected, which would not allow it to contribute to meeting capacity needs in 2024 and 2025.[44]

None of the parties expressed opposition to PGE's proposal to exclude emitting resources from the capacity RFP, though Staff recommended that PGE provide additional justification for the exclusion of thermal resources from long term planning.[45] RNW also encouraged PGE to focus on non-emitting resources in the bilateral negotiation process.[46]

PGE's Response

PGE designed the Capacity Action based on key insights gleaned from portfolio analysis as well as feedback received from the Commission, Staff, and stakeholders in the 2016 IRP and in the public roundtable process supporting the 2019 IRP. In Order No. 17-386, the Commission stated: "We agree with parties that short- to medium-term contracts provide optionality in the face of tremendous uncertainty in the energy market and could help PGE avoid committing customer dollars to irreversible, long-term resource decisions that may not be the least cost path."[47]

PGE made the consideration of such uncertainties, the value of optionality, and the avoidance of risks associated with large irreversible commitments central to the design of the 2019 IRP portfolio analysis and Action Plan. PGE understands that the narrative related to capacity is evolving, especially considering the acceleration of coal retirements and the potential for regional capacity shortages as a result. PGE appreciates that Staff is being thoughtful about this changing landscape and is committed to ensuring that the Capacity Action will allow PGE to act in a way to maintain resource adequacy for PGE customers. PGE provides responses to Staff's specific concerns in the following sections.

Structure of the Capacity Action

PGE has assessed both the potential benefits and drawbacks of conducting the non-emitting capacity RFP concurrently with the bilateral negotiation process and maintains the position that it is in

[40] LC 73 Opening Comments of AWEC at 6, Attachment B.
[41] LC 73 Opening Comments of Staff at 7.
[42] LC 73 Opening Comments of Swan Lake at 5-11.
[43] LC 73 Opening Comments of Staff at 7.
[44] LC 73 Opening Comments of Swan Lake at 6.
[45] LC 73 Opening Comments of Staff at 38.
[46] LC 73 Opening Comments of RNW at 7.
[47] Order No. 17-386 at 18.

customers' interest to conduct a staged process that first considers options for existing resources before considering new capacity resource development.

While PGE expects that the region will be more capacity constrained in the future, it is still the Company's expectation that there are likely to be existing resources available in the region that could help to meet PGE's capacity needs through the mid-2020s. The staged Capacity Action is designed to provide for a robust exploration of these options, to support more efficient utilization of existing resources in the region, and to realize potential diversity benefits in the region to meet PGE customer needs. PGE's proposed approach would test the availability and competitiveness of these existing resource options before committing to add new resources to the region.

With regard to new resource additions, PGE's portfolio analysis suggests comparable economics between pumped storage and 6-hour battery storage resources and forecasts continued improvement of battery economics into the future as technology costs decline. PGE has not identified adequate evidence to support the notion that a procurement activity should be designed to specifically target pumped storage over battery storage. While PGE understands the development constraints faced by pumped storage resources and the resulting desire to achieve commitments far in advance of need, PGE notes that such requirements for early commitments could create risks for customers should battery storage outperform pumped storage or should proposed pumped storage projects fail to bid into the RFP or fail to meet RFP requirements. With short lead times (approximately 18 months) and rapidly declining technology costs, PGE believes that better outcomes can be achieved for customers by delaying commitments to storage technologies than by requiring commitments multiple years before battery construction would need to commence.

Conducting the RFP after the bilateral negotiation process, closer to the timing of PGE's need, would also allow for additional refinement of PGE's need assessment, with updates to the load forecast and contracts, contracts that may be executed as a result of the bilateral negotiation process. As highlighted in the 2019 IRP, there remains significant uncertainty in PGE's resource needs in 2025. The short lead time of battery storage provides additional flexibility to right-size capacity additions over time as more information is gained about resource needs. This ability to right-size reduces the likelihood that PGE over-procures energy storage resources or commits to energy storage resources earlier than is needed.

Finally, PGE does not believe that the design of the staged Capacity Action is mutually exclusive with participation by pumped storage resources. PGE agrees that the prospect of a regional capacity shortage in the mid-2020s is concerning and that pumped storage resources may be well-suited to meet a portion of the region's growing capacity needs. PGE notes that there are multiple pumped storage resources in various stages of development in the region and that the timelines described by Swan Lake suggest that an RFP in 2020 would still not guarantee that the Swan Lake pumped storage project could be online in time to meet PGE's 2025 capacity need.[48] PGE also notes that the

[48] The project schedule that Swan Lake includes in Appendix A of their comments suggests that a 2020 Capacity RFP would allow the project to come online at the end of 2025, if it were selected. This would allow the project to contribute to PGE's 2026 capacity needs, but not PGE's 2025 capacity needs. Swan Lake Appendix A.

Company's capacity needs are expected to continue to grow beyond 2025 and that new capacity resources that can come online after 2025 could still provide significant value to PGE customers.

PGE believes that it is important to design the non-emitting capacity RFP to allow for the opportunity to take advantage of the potential benefits of both battery storage and pumped storage. PGE also believes that this can be achieved without accelerating the RFP by designing the capacity RFP to allow for new resources with long lead times to be paired with contract options that can meet capacity needs in the interim.

- **Proposed Condition to Action Item 3C:** Resources with long lead times may participate in the non-emitting Capacity RFP, provided that PGE is able to pair them with contract options to meet PGE's capacity needs in the interim.

As stated in the 2019 IRP, PGE plans to provide an update on Action Item 3C within an IRP Update to provide additional specification regarding qualification for the RFP. PGE plans to include in that filing more specific information about the treatment of existing low emissions resources, for example BPA system power, within the non-emitting Capacity RFP. At that time, PGE will also provide additional specification regarding requirements for qualifying long lead time resources that are consistent with the proposed condition described above. PGE will also report on any changes to the needs assessment that result from bilateral negotiations within the IRP Update.

Exclusion of Emitting Resources

PGE interprets Staff Recommendation 23 to refer explicitly to the exclusion of new thermal resources from portfolios in portfolio analysis beginning in 2026. However, the wording of Recommendation 23 suggests a potentially broader interpretation inclusive of long-term planning decisions that are included in the Action Plan.[49]

PGE clarifies that the Company did not exclude thermal resources from the 2019 IRP analysis. PGE conducted extensive analysis of four thermal resource options, including combined-cycle combustion turbines, simple-cycle combustion turbines, aero-derivative LMS 100 turbines, and reciprocating engines. PGE evaluated portfolios that meet near-term capacity needs with each of these resources and considered the capacity, energy, and flexibility value brought by each. In addition, six of 11 optimized portfolios allowed for thermal resource additions, while thermal resources were only selected in five of them. Three of the portfolios that included thermal resources met the non-traditional screening metrics and were among the best performing portfolios.

PGE observed that portfolios with thermal resources tended to have lower expected costs but higher quantified risk, than those portfolios that excluded thermal resources. Continued adoption of clean

[49] Staff Recommendation 23 states: "PGE should provide a thorough justification of why its decision to exclude thermal resources from its long term planning is consistent with the best interest of ratepayers, or else update its analysis to consider all resources available to meet its long-term needs." LC 73, Opening Comments of Staff at 38.

energy policies in the West and continued technological progress would favor those portfolios that incorporate energy storage over those that incorporate new thermal resources. PGE's analysis of new thermal resource additions supports CUB's position that reliance on emitting resources poses economic risks to customers.[50] For these reasons, while PGE included new thermal resources in the 2019 IRP analysis, the Action Plan does not pursue the development of new thermal resources to meet PGE's identified capacity needs in 2025.

PGE has not applied the same constraint regarding emitting resources to the bilateral negotiation process. PGE does not believe that agreements with existing emitting thermal resources pose the same risks as the addition of new long-lived emitting resources, particularly if agreements can be structured for short or medium durations. Without specific terms and conditions for potential resources, PGE cannot quantitatively evaluate the costs and risks associated with shorter duration emitting resources in the same manner that the Company evaluated new proxy thermal resources within the IRP. In evaluating potential resources in the bilateral negotiation process, PGE would apply the same principles applied in the 2019 IRP to evaluate cost and risk.

With respect to portfolio analysis, PGE did exclude new thermal resources from portfolios beginning in 2026 but relied on the cost and performance data corresponding to a SCCT to estimate the cost of capacity, modeled via a Capacity Fill resource, during this period. The Capacity Fill resource could represent the capacity provided by an SCCT or from alternative technologies and/or programs that provide capacity at an equivalent capacity cost. PGE relied on the net cost of capacity analysis to provide this proxy cost for generic capacity resources based on the theoretical long-run equilibrium cost of capacity in a system that is capacity constrained, also known as the net cost of new entry (or Net CONE). This approach allows for a consistent comparison of cost across portfolios. See **Section 3.7** for additional discussion of the Capacity Fill resource.

PGE believes the determination of whether thermal resource additions after 2025 are in the best interest of customers is out of scope for the 2019 IRP. There remains considerable uncertainty in the future evolution of energy storage cost and performance, and the future of existing coal and natural gas resources in the region. PGE's Decarbonization Study demonstrates that thermal resources that satisfy resource adequacy needs do not preclude a low carbon future; but that operational paradigms will need to change significantly over time. Due to these future uncertainties and the defined scope of the IRP Action Plan per IRP Guideline 4(n), the 2019 IRP Action Plan focuses only on resource additions that could result from actions taken in the next two to four years and is not making recommendations about new thermal resource additions after that time.

2.4. Enabling Analyses

Parties have highlighted multiple areas that they believe warrant further investigation to inform future IRPs. Therefore, PGE believes that the following enabling analyses would inform future IRP processes.

[50] LC 73 Opening Comments of CUB at 1.

- **Proposed Enabling Analyses:**
    - **Transmission-Related Constraints** to incorporate transmission-related constraints into IRP analysis. This is discussed further in **Section 6.3**.
    - **Climate Adaption Study** to investigate the potential impacts of climate change on PGE's loads and resources. This is discussed further in **Section 8.2**.
    - **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. This is discussed further in **Section 5.5**.

2.5. Treatment of Risk

At the October 31, 2019 Commission workshop, the Commissioners urged PGE to provide more thorough narrative describing the consideration of risk in the IRP analysis and development of the Action Plan. Specifically, the Commission noted that while some risks can be addressed quantitatively, others may require qualitative consideration within long-term planning. PGE agrees that long-term planning requires both quantitative and qualitative evaluation and mitigation of risk. Qualitative treatment of risk may be required when quantitative evaluation would require unknowable information, for example, confidential information from potential counterparties in the market, or when available analytical methodologies are not capable of providing for the full evaluation of risk, due to computational limits and/or prioritization of other cost or risk factors in the design of the evaluation.

To provide for a more complete review of the risks that PGE evaluated as part of the 2019 IRP, PGE provides this summary of those risks that PGE prioritized in designing the 2019 IRP analysis and Action Plan. Some of these risks are evaluated quantitatively as part of portfolio analysis,[51] while others were addressed qualitatively through design decisions in formulating the Action Plan. Some complex risks have both quantitative and qualitative treatments in the 2019 IRP. To aid in synthesizing the various risks under consideration, PGE categorizes them into reliability risks, market risks, resource risks, and policy risks.

Reliability Risks

Loss of load risk: The possibility that the future resource portfolio will be unable to meet load.

Quantitative Consideration: PGE conducts rigorous loss of load probability modeling that incorporates probabilistic treatments of loads and resource availability using the RECAP model. The capacity needs in the 2019 IRP correspond to a loss of load expectation of 2.4 hours per year. In addition to the Reference Case, PGE developed Low and High Need Futures to inform the potential range of Capacity Needs that the Company could encounter. This uncertainty is discussed further in the local economic risk section.

[51] More information on quantitative risk treatment can be found in Chapter 3 and Chapter 7 of the 2019 IRP.

Qualitative Consideration: All the aspects of the Action Plan help to address this risk by bringing capacity to the portfolio (Distributed Flexibility, Renewable Action, and Capacity Action) or by reducing the need for capacity (Energy Efficiency) to meet the loss of load expectation target. PGE has specifically framed the Capacity Action to offer the opportunity to acquire existing resources (Action Item 3.A.) while maintaining the flexibility needed to bring new resources to the system if needed (Action Item 3.B and 3.C). As in past planning and procurement cycles, PGE periodically updates its need assessments to capture changes to forecasts of loads and resource information, providing more current information.

Market Risks

Fuel price risk: The possibility that future fuel prices will deviate from current expectations, impacting some resource variable costs as well as the costs of wholesale market purchases.

Quantitative Consideration: PGE incorporates three natural gas price curves, testing relatively wide lower and upper bounds on potential future prices. These are tested across the other drivers of market price uncertainty and flow into the Variability and Severity portfolio scores as well as the resource-specific insights in Chapter 6 of the IRP. Fuel price futures are also considered as part of portfolio construction for some optimized portfolios, including the Mixed Full Clean portfolio.

Hydro availability risk: The possibility that future hydro availability will deviate from average hydro conditions, impacting costs of market purchases and associated impacts to customer prices.

Quantitative Consideration: PGE incorporates three hydro availability futures, testing plus or minus one standard deviation from average hydro. These are tested across the other drivers of market price uncertainty and flow directly into the Variability and Severity portfolio scores.

Market risks associated with clean technology expansion: The possibility that further acceleration of renewable and storage deployment in the West could lead to material deviations in future market prices from current expectations, potentially resulting in reduced energy value for some resources, in particular, renewable resources.

Quantitative Consideration: PGE incorporates a future with high buildout of renewables and storage and accelerated phase out of coal resources across the West. This future is tested across the other drivers of market price uncertainty and flows directly into the Variability and Severity portfolio scores, as well as the resource-specific insights in Chapter 6 of the IRP. This future is also considered as part of portfolio construction for some optimized portfolios, including the Mixed Full Clean portfolio. The non-traditional scoring metric of the High Tech Future, which incorporates this future, was also used to screen out portfolios with poor performance under these conditions.

Qualitative Consideration: By limiting the Renewable Action to 150 MWa, PGE further reduced potential exposure to this risk.

Local economic risk: The possibility that the local economy will grow slower or faster than current expectations and the potential for resource plans to be out of alignment with future needs.

Quantitative Consideration: PGE incorporates Low and High Need Futures, which explore bounds on slow and fast economic growth and potential impacts to load. These futures flow directly into the need assessments and Variability and Severity portfolio scores. These futures are also considered as part of portfolio construction for some optimized portfolios, including the Mixed Full Clean portfolio.

Qualitative Consideration: As discussed above, PGE periodically updates its need assessments to capture more current data, including updated load forecasts, allowing the Company to adjust procurement decisions. Given the wide range of uncertainty in capacity need (with load being the largest driver of uncertainty), PGE designed the stages of the Capacity Action to provide flexibility to respond to updated load forecast information.

Market expansion risk: The possibility that resource economics will be impacted by future expansion of organized wholesale markets in the West.

Quantitative Consideration: PGE's economic dispatch analysis assumes optimal dispatch of resources across the West without regard to the friction between balancing areas that the current market experiences, which could be eliminated by an organized wholesale energy and ancillary services market across the West. In this way, PGE does not presume the absence of an organized wholesale market in forecasting future resource market value.

Qualitative Consideration: While not necessarily a component of future market expansion, a regional resource adequacy program that enables more efficient utilization of existing resources to maintain resource adequacy would increase the risk that near-term procurement of new capacity by actors in the region will result in regional capacity overbuild and elevated costs to customers. The staged nature of PGE's Capacity Action ensures that PGE has pursued opportunities provided by existing resources and the benefits afforded by regional diversity before adding new resources to the region.

<u>Resource Risks</u>

Availability risk: The possibility that actual resource bids similar to the proxy resources investigated in the IRP are not available in the market and the potential for procurement activities to fall short of resource needs.

Qualitative Consideration: For energy efficiency and distributed flexibility, PGE addresses this risk by designing Customer Resource Actions to focus on cost-effective resources, rather than specific MW or MWa targets. Additionally, the need assessments examine the potential impact of reduced quantities of customer resources. These resources are typically added incrementally to the system rather than in large lumpy additions, which reduces the potential for significant changes between forecast updates. The Renewable Action is designed in terms of a maximum procurement target to address this risk, rather than a minimum procurement target. This allows flexibility for PGE to procure fewer or no resources if resources with adequate value to customers are not available. For existing capacity resources, PGE addresses this risk by setting no minimum target for Action Item 3.A to allow PGE to procure a quantity of existing resources based on actual availability. For new resources, Action Item 3.C is designed to be technology and location agnostic to increase the likelihood of resource availability. Furthermore, the anticipated consideration of on-system battery storage as part of Action Item 3.C reduces the exposure to availability risks associated with siting, permitting, and transmission that can be associated with traditional or off-system resources.

Current cost risk: The possibility that actual resource costs are higher or lower than the third-party estimates considered in the IRP and the potential for customers to overpay for resources or to miss opportunities for low cost resources.

Quantitative Consideration: PGE incorporates low and high cost estimates for each proxy resource into IRP analysis. Low and high cost estimates for wind, solar, and batteries flow directly into the Variability and Severity portfolio scores. These futures are also considered as part of portfolio construction for some optimized portfolios, including the Mixed Full Clean portfolio. In addition, low solar and battery costs are considered in the non-traditional scoring metric (Cost in High Tech Future), which is applied in portfolio screening. Low and high costs for all proxy resources are reflected in the resource-specific insights in Chapter 6 of the IRP.

Qualitative Consideration: For energy efficiency and distributed flexibility, PGE addresses this risk by designing Customer Resource Actions to focus on cost-effective resources, rather than specific MW or MWa targets. For existing capacity resources, PGE addresses this risk by setting no minimum or maximum target (up to the identified need) for Action Item 3.A to allow PGE to procure a quantity of existing resources based on actual prices and terms rather than estimates. For new resources, PGE addresses this risk by designing Action Item 2 and Action Item 3.C to be technology and location agnostic to increase the likelihood of participation by low cost resources. Further, Action Item 2 includes the cost containment screen to provide further assurance that PGE will not pursue renewable resources if actual costs are sufficiently high that they outweigh levelized benefits.

Future cost risk: The possibility that future costs will decline slower or more quickly than current expectations and the potential for commitments to resources to be made earlier or later than the optimal timing for customers.

Quantitative Consideration: The low and high technology cost estimates considered for wind, solar, and batteries incorporate different future cost trajectories to reflect more rapid technological progress in the low cost futures and slower progress in the high cost futures. These futures flow directly into the Variability and Severity Portfolio scores. These futures are also considered as part of portfolio construction for some optimized portfolios, including the Mixed Full Clean portfolio. In addition, more rapidly declining solar and battery costs are considered in the non-traditional scoring metric (Cost in High Tech Future), which is applied in portfolio screening.

Qualitative Consideration: Battery storage has only recently been commercially deployed at grid scale. Significant learnings and cost reductions have occurred in recent years and are expected to continue at a rapid pace. The staged nature of the Capacity Action is designed in part to allow additional time for future cost declines and development maturity for battery storage. In contrast, wind and solar are more mature technologies. PGE's portfolio analysis suggests that the risk associated with potentially more rapid cost declines for these technologies in the future do not outweigh the cost benefits of near-term action. However, the 150 MWa maximum procurement size of the Renewable Action further reduces the potential exposure to this risk.

Performance risk: The possibility that the performance of actual resources will not be comparable to the performance assumptions for proxy resources in the IRP and the potential for alternative performance estimates to impact procurement recommendations.

Quantitative Consideration: PGE tested sensitivities for wind capacity factor in Chapter 6 of the 2019 IRP and provides in Section 3.5 of these comments additional insights regarding portfolio performance under various capacity factor sensitivities.

Qualitative Consideration: This risk is addressed with the same designed decisions that are described above for “current cost risk” mitigation.

Customer participation risk: The possibility that actual customer program participation will not meet or will exceed current expectations and the potential for PGE to over plan or under plan for remaining needs.

Quantitative Consideration: The High and Low Need Futures incorporate different levels of participation in energy efficiency and distributed flexibility programs. These flow directly into the Variability and Severity portfolio scores. These futures are also considered as part of portfolio construction for some optimized portfolios, including the Mixed Full Clean portfolio. PGE also tested sensitivities related to customer participation in voluntary programs, including Community Solar and PGE’s Green Tariff in Chapter 4 of the 2019 IRP and discusses these further in these comments.

Qualitative Consideration: As discussed above, PGE periodically updates its need assessments, providing the ability to respond to changing customer commitments and forecasts. The staged Capacity Action is designed to provide flexibility to adapt to changes in customer program participation. Action Item 3.B allows PGE to adjust the sizing of the non-emitting Capacity RFP based on recent information related to customer participation in programs that impact PGE’s resource needs. The 150 MWa maximum procurement size of the Renewable Action further reduces the potential exposure to risks associated with future customer participation in voluntary renewable programs.

Policy Risks

Greenhouse Gas (GHG) Regulation risk: The possibility that future greenhouse gas regulations will be more or less impactful to resource economics than current expectations and the potential for increased costs associated with GHG-emitting resources and market purchases.

> *Quantitative Consideration:* PGE tested three futures that consider various economic consequences for GHG emissions due to future regulation. These flow directly into the Variability and Severity portfolio scores. These futures are also considered as part of portfolio construction for some optimized portfolios, including the Mixed Full Clean portfolio.

Clean Energy Policy risk: The possibility that the state or federal government will adopt additional clean energy policies that place limitations on GHGs or other emissions.

> *Quantitative Consideration:* PGE considered the potential impacts of other clean energy policies through three non-traditional scoring metrics: GHG Emissions, New Resource Criteria Pollutants, and GHG-Constrained Cost. Portfolios that scored worst with respect to each of these metrics were screened out of consideration for the preferred portfolio.
>
> *Qualitative Considerations:* PGE also considered the potential for future clean energy policies to create significant risk associated with new emitting resources. PGE considered this risk in excluding new emitting resources from the Mixed Full Clean portfolio optimization and in excluding new emitting resources from the Action Plan.

Additional unspecified risk: The possibility that there may be additional risks that are not described above or that are not fully quantified by PGE's models, which could have implications for the decision to procure long-lived resources.

> *Qualitative Consideration:* The prospect of additional unspecified risks was a consideration in PGE's approach to designing the Action Plan to allow for incrementalism and the preservation of optionality to respond as conditions change. PGE applied this principle in screening out portfolios with energy additions exceeding 250 MWa, which was a qualitatively determined approach based on quantitative analysis of the range of potential future energy needs. PGE also applied this principle in further constraining potential near-term renewable additions to 150 MWa in designing the Mixed Full Clean portfolio and the sizing of the Renewable Action. Consideration of additional unspecified risks also played a role in the framing of the staged Capacity Action, which provides the ability to secure needed capacity with the flexibility to adapt to updated information about loads and resources.

The information provided above focus on those risks that PGE prioritized and is not an exhaustive list of the risks considered as part of the 2019 IRP. It also excludes additional risks associated with specific bids or contract options, which are addressed through RFP design and contracting with counterparties. PGE provides the information in this section to enable a more thorough review of risk treatment in the IRP. PGE understands that each of the topics described above could spur more in-depth discussion. The Company plans to provide additional information on these or other risks in our Final Comments, based on the specific areas of interest expressed by Staff and parties.

3. Portfolio Analysis

PGE included an expanded treatment of risk in the 2019 IRP portfolio analysis. PGE's approach incorporated significantly more potential futures that capture uncertainties in resource needs, market conditions, and technological progress, which flow directly into the traditional Variability and Severity risk metrics. In addition, PGE developed a set of non-traditional scoring metrics that reflect risks not accounted for by the traditional risk analysis and used these metrics to screen out only the poorest performing portfolios. Parties expressed interest in better understanding the implications of PGE's new, more complex approach to portfolio analysis in the identification of the preferred portfolio and the design of the Action Plan. PGE has responded by conducting additional analysis to test the robustness of the Company's findings with respect to each of the areas of potential concern. Parties' comments and PGE's new analysis are described in the following sections.

3.1. Scoring Metrics

Parties Comments

Staff expressed concern over the use of non-traditional metrics, stating that "PGE's overall approach to scoring and selecting a preferred portfolio is too removed from the results of the portfolio modeling."[52] In Recommendation 3.a, Staff requested more analysis on the traditional cost/risk performance of each portfolio.[53] RNW described the portfolio scoring approach as "a careful portfolio analysis as part of a robust stakeholder process,"[54] and noted that PGE "sought feedback on the development of its well-defined set of scoring metrics early and often."[55]

PGE's Response

Staff and stakeholders were instrumental in shaping both traditional and non-traditional metrics in the 2019 IRP. As the non-traditional scoring metrics represented a new approach in the 2019 IRP, PGE appreciates this opportunity to further investigate the implications of these metrics on the insights gleaned from portfolio analysis.

For reference, for each of the 44 portfolios evaluated, PGE estimated the traditional cost metric by calculating the Reference Case net present value of revenue requirement (NPVRR), expressed in $2020. The traditional risk metrics estimated the variability (as measured by the semi-deviation) of each portfolio over all 810 futures and the severity (90th percentile NPVRR).

Using the data provided in the Table 7.4 in the 2019 IRP, **Figure 1** and **Figure 2** present the performance of all portfolios evaluated by traditional cost and risk metrics. This is similar to Figures 7-9 and 7-10 from the IRP, but retains portfolios not screened by the non-traditional metrics.

[52] LC 73 Opening Comments of Staff at 8.
[53] LC 73 Opening Comments of Staff, Recommendation 3.a.
[54] LC 73 Opening Comments of RNW at 6.
[55] *Id.* at 3.

Figure 1: Portfolio performance based on traditional cost and variability metrics[56]

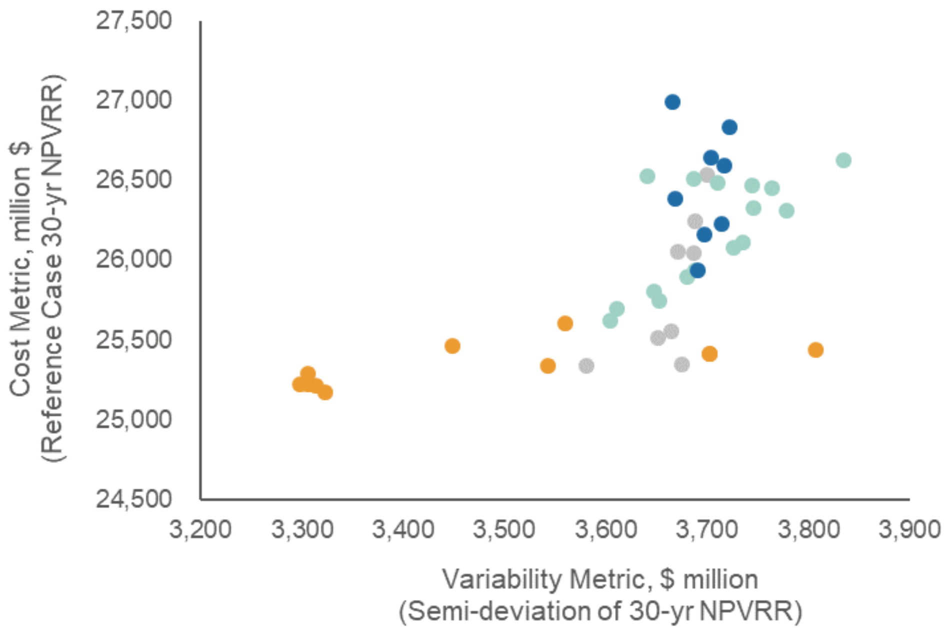
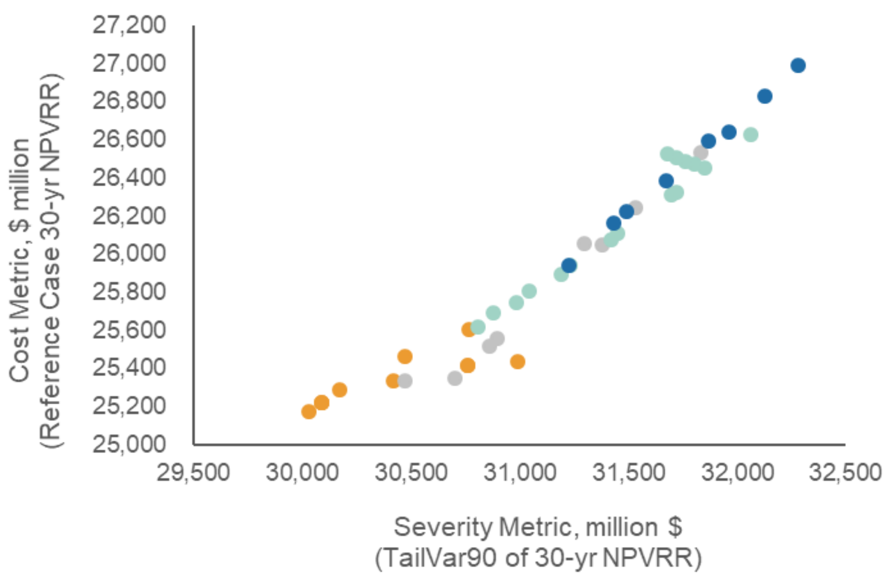


Figure 2: Portfolio performance based on traditional cost and severity metrics



Optimized portfolios (colored orange) display the lowest combinations of cost and risk. Given the clustering of portfolios in the lower left portion of the figure, it is instructive to examine these further. This is done in **Figure 3** and **Figure 4** below, which contains the same data as above, but restricts the axes values to show the lowest combinations of the traditional cost and risk metrics.

[56] Consistent with the 2019 IRP, portfolio categories (optimized, renewable resource, dispatchable capacity, and renewable size & timing) are grouped by colors (orange, blue, grey, and teal, respectively).

Figure 3: Portfolio performance based on traditional cost and variability metrics

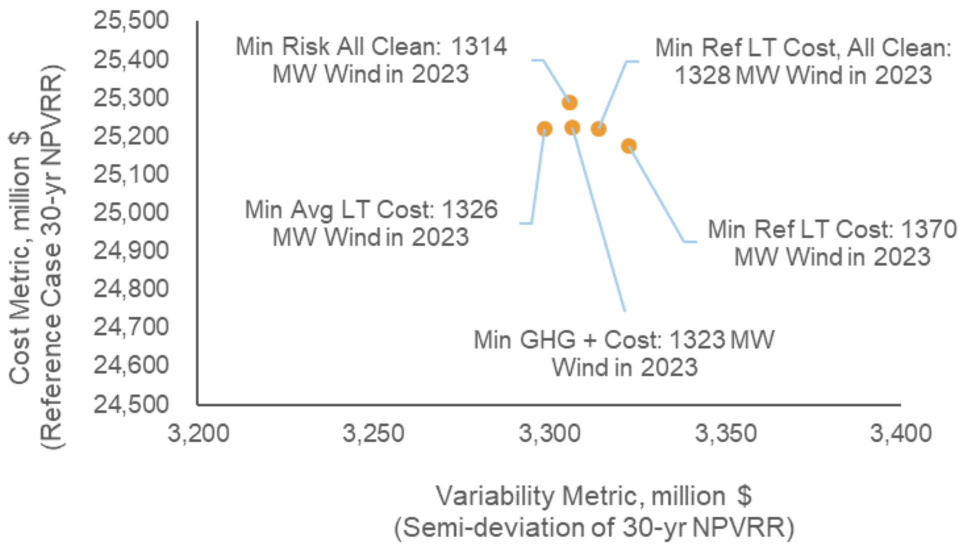
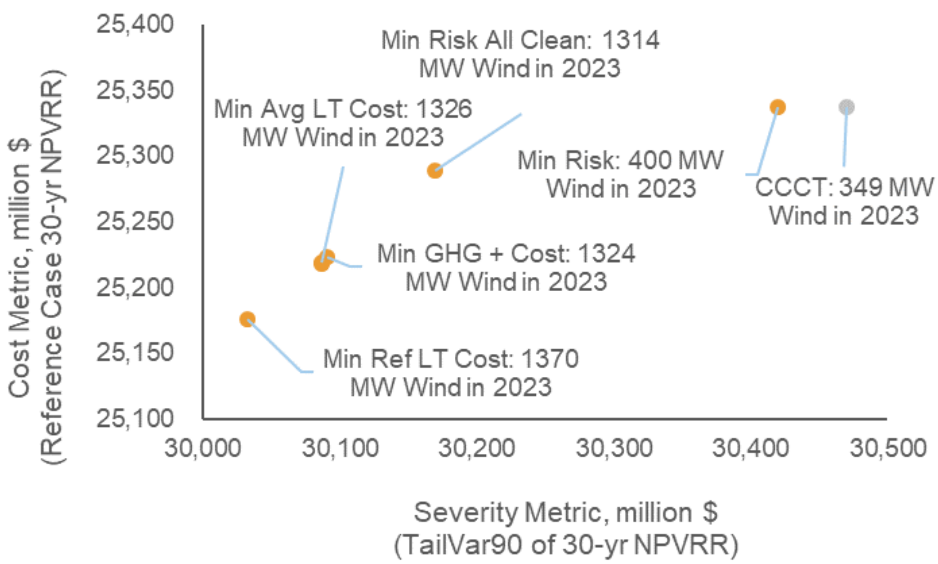


Figure 4: Portfolio performance based on traditional cost and severity metrics



There are two common themes among each of these portfolios. The first is that optimization of very different objective functions consistently selects a large renewable addition as early as possible. This can be seen even in portfolios which select additional thermal resources as well. Most of these additions are quite large, as the majority optimized portfolios in these groups add more than 1300 MW of wind resources in 2023. These renewable additions serve to provide both low cost energy to the portfolios and avoid the need for additional capacity resources.

The second common theme is that each of the portfolios depicted in Figure 4 above is screened out by the non-traditional screen of Energy Additions Through 2025. This screen is applied to portfolios that put PGE at an elevated risk due to being persistently long to the market on an average annual basis.[57]

These findings demonstrate that even without the non-traditional scoring metrics, the inclusion of a near term Renewable Action is consistent with traditional least-cost least-risk principles. PGE's focus on smaller renewable additions within the preferred portfolio allows PGE to pursue the cost and risk benefits described above while providing for additional flexibility to meet energy needs over time with other resources, including those procured as part of the Capacity Action or those that may result from voluntary renewable program participation.

3.2. Preferred Portfolio

Parties' Comments

Staff questioned the performance of the preferred portfolio, stating its construction was "somewhat puzzling, and may present another blunt instrument in portfolio selection. Staff finds this approach particularly curious given that the Mixed Clean Full (sic) is outperformed by others in terms of cost and risk, as shown by PGE's graphics."[58]

PGE's Response

For clarification, the Mixed Full Clean portfolio was constructed as an optimized portfolio by selecting a reasonable set of constraints that aimed to capture the best characteristics of other top performing portfolios. Included in these constraints was the ability to select up to 150 MWa of renewable energy between 2023-2024. This addition of 150 MWa was determined by ROSE-E to be part of the cost-minimizing solution. The Mixed Full Clean portfolio was chosen as the preferred portfolio based on a comparison of traditional cost and risk measures relative to other top performing portfolios.

Staff's comments regarding preferred portfolio performance refer to IRP Figures 7-13 and 7-14, which display the preferred portfolio's performance of cost/risk measures relative to other portfolios not screened by the non-traditional metrics. Similar to **Figure 3** and **Figure 4** above, when plotting cost and risk metrics, any movement among portfolios both down and left represent a universal improvement and moving either down and right or up and left represents a trade-off between cost and risk. Staff's concern seems to come from the existence of portfolios down and to the left of the preferred portfolio. It is instructive to examine both figures closer. In **Figure 5** and **Figure 6** below, these IRP graphics are replicated, with relevant individual portfolios highlighted.

[57] For more information on the development of this non-traditional screen, please refer to Sections 4.4.1 – Market Energy Position and 7.2.1 – Scoring Metrics.
[58] LC 73 Opening Comments of Staff at 9.

Figure 5: IRP Figure 7-13, highlighting relevant portfolios

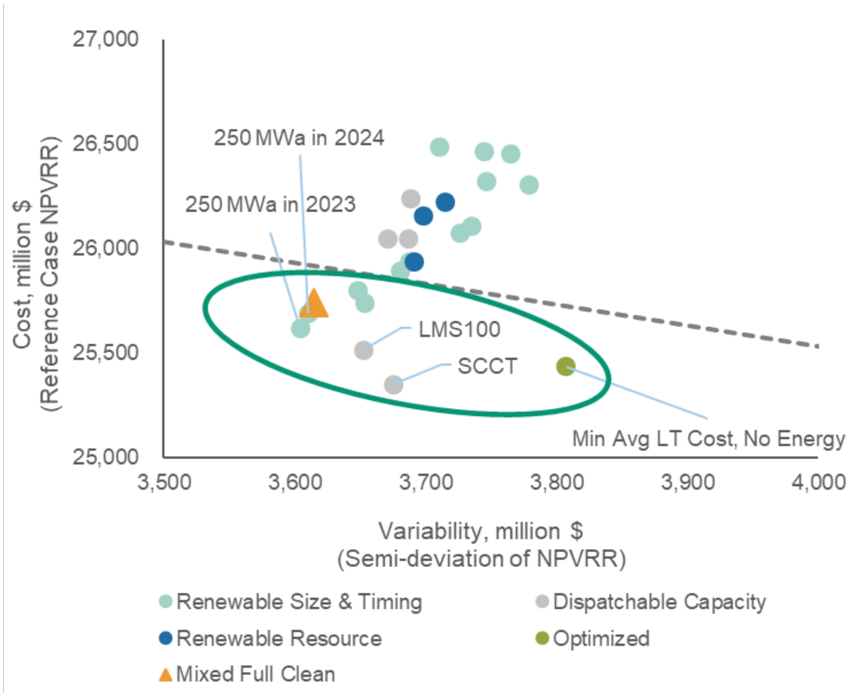
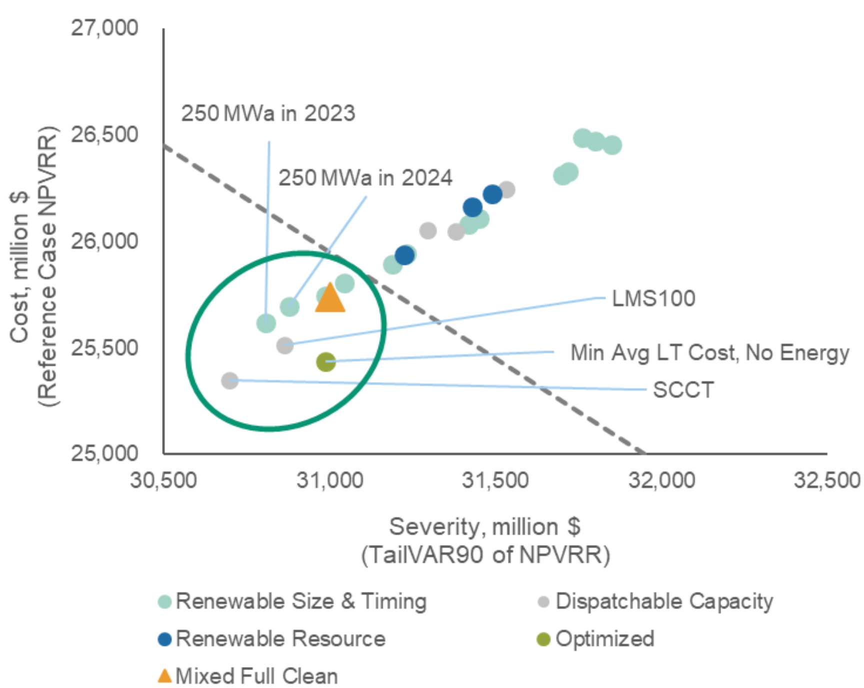


Figure 6: IRP Figure 7-14, highlighting relevant portfolios



While the LMS 100, Min Avg LT Cost, No Energy, and SCCT portfolios outperform the preferred portfolio in terms of cost versus severity, they do not in terms of cost versus variability. Each of these portfolios increase the variability metric relative to the preferred portfolio. Only the renewable size and timing portfolios (250 MWa in 2023 and 250 MWa in 2024) uniformly decrease cost and risk across both variability and severity metrics. In other words, the only way to uniformly reduce cost and risk relative to the preferred portfolio is to add more renewables. However, as discussed above, the preferred portfolio was limited to a 150 MWa addition between 2023-2024 to allow for additional flexibility should other activities bring energy to PGE's portfolio. While allowing additional renewables could result in lower cost and risk scores, PGE believes that limiting the size of the renewable addition provides for future flexibility and mitigates potential unquantifiable risks and does so without significantly impacting the cost and risk performance of the preferred portfolio relative to the best performing portfolios.

3.3. IRP Guideline 8

Parties' Comments

In opening comments, Staff recommended that PGE evaluate the 2019 IRP's compliance with IRP guideline 8.[59] For reference, this guideline specifies how environmental costs should be treated by each utility in their IRP.[60] Under part c, utilities are instructed to identify "should identify at least one set of CO2 compliance costs within the range of alternative regulatory scenarios considered that would lead to, or "trigger," a set of resources that is substantially different from the preferred portfolio."[61]

PGE's Response

As described in Appendix A – IRP Guidelines, PGE complied with IRP Guideline 8 by testing each portfolio in a carbon-constrained future, which is one of the non-traditional metrics by which all portfolios are screened. In response to Staff's concerns, PGE does not expect a more stringent set of carbon regulations would change the preferred portfolio, as it contains no GHG-emitting resources. The assumption that increasingly stringent carbon legislation would create alternative portfolios, or one that is more consistent with Oregon energy policies as described in part e,[62] does not comport with a broad set of futures with renewables with negative net-costs. Accordingly, additional "turning point" analysis would produce no different results.

[59] *See* LC 73 Opening Comments of Staff, Recommendation 3.b.
[60] *See* Order No. 08-339, Appendix C.
[61] *Id.* at 10.
[62] Part e. instructs utilities to "assess the costs and risks of adapting the preferred portfolio to a scenario (or scenarios) where the utility must change course unexpectedly due to a major change in the CO2 compliance requirements".

3.4. Benefits of Early Action

Parties' Comments

Staff raised concerns about the benefits derived from PGE's proposed Renewable Action in 2020, stating "the cost and risk metrics for renewable size and timing portfolios because the portfolios that add 50 - 250 MWa in 2024 appear similar under the cost metric to the performance of the renewable size and timing portfolios that add 50 - 250 MWa of renewables in 2023."[63] Further, Staff stated they seek to understand "the costs and risks of rushing to acquire resource with a COD of 2023."[64]

PGE's Response

For clarification, Staff is referring to the cost metrics of the Renewable Size and Timing portfolios presented in Table 7.4 of the IRP, which reflect the net present value of the revenue requirement (NPVRR) in the Reference Case. When comparing the economic performance portfolios which add a renewable resource in 2023 versus 2024, there are several differences which can drive costs apart. The cost of building the resource is moved a year sooner/later, but so too is the associated value created from the resource. This value is comprised of the energy the resource produces, the capacity value it provides (allowing PGE to not procure other capacity resources), and the PTCs generated.

Comparing the NPVRR of Renewable Size and Timing portfolios, there is a $16-73 million cost savings associated with a 2023 versus 2024 COD, increasing with the size of the renewable addition. This is displayed below in **Figure 7** and **Figure 8**. **Figure 7** suggests a total system NPVRR decrease associated with adding larger quantity of renewables, unless that action is delayed until 2025. Below, **Figure 8** demonstrates a decrease in variability associated with increasing size, and a changing relationship between CODs: a COD of 2025 shows the slowest decline when adding size, while the CODs of 2023 and 2024 vary depending on renewable addition size.

[63] LC 73 Opening Comments of Staff at 32.
[64] *Id*. at 33.

Figure 7: Cost associated with renewable addition, by size and COD

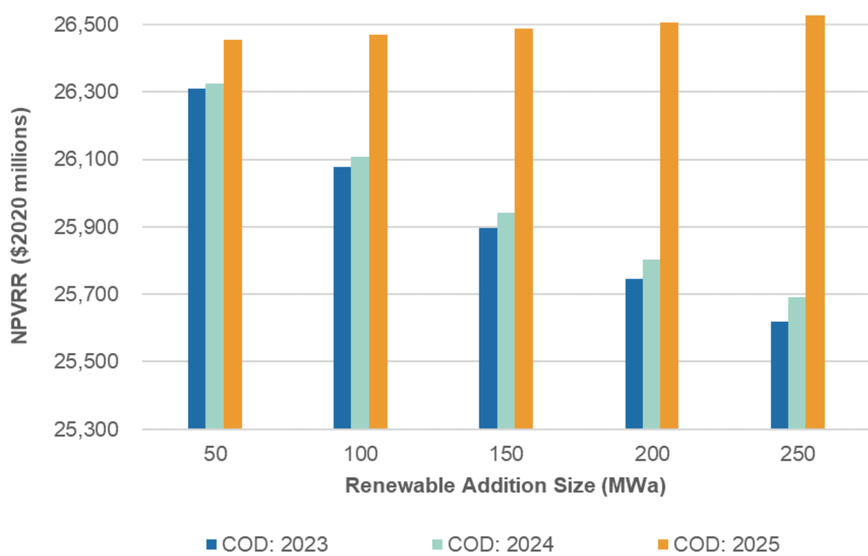
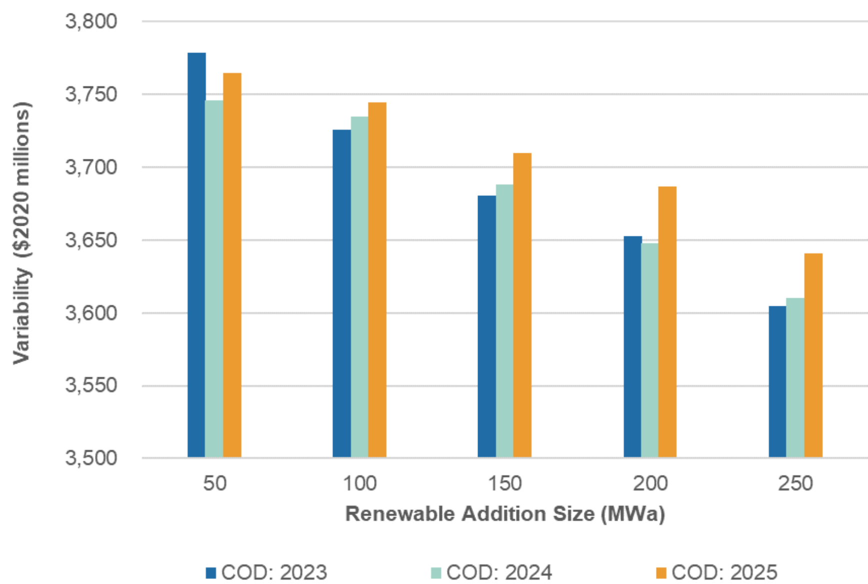


Figure 8: Variability associated with renewable addition, by size and COD



A significant portion of this value is attributable to the reduction in PTC credits for resources with an earlier COD. As shown in **Table 1** below, this depends on the size of the addition, but remains an important driver in the cost savings associated with early action.

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

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

3.5. Capacity Factors

Parties' Comments

Staff and AWEC both commented on the capacity factors used in PGE's portfolio analysis. AWEC stated "none of PGE's wind resources currently operate at a 40 percent capacity factor and so PGE is likely optimistic about the new wind resource operating capability."[65] Staff raised concerns about the impact of capacity factor assumptions, and questioned "whether the Company's sensitivity analysis should have been performed on the Mixed Full Clean portfolio to help characterize the risk of acquiring near-term wind assets based primarily on economic performance."[66]

PGE's Response

PGE clarifies that the values for the proxy wind resources were estimated by third-party contractor HDR based on wind resource quality and industry trends.[67] Historical performance of existing wind generation does not provide the best prediction of capacity factors associated with new resources due to continued evolutions in wind turbine technologies.

PGE agrees with Staff that the economics of wind resources are an important consideration in this IRP, as many portfolios add significant wind capacity through 2050. To test how changing capacity factors affect the preferred portfolio in response to Staff's Recommendation 20, PGE ran a sensitivity where capacity factors of wind resources are reduced proportionally to the capacity factors used in the capacity factor sensitivity from Section 6.5 – Capacity Factor Sensitivities.[68] **Table** 2 shows these reductions.

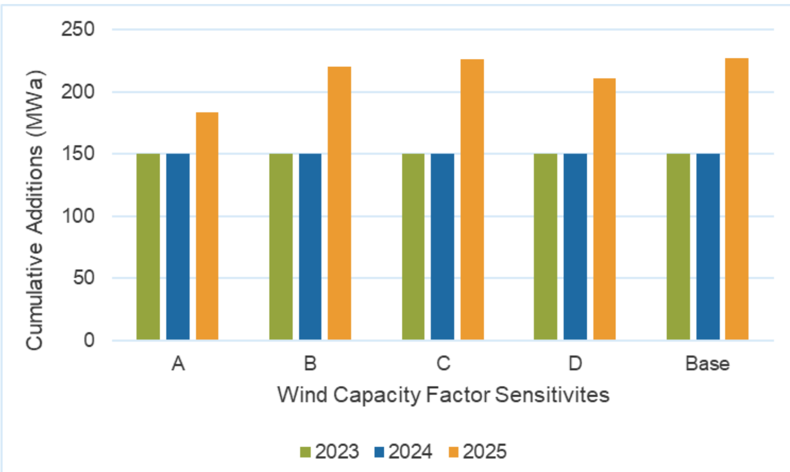
[65] LC 73 Opening Comments of AWEC at 8, Footnote 7.
[66] LC 73 Opening Comments of Staff at 34.
[67] The methodology used to create renewable shapes is available in External Study D of the 2019 IRP. Characterizations of Supply Side Resources.
[68] The associated capacity contribution values (ELCCs) were adjusted downward as well. However, rather than rerunning the RECAP model 40 times to estimate new ELCCs associated (10 x 100 MW addition under each four capacity factor sensitivities), PGE used a heuristic which modeled the ELCC decrement as a proportional decrease to that found in other internal resource analysis. While this method does not provide as exact results, PGE feels that given the lack of movement of the results, this heuristic is appropriate.

Table 2: Capacity factor sensitivity proportional reductions

Proxy Wind Resource	HDR Capacity Factors	Wind CF Sensitivities A	B	C	D
Montana	43%	32%	34%	36%	38%
SE WA	43%	32%	34%	36%	38%
Gorge	41%	30%	32%	34%	36%
Ione	33%	24%	26%	27%	29%

The results from the capacity factor sensitivity suggests the renewable resource addition made in 2023 and 2024 in the preferred portfolio are robust and do not change based on significant differences in capacity factors. As shown below in **Figure** , the cumulative size of MWa additions in these years remain consistent across capacity factor sensitivities.

Figure 9: Preferred portfolio composition in changing wind capacity factor sensitivities (MWa)



For reference, the preferred portfolio is based on a common set of themes that emerged from the best performing portfolios. Further, the preferred portfolio's RPS addition constraint is set to a maximum of 150 MWa cumulative additions for 2023 and 2024, however, the minimum is set to zero. In both the Reference Case and this capacity factor sensitivity, if ROSE-E selects resources to add for the preferred portfolio, it does so because they minimize NPVRR. This supports the conclusion that the renewable action proposed from this IRP is a reasonable method to reduce long-term costs, and this action is robust to reduced capacity factors from wind resources.

There are changes in both cost and risk associated with decreased capacity factors; however, the cost savings associated with near term Renewable Action are tangible relative to the Delay Renewables portfolio. This is displayed below in **Table 3**, which compares the preferred portfolio with the Delay Renewables portfolio.

Table 3: Wind capacity factor sensitivity

	Wind Capacity Factor Sensitivity				
Cost, $ millions	**A**	**B**	**C**	**D**	**Base Case**
Mixed Full Clean	27,070	26,762	26,551	26,191	25,740
Delay Renewables	27,740	27,527	27,311	27,084	26,625
Difference	-670	-765	-761	-893	-885
Variability, $ millions					
Mixed Full Clean	4,163	4,047	3,937	3,839	3,614
Delay Renewables	4,266	4,173	4,096	4,015	3,835
Difference	-103	-126	-160	-176	-220
Severity, $ millions					
Mixed Full Clean	33,067	32,615	32,285	31,815	31,004
Delay Renewables	33,819	33,501	33,186	32,838	32,065
Difference	-752	-886	-901	-1,022	-1,061

3.6. Weighting Futures

Parties' Comments

Staff raised a concern that the method in which futures are modeled in ROSE-E are inappropriately weighted equally stating, "For example, a future with a high WECC renewable buildout and high hydro generation may increase the likelihood of lower natural gas prices due to lower demand. Similarly, a future with a high carbon price would likely incentivize more renewable energy, resulting in a higher WECC Renewable buildout."[69]

PGE's Response

For reference, PGE's resource optimization tool ROSE-E evaluates portfolio performance over 810 futures, which are comprised of different combinations of need, price, and technology cost trajectories.[70] The design of ROSE-E provides two methods of changing the relative weights associated with the futures considered, in either changing weights in its optimization or in the scoring of portfolios after the model runs. In optimization, a user can instruct ROSE-E to optimize portfolios on different likelihoods of those trajectories (for example, making the likelihood for the reference, high, and low need futures to be weighted heavier towards the low need).[71] For portfolio analysis in the 2019 IRP, these future trajectories are given equal weights, except in the case of some optimized portfolios (that give 100% probability to the Reference Case, and 0% to the high, low, and alternative technology cost cases). In scoring, portfolios are evaluated over the individual futures, and each 810 futures are given an equal probability of occurring.

In its comments, Staff refers to the possibility of raising and lowering these assigned probabilities of individual futures in scoring. PGE clarifies that as currently calculated, a change in weighting of the

[69] LC 73 Opening Comments of Staff at 11-12.
[70] Please refer to IRP at 85, Table 3.4, for more details.
[71] Please refer to Appendix I.6 – ROSE-E – PGE's Optimization Tool for more detail.

futures in scoring would only affect the traditional metrics of variability and severity, as both metrics rely on the distribution of NPVRR estimates across each of the 810 futures. Neither the cost metric nor any non-traditional metric is changed by a different weighting of these futures, as these metrics rely on single futures, either the reference or one of specific interest.

PGE believes the reference trajectory of the price, need, and technology cost futures is the most likely. To test whether in optimization a focus on the Reference Case would make tangible changes, a sensitivity of the Mixed Full Clean and Delay Renewables was created. Here the Reference Case price, need, and technology cost futures were given 100 percent probabilities in portfolio optimization. The results of this sensitivity are presented below in **Table 4**, and demonstrate that ROSE-E does not make tangible differences in cost or risk in either portfolio when optimizing on the most likely scenario.

Table 4: Preferred and Delay Renewables portfolios optimized on Reference Case

Cost, millions $	Base Case – Optimized with Equal Weights Across Futures	Sensitivity – Optimized for the Reference Case
Mixed Full Clean	25,740	25,739
Delay Renewables	26,625	26,625
Difference	-885	-886
Variability		
Mixed Full Clean	3,614	3,621
Delay Renewables	3,835	3,835
Difference	-220	-213
Severity		
Mixed Full Clean	31,004	31,012
Delay Renewables	32,065	32,065
Difference	-1,061	-1,053

In considering Staff's concern about the likelihood of specific futures, PGE notes that it is not evident that the two futures that Staff mentions point to any clear direction of likelihood. In the former, Staff highlights natural gas, a globally traded commodity. There could be much larger drivers of natural gas prices that could counteract any regional influence, and that could push prices in the opposite direction than Staff supposes. For the latter, while carbon prices are forecasted to impact California, Oregon, and Washington, the WECC-wide renewable build-out covers many more states. Accordingly, it is plausible that even in a future of higher carbon prices, the WECC, as a whole, does not see the scale of renewable build-out envisioned in that future. It is also possible that high renewable buildout across the West is driven by policies or market factors other than carbon pricing.

These examples are raised to highlight that there are few clear sets of futures to which all stakeholders would agree. Throughout the IRP process, PGE has worked with Staff and stakeholders to develop appropriate bounds of future estimates. PGE will continue to do so to determine whether any potential sensitivities could be useful for furthering our understanding of portfolio performance.

3.7. Capacity Fill Resource

Parties' Comments

In discussing the introduction of the Capacity Fill resource in the 2019 IRP, Staff recognized the potential value of the Capacity Fill resource for the consideration of risk and optionality but recommended that PGE provide additional justification for the costs attributed to and the constraints imposed upon the Capacity Fill resource in PGE's portfolio analysis.[72]

PGE's Response

PGE appreciates the discussion of the Capacity Fill resource in Staff's opening comments, as this is a new construct within the 2019 IRP portfolio analysis. The introduction of the Capacity Fill resource achieves two objectives. First, it provides for a fair cost comparison across portfolios without technological specificity on capacity additions in the outer years when there is significant uncertainty in the cost and performance of battery storage as well as the availability of new customer-side resources and other technologies that could help to avoid the need for new thermal resources. Second, it allows the portfolio analysis the flexibility to meet a portion of near-term capacity needs with something other than new resources, for example capacity contracts, without assuming that those alternative resources could be acquired at zero cost. This flexibility was introduced in response to feedback in the 2016 IRP process, where PGE originally filed the IRP with a preferred portfolio that filled all identified capacity needs through 2021 with new resources but was ultimately able to largely meet capacity needs with contracts through bilateral negotiations.

The near-term constraint on the Capacity Fill resource is applied across all portfolios to achieve this flexibility in a consistent manner and to allow for fair comparison based on cost, but it is not intended as a prescriptive limit on, or target for, the capacity that could be achieved through bilateral negotiations. It would be speculative to assert the quantity of cost-competitive capacity that PGE could acquire from potential counterparties in the region. It would also be speculative to assert the cost and performance specifications of these resources within the IRP. In bilateral negotiations, cost, performance specifications, and volume are negotiated on an individual basis with each counterparty and reflect not only PGE's needs and preferences, but also those of each individual counterparty. Nevertheless, when contracts may contribute a large quantity of capacity to the portfolio, PGE finds value in testing portfolios that presume some amount of capacity needs could be filled with such contracts.

As a proxy for the share of PGE's capacity needs that could be met without new resource development in portfolio analysis, PGE allows the Capacity Fill resource to be selected in the near-term up to the amount of capacity associated with the expiration of contracts during that period. In other words, new resource additions in the portfolios must provide only enough capacity to meet the portion of PGE's capacity needs that are not driven by contract expirations. It is important to differentiate between this modeling constraint and PGE's Action Plan, which does not constrain the portion of capacity needs that could be met through the bilateral negotiation process in either the upward or

[72] LC 73 Opening Comments of Staff at 38-39.

downward direction. PGE set no minimum level of capacity to secure through bilateral negotiations because the Company has no way to guarantee that cost-competitive capacity will be available at any given volume, and PGE set no maximum to allow for the flexibility to pursue all cost-competitive options that are available and meet PGE's needs.

Regarding price, PGE makes no assertion that the cost of the Capacity Fill resource accurately reflects the cost of capacity that could result from bilateral negotiations. As described in Section 7.1.1.1 of the 2019 IRP, the cost of the Capacity Fill resource represents the net cost of providing capacity with the lowest cost capacity resource option in the Reference Case, the proxy simple-cycle combustion turbine (SCCT). This "net cost of new entry" or "Net CONE" is the expected cost of capacity at long-run equilibrium in a system that is capacity constrained. It would be speculative to assert that this cost would necessarily align to the cost of potential capacity contract options. However, in theory, the long-run cost of capacity associated with cost competitive existing resources should not exceed the Net CONE; otherwise, it would be more economical to build a new capacity resource. Accordingly, the cost of the Capacity Fill resource can be considered a theoretical upper bound on the long-run cost of capacity secured via bilateral negotiations.

Actual prices for resources available in the market could, however, exceed this price for a number of reasons including: a desire on the part of potential counterparties to recover a larger portion of the costs associated with a facility through a fixed charge versus a variable charge; or a belief by potential counterparties that new resource additions at the net cost of new entry are not feasible alternatives for the utility. Under such a circumstance, PGE retains the ability to not execute on a contract if the proposed terms are not cost competitive for customers. PGE can only determine the volume, performance specifications, and price of capacity from existing resources by conducting a solicitation for available capacity resources.

3.8. Colstrip

Parties' Comments

Staff requested that PGE perform additional analysis and provide updated information related to Colstrip. Staff suggested inclusion of the following: rate impact analysis of advancing depreciation of Units 3 and 4 to 2027; information that explains the increase in the variability metric in Colstrip Sensitivity A; a summary of activities related to negotiating an early exit date from Colstrip; and updated analysis of any updated information on variable costs.[73]

Additionally, both NWEC and RNW encouraged PGE to continue to evaluate actions related to Colstrip.[74, 75]

[73] *Id.* at 15-16.
[74] LC 73 Opening Comments of RNW at 11.
[75] LC 73 Opening Comments of NWEC at 7.

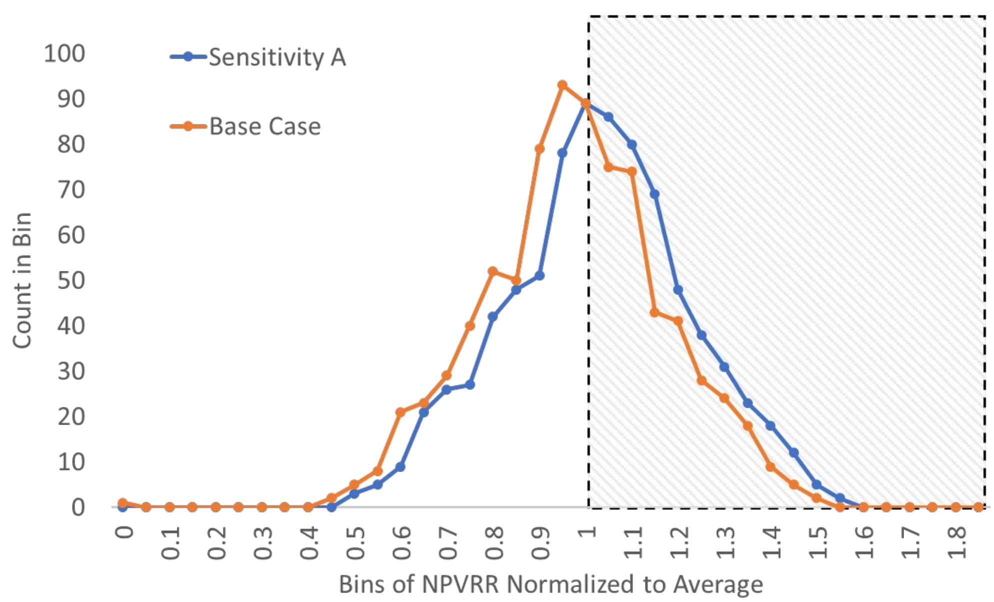
PGE's Response

PGE agrees that it is appropriate to continue to evaluate Colstrip within the IRP processes as more information becomes available. At this time, the near-term uncertainties pertaining to Colstrip that are described in Section 7.4.2 of the IRP remain. PGE commits to updating the Commission regarding the Colstrip sensitivity analysis when additional information becomes available.

In response to Staff's question regarding the variability metric in the Colstrip sensitivity analysis, PGE provides the following additional information. Under Sensitivity A in which Colstrip is fully depreciated and exits PGE's portfolio by the end of 2027, the energy and capacity required as a result of Colstrip's exit from 2028 to 2034 is solved for by the portfolio optimization.

Figure 9 below depicts histograms that show the distribution of NPVRR normalized to the average over all price futures for the Base Case and for Sensitivity A. Normalizing the NPVRR to the average for Sensitivity A and Base Case allow comparison of the NPVRR distributions. Since Sensitivity A results in additional years of market exposure relative to the non-Sensitivity future, Sensitivity A's corresponding normalized NPVRR distribution is shifted to the right relative to the Base Case and has a larger upper tail. This shift is reflected in the variability portfolio metric, which is the semi-deviation of NPVRR through 2050 across futures, relative to the Base Case. The variability metric is slightly higher for Sensitivity A compared to the Base Case as seen in Table 7-10 of the 2019 IRP.

Figure 9: Histogram describing distribution of NPVRR normalized to average for Base Case and Colstrip Sensitivity A



4. Needs Assessment

In this section, PGE addresses the comments from stakeholders regarding the load forecast, electric vehicles, energy efficiency, the need assessments, and the need sensitivities. PGE appreciates the thoughtful feedback provided by stakeholders.

As in previous IRPs, PGE periodically updates its need assessments to capture more recent load forecasts and updated contract and resource information. PGE is preparing updated assessments and sensitivities that the Company plans to share with stakeholders at the November 21 public Roundtable meeting and will also provide the update in this docket in November 2019.

4.1. Econometric Load Forecast

Parties' Comments

Staff and CUB raised concerns about the accuracy of PGE's system-level econometric load forecast. CUB's comments focused on the industrial sector within the system load forecast,[76] and Staff noted a concern about the accuracy of the commercial and industrial sector forecasts.[77]

CUB stated its concern about "possible overestimation" of the industrial sector's load growth rate[78] is based on four observations: (1) projections of customers opting out of cost-of-service through the NLDA program and/or an increased cap on the LTDA program (discussed in **Section 4.7**);[79] (2) treatment of Green Tariff subscriptions (also discussed in **Section 4.8**);[80] (3) potential for energy efficiency in data centers (discussed in **Section 4.3**);[81] and (4) consideration of alternate economic drivers.[82]

On behalf of AWEC, Mr. Mullins commented on the level of growth in the industrial sector. As discussed below, Mr. Mullins misstated the level of growth in PGE's industrial sector forecast for the net system load from 2020 to 2025 as 150 MWa[83] rather than 58 MWa, 67 MWa, or 77 MWa, as is forecasted for the low, reference, and high need cases,[84] respectively. AWEC also stated a concern that potential NLDA should be removed from the forecast, and this concern is discussed in **Section 4.7**.

RNW expressed support of PGE's load forecasting approach and the reasonableness of embedded assumptions.[85]

[76] LC 73 Opening Comments of CUB at 2-11.
[77] LC 73 Opening Comments of Staff at 21.
[78] LC 73 Opening Comments of CUB at 2.
[79] *Id*. at 4-5.
[80] *Id.* at 5-6.
[81] *Id.* at 6-8.
[82] *Id.* at 8-9.
[83] LC 73 Opening Comments of AWEC at 25.
[84] 2019 IRP at 270-273.
[85] LC 73 Opening Comments of RNW at 3-4.

PGE's Response

PGE appreciates parties' emphasis on the importance of the load forecast within the assessment of system need. PGE has made significant refinements to its forecasting models over the past several years. These improvements include developing econometric models to establish long-term sector-level growth rates, shortening the historical period of data used to build the long-term models, refining model structures including different handling of non-stationarity, testing alternate economic drivers, testing weather sensitivity, adding additional and more formal model evaluation processes including out-of-sample testing, building a use-per-customer model for residential sector long-term forecast, and developing a probabilistic load forecasting approach to creating its high and low need scenarios.

PGE's econometric load forecast has been performing well, particularly in recent years. PGE participates in Itron's utility benchmarking survey and tracks its performance compared to this benchmark. The survey demonstrates PGE's forecast performs well within the bounds of industry normal variance and frequently outperforms peers. Survey results, reflecting the year-ahead forecast compared to weather-normalized actuals, are shown in **Table 5** below.

Table 5: Comparison of PGE Forecast Error to Industry Benchmark

	2015	2016	2017	2018
Industry Benchmark Mean Absolute Percentage Error				
Residential	1.9%	1.7%	1.4%	1.8%
Commercial	1.6%	1.8%	1.3%	2.0%
Industrial	3.0%	3.3%	2.3%	1.9%
System	1.9%	1.6%	1.1%	1.3%
PGE Percentage Error				
Residential	1.5%	0.1%	-1.3%	-0.5%
Commercial	0.8%	-2.0%	0.3%	1.1%
Industrial	2.8%	-2.7%	2.0%	0.7%
System	1.5%	-1.4%	0.0%	0.4%

CUB pointed to a 2016 Lawrence Berkley National Lab (LBNL) study[86] to demonstrate issues in PGE's past load forecasts. As discussed in PGE's Reply Comments in LC 66 2016 IRP, the LBNL study is a flawed comparative analysis, because it used incorrect PGE data resulting in inappropriate comparisons,[87] it does not normalize loads for weather (IRP load forecasts do not attempt to forecast weather and weather variability is expected), and it focuses on data from an unusually extreme

[86] Juan Pablo Carvallo, Peter H. Larsen, Alan H. Sanstad, Charles A. Goldman, October 2016, "Load forecasting in Electric Utility Integrated Resource Planning" (LBNL-1006395), Energy Analysis and Environmental Impacts Division, Ernest Orlando Lawrence Berkeley National Laboratory.

[87] LBNL's Table 13 reproduced in CUB's comments presents incorrect actual (non-weather adjusted) average annual growth rates for PGE's system. Correct actual (non-weather adjusted) average annual growth rates for the periods of 2007-2014, 2010-2014, and 2012-2014 are -0.3%, 0.6%, and 0.4%, respectively. Other tables in LBNL's report also present incorrect PGE data.

business cycle (the period 2007-2014) encompassing both the Great Recession and the historically slow economic recovery.

CUB also recommended PGE "separate out the industrial load from the total load forecast and conduct specific risk analyses."[88] PGE has recognized the industrial sector as the most volatile sector of the load forecast, and PGE's forecast analysis assessed uncertainty individually for the residential, commercial, and industrial sectors. Therefore, PGE believes that the information requested by CUB is already included in the analysis. The confidence bounds surrounding the industrial load forecast was presented at two workshops in 2018.[89]

With respect to CUB's interest in how the Green Tariff program impacts the industrial sector load forecast, PGE clarifies that the Green Tariff program impacts long-term planning by bringing new renewable generation resources to PGE's system, not by reducing demand. Green Tariff-enrolled load will continue to be represented in the load forecast (Green Tariff subscribers remain cost-of-service customers), and the energy and capacity provided to PGE's system by these future Green Tariff resources are included in the need analysis. Refer to **Section 4.8** for further discussion of the Green Tariff program and its impact on need.

CUB and AWEC expressed concern that PGE uses US Gross Domestic Product (GDP) as a driver of industrial load. PGE explored several alternative economic drivers for its industrial load forecast and discussed considerations for these alternate drivers in its May 2018 workshop.[90] US GDP is an indicator with a reliable long-term history and available third-party long-term forecasts, two requirements to driver selection, and it was selected based on those attributes as well as its relative statistical significance in the industrial forecast model.

4.2. Electric Vehicle Forecast

Parties' Comments

In Recommendation 12, Staff requested information on the electric vehicle (EV) population assumed to be included in the classification of light-duty vehicles (LDV) in the Navigant DER Study, noting a concern that the analysis may have overestimated EV load by stratifying the forecast for vans and trucks with an equal weighting as smaller sedans.[91] In Section 5 of their comments, NWEC expressed concern that PGE may have underestimated EV load by only accounting for LDVs in the adoption forecast, thereby excluding load from medium- and heavy-duty vehicles (M/HDV).[92] NWEC also

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[88] LC 73 Opening Comments of CUB at 9.

[89] See presentations at https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2018-05-16-irp-roundtable-18-2.pdf?la=en, slide 44, and https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2018-10-31-irp-roundtable-18-5.pdf?la=en, slide 60.

[90] See presentation https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2018-05-16-irp-roundtable-18-2.pdf?la=en, slide 25.

[91] LC 73 Opening Comments of Staff at 22-23.

[92] LC 73 Opening Comments of NWEC at 5-6.

requested further information on the assumptions of growth trajectory, energy consumption, and available demand response (DR) related to EVs.[93]

PGE's Response

EV Market Details

PGE appreciates Staff's request for clarity on the modeling inputs to the LDV forecast. Navigant forecasted LDV new vehicle sales for all powertrains (PHEV, BEV, ICEV) using the Vehicle Adoption Simulation Tool (VAST™). VAST™ is an enhanced Bass Diffusion model, where the long run market equilibrium sales are determined by the economics of the competing powertrains within a vehicle class, conditioned on the availability of that vehicle class in the relevant powertrain. The approach to the long-run equilibrium sales is determined by coefficients on the word of mouth and marketing parameters in the Bass Diffusion model to simulate consumer preferences and awareness. These coefficients were calibrated to historical data on new vehicle sales and vehicle registrations in Oregon at the zip code level. Short-run (five to ten year) model availability projections were derived from press-releases and long-run availability was derived from the combined trajectory of historic new model releases, a five-year development cycle, and short-run projections. The resulting LDV population reflected existing and anticipated market conditions in the PGE service area, which aligns with the characterization of the EV market noted by Staff for Recommendation 12.[94]

PGE acknowledges concerns expressed by NWEC on the exclusion of M/HDV from the EV forecast in the IRP.[95] The outlook for larger vehicles is more uncertain than for LDV due to a slower relative pace of technology development and a lower market sales potential. While the 2019 IRP does not contain forecasts for medium or heavy-duty electric vehicles, it does include a scenario of high light-duty vehicle adoption, which comprises an increase of approximately 70% energy consumption from EV load by 2050 in comparison to the Reference LDV forecast. In future IRP cycles, PGE will continue to refine the EV forecasts used in long-term planning.

Regarding NWEC's inquiry on the market share of plug-in electric vehicles (PEV) in the LDV forecast,[96] Navigant's model accounts for various market drivers and technology futures in the long-term. Observed market share of BEV during early stages of development may not be indicative of longer-term trends.

PGE appreciates the feedback and interest from stakeholders and recognizes that this market is in early development. PGE looks forward to working with stakeholders in future planning cycles to continue to refine the development of the EV forecasts.

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[93] LC 73 Opening Comments of NWEC at 5.
[94] LC 73 Opening Comments of Staff at 23.
[95] LC 73 Opening Comments of NWEC at 5-6.
[96] *Id.* at 5.

EV-Grid Interaction

In response to NWEC request,[97] Navigant's assumptions of energy consumption per vehicle were as follows:

- Individual BEV: 3.72 MWh/year
- Individual PHEV: 1.90 MWh/year
- Fleet BEV: 6.47 MWh/year
- Fleet PHEV: 3.29 MWh/year

PGE shares NWEC's interest in further investigating options for LDV participation in demand response.[98] In the 2019 IRP, PGE included analytical advancements in forecasting and modeling direct load control for LDVs. We are actively analyzing potential programs through the DR Testbeds and Transportation Electrification plans and will continue to include new developments in EV-grid capabilities in future IRPs.

4.3. Energy Efficiency

Parties' Comments

Staff expressed concern that the High Need Future did not include increased assumptions for energy efficiency and Staff stated an intent "to work with PGE and ETO to see if there are opportunities to apply more appropriate input selection for energy efficiency, and potentially for other demand-side and load forecast inputs to scenarios."[99]

CUB provided comments regarding energy efficiency specifically related to data centers and recommended that energy efficiency savings for data centers be examined in future IRPs.[100]

In addition to comments regarding the Customer Resource Action that are addressed in **Section 2.1**, NWEC noted that "while we recognize that some work has been done to try to capture the capacity value of energy efficiency resource acquisition, we encourage PGE to work with the Energy Trust to further refine this methodology."[101]

PGE's Response

PGE agrees with Staff's concern that some of the same drivers that could create an increase in load in a High Need Future may also lead to the opportunity to acquire increased energy efficiency savings. However, in constructing the High and Low Need Futures, PGE sought to create wide sensitivities to the Reference Case by varying drivers in the same direction of impact on need. As PGE developed the Need Futures, the assumptions were shared in the public roundtable process and PGE received

[97] *Id*.
[98] *Id*.
[99] LC 73 Opening Comments of Staff at 22.
[100] LC 73 Opening Comments of CUB at 7-8.
[101] LC 73 Opening Comments of NWEC at 3.

positive feedback from stakeholders. A description of the drivers of the Need Futures is provided in Section 3.1 of the 2019 IRP.

PGE continues to support the treatment of drivers in the Need Futures as appropriate for this examination of uncertainty and notes that if PGE increased the forecast for energy efficiency savings and demand response in the High Need Future and decreased the forecasts for these resources in the Low Need Future, the result would be sensitivities that are both closer to the Reference Case.

PGE appreciates NWEC's comments regarding the capacity value of energy efficiency. PGE notes that Energy Trust of Oregon's (Energy Trust) cost-effectiveness calculations for the forecast in the 2019 IRP did contain a component for capacity value.[102] Additionally, PGE has been working with Energy Trust, Staff, and stakeholders in Docket No. UM 1893 to improve the energy efficiency avoided cost inputs process, including improvements to the treatment of capacity value.

PGE appreciates CUB's comments with respect to energy efficiency opportunities for data center loads and agrees with the importance of evaluating new opportunities. Nevertheless, an in-depth energy efficiency analysis in the IRP specifically for data centers is not necessary. Some energy efficiency measures discussed in the Northwest Power and Conservation Council's Seventh Plan[103] referenced by CUB are now considered normal course of business, and others are considered by the Energy Trust, for example through its New Building program, which has a specific application for data centers.[104]

The Energy Trust has recently reached out to PGE with updated information regarding their forecast for savings acquisitions for 2020 through 2022. The forecast has declined due in part to the success of past programs and lighting market transformation. As seen in **Table 6**, the cumulative reduction in savings is approximately 14.7 MWa by year-end 2022. PGE will coordinate with Energy Trust to understand the details of the updated forecast and implications for the forecast after 2022.

Table 6. Forecasts of annual energy efficiency acquisitions, MWa at the busbar

	2020	2021	2022
2019 IRP Forecast	30.4	29.5	28.3
Updated Forecast	27.5	23.4	22.6

[102] Energy Trust Avoided Costs, https://www.energytrust.org/wp-content/uploads/2018/01/Energy-Trust-Avoided-Cost-Update-for-Oregon-2018.pdf.
[103] Seventh Northwest Conservation and Electric Power Plan at 54, Appendix E.
[104] Energy Trust Data Center New Building application with list of energy efficiency measures to be considered: https://www.energytrust.org/wp-content/uploads/2016/10/NBE_FM0520DC.pdf.

4.4. Capacity Need

Parties' Comments

Staff noted the thoroughness of the capacity need assessment and expressed appreciation for the analysis of need with and without contract expirations and for the modeling of demand response.[105] Staff expressed concern about the timing of PGE's capacity need in relation to the upcoming regional adequacy challenges[106] and that not all demand response was included in the capacity assessment, noting: "PGE reports that RECAP is not capable of modeling some types of demand response."[107] Regarding the examination of expiring capacity contracts, Staff stated that they are "…concerned that there is not sufficient analysis on the probability of capacity contract renewal or non-renewal; they are all equally weighted probabilities."[108]

NWEC mentioned the importance of considering resource adequacy from a portfolio perspective and the importance of the role of demand side resources.[109] NWEC noted that "further work is needed to incorporate these fully into the resource adequacy context," and that they consider the achievable potential for energy efficiency and distributed flexibility to be larger than the IRP Reference Case.[110]

RNW commented on the uncertainty captured by the three Need Futures and noted that they found the capacity need to be reasonable.[111]

AWEC noted three issues which they believe leads to the overestimation of capacity need: the treatment of the Green Tariff program, the assumptions regarding expiring contracts, and the treatment of market capacity.[112] AWEC provided comments and analysis from Mr. Mullins examining the capacity need.

Swan Lake commented that "PGE's overall approach of presenting a range of potential capacity needs is meritorious and appropriate, and the Low Need and High Need Futures appear to generally provide a reasonable range of uncertainty around the Reference Case."[113] However, Swan Lake expressed concern that "the Reference Case appears to be overly conservative, underestimating PGE's future capacity need."[114]

Several parties expressed concerns about upcoming regional adequacy challenges, including Staff,[115] NIPPC,[116] and Swan Lake.[117]

[105] LC 73 Opening Comments of Staff at 24.
[106] *Id*.
[107] *Id.* at 45-46.
[108] *Id.* at 24.
[109] LC 73 Opening Comments from NWEC at 6.
[110] *Id*.
[111] LC 73 Opening Comments of RNW at 3-4.
[112] LC 73 Opening Comments of AWEC at 8.
[113] LC 73 Opening Comments of Swan Lake at 3.
[114] *Id. at* 3-4.
[115] LC 73 Opening Comments of Staff at 24.
[116] LC 73 Opening Comments of NIPPC at 22.
[117] LC 73 Opening Comments of Swan Lake at 18.

Comments from parties regarding capacity need and the following topics are addressed in the following sections: **Section 4.8. Green Tariff Program**, **Section 4.7 Direct Access**, **Section 4.9. PURPA Qualifying Facilities** , and **Section 4.10. Regional Markets** (EIM).

PGE's Response

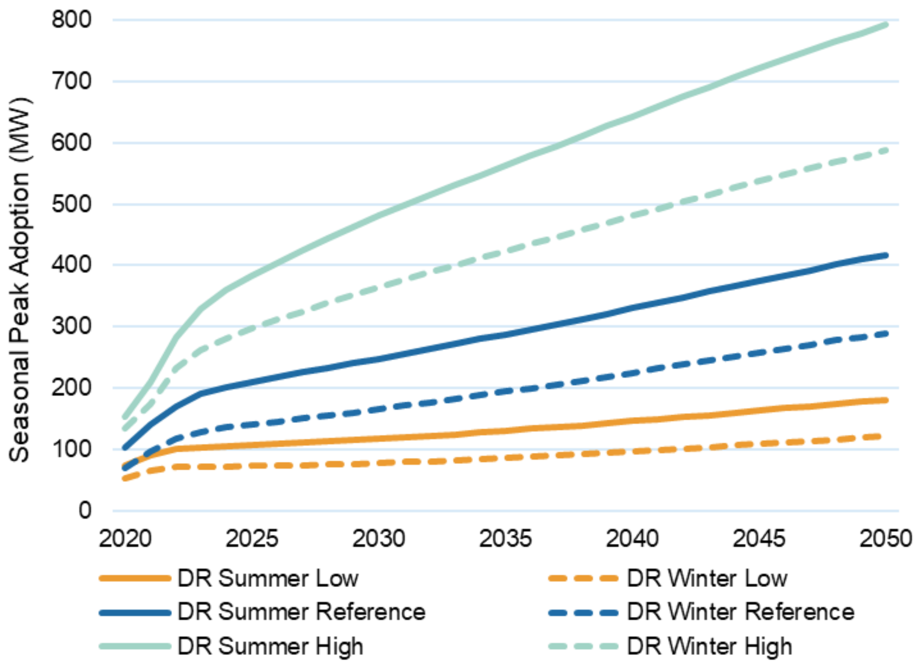
PGE appreciates parties' comments regarding capacity need and addresses these issues in four subsections below: Distributed Energy Resources, Bilateral Contracts, Regional Adequacy, and Modeling. As noted above, other related topics are addressed in their respective sections.

Distributed Energy Resources

PGE appreciates Staff and NWEC's feedback regarding DERs and capacity need. While the 2019 IRP contains significant progress for the treatment of DER compared to the 2016 IRP, PGE looks forward to making additional refinements in future IRPs. PGE will continue to build on the progress made in this IRP and anticipates that learnings from the Test Bed and DRP process will inform forecasts and program characterizations in capacity modeling in future IRP cycles. Additional discussion about DERs beyond the capacity related comments is provided in **Section 5.7**.

PGE recognizes the uncertainty in the DER forecast and included low and high forecasts to account for a range of potential customer adoption scenarios. The scenario for high adoption of DERs includes additional energy efficiency savings based on the Energy Trust's achievable deployable forecast and additional demand response based on the high adoption scenario from Navigant. **Figure 10** shows the substantial increase in demand response captured in the high scenario (depicted in the green line in **Figure 10**). Importantly, as discussed in **Section 2.1**, PGE's Action Plan includes acquisition of all cost-effective and reasonable distributed flexibility that customers choose to provide. If demand-side resources grow at a faster rate than forecasted in PGE's Reference Case, the staged Capacity Action provides the flexibility to adapt to this scenario.

Figure 10. Seasonal Demand Response Adoption Scenarios



PGE clarifies that the capacity need assessment does capture all the demand response programs included in the Navigant Study. Staff and NWEC expressed concern about this in their comments and PGE provides the following clarification.

The beginning of Section 4.3.1.1 of the 2019 IRP states: "In the 2016 IRP, PGE modeled all demand response resources in RECAP with two simplified seasonal profiles. The analysis did not contain explicit forecasts of adoption of distributed PV or electric vehicles."[118] To clarify, the second sentence is referring to the 2016 IRP, not the 2019 IRP. The 2019 IRP capacity modeling does include forecasts for the adoption of distributed PV and light-duty electric vehicles.

In the second paragraph of Section 4.3.1.1 of the 2019 IRP, PGE states: "The modeling in this IRP captures many of these characteristics, but in some cases, simplifications were necessary due to limited information or constraints of the RECAP model. PGE anticipates that continued development of the modeling of these resources will be a focus of the next IRP cycle." PGE clarifies that the capacity assessment includes all the demand response from the Navigant Study (including direct load control of light-duty EVs). The referenced simplification was to the treatment of complex characteristics of the demand response programs.

PGE apologizes for any confusion caused by the wording of the text in the 2019 IRP.

Bilateral Contracts

In the 2019 IRP, PGE notes that the Company has a large quantity of bilateral contracts expiring from 2024 through the end of 2025. PGE does not have renewal rights to these contracts and has indicated

[118] 2019 IRP at 104.

that the ability to renew or replace them with competitively priced contracts for existing resources is uncertain.

As Staff mentioned, PGE provided an analysis in the 2019 IRP of the potential impact to capacity need if the expiring contracts were to be replaced by other contracts on a one-to-one basis. PGE, however, did not assign equal probabilities to replacing and not replacing these contracts. The identified capacity need reflects PGE's portfolio, including the impact of contract expirations. It does not assume a 50 percent probability of renewal. Instead, to allow for the potential to secure additional bilateral contracts while acknowledging the uncertainty of the outcome of that process, PGE has proposed a staged Capacity Action that seeks to first acquire capacity from existing resources before holding an RFP for capacity resources. PGE believes this is a more meaningful method for addressing the uncertainty in the availability of existing resources than an exercise to attempt to estimate the probability of acquiring bilateral contracts. The Capacity Action is discussed **Section 2.3**.

PGE disagrees with AWEC's suggestion that the capacity need is overstated because PGE does not presume renewal of expiring contracts. Reducing the identified need based on the presumption of renewal would provide an inaccurate understanding of the portfolio's position and is an especially risky assumption given the region's forecasted resource adequacy challenges. As discussed above, PGE recommends a staged Capacity Action that begins with bilateral negotiations to secure cost-competitive existing resources. PGE considers this to be a more appropriate approach for addressing the potential to acquire existing resources than to assume renewal of expiring contracts.

Regional Resource Adequacy

PGE's 2019 IRP discussed the upcoming regional resource adequacy challenges and included a study from E3 that examines adequacy in the Pacific Northwest.[119] Since the E3 study was finalized, additional announcements have been made about plans for plant retirements. As noted above, the growing concern about regional adequacy was reflected in comments from multiple parties. PGE shares these concerns and has been actively engaged in regional resource adequacy conversations, including those surrounding a potential regional resource adequacy program. PGE notes that the lack of long-term planning requirements for Direct Access loads is a growing issue in the regional adequacy discussion and PGE provides additional comments specific to Direct Access in **Section 4.7**.

The resource adequacy of the Pacific Northwest impacts the assumption regarding market capacity in PGE's capacity assessment. The summer and winter on-peak assumptions for market capacity are based on recommendations provided by E3 in their study of the Pacific Northwest. The values decline year-over-year due to planned regional resource retirements and continued forecast of regional load growth. Uncertainty is addressed through low and high forecasts in addition to Reference. PGE provided the full confidential RECAP model in the Company's response to AWEC Data Request No. 003, which includes the input values for market capacity for each year for the Low, Reference, and High Need Futures. PGE appreciates that the modeling is complex but notes that in comments, AWEC

[119] 2019 IRP, External Study E. Market Capacity Study.

provides an inaccurate description of the Reference market capacity assumptions.[120] AWEC's description conflates approximate annual ELCC values with seasonal peak values.

PGE also disagrees with AWEC's suggestion that additional market capacity should be assumed based on PGE's transmission rights. Transmission rights, without a contract that assures availability of generation under constrained conditions, do not equate to a capacity resource. E3's study examined the Pacific Northwest resource position, including assumptions regarding imports. This provides a comprehensive assessment of market capacity, rather than the arbitrary value recommended by AWEC, which confuses import capability with assumptions of regional resource availability.[121]

Modeling

Staff indicated that they may have additional questions for PGE as they continue their analysis of RECAP.[122] PGE reached out to Staff regarding RECAP and looks forward to continued conversations as needed by Staff.

In Attachment B of AWEC's comments, Mr. Mullins produced a simplified load-resource balance spreadsheet calculation as an alternative proposal for assessing capacity need.[123] PGE noted several issues with the analysis, including: the energy efficiency savings values added by Mr. Mullins contain errors[124] and the savings are already accounted for in the load forecast;[125] the assumptions of bilateral contract executions and COB market capacity are unsupported; it contains an incorrect and duplicative adjustment for demand response; and the analysis contains an incorrect adjustment for New Load Direct Access, which is not included in the load forecast. Further, the spreadsheet analysis does not capture the complexity of the resource and load characterization contained in a loss-of-load probability model such as RECAP. As noted in Section G.1 of the 2019 IRP, Table G-1 (the table that Mr. Mullins began his calculations from), is provided informationally in the IRP as a simplified summary of the analysis from RECAP.

4.5. RPS Need

Parties' Comments

Staff, RNW, and AWEC commented on PGE's treatment of RPS need in the 2019 IRP, focusing on the method in which PGE is forecasting to meet its RPS obligations. Renewable Northwest expressed support for PGE's determination of need based on the amount of RECs forecasted to be generated in a given year (referred to as 'physical compliance' with RPS obligations), stating that "maintaining PGE's REC bank and meeting its RPS obligation through physical compliance is sound risk

[120] LC 73 Opening Comments of AWEC, at 4, Attachment B.
[121] *Id.* at 5, Attachment B.
[122] LC 73 Opening Comments of Staff at 24.
[123] LC 73 Opening Comments of AWEC, at 8, Attachment B.
[124] The 2023-2025 values are MWa at the meter. The values for the other years do not reflect the MWa or MW forecast and appear to be extrapolated from the 2023-2025 MWa values.
[125] 2019 IRP, at 287, Section G.1, third bullet point.

management."[126] AWEC expressed concerns over this methodology, and continues to recommend that the Commission "require PGE to forecast the purchase of unbundled RECs when analyzing the need for a new RPS purchase."[127] Staff highlighted two concerns from the use of physical compliance: the potential savings associated with retiring 20 percent unbundled RECs and the use of unused (or 'banked') RECs for RPS compliance.[128] Staff stated in Recommendation 7 "PGE must model 20 percent unbundled RECs in RPS compliance in all portfolios."[129] Further, Staff requested that PGE run its preferred and select group of other portfolios while "allowing the model to choose a reasonable number of banked RECs."[130]

AWEC disagreed with the treatment of RECs forecast to be generated by Wheatridge prior to 2025 and those forecast to be produced after the completion of the Faraday Repowering Project.[131]

PGE's Response

PGE believes that when considering RPS need in long-term planning, requiring physical RPS compliance is the most appropriate method of aligning with the policy objectives of SB 1547. However, in responding to Parties' comments, PGE looked further into its treatment of RPS need in the IRP. Specifically, PGE investigated whether the treatment of physical compliance and future unbundled REC purchases affect portfolio composition and performance. Results strongly suggest that RPS need and PGE's treatment of banked and unbundled RECs is not driving portfolio composition or performance, especially regarding near-term renewable additions.

PGE further clarifies that ROSE-E currently allows the retirement of RECs in its bank for each portfolio. However, as a practical matter, PGE understands that enforcing the physical RPS constraint means that retirement of banked RECs is not required in any year for RPS compliance.

To investigate the treatment of RPS need, PGE ran a sensitivity (RPS Sensitivity A) that tested a future where portfolios were able to meet 20 percent of their RPS obligations with zero-cost unbundled RECs.[132] This simplification leads to an overestimation of the value provided by unbundled RECs. Further, in this sensitivity, the physical RPS constraint was removed, allowing for RPS compliance to be achieved in years in which RPS obligations exceeds generated RECs if adequate volumes of banked RECs are available.

The results, displayed in **Table 7**, show very little difference in portfolio cost or risk. While there are differences in both resource decisions and costs, in the Reference Case, each of the three portfolios

[126] LC 73 Opening Comments of RNW at 5.
[127] LC 73 Opening Comments of AWEC at 4.
[128] LC 73 Opening Comments of Staff at 12.
[129] LC 73 Opening Comments of Staff at 14.
[130] LC 73 Opening Comments of Staff at 14.
[131] LC 73 Opening Comments of AWEC at 5.
[132] This is done by simply reducing the RPS need by 20%.

procured the same sized resources in the same years as the original portfolio.[133] Further, the results of this RPS need sensitivity maintain the relationship between the near-term Renewable Action and delaying procurement; early renewable procurement is a more cost-effective option. This is highlighted also by the optimized Min Avg LT Cost portfolio, which achieves lower cost and risk by adding 1326 MW of wind in 2023.

Table 7: RPS Sensitivity – Meeting RPS Compliance with 20% Unbundled RECs

Cost, millions $	Base Case	RPS Sensitivity A
Mixed Full Clean	25,740	25,740
Delay Renewables	26,625	26,625
Difference	-885	-885
Variability, millions $		
Mixed Full Clean	3,614	3,706
Delay Renewables	3,835	3,865
Difference	-220	-159
Severity, millions $		
Mixed Full Clean	31,004	30,970
Delay Renewables	32,065	32,035
Difference	-1,061	-1,065

To test this point further, PGE ran a sensitivity (RPS Sensitivity B) without any RPS compliance obligations. **Figure 11** displays the composition of the preferred portfolio under reference and no RPS obligation scenarios, with only slight differences between them.

[133] Note that the Mixed Full Clean and Delay Renewables portfolios treat capacity options differently: alongside the Capacity Fill resource, the latter only allows 6-hour batteries, while the former also allows pumped storage and 2-, 4-hour batteries. This difference is consistent with the capacity additions available to Optimized and Renewable Size & Timing portfolios. Note also that the Mixed Full Clean portfolio allows for renewable additions in 2025 in addition to the near term addition.

Figure 11: Composition of Preferred Portfolio with no RPS obligation

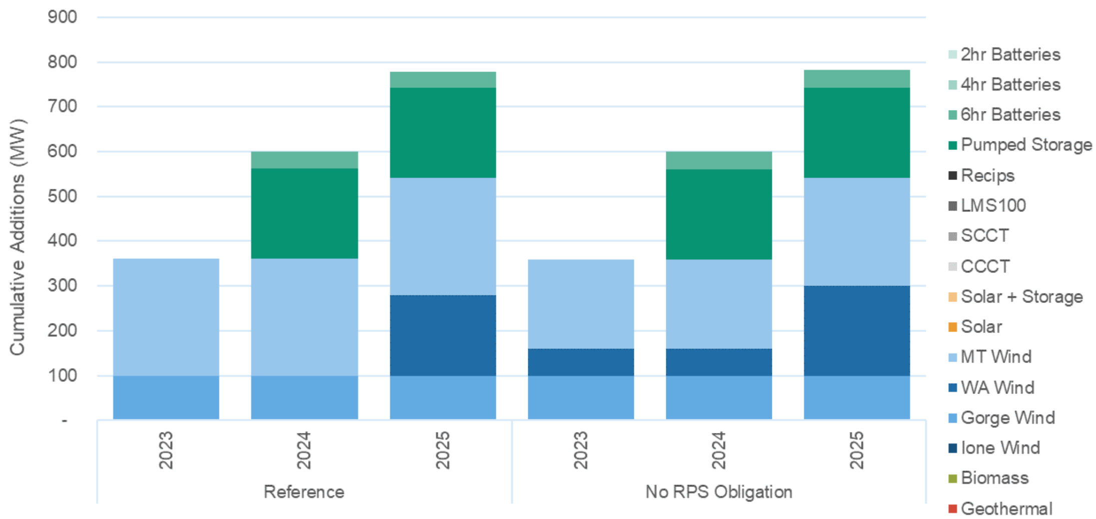


Table 8 displays the performance of the preferred and Delay Renewables portfolio. Under this scenario, the preferred portfolio with a near-term Renewable Action far outperforms the Delay Renewables portfolio in both cost and risk metrics.

Table 8: Portfolio cost and risk with no RPS obligation

Cost, millions $	Base Case	RPS Sensitivity B
Mixed Full Clean	25,740	25,744
Delay Renewables	26,625	27,051
Difference	-885	-1,308
Variability, millions $		
Mixed Full Clean	3,614	3,700
Delay Renewables	3,835	4,126
Difference	-220	-427
Severity, millions $		
Mixed Full Clean	31,004	30,968
Delay Renewables	32,065	32,734
Difference	-1,061	-1,766

In aggregate, these results show that RPS compliance is not driving early procurement of renewable resources and that PGE's findings with respect to the value of the near-term Renewable Action from the perspective of both cost and risk are unaffected by the assumptions that PGE made regarding banked and unbundled RECs.

PGE disagrees with AWEC's opinion that Wheatridge RECs generated prior to 2025 should be included in the forecast of RECs available for RPS compliance. In Order No. 18-044, the Commission directed PGE to return the value associated with these RECs to customers.[134] In alignment with this order, the

[134] Order No. 18-044 at 2.

2019 IRP analysis appropriately does not include these Wheatridge RECs in the RPS compliance forecast. The analysis does account for RECs generated by Wheatridge beginning in 2025.

Regarding the Faraday Repowering, PGE's estimate of whether the project would result in increased REC generation was not determined in time for the 2019 IRP need assessments. While the forecasted change to REC generation is small, this will be included in the updates to the need assessments that PGE plans to provide before December.

4.6. Energy Need

Parties' Comments

Parties offered differing opinions regarding PGE's energy need. RNW expressed support of PGE's analysis of energy need in terms of the energy market position and stated that "PGE presents a flexible and reasonable approach to energy need that again squares with the Commission's guidance on Order No. 17-386."[135] Staff, on the other hand, noted that they "would have serious concerns with portfolio modeling that bases its energy need on its market price forecast and resulting economic dispatch model."[136] Additionally, in Recommendation 13, Staff states: "In future IRPs, PGE should be careful not to imply that the Market Energy Position analysis represents an energy shortage or a need to acquire new resources."[137] Some parties expressed concern about how the proposed Renewable Action might impact the energy position given the potential for energy from resources for voluntary renewable programs.[138,139]

PGE's Response

PGE appreciates Staff concerns but notes that Staff's consideration of need without economic dispatch considerations more appropriately aligns with identifying capacity need. Energy need has historically, and in the 2019 IRP, been associated with assumptions regarding economic dispatch. The traditional energy load resource balance (energy LRB) was a simplified proxy which accounted for energy from resources that were traditionally considered baseload but excluded the potential energy from resources traditionally categorized as peaking resources, categories that may be less relevant under future market conditions (such as high renewables penetrations and carbon pricing). The energy LRB, for many IRPs, was the tool used to estimate energy need. The resource actions taken to fill portions of the identified energy need were taken to reduce customers' exposure to variability risks due to market energy price exposure. In the 2019 IRP, PGE advanced the consideration of energy need by examining the changing energy position across need and market energy price futures, capturing, for example, the impact of carbon prices on coal plant economics. This analysis provides greater insight into the uncertainties of the existing portfolio's future energy position and potential exposure to variability risk.

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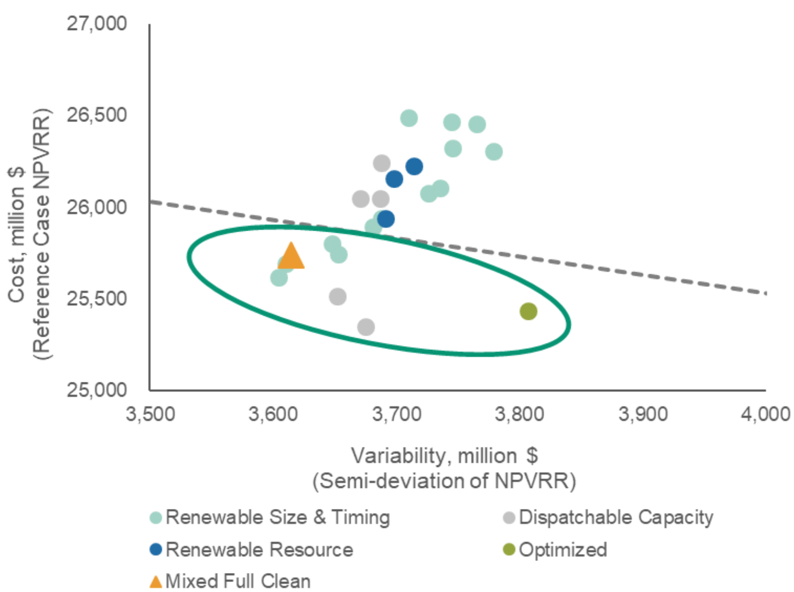
[135] LC 73 Opening Comments of RNW at 5.
[136] LC 73 Opening Comments of Staff at 25.
[137] *Id.*
[138] *Id.* at 4.
[139] LC 73 Opening Comments of CUB at 5.

While there are risks associated with having a significantly short market energy position, there are also risks associated with having a significantly long market energy position. In prior IRPs, PGE built portfolios by hand and designed them to not take overly-long market energy positions. In the 2019 IRP, with the introduction of ROSE-E for portfolio optimization, PGE also introduced a non-traditional scoring metric to screen out portfolios from consideration that had the potential to result in persistently long energy positions, as discussed in **Section 3.1. Scoring Metrics**.

Consistent with the 2016 IRP, portfolios constructed in the 2019 IRP were designed with a constraint that requires them to meet the identified capacity need. The optimized portfolios and the Preferred Portfolio were not designed with a constraint that specified a minimum energy addition.[140] In examining the top performing portfolios, however, PGE found that only one portfolio did not contain energy additions (Min Avg LT Cost, No Energy)[141] and this portfolio had the greatest variability risk of all of the top performing portfolios, as seen in **Figure 12** (the portfolio is labeled "Optimized" in **Figure 12**). In the other top performing portfolios, variability risk was reduced due to the addition of resources with energy that limited the exposure to market energy prices.

Figure 12: Portfolio performance on the basis of cost and variability, 2020$

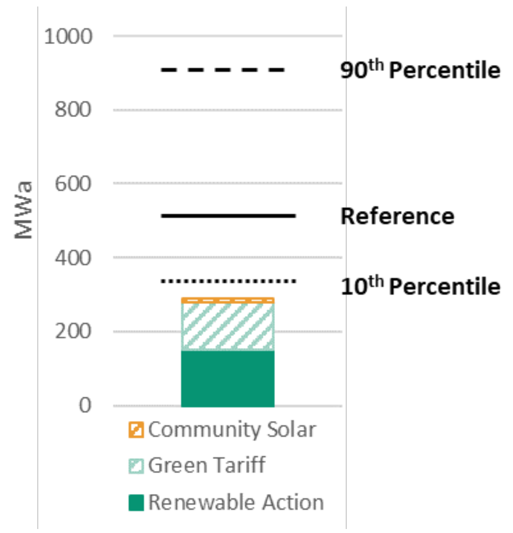


PGE appreciates that examining energy need is not as straightforward as examining capacity need; however, energy need has a long history of serving as an important measurement of exposure to variability risk due to potentially high market energy prices. PGE maintains that this continues to be a valuable element of the IRP process.

[140] In order to examine questions of size, timing, and resource comparison, the sets of portfolios for renewable size and timing, renewable resources, and dispatchable resources did contain specified quantities of renewable additions. See Sections 7.1.3, 7.1.4, and 7.1.5 of the 2019 IRP.
[141] The resource additions of the top performing portfolios are shown in Figure 7-11 in the 2019 IRP.

As noted above, some parties expressed concern about the Renewable Action due in part to how the energy position might be changed by voluntary renewable programs. In Section 4.7.2 of the 2019 IRP, PGE provided analysis of the potential energy impacts from three sensitivities regarding voluntary programs, including a sensitivity (Sensitivity C) which assumed 93 MW of Community Solar resources (the full first tier, approximately 12 MWa) and 300 MW of Green Tariff resources (approved cap, approximately 129 MWa). **Figure 13** compares the energy position (Reference, 10^{th} percentile, and 90^{th} percentile) to the energy from the Renewable Action plus the voluntary program energy from Sensitivity C. The total additional renewable energy (approximately 291 MWa), is less than the 10^{th} percentile of the energy position and 224 MWa less than the Reference Case.

Figure 13: Energy position distribution compared to renewable energy action with voluntary program sensitivity



As noted previously, PGE plans to provide an update to its need assessments and sensitivities in November 2019.

4.7. Direct Access

Parties' Comments

Staff summarized PGE's Direct Access sensitivity and noted that related issues "are being considered by the Commission in other dockets."[142] In Recommendation 14, Staff stated that "PGE should discuss how the resource needs assessment and Action Plan should be altered, if at all, in response to the potential outcomes of current Commission activities related to Direct Access."[143] Staff also expressed concern that PGE's load forecast did not assume growth in the number of customers enrolled in the current LTDA program.[144]

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[142] LC 73 Opening Comments of Staff at 26-27.
[143] *Id.* at 27.
[144] *Id*.

CUB requested PGE's load forecast include projections of future load leaving cost-of-service under the NLDA program or under a hypothetical expanded LTDA program.[145]

NWEC noted that "[t]he rise of long term direct access represents a significant change to the underlying utility business model. While some progress has already been made on assessing spillover effects, including load forecasting, as described at some length in the IRP (Section 4.1.4 and elsewhere), further work is urgent."[146]

AWEC asserts that ". . . PGE's proposal will result in substantial cost increases for direct access and cost-of-service customers . . ." and that assuming increased enrollment in Direct Access programs should be used to reduce capacity need.[147] AWEC also recommends that Direct Access issues be addressed in Docket No. UM 2024, rather than in this IRP docket.[148]

With respect to complying with Guideline 9, NIPPC stated that "PGE's 2019 IRP appears to comply with all aspects of the resource needs."[149] However, NIPPC described the Direct Access Sensitivity as "fundamentally flawed" and recommended that concerns regarding resource adequacy and Direct Access be addressed in Docket No. UM 2024.[150]

PGE's Response

PGE believes that a responsible entity must plan and procure for the capacity needs of all loads within PGE's service territory. To do otherwise will undermine the reliability of the electric system. Direct access programs, including Long-Term Direct Access (LTDA) and New Load Direct Access (NLDA) are not currently being planned for within PGE's IRP load forecast. PGE is concerned that Oregon's current direct access policy does not require alternative energy service suppliers (ESSs) to plan and procure capacity resources necessary to support reliability. Rather, nothing prohibits ESSs from relying on short-term energy purchases available on wholesale market exchanges, which is an inadequate substitute to capacity planning necessary to support resource adequacy. Even though PGE is not planning for these loads, current direct access policy dictates that if a load curtailment reliability event occur, PGE is under the obligation to curtail cost-of-service and direct access loads equally. This obligation to curtail loads equally persists even when a reliability event is triggered by inadequate ESS supply. In PGE's view, current policy allows for an undue transfer of cost and risk from direct access customers to cost-of-service customers and allows large industrial loads to freely enjoy the reliability benefits of PGE's capacity procurement without contributing toward the costs.

There is an urgent need to commence the planning and procurement for the capacity needs of direct access loads. PGE believes that PGE is the best entity to engage in the capacity procurement for direct access loads, given PGE's role and responsibility to be the reliability provider within the balancing

[145] LC 73 Opening Comments of CUB at 4-5.
[146] LC 73 Opening Comments of NWEC at 6.
[147] LC 73 Opening Comments of AWEC at 2.
[148] *Id.* at 3.
[149] LC 73 Opening Comments of NIPPC at 21.
[150] *Id.* at 22.

authority. To effectuate this change, PGE urges the OPUC to allow PGE to plan for the capacity needs of direct access customers by providing additional guidance on Guideline 9 allowing for the planning and procurement for the capacity, not energy, needs of direct access customers. PGE recognizes that these questions are under active consideration within Docket No. UE 358 and Docket No. UM 2024. PGE believes it is appropriate to continue discussion of planning for the capacity needs of direct access customers in both dockets in addition to the IRP.

PGE agrees with NWEC regarding the urgency of addressing direct access issues and notes that this urgency extends beyond the utility business model, as the reliability of the grid depends on the planning processes that account for all loads. PGE will continue to be actively engaged in working in other dockets toward resolutions that are fair to all customers. PGE agrees that resource adequacy is a system capability to provide capacity from a portfolio of resources when needed.

PGE notes that CUB misstated the size eligibility requirement for potential NLDA customers as being over 1 MWa.[151] NLDA-eligible customers are customers that are not yet receiving service from PGE and whose loads will meet or exceed 10 MWa for 12 consecutive months within the first 36 months of operation.[152] The program was designed on the presumption that these very large new customer loads, of 10 MWa or greater, are of sufficiently large scale that they would not be captured within the top-down econometric forecast. Therefore, the load forecast already, without further adjustment, excludes future NLDA load.

Additionally, PGE disagrees with CUB's and Staff's recommendation to speculate on the future direct access elections of its customers and CUB's recommendation to account for a hypothetical increase to the cap on the LTDA program. PGE bases its load forecast on the best information available at the time, which includes the current customer elections. PGE assumes all current LTDA customers will remain on LTDA and assumes all current and future cost-of-service customers will remain cost-of-service. Several factors might motivate an individual customer to select LTDA, and PGE does not have direct insights into these motivations or access to information about terms being offered by ESSs that would help inform such decisions.

PGE seeks to clarify the nature of resource adequacy implications associated with Direct Access. As discussed in the IRP, the sensitivity examined the impact to the long-term planning capacity need of two quantities of Direct Access load. PGE notes that this examination of long-term planning impact is not the same as an assessment of the potential impact of an ESS failure to deliver. Staff correctly notes that PGE's IRP analysis has identified over 500 MW of capacity need associated with meeting resource adequacy needs associated with fully subscribed direct access programs. However, this capacity need does not simply present itself "in the event that PGE must serve LTDA customers", as Staff suggests.[153]

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[151] LC 73 Opening Comments of CUB at 5.
[152] OAR 860-038-0730(3).
[153] LC 73 Opening Comments of Staff at 26.

The unmet resource adequacy needs of direct access load is constantly present. It is inaccurate to suggest that related capacity deficits only arise if direct access load returns to PGE under emergency conditions or its supplier fails to deliver. Long-term planning and capacity procurement are necessary to achieve resource adequacy targets and to avoid emergency conditions. Additional capacity is required to ensure that the capacity needs of all OPUC jurisdictional load, including direct access loads, are planned for to support reliability on a long-term expected basis.

PGE disagrees with AWEC's assumption that planning and procuring the capacity necessary to support direct access resource adequacy needs will result in substantial cost increases to cost-of-service supply customers. Thoughtful planning, such as PGE's proposal in UE 358 can address the lack of capacity planning for direct access customers without unfairly shifting cost and risk to cost-of-service customers.

PGE disagrees with NIPPC's opinion that the direct access sensitivities in Section 4.7.3.1 of the 2019 IRP are "fundamentally flawed" and notes that NIPPC has confused average annual energy (MWa) with capacity (MW).[154] The long-term planning sensitivities examined two quantities of direct access (300 MWa and 419 MWa) and calculated the additional capacity needed for planning for each sensitivity. The 1-in-2 peak load for direct access load is higher than the annual average direct access load, in addition, as with other loads, weather events, plant outages, and required operating reserves increase the need for capacity above the 1-in-2 peak.

PGE appreciates ongoing work by Staff and parties to address issues related to direct access in Docket Nos. UE 358 and UM 2024. PGE believes it is appropriate to continue discussion of planning for the capacity needs of direct access customers in both dockets in addition to the IRP.

4.8. Green Tariff Program

PGE received Commission approval for its Green Tariff program (also known as Green Future Impact or the Green Energy Affinity Rider) in March 2019,[155] and subsequently launched enrollment, offering commercial and industrial cost-of-service customers access to bundled RECs from new renewable energy facilities. A primary goal of this program, consistent with other green tariff programs nationwide, is to provide subscribers the opportunity to accelerate decarbonization of the electric power supply above and beyond that which would occur otherwise.[156] For this reason, RECs must be retired on behalf of participants.[157] Subscribers of the first Green Tariff offering have enrolled for the energy equivalent to the output of an approximately 160 MW renewable energy facility. This facility

[154] LC 73 Opening Comments of NIPPC at 23.
[155] Order No. 19-075.
[156] Corporate Renewable Energy Buyers' Principles, Renewable Energy Buyers' Alliance, retrieved from: https://buyersprinciples.org/principles/.
[157] House Bill 4126 (2014), Section (3)(6); see also UM 1953, PGE/400 Sims-Tinker/2: 14-23.

is expected to be a new solar facility located in Oregon and is planned to be operational by the end of 2021.[158,159]

PGE's first Green Tariff contracts are 15-year, fixed-fee contracts, with subscribers paying the subscription fee in addition to cost-of-service rates. The subscription fee includes any premium above the incremental energy and capacity value of the renewable resource, in addition to the costs of administering the program, and any applicable risk adjustment fee. When the Green Tariff resource delivers green energy and capacity to PGE's system, all cost-of-service customers receive the energy and capacity, and the RECs are retired on the subscribers' behalf.

While this first offering of the Green Tariff is underway, PGE and stakeholders have been directed by the Commission to seek, in Docket No. UM 1953, to clarify Order No. 19-075 which will determine the terms under which the unsubscribed approximately 140 MW of the previously-approved 300 MW cap will be offered to customers.[160] The Commission also suspended phase two of that docket where PGE is seeking to: 1) increase the program cap up to 500 MW; and 2) discuss green tariff-related policy issues and program design topics with parties.

Parties' Comments

In Recommendation 8, Staff requested that PGE update the portfolio analysis to include the impact of the Green Tariff (or reduce the Renewable Action by the size of the Green Tariff subscription).[161] Staff also requested information about "the transmission arrangements for its first phase of GEAR resources and the impacts of these resources on the availability of transmission for resources modeled in the IRP."[162]

CUB noted the rapid enrollment in the Green Tariff program and requested additional information about PGE's assessment of impacts due to program expansion.[163,164]

In comments on behalf of AWEC, Mr. Mullins noted the popularity of the Green Tariff program[165] and requested that PGE be required to "consider the capacity and Renewable Portfolio Standard ("RPS") attributes associated with the voluntary Green Tariff program in its resource needs assessment ..."[166]

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158 https://www.portlandgeneral.com/our-company/news-room/news-releases/2019/08-21-2019-sustainability-leaders-claim-pges-green-future-impact-in-record-time.
159 https://www.facebook.com/PortlandGeneralElectric/videos/449074239282464/.
160 Order No. 19-075 at 4, Order No. 19-438.
161 LC 73 Opening Comments of Staff at 15.
162 *Id*.
163 LC 73 Opening Comments of CUB at 5-6.
164 PGE notes that, in the Opening Comments of CUB at 5, the quote attributed to the 2019 IRP ("there is a very low likelihood. . .") is from the *Draft* 2019 IRP.
165 LC 73 Opening Comments of AWEC, at 4, Attachment B.
166 *Id.* at 1, Attachment B.

Mr. Mullins expressed the opinion that the resources for the Green Tariff program should reduce PGE's RPS obligations.[167]

In describing the Green Tariff program, parties appeared to have differing understandings of the current level of enrollment in the program, quantities of resource to be acquired in the first phase, and PGE's recommendations regarding the process for program expansion.

PGE's Response

PGE appreciates parties' comments regarding the Green Tariff program and appreciates this opportunity to provide additional clarification.

As discussed above, the Green Tariff program does not reduce PGE's RPS obligation, nor does it provide PGE with RECs. The program is intended to be incremental to the RPS requirement.[168] All RECs generated are retired on behalf of the Green Tariff participants, allowing them to make claims associated with the green attributes. AWEC's and Mr. Mullins's opinion that the Green Tariff resource should reduce PGE's RPS obligation is inconsistent with Oregon statute for the implementation of a green tariff program.

PGE appreciates Staff's request for additional portfolio analysis, however, PGE notes that portfolio optimization selected significant quantities of additional renewable resources from 2023-2024 (over 520 MWa, much greater than the sum of PGE's recommended action plus energy from the planned Green Tariff resource). The Mixed Full Clean portfolio was constrained to adding no more than 150 MWa, reducing the risk of energy length, including possible energy brought by capacity resources. PGE believes that the concerns raised by Staff and CUB can be better addressed through updated capacity, energy, and RPS need assessments. PGE intends to provide updated need assessments in November 2019 that will include the contracted Green Tariff resource for the first offering in the resource stack. PGE will also provide updated sensitivities of the potential impact to need assessments from the remaining portion of the previously-approved 300 MW offering and from possible expansions of the Green Tariff program.

The resource planned for the first Green Tariff offering is in advanced stages of permitting and the project has sufficient associated transmission rights for firm delivery to PGE's service area. This resource does not impact the transmission assumptions for the resources modeled in the IRP.

PGE notes that in comments, some parties have mischaracterized the Green Tariff program, the enrollment and resource quantities, and the process proposed by PGE for program expansion. PGE recognizes that because it is a new program, there may be less familiarity with the details. PGE hopes that the description provided above helps to clarify this information. PGE looks forward to continuing to work with Staff and parties to respond to questions regarding Green Tariff.

[167] *Id* at 4, Attachment B.
[168] House Bill 4126 (2014), Section (3)(6); see also UM 1953, PGE/400 Sims-Tinker/2: 14-23.

4.9. PURPA Qualifying Facilities

Parties' Comments

Parties expressed opinions that PGE's current treatment of PURPA qualifying Facilities (QFs) both overestimates and underestimates the impact of QFs on resource need. They requested a change to the treatment of QFs in Portfolio Analysis and additional sensitivities to examine the potential impacts of QFs.

Staff recommended that PGE update its treatment of QFs in portfolio analysis to include a forecast of future QF contracts acquired across the planning horizon and stated that the "lack of incremental QF contracts in PGE's long term planning may be contributing to PGE's finding that near-term renewable acquisition is cost-effective."[169] Staff asserts that because PGE is required to take QF generation, a forecast of additional QFs in the need assessment provides "a more realistic view of PGE's position and the resources it may need to acquire."[170]

REC recommended that PGE update the need assessment to reduce the quantity of executed QFs contracts included to reflect an assumption of some amount of QFs with executed contracts failing to achieve COD (with a recommendation of a failure rate between 50 percent and 75 percent).[171] REC also recommended that PGE assume that 100 percent of QFs in current operation be assumed to enter into new agreements upon expiration of their current contracts, claiming that "the vast majority of QFs that are able to operate will continue to sell power to their host utility."[172]

While acknowledging that the QF sensitivity provides insight, REC was dismissive of the quantities examined, particularly for the high sensitivity, which REC states "does not appear to be based in any reasonable factual data or forecasts." Instead, REC recommends that PGE include assumptions for additional QF projects across the planning horizon.[173]

Additionally, REC included extensive comments regarding PGE's QF procurement and interconnection process that are outside the scope of this IRP proceeding. PGE will not respond to these inaccurate, misleading, and inflammatory statements. However, PGE would like to simply note that the Company has been actively trying to engage parties to update our contracting procedure and standard agreement in order to require additional due diligence on part of sellers prior to the issuance of an executable agreement.

PGE's Response

PGE appreciates the challenges that parties have noted with assessing the changing portfolio of QF resources. Over the past few years, there was a large shift in the types of projects under consideration, a large influx of executed and proposed contracts, delays of Schedule CODs, and

[169] LC 73 Opening Comments of Staff at 27-28.
[170] *Id.* at 28.
[171] LC 73 Opening Comments of REC at 1.
[172] *Id.* at 4.
[173] *Id.* at 10.

terminations of executed agreements. In the upcoming months, PGE will likely see additional executions, delays, and terminations of projects – though potentially at a significantly different pace than in 2016 and 2017. And it is yet to be seen how recent land use policy will impact developers' decisions regarding further QF project development.

In recommending both increases and decreases to the quantity of QFs included in the IRP need assessments, parties demonstrate the challenges associated with developing a "reasonable" forecast. PGE has concerns with both recommendations as described below. PGE continues to find that the method of assessment based on executed contracts provides a balanced approach that uses known and measurable values, aligns with actual obligations, and is in the best interest of customers. PGE also notes that Docket No. UM 2000 will address the treatment of QFs in the IRP process.[174]

Commercial Operation

PGE disagrees with the suggestion from REC to de-rate the quantity of QFs in the need assessment based on an estimated rate of failure to achieve COD for the following reasons.

PGE does not believe that the recent history of QF development, in light of the rapidly changing nature of QF development, provides a meaningful basis for developing forward-looking planning expectations of project completion. Further, while PGE does not advocate for forecasting future executions as discussed below, if PGE included speculation on failure rates, then on a similar "reasonable" basis, speculation on future executions could also be included. This would result in a forecast based on two opposing highly speculative and unsupported assumptions which would partially cancel each other out while also introducing the need for additional assumptions regarding future QF pricing and terms, as discussed below.

The IRP Reference Case provides inputs to QF contract pricing and conditions. REC's recommendation to assume a lower quantity of QFs than executed obligations would serve to raise future prices that customers would be required to pay to QF developers, risking overpayments from customers with no recourse. There is no guarantee that projects with executed contracts will fail and no ability for customers to adjust executed contract prices if the assumption is incorrect. The proper treatment for pricing, especially in this non-competitive structure, is to base it on the most current snapshot of executed contracts, which reflect the legally enforceable obligations in the Company's portfolio. If QFs would like to wait to sign contracts until they are further along in their project development, they are welcome to pursue that opportunity, however, the Company should not be obligated to inflate avoided cost payments at customers' expense.

Projecting Additional Executions

PGE disagrees with the suggestions to modify the need assessment used for portfolio analysis to include assumptions for generation from additional QF contract executions across the planning

[174] Order No. 19-254, Staff's Recommendation Adopted as Modified, Appendix A at 1.

horizon and for QF contract renewal. PGE objects to these recommendations for the following reasons.

In public meetings, stakeholders and Staff have noted that PGE's need assessments provide important information to the market about PGE's upcoming needs. Obscuring this picture reduces the value of the assessment. Whether those needs are met by QFs or others, it is important to provide a clear picture of PGE's position.

PGE is required to accept QF contracts and to pay deficiency payments during the established deficiency periods, but the company is not required to "hold space" in its resource stack reserved only for QFs. As PGE moves through its IRP and bilateral and RFP procurement processes, the Company updates its need assessment to capture more recent load and contract information. If PGE were to forego customer opportunity to acquire cost-competitive renewables from an RFP process due to a forecast of unknown potential future QF projects over the planning horizon, PGE would not be following least-cost, least-risk planning. This would be gambling on the unknown and speculative possibility that non-competitively priced resources (with no obligation to materialize) will be put on the Company, at the cost of forgoing the acquisition of competitively priced resources that bring important terms and conditions to protect customers.

The very nature of how QFs are funded is based on the Reference Case view of need and projecting more might result in acquiring less. The pricing tables contained in QF contracts are based on a concept of sufficiency and deficiency. If PGE were to speculate about future QF contracts in the need assessment, this would distort the sufficiency/deficiency values. The future sufficiency/deficiency conditions (along with many other inputs) are unknown currently. These conditions impact price assumptions of future QF contracts, including renewals and assumptions regarding RECs received by PGE.

The decision of QF projects to enter into agreements are highly specific to each project's circumstances and circumstances in the region at the time of the decision. QF activity in the last few years has shown that developers are willing to enter into QF contracts with utilities other than those whose service area they are located in if another utility provides prices that are high enough to offset the QF's extra costs.[175] This means that it is highly speculative to assume a quantity of future QF contract executions in the need assessment, including assuming that current QF contracts will elect to enter into new contracts with PGE in seven to 15 years.

Parties have provided no relevant evidence that an assumption of renewal is appropriate on a forecast basis. PGE has a very limited number of already expired QF contracts, and those older projects were developed under substantially different conditions than exist today or than are likely to exist in the near future. PGE notes that as of the time of the QF snapshot for the 2019 IRP, only one contract was

[175] As of the time of the QF snapshot for the 2019 IRP, over 50 percent of the nameplate capacity of the executed QFs were located outside of PGE's system.

for a resource that had a previous QF contract with PGE. PGE also notes that the next QF expiration is in 2027 and that the Action Plan is robust to an assumption of QF renewal.

As noted earlier, the optimized portfolios selected substantially more than 150 MWa of renewable additions in 2023 and 2024. While a "reasonable" forecast of additional QFs has not been defined by parties, PGE suspects that it would be a smaller quantity than selected in the optimized portfolio.

PGE did provide a sensitivity to the need assessment regarding the potential impact of a renewal assumption in the response to REC Data Request No. 006. If parties are interested in potential impacts of renewal, PGE recommends that a sensitivity is the appropriate tool for analysis.

PGE intends to provide updates to the need assessments which will contain a more recent snapshot of QFs. Additionally, PGE will provide updated QF sensitivities. PGE looks forward to working with parties in Docket No. UM 2000 to address concerns about QF modeling.

4.10. Regional Markets

Parties' Comments

In Recommendation 27 5.B.2, Staff notes that PGE's IRP has considered capacity and flexibility adequacy, and Staff would like to see "consideration of EIM benefits to PGE's system."[176]

CUB notes that "a regional market will fundamentally change the dispatch of resources. Examining how resource portfolios perform in a regional market would be informative and could influence the Company's portfolio selection."[177] AWEC suggests that "PGE closely study the capacity effects of participating in a regionalized Extended Day-Ahead Market, or similar market structure." [178]

PGE's Response

PGE would like to clarify that the Western Energy Imbalance Market (EIM) is an energy imbalance market and does not provide additional capacity or flexibility adequacy benefits to PGE. In order to participate in the EIM, PGE must demonstrate resource sufficiency for each 15-minute segment of the hour. Since EIM benefits are economic and operational in nature, IRP studies aimed at assessing adequacy do not consider the EIM to provide benefits. However, the nature of production cost modeling used for studies like the Flexibility Adequacy Study assume perfect foresight of forecasted prices and optimized system dispatch decisions. These modeling practices likely capture a portion of the economic benefits associated with the EIM.

Efforts around the California ISO's Extended Day-Ahead Market (EDAM) initiative are ongoing, with current focus on design details that could allow Western EIM entities to participate in a day-ahead market. CAISO has posted an Issue Paper and initiated discussion on EDAM development through a

[176] LC 73 Opening Comments of Staff at 44.
[177] LC 73 Opening Comments of CUB at 12.
[178] LC 73 Opening Comments of AWEC at 5, Attachment B.

stakeholder process.[179] PGE has been actively participating in ongoing discussions. PGE was a member of the EDAM steering committee and led work groups involved in the Feasibility Assessment. PGE will be participating in the relevant issues as they are identified. In the Issue Paper, CAISO has noted that just as with the EIM, resource sufficiency requirements are being considered for the EDAM, and resource adequacy will continue to be the responsibility of each entity and their regulatory authority.[180] PGE plans to continue engaging in the stakeholder process surrounding the EDAM.

5. Resource Economics

5.1. Technology Costs

Parties' Comments

Staff requested additional information about two aspects of the technology cost trajectories for wind resources: (1) the development of the low and high fixed cost scenarios; and (2) why Bloomberg New Energy Finance (BloombergNEF) was not used as the source for the learning rate for the low cost trajectory for wind resources when BloombergNEF was used for the learning rate for solar's low cost trajectory.[181]

PGE's Response

In order to capture the uncertainty of future technology costs for resources, PGE prepared low and high cost trajectories in addition to the Reference Case trajectory. The development of the cost trajectories was shared with stakeholders during the public Roundtable process. The trajectories examine uncertainty in the overnight capital costs of resource. Other fixed costs, such as fixed operating and maintenance costs, do not change in these scenarios.

For wind resources, the initial year technology costs in the low, reference, and high scenarios are based on values provided by HDR in their report on supply-side resources. The low and high values are one standard deviation from the Reference values.[182] The Reference cost trajectories for wind were also provided by HDR.[183]

In developing the experience curve analysis for the low and high technology cost trajectories for wind, solar, geothermal, and battery storage for the 2019 IRP, PGE relied on the Energy Information Administration's (EIA) 2018 Annual Energy Outlook (AEO 2018) as the primary source of learning

[179] CAISO extended Day-Ahead market. Available at: http://www.caiso.com/informed/Pages/StakeholderProcesses/ExtendedDay-AheadMarket.aspx

[180] CAISO Issue Paper at 3. Available at: http://www.caiso.com/Documents/IssuePaper-ExtendedDayAheadMarket.pdf.

[181] LC 73 Opening Comments of Staff at 37-38.

[182] 2019 IRP External Study D at 578 of 678.

[183] https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning, 2019 IRP Studies, Supply Side Options Studies: Renewable & Battery Options (Excel), "TMO" worksheet, rows 10, 13, 16, and 19.

rates[184] because the AEO 2018 provides publicly available data for a wide range of technologies. In one case, the low technology cost for solar, PGE determined that for IRP analysis, the AEO 2018 learning rate did not appropriately capture risks associated with the potential for rapidly declining costs. In particular, because the 2019 IRP examines the costs and risks associated with near-term renewable additions, PGE was concerned that a low learning rate for solar (10 percent) might underestimate the risks associated with a near-term Renewable Action by significantly underestimating the potential for solar costs to decline across the planning horizon.[185] The BloombergNEF solar learning rate (28 percent) was selected instead of the AEO rate to provide a conservative assumption with respect to the risk of near-term Renewable Action.

5.2. Wind Energy Value

Parties' Comments

Staff conducted analysis of historical wind generation and wholesale market prices and noted a significant difference between the implied historical energy value for existing wind and the forecasted energy value of new wind. Staff recommended that PGE explain how the Company considered the coincidence of market prices and wind generation in evaluating energy value.[186]

PGE's Response

Wind energy value is impacted by energy prices in addition to wind production. Historical energy value of a wind resource can differ from forecasted future energy value due to differences in these aspects.

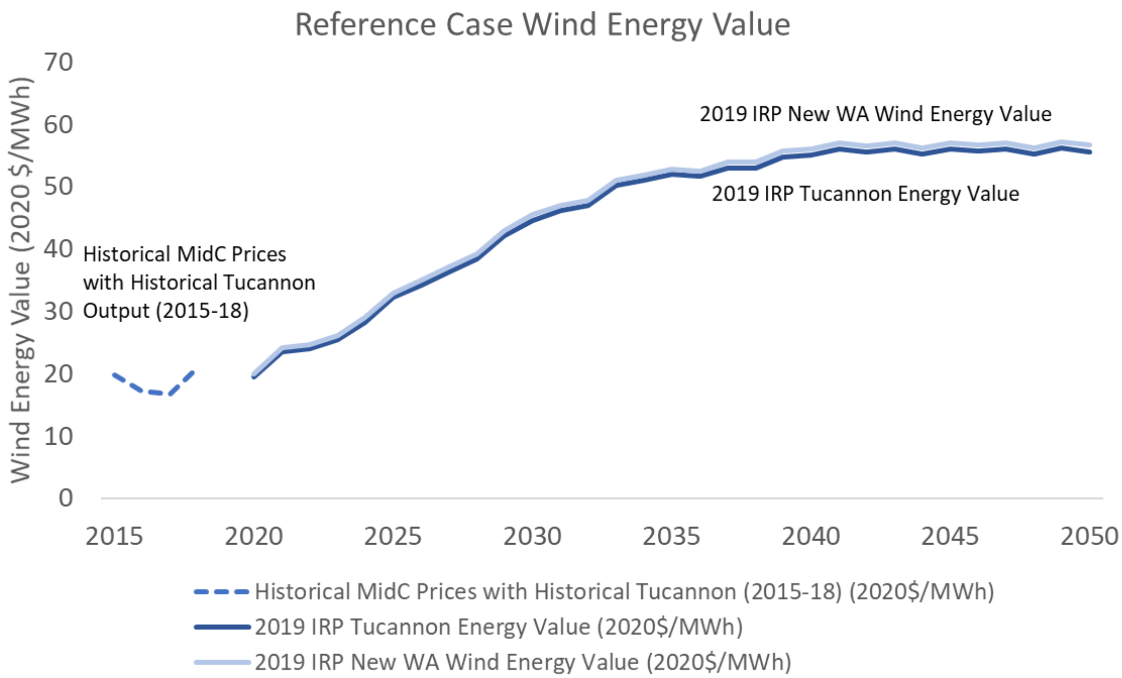
Figure 14 depicts annual historical energy value at Tucannon using Tucannon production and Mid-C prices from 2015 through 2018. It also depicts annual forecasted energy value from 2020-2050 for Tucannon and a candidate WA wind resource from the 2019 IRP. Both are shown in real 2020$/MWh. In the near-term, forecasted energy values for Tucannon and the candidate WA Wind resource are at similar levels with the implied historical energy value of Tucannon. The 2020 energy value for the candidate WA wind resource is $19.98/MWh. However, the energy value escalates over time due to escalation of wholesale market prices. Over the lifetime for a 2023 COD candidate WA wind resource, the levelized energy value is $46.51/MWh in 2020$ and the levelized energy value for Tucannon under the same framework and over the same period is $45.64/MWh in 2020$. Differences in energy value between the two resources are attributable to differences in the timing of wind generation.

[184] The fractional cost reduction per doubling of cumulative capacity.

[185] The same concern did not apply to the 20 percent learning rate for wind used in the low technology cost trajectory.

[186] LC 73 Opening Comments of Staff at 36.

Figure 14: Energy value for Tucannon and a candidate WA wind resource.[187]



In the Reference Case, wind energy value increases as market prices experience positive real escalation from 2020 to 2040. Observable positive real growth from 2020 to 2040 in Reference Case market prices results from the interactions of the WECC-wide load with available resources, fuel costs and carbon prices from the WECC-wide run detailed in Section 3.2 of the 2019 IRP. From 2020 to 2030, the relative impacts of gas price and carbon price escalation on market prices are comparable. After 2030 until 2040, continued growth in market prices is predominantly driven by gas prices as carbon prices are held constant in real terms.

5.3. Intergenerational Equity Analysis

Parties' Comments

Staff expressed appreciation for the inclusion of the intergenerational equity analysis and recommended that PGE hold a stakeholder workshop on the topic.[188]

PGE's Response

PGE incorporated the intergenerational equity analysis, which can be found in Section 7.3.1 of the 2019 IRP, in response to guidance from the Commission in the 2016 IRP, which suggested that it is appropriate to consider near-term cost impacts in additional to the traditional long-term NPVRR

[187] Note that to calculate historical Tucannon energy value in units of $2020/MWh, inflation is assumed at 2.05%.
[188] LC 73 Opening Comments of Staff at 10-11.

analysis that factors into the traditional cost and risk metrics.[189] PGE believes that discussion of this analysis and its implications is important for the thorough review of PGE's Renewable Action and therefore plans to include this item on the agenda for the Company's next public roundtable meeting on November 21, 2019.

5.4. Federal Tax Credits

Parties' Comments

Staff raises multiple questions related to federal tax credits, specifically the Production Tax Credit (PTC) for wind. Staff recommends that PGE clarify how risks associated with tax credit expiration are addressed, making specific reference to the risk that a competitive solicitation may not yield 150 MWa of wind resources that can qualify the level of PTCs modeled in the preferred portfolio and project risks that could impact PTC eligibility.[190] Staff also recommends that PGE explain how the IRP accounts for the potential rate impacts of deferred PTCs.[191]

PGE Response

<u>Tax Credit Expiration Risks</u>

Regarding tax credit expiration, Staff raises real potential risks that PGE considers in both resource planning and procurement. For example, the Renewable Action is designed for up to approximately 150 MWa to allow PGE the flexibility to procure less than 150 MWa in a circumstance in which there are less than or no resources available in the market that capture the benefits as described in the IRP. The cost containment screen specifically helps to provide this assurance. If fewer than 150 MWa of resources meet the cost containment screen, PGE would necessarily procure less than 150 MWa. PGE also retains the option to procure less than 150 MWa (down to 0 MWa) even if an adequate volume of resources passes the cost containment screen if there exist other indications that procurement of such resources could result in poor outcomes for customers. Further, any subsequent RFP proceeding will allow the commission to decide whether to acknowledge the final shortlist or recommend alternative actions within the RFP process.

Regarding project risk, including cost overruns and schedule delays, PGE manages this risk through RFP design and through contractual terms for winning bids. RFP non-price scoring includes project development criteria (including the maturity of interconnection transmission requests, permitting status, and site and equipment control) that help to ensure that selected bids have reduced project development and execution risk. Once a winning bid or bids are selected, PGE includes contractual provisions to mitigate the risk that customers do not receive the full benefit of the tax credit. For third-party ownership, these provisions are focused on price certainty while utility ownership provisions require firm schedule commitments for delivery of assets or construction. If a counterparty fails to meet its contractual obligations, they must pay liquidated damages that reimburse customers

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[189] Order No. 17-386 at 3.
[190] LC 73 Opening Comments of Staff at 32-33.
[191] *Id.* at 33.

for the loss of tax credit value. Ultimately, the Commission has the authority to weigh whether PGE took appropriate steps of behalf of customers to mitigate these risks in a future ratemaking proceeding.

Tax Credit Utilization

Staff raises concern about PGE's ability to utilize additional large volumes of federal tax credits given PGE's PTC carryforwards and expected future tax liability. However, PGE notes that the Company only earns tax credits for PGE-owned resources that are tax credit eligible. Consistent with past practice, proxy resources in the 2019 IRP are ownership agnostic. PGE does not believe that it is appropriate to limit procurement opportunities that could benefit customers based on the assumption of a specific ownership structure. Because PGE cannot speculate as to the tax appetite or tax credit utilization strategies of potential counterparties, IRP analysis assumes full utilization of federal tax credits in estimating resource levelized costs and expects the competitive market to optimize for efficient credit utilization.

PGE does, however, believe that it is important to consider the potential cost impacts related to tax credit utilization in evaluating resource bids in the RFP. In RFP evaluation, PPA prices reflect any costs associated with tax credit utilization by the counterparty, so tax credit utilization is implicitly accounted for within price scoring. For PGE-owned resources, potential costs associated with tax credit utilization must be explicitly calculated and accounted for. This component of RFP price scoring is described in Appendix J of the 2019 IRP: For those resources eligible for federal tax credits and offered under a utility-ownership proposal, the Company will evaluate its customer costs associated with utilization of the incremental tax credits.[192]

In this way, the RFP will allow PGE to bear out whether tax credit utilization challenges offset the potential value to customers of tax credit-eligible resources. If a bid does not have an effective tax credit utilization strategy and this results in failure to meet the cost containment screen, the bid would not be selected.

5.5. Integration Costs

Parties' Comments

RNW noted concerns that solar integration costs may be overstating the cost of solar integration and presented concerns about the use of a linear scaling of a single solar resource as input data. [193]

PGE's Response

PGE would like to clarify that the solar shape used to estimate solar integration costs is composed of three sites in central Oregon aggregated into one shape for input.

[192] PGE 2019 IRP at 370 (Appendix J).
[193] LC 73 Opening Comments of RNW at 10-11.

In addition, PGE is conducting ongoing analysis to provide additional insight into integration-cost drivers. PGE has included this exercise as a proposed enabling analysis to support future IRPs.

5.6. Flexibility Value

Parties' Comments

RNW recommends that the flexibility value of hybrid resources such as a combination of storage and renewable resources be estimated so that bids into an RFP could be appropriately valued.[194]

PGE's Response

PGE wishes to clarify that flexibility value of hybrid resources (e.g. combinations of wind/solar/storage) was not explicitly evaluated in this IRP due to the challenge selecting a representative hybrid resource for which to evaluate the flexibility value. This does not preclude the incorporation of flexibility value into the evaluation of hybrid resources that bid into an RFP.

PGE recognizes that there can be flexibility value in paired storage and renewable resources, depending on configuration and operational constraints specific to each resource. In RFP evaluation, PGE intends to include both the flexible value of the resource and any impact that energy-limitations or contract-limitations may have on resource flexibility within price scoring.

5.7. Distributed Resources

Parties' Comments

In Recommendation 29, Staff provided feedback that requested further progress on demand response (DR) modeling in future IRPs, as well as the establishment of processes to collaborate with Staff on development of various distributed resources and pricing programs.[195] In Recommendation 18, Staff also requested that PGE include conservation voltage reduction (CVR) in future distribution system modernization analysis.[196] NWEC, in Section 3 of their comments, encouraged aggressive development of both energy efficiency (EE) and DR.[197] Further comments regarding topics in this section are addressed in the following locations: electric vehicles (**Section 4.2**), energy efficiency (**Section 4.3**), demand response in the capacity assessment (**Section 4.4**).

PGE's Response

PGE appreciates the continued support from Staff and stakeholders in the advancement of energy efficiency, demand response, and the wider suite of distributed resources. PGE is also encouraged by the support of Action Item 1 of the 2019 IRP, related to the acquisition of customer resources.

[194] *Id.* at 5-6.
[195] LC 73 Opening Comments of Staff at 45-47.
[196] *Id.* at 29-30.
[197] LC 73 Opening Comments of NWEC at 2-4.

The planning and development practices for distributed resources at PGE are robust but in early stages. PGE recognizes and wants to serve the call for transparency and set reporting practices noted by Staff in their comments.[198] To address these suggestions, PGE is assembling a cross-functional team to develop a Flexible Load Plan which will be submitted to the Commission in 2020. The plan will address current and future implementation practices, as well as program cost effectiveness.

PGE agrees with Staff that CVR should be included within the analysis of options to modernize the grid as part of advanced distribution system planning. Future development of CVR would be represented in IRP analysis in a manner consistent with the treatment of other distributed resources. We also look forward to continued collaboration in further refining the representation of demand-side resources in future IRPs.

PGE takes seriously our unique responsibility to the customer and the customer experience under the law as a regulated utility. Through the Demand Response review committee, which was mandated as part of Order No. 17-386, PGE is actively engaged with stakeholders[199] in long-term planning for the acquisition of demand response, flexible load, and distributed resources. These are being investigated in a structured manner through the Demand Response Testbed, the Flexible Load Plan, and the DRP Investigation. We look forward to further discussion with stakeholders within these various forums.

5.8. Carbon Pricing

Parties' Comments

Staff raised concerns that the carbon price forecast used in the IRP begins in 2021. In Recommendation 26, Staff recommends that "In future IRP analysis…carbon prices should be modeled beginning in a range of potential years..."[200]

PGE's Response

For clarification, PGE's portfolio analysis does not allow for any resource addition before 2023. A change in carbon price any time before this would affect the absolute cost of all portfolios, though it would not change the relative performance between portfolios. In other words, we do not expect that it would affect the preferred portfolio or Action Plan. Further, during the development of the 2019 IRP, PGE worked with Staff and stakeholders to determine the most appropriate starting date for potential carbon legislation, as well as the best information available about price trajectories. In future IRPs, PGE will continue to involve Staff and stakeholders through the public roundtable process to determine appropriate ranges and starting dates of carbon prices.

[198] LC 73 Opening Comments of Staff at 45-47.
[199] Staff, NWEC, CUB, ETO, NEEA, and others.
[200] LC 73 Opening Comments of Staff at 44.

5.9. WECC-wide Modeling

Parties' Comments

Staff, in recommendation 27, suggested that PGE include varied regional demand scenarios in future market price forecasts.[201] Staff also suggested in recommendation 28.D that, among other elements, PGE provide further analysis on market volatility, noting price spikes from the Enbridge pipeline failure.[202]

PGE's Response

Regional Demand Scenarios

PGE is open to further discussion with Staff and stakeholders on alternative views of regional demand in future IRP cycles. However, PGE also notes the lack of scenarios available from third parties that provide WECC-wide load and resource AURORA databases under high and low regional demand assumptions. This lack of information requires that we conduct capacity expansions in Aurora to assess regional demand scenarios. PGE did not conduct these expansions as part of the 2019 IRP because they are computationally intensive, require several speculative assumptions, and may not yield substantive insight beyond the range of futures we already explore. For the 2019 IRP, scenarios were instead developed to address variation in load growth specifically within the PGE service territory through utilizing information from the Load Forecast and the Navigant DER Study. Additionally, in our capacity adequacy assessments for the High and Low Need Futures, we included low and high market capacity values based on a market capacity study prepared by E3 which included regional load scenarios.[203] PGE will continue to discuss options and methods to examine variations in regional demand with Staff and stakeholders in future IRP public roundtables. We will also continually re-evaluate as information becomes available and as the primary drivers of market price uncertainty evolve.

Market Volatility

PGE clarifies that market volatility was analyzed in the 2019 IRP through the High Renewable WECC Future. Variable energy resource penetration was chosen as the primary driver of volatility because these resources are a constant presence in the market. Transient changes in supply caused by events like Enbridge do not significantly impact the 30-year market price outlook because they are rare and are not sustained in the long-term. These transient risks are, however, important considerations for regional resource adequacy and PGE looks forward to continuing discussions with Staff and stakeholders in future planning cycles regarding the impacts to the capacity assessment.

6. Transmission

During the development of the 2019 IRP, both Staff and stakeholders expressed concerns that transmission could tangibly affect plans for resource procurement. PGE has identified transmission-

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[201] *Id.*

[202] *Id.* at 44-45.

[203] 2019 IRP, External Study E. Market Capacity Study.

related constraints as a key area of focus for future planning cycles and has included this as a proposed enabling analysis for future IRPs. To help address concerns specifically related to transmission availability and more efficient utilization of existing transmission for the development of low-cost renewable resources, PGE has proposed an Interim Transmission Solution as part of this IRP, which proposes a set of changes to RFP requirements and scoring methodology. Parties provided comments on PGE's Interim Transmission Solution, PGE's use of its transmission rights, and PGE's approach to capturing transmission-related constraints in the IRP. PGE provides responses to each of these topics in this section.

6.1. Interim Transmission Solution

Parties' Comments

While Staff, NWEC, RNW, and NIPPC each expressed some positive impressions about the Interim Transmission Solution,[204] each sought additional clarification from PGE about its implementation. Staff recommended PGE provide additional information on the following topics: (1) the appropriateness of requiring firm transmission for an intermittent resource; (2) the trade-off between wind resource quality and available transfer capability (ATC); (3) the benefits of blending diverse regime wind profiles; (4) the role of partnerships; and (5) transmission paths and resources. Further, Staff raised concerns that the Interim Transmission Solution did not contain sufficient methodological detail, stating "PGE seems to have attempted to push the details about this framework to the RFP process, leaving the Commission with limited information on which to make a major acknowledgement decision about resource need in the IRP."[205] Both RNW and NIPPC expressed similar concerns.[206]

RNW was generally supportive of PGE's approach in the Interim Transmission Solution, but encouraged the Company to provide additional details that are traditionally addressed in an RFP so RNW can more fully evaluate the proposal.[207] Additionally, RNW encouraged PGE to consider non-firm products, allowing delivery of project output to the Mid-C, and relying on historical conditional firm curtailment in capacity contribution methodology.[208] NWEC was generally supportive of RNW's comments.[209]

With respect to the IRP addendum, NIPPC recommended that the Commission make changes to PGE's proposed provisional program.[210] It appears that NIPPC would like to require the Company to (1) allow bidders to rely on PGE's BPA transmission rights for delivery; (2) allow for additional products

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[204] *See* LC 73 Opening Comments of Staff at 40, LC 73 Opening Comments of RNW at 8, LC 73 Opening Comments of NWEC at 7, and LC 73 Opening Comments of NIPPC at 13.
[205] LC 73 Opening Comments of Staff at 41.
[206] LC 73 Opening Comments of RNW at 9, LC 73 Opening Comments of NIPPC at 19-20.
[207] LC 73 Opening Comments of RNW at 7.
[208] *Id.* at 8.
[209] LC 73 Opening Comments of NWEC at 7.
[210] LC 73 Opening Comments of NIPPC at 20.

such as short-term firm and non-firm service; and (3) provide further details regarding RFP scoring of transmission. NIPPC also recommended that PGE base its capacity analysis on "the historical number of actual hours of curtailment of conditional firm service on the impacted path"[211] and that a "discount [to the capacity assessment] may not be appropriate given that expectation that PGE would be able to use its portfolio of existing transmission rights (and rights that are currently in deferral status) to 'firm up' conditional firm service."[212]

PGE's Response

<u>*Firm Transmission Products*</u>

In order to respond to parties' comments, PGE provides the following clarification regarding the different risk profiles of firm versus non-firm transmission products. BPA defines non-firm service as "reserved and scheduled on an as-available basis and is subject to Curtailment of Interruption as set forth in Section 14.7…Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month."[213] Essentially, non-firm transmission is "as-available" transmission that results from either unpurchased short-term firm ATC or unscheduled firm rights. In both cases, non-firm service is available only on a short-term basis, can be recalled due to several factors such as the usage of firm rights, can be superseded by other requests, and is the first service to be curtailed.[214] Regardless of the increment, firm transmission service cannot be recalled because another customer elects to use their existing rights, cannot be superseded by other similar requests, and is curtailed last and on a pro-rata basis with all firm products regardless of duration or increment. These distinctions are important as they highlight the substantially different availability and risk profiles between firm and non-firm service.

PGE procures renewable resources, which may be intermittent, on the basis that they provide energy, capacity, and environmental benefits to our customers. In order to do so, PGE must ensure that these resources have sufficient transmission to deliver their output to PGE's customer load rather than being forced to reduce output or shut off completely. Firm transmission products are the only way to achieve these necessary elements.

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[211] *Id.* at 18.
[212] *Id*.
[213] BPA OATT Section 1.28.
[214] As detailed further in BPA OATT Section 14.7, "The Transmission Provider reserves the right to Interrupt, in whole or in part, Non-Firm Point-To-Point Transmission Service…for economic reasons in order to accommodate (1) a request for Firm Transmission Service, (2) a request for Non-Firm Point-To-Point Transmission Service of greater duration, (3) a request for Non-Firm Point-To-Point Transmission Service of equal duration with a higher price, (4) transmission service for Network Customers from non-designated resources, or (5) transmission service for Firm Point-to-Point Transmission Service during conditional curtailment periods… If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (e.g., hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under the Tariff."

Although wind and solar resources are intermittent resources, their output does not necessarily translate to “non-firm” energy. Instead, integration services are procured or provided to “shape” or supplement the underlying output of the resources to ensure that a flat amount of energy is delivered. This integrated product is relied upon to serve customer demand and requires delivery assurance, which cannot be provided by non-firm transmission service. PGE acknowledges the output of these resources is variable, but to categorize them as non-firm resources implies that they can be interrupted at any point for any reason, which is not the case. Additionally, while the output is variable, there are forecasts and tools used to predict this output and plan for it accordingly in operations. Relying on non-firm transmission service, which is offered only for short-term increments whereas firm service is offered for both long-term and short-term increments, fails to provide the transmission customer with known availability and certainty after procurement. Instead, it diminishes the resource being procured and introduces additional uncertainty and risks with no actual cost benefit.

While NIPPC highlights renewable capacity factors, they fail to acknowledge that these resources produce hourly output at levels higher than their capacity factor and they do not have binary output profiles of maximum production and zero production. Relying on non-firm transmission for these resources would result in attempts to procure transmission using a “just-in-time” approach. Additionally, contrary to NIPPC’s suggestions, the reliability of non-firm products is limited and will become increasingly so as usage grows. Even if non-firm service could be procured on the short notice for which it is available, the use of the service would require PGE to evaluate the appropriate amount and type of reserve capacity needed if non-firm service is recalled or curtailed. These reserves would be above and beyond those for contingency events and integration because the usage of non-firm service is an acknowledgement that the transmission customer is first in line to lose its service with little or no notice required. Importantly, BPA charges the same tariff rate for non-firm and firm service, eliminating any cost savings between the two products. This is counter to NIPPC’s statement regarding more “economic transmission solutions”. However, NIPPC is correct that non-firm service will lead to a higher risk of curtailment of generation and appears to indicate that PGE and its customers should readily accept this and other risks for the benefit of resource developers.

While long-term firm service provides the most assurance, the Company understands the limitations in the region and incorporated those limitations into the Interim Transmission Solution by allowing for conditional firm products and short-term firm products. It is important to delineate between long-term and short-term firm availability, as BPA uses two methodologies with the latter calculated on a more regular basis and using different assumptions that reflect the operating period rather than a longer-term planning period. This distinction is important because the limitations on long-term firm point-to-point service will not all directly carry over to short-term firm service, meaning that there may be increased availability in the short-term. Relying on short-term service introduces more uncertainty but relying on short-term firm service rather than non-firm will mitigate the numerous other risks associated with non-firm. However, reliance on short-term firm service must be balanced with usage of long-term service when procuring long-term resources, either owned or contracted, as short-term service alone provides no assurances over the term of the resource.

Resource Quality and Transmission

Staff's Recommendation 25.h suggests that IRP analysis could be more instructive if it evaluated the trade-offs between selecting resources from areas with the best renewable generation profile and areas with greater ATC. A complication in considering the quantity of transmission resources available is that ATC is only a measure of current capability and does not reflect all capacity that could potentially be used for moving generation to PGE's load. For example, transmission rights could be held by third parties and/or bought and sold among market participants; developers are likely in queue and additional service could result from already planned or low-cost upgrades; and changes to BPA assumptions or methodologies (e.g., outages, renewals, etc.) may impact future ATC. Relying solely on existing posted ATC would omit important information that PGE does not have, which could limit opportunities for customers to secure more cost-effective resources. Furthermore, PGE has no way of determining upgrade costs associated with queued requests as that information only results from a developer participating in BPA's processes (e.g., TSEP and individual study) and is unique to the project.

PGE appreciates the desire of Staff to have a comprehensive understanding of available options and potential cost implications. While PGE believes that an RFP is the best way to achieve price discovery and understand available options, the Company is investigating incorporating average flowgate impacts of sub-regions to inform assumptions about transmission availability and impacts to potential resources.

Diverse Wind Regimes

When evaluating potential new resources, PGE's modeling practices are designed to capture benefits brought by diverse resources. The methodologies for these analyses are compatible with the Interim Transmission Solution.

To the extent that resources in an RFP bring diversity benefits with respect to PGE's existing portfolio or diversity benefits when combined in a portfolio with other bids in the competitive procurement process, the RFP evaluation will capture the diversity benefits. This may include benefits from reducing the potential risks associated with exposure to market price futures and benefits of increased capacity value due to complementary resource characteristics. The RECAP model (described in Section I.3 of the 2019 IRP) captures the capacity contribution benefits of adding complimentary resources to the portfolio. For example, pairing a wind regime that tends to generate during hours when PGE's summer load is high with a wind regime that tends to generate when PGE's winter load is high may produce a higher capacity contribution on a percentage basis than either resource independently.

The RFP analysis will also capture the impact of the transmission services associated with each resource, as described in the Interim Transmission Solution. If a bid contains two or more diverse resources which share one or more legs of transmission service to PGE, the RFP analysis will account for both the diversity benefits of the resources and the limitations or benefits of the transmission service associated with the combined resources. The assessment of the benefits provided will depend on the specific characteristics of the generating resources and transmission service associated with the bid. 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.

Partnerships

In its comments, Staff requested PGE discuss the potential for partnerships or partial shares of larger projects to lower cost and risk for customers.[215] While the benefits in terms of costs and risks are likely project- and partnership-specific, there are benefits associated with shares of larger projects. These benefits generally materialize in the form of fixed costs, such as interconnection costs, being spread over a larger amount of output or as economies of scale due to the larger development, reducing the overall costs. Additionally, partnerships or project shares provide for the ability to share project development risks across multiple counterparties; however, multiple counterparties increase the complexity of negotiations and contracts as requirements or key terms may not align across the partners. PGE has had beneficial partnerships in the past with facilities such as Boardman, Coyote Springs, and the Pelton and Round Butte projects. Generally, the driving factors for such arrangements is broad alignment on need, timing, resource type, and resource location, which can be difficult elements to synchronize across multiple parties.

Scoring Framework

As indicated in parties' comments, PGE provided a scoring framework in the 2019 IRP Addendum when outlining its proposed Interim Transmission Solution. PGE understands the parties' desire for additional details to allow a thorough review of the proposal. While PGE believes that the detailed aspects of the scoring should be vetted further in a subsequent renewable RFP, the Company has attempted to address some of the concerns in **Section 7.3** below.

Sub-region Transmission Paths

As discussed above, a complication in considering the quantity of transmission resources available is that ATC is only a measure of current capability and does not reflect all capacity that could potentially be used for moving generation to PGE's load. Because BPA manages the system through the usage of flowgates rather than explicit paths, there is not a single transmission path for a resource, but rather a set of impacts on the BPA flowgates. The impacts to these flowgates depends on the resource location and point of interconnection. Tools such as BPA's Long-Term Power Transfer Distribution Factor (PTDF) Calculator[216] can be used to estimate these impacts, but the ability to receive transmission service depends on several factors that BPA must assess, such as sub-grid[217] and queue.

[215] LC 73 Opening Comments of Staff at 42.
[216]https://www.bpa.gov/transmission/Doing%20Business/ATCMethodology/Documents/long_term_ptdf_table.xls.
[217] Subgrid is defined as "Any facilities on the interconnected transmission system that do not, by themselves, make up one of the monitored Flowgates e.g., lines, transformers, or substations. *See* BPA Business Practices Acronyms and Glossary.

As stated above, the Company is working to develop an approach to incorporate the average flowgate impacts of sub-regions to provide greater insight to transmission impacts and availability.

6.2. PGE's Transmission Rights

Parties' Comments

NIPPC raised concerns that additional transmission for new renewable resources was needed, stating that "PGE appears to have more than enough transmission to meet its forecasted loads."[218] Additionally, NIPPC proposed that PGE should make its transmission rights available to third parties to support acquisition of new renewable generation,[219] requiring PGE to retain and/or redirect existing rights on behalf of third parties.

PGE's Response

PGE disagrees with several assertions made by NIPPC regarding PGE's transmission rights. In making recommendations regarding third-party use of PGE's transmission rights, NIPPC overlooked the financial risk, redirect risk[220], and renewal risk this would unnecessarily place on PGE and its customers. NIPPC's proposal requires PGE to be the contracting entity with BPA thus, responsible for the financial obligations to BPA on behalf of the developer. It is not reasonable to expose PGE's customers to the financial burden associated with the posting security, deposits and carrying costs associated with transmission service while the third parties who may use such transmission have no exposure to those risks.[221] This risk is compounded because if such assumed third-party beneficiary of the transmission rights fails to energize its facility or otherwise fails to honor the terms of the transmission agreement, PGE's customers could incur these additional costs.

NIPPC's suggestion that PGE could use its existing portfolio of transmission rights[222] on BPA's system to deliver new renewable resources implies the existing rights are broadly redirectable at any point in time. When BPA assesses transmission availability for a redirect, it evaluates the net impacts of the redirect request against as available capacity on each flowgate. Because not all requests have the same flowgate impacts and just because two requests are similar, having existing service and attempting to redirect it does not provide a guarantee of viability. For a redirect request to be granted, BPA must have sufficient capacity on all impacted flowgates, not just a specific subset. For this reason, 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

[218] LC 73 Opening Comments of NIPPC at 14.
[219] *Id.* at 15.
[220] On BPA's system, a customer with existing point-to-point transmission rights can submit a request to move those rights from one POR/POD combination to a different POR/POD combination. This process is known as redirecting.
[221] In fact, third parties' financial exposure to BPA can be mitigated or limited through project entities, whereas should PGE be unable to meet its financial obligations to BPA, PGE's service for all BPA transmission would be at jeopardy.
[222] LC 73 Opening Comments of NIPPC at 15.

that were placed in the queue due to insufficient capacity, granted for only a part of the requested term, or granted for the term and given no renewal rights on the new POR/POD. In the case when a redirect request is granted with no renewal rights, the transmission renewal right reverts to the original POR/POD combination. Thus, potentially stranding the generation asset without transmission to PGE's load.

6.3. Transmission in the IRP

Parties' Comments

Staff expressed concern with PGE's modeling of transmission in the IRP, stating that "because the cost and availability of transmission capacity is closely related to location, Staff is concerned about its ability to evaluate the transmission-related costs or risks associated with this action item."[223] NIPPC raises similar concerns.[224]

PGE's Response

PGE appreciates the concerns raised by both Staff and NIPPC regarding modeling transmission in the IRP. PGE's geographic location makes them reliant on off-system resources to meet a significant portion of system needs, which is primarily enabled by BPA's transmission network. Incorporating this reliance into PGE's long-term planning is a challenging task. Consistent utility practice is to use production cost simulations, which rely on general abstractions of transmission topology and utilization. While modeling existing transmission infrastructure, and planned expansions, may be a focus of power flow simulations underpinning transmission reliability studies, it is currently not clear that their inclusion in long-term least cost least risk planning analysis would lead to more credible planning. Taking these factors into consideration while developing more rigorous insights into transmission as it relates to long-term planning will require analytical innovation and close collaboration with stakeholders. PGE looks forward to working with both Staff and stakeholders to improve the treatment of transmission-related constraints in PGE's future IRP analysis.

7. RFP Information

Parties' Comments

Staff requests additional explanation of how PGE has complied with the competitive bidding rules. Staff is specifically interested in better appreciating how PGE has complied with OAR 860-089-0250(3)(g), that calls for "The alignment of the electric company's resource need addressed by the RFP with an identified need in an acknowledged IRP."[225]

NIPPC argues that PGE has not made any reasonable effort to comply with the Commission's competitive bidding rules and asks that the Commission require that PGE re-file the IRP with additional

[223] LC 73 Opening Comments of Staff at 40.
[224] LC 73 Opening Comments of NIPPC at 8.
[225] OAR 860-089-0250(3)(g)

analysis regarding the PGE's proposed RFP elements, scoring methodology, and modeling.[226] NIPPC maintains that compliance with the competitive bidding rules requires a detailed accounting of all proposed non-price scoring criteria and scores.[227] NIPPC believes that the absence of such detail is the major deficiency of PGE's Appendix J, which describes the elements and methods for PGE's proposed renewable RFP.[228] NIPPC interprets the Commission's competitive bidding rules to require within the IRP filing, scoring criteria whose detail is equivalent to that which would be included in a final RFP filing. Without such a detailed account of non-price scoring within the IRP, NIPCC argues that the role of the IRP within the RFP approval process would be meaningless.[229]

PGE's Response

PGE believes the 2019 IRP positions the Company to comply with all competitive bidding rules including OAR 860-089-0250(3)(g) following the request for approval of an RFP. PGE has identified a set of actions that will allow the Company to pursue resources with attributes as identified within the preferred portfolio. Should the Commission choose to acknowledge PGE's Action Plan, PGE's proposed RFP for renewable resources of an energy volume comparable to acknowledged Action Plan would comply with OAR 860-089-0250(3)(g) through explicit alignment with the acknowledged Action Plan.

As a procedural matter, PGE notes that the new competitive bidding rules contemplate that certain aspects of RFP be consistent with informational content included in the IRP and specific acknowledged actions proposed in the IRP. But it is PGE's understanding that the competitive bidding rules do not alter the criteria by which the Commission should acknowledge the IRP -- the competitive bidding rules relate to RFP requirements, not IRP acknowledgment guidelines. The competitive bidding rules establish the required content and process necessary to receive RFP approval in a subsequent proceeding, but the competitive bidding rules alone do not establish requirements necessary to receive IRP acknowledgment.

PGE disagrees with NIPPC's characterization of the intent of the competitive bidding rules and NIPPC's interpretation of the rules. Importantly, PGE believes NIPPC may misunderstand PGE's Appendix J as a request for acknowledgment of a final RFP design, which is not PGE's position. PGE's Appendix J is an informational filing that describes the scoring methods, tools, and elements that will the basis for resource evaluation in a future renewable RFP.

Plain reading of the competitive bidding rules makes clear that information and content included in the IRP regarding a proposed RFP is distinct from the information and content included in an RFP approval application. Complete and detailed scoring criteria are to be included in the draft and final

[226] LC 73 Opening comments of NIPPC at 3.
[227] *Id.* at 27.
[228] *Id.*
[229] *Id.* at 31.

RFPs filed with the Commission, not the IRP.[230] If the Commission intended for utilities to include complete RFP approval applications in the IRP, the rules would say so and would not include the considerable detail regarding the necessary process for reviewing and approving RFP designs within the RFP approval process.

PGE believes that finalizing and included all details associated with RFP non-price scoring is outside the scope of the IRP proceeding. PGE's disagrees with NIPPC's interpretation of the rules that would require PGE to include such detailed non-price scoring information within the IRP. While OAR 860-089-400 requires that final non-price scoring criteria be objective and reasonably subject to self-scoring by bidders, the requirements relate to the approved scoring criteria included in RFP applications filed with the Commission. Furthermore, the final non-price criteria should be consistent with characteristics included in an informational IRP filing. This requirement should not be construed to require all proposed non-price scoring criteria within the IRP. Such a requirement would be inconsistent with IRP guidelines and the competitive bidding rules.

The intent of the competitive bidding rules' reference to IRP information and content is to create consistency regarding the methods and tools that are used within a utility's resource evaluation. To that end, PGE has described the resource evaluation methods and characteristic RFP elements that will determine resource evaluation in the RFP. PGE does not believe that the intent of the competitive bidding rules is to move the RFP approval process entirely into the IRP proceeding or use the IRP process to fully consider all aspects of RFP design.

7.1. Identifying Potential RFP Resources

Parties' Comments

In recommendation 19.d, Staff requested PGE "[a]nalyze the OASIS interconnection and transmission queues for PGE, BPA and PAC to develop an understanding of the pool of possible resources able to compete and come online by 2023 proposes using OASIS to identify a pool of resources."[231]

PGE's Response

PGE appreciates Staff's efforts to further understand the development status of resources in the Pacific Northwest. However, PGE does not believe this exercise would lead to credible forecast of resources that would participate in a 2020 RFP. The BPA interconnection queue alone has almost 100 requests with varying request dates, points of interconnection, and status. The interconnection queue does not indicate which entities have an interest in participating in PGE's 2020 RFP. Additionally, there is no explicit relationship between interconnection queue position and the transmission service request queue as the two function independently.

[230] OAR 860-089-0400 (1): "To help ensure that the electric company engages in a transparent bid-scoring process using objective scoring criteria and metrics, the electric company must provide all proposed and final scoring criteria and metrics in the draft and final RFPs filed with the Commission."
[231] LC 73 Opening Comments of Staff at 33.

Regarding the transmission service request queue, there are hundreds of possible substation combinations which could be used to move generation to load. PGE is unable to determine which requests would successfully get through the queue, what offers and upgrades the entity may have already received, or ultimate plan of service is expected to be, assuming the entity was planning to participate in PGE's 2020 RFP. As noted above, any such analysis would also omit transmission rights currently held by developers or third-parties and the results of any pending TSEP cluster study.[232]

PGE continues to believe a solicitation is the best way to gauge the market. Ultimately, PGE reserves the right to elect not to move forward with the results of an RFP depending on the quantity and quality of responses received. However, based on response to PGE's recent Green Tariff Phase 1 solicitation and other general knowledge about resource development in the region, PGE is aware of facilities that can achieve a 2023 COD and expects a robust market response to an RFP.

7.2. Renewables RFP Timing

Parties' Comments

Both RNW and NIPPC suggested aligning the proposed 2020 renewables RFP to account for BPA's transmission related timelines.[233,234] NWEC generally supports the views submitted separately by RNW.[235]

PGE's Response

PGE appreciates the comments and responsive feedback from parties regarding the Interim Transmission Solution proposal the Company provided in the IRP Addendum. PGE appreciates the flexibility of parties in reviewing the IRP Addendum given the timing of this proceeding. As PGE's expected RFP evaluation will suitably align with BPA's TSEP process and allows for potential bidders to use the other options available to them, such as individual study and requesting conditional firm service.

Regarding BPA's TSEP process, PGE has identified and attempted to incorporate the timing and stages of the TSEP process into its proposal. Importantly, PGE expects that most bidders will be able to participate in an RFP by demonstrating available inventory of conditional firm reassessment service. PGE's proposed RFP eligibility requirements require " a notice of available long-term firm inventory… [or] demonstrated participation in an ongoing transmission study (cluster study or individual study) ."[236] Additionally, PGE's proposal allows time for TSEP results to be developed by requiring additional information by December 31, 2020, which will be a year and a half after BPA issued its 2020 TSEP notice.

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232 This point was also included in LC 73 Opening Comments of NIPPC at 10.
233 LC 73 Opening Comments of NIPPC at 20-37.
234 LC 73 Opening Comments of RNW at 8-10.
235 LC 73 Opening Comments of NWEC at 8.
236 PGE's 2019 IRP Addendum – Interim Transmission Solution at 10.

If bidders are unable to demonstrate available inventory of condition firm reassessment service, PGE recognizes that this approach may require bidders to participate in the TSEP process. For those bidders, transmission study participation must be planned for accordingly. However, PGE believes that the information provided by participation in TSEP is essential for determining both the costs and viability of a bid. Additionally, procuring transmission service is an essential part of the resource development cycle and bidders should be familiar with the transmission service processes.

PGE's proposed approach in the Interim Transmission Solution is designed to allow for full participation in a TSEP or BPA study process. For a bid to be qualify for the RFP, it must satisfy the initial conditions that allow the bidder to provide a description of its transmission plan and at minimum demonstrate available transmission inventory or participate in a transmission study. Final short-list eligibility requires the bidder to have received an acceptable offer of transmission service which include: "a full offer of transmission service, an executable PTSA, offer of conditional firm transmission service, or a proposed plan of service identified from a transmission study for which the bidder has received completed preliminary engineering results and has signed an Environmental Review Agreement."[237]

PGE expects to be positioned to incorporate the results of BPA's next cluster study into its final bid evaluation. BPA's current estimated start date for the 2020 cluster study is January 2, 2020, and the results are expected 120 days after starting the study. Bidders with offers of conditional firm service, both bridge and reassessment, made outside or within cluster study process will meet this final short-list requirement.

7.3. RFP Scoring Methodology

Parties' Comments

In Opening Comments, Staff was concerned at the level of detail included in the IRP about the methodology to be employed in the RFP: "PGE seems to have attempted to push the details about this framework to the RFP process, leaving the Commission with limited information on which to make a major acknowledgement decision about resource need in the IRP."[238] They further stated that "Additional detail should be provided in order to give the Commission a full representation of transmission requirements in advance of the RFP process."[239] NIPPC too recommended more detail on the RFP process.

Further, Staff states PGE's methodology will also "assume that the curtailment occurs in those hours in which PGE experiences the greatest capacity need as it is reasonable to assume that the curtailment occurs during the periods of greatest system stress also experienced by PGE. The Company does not provide any evidence for this assumption."[240] Both NIPPC and RNW suggested that any reduction in

[237] *Id.* at 9.
[238] LC 73 Opening Comments of NIPPC at 18.
[239] *Id*.
[240] LC 73 Opening Comments of Staff at 41.

capacity value attributed to less than long-term firm transmission products be based on historical curtailment.

PGE's Response

PGE notes that while issues outlined in PGE's 2019 Addendum are typically vetted in an RFP proceeding, PGE has provided in this information in this IRP proceeding based on stakeholder and Commission interest in this topic. PGE recognizes that the approval process will occur in a subsequent RFP proceeding and not as part of IRP acknowledgment. Detailed scoring criteria associated with proposed resources will be vetted and approved in an RFP proceeding. PGE recognizes stakeholder's and the Commission's specific interest in transmission limitations and valuation methods and has attempted to be responsive to those questions within the IRP. Accordingly, PGE offers these informational descriptions of RFP scoring methods in the Interim Transmission Solution and in these comments but may propose alternative methods and specific detail within subsequent RFPs where review and approval of this Interim Transmission Solution will be considered. In the 2019 IRP Addendum, PGE identified three areas of an RFP that will be impacted by the Interim Transmission Solution: price scoring, non-price scoring, and contract requirements. We cover each of these three below.

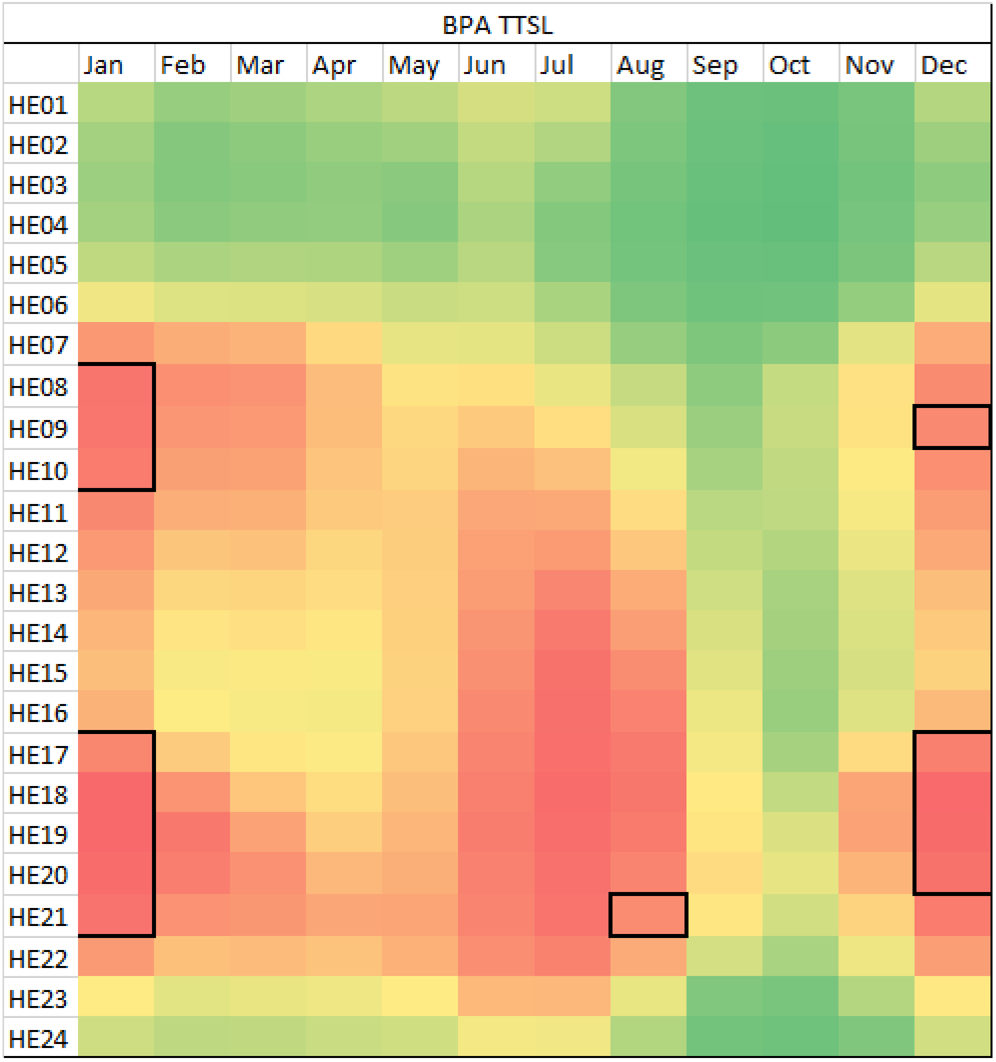
Price Scoring

In its proposal, PGE offers the following adjustments to the Company's capacity scoring approach: "capacity value estimation methodology will only credit capacity value for the portion of a resource served on long-term transmission (including LTF, CFB, CFR)."[241] Capacity value will not be assessed for the portion of the resource expected to be served on short-term firm. Furthermore, for those resources that plan to rely on conditional firm service, the expected output of the resource will be diminished by the number of hours of allowed curtailment identified in the transmission service offer or plan.[242] PGE's approach is based on the assumption that the transmission system will be most heavily in use at times when PGE's system is experiencing highest need. During these times, PGE is expected to be in the most difficult position to be unable to manage curtailment would occur and believes it is a prudent and conservative assumption to plan for curtailments to occur during periods of highest need, which coincide with periods of highest system usage. Furthermore, PGE assumption is consistent with regional data regarding periods of elevated transmission loading. In response to Staff's request for additional detail, PGE reviewed BPA's public Total Transmission System Load (TTSL) information to determine the times of high loads on BPA's system and compare those to the month/hours identified by PGE.

Figure 15 shows a heatmap of these month/hours.

[241] 2019 IRP Addendum at 10.
[242] Id. at 9.

Figure 15: Heat Map of BPA Total Transmission System Load



The hours outlined in bold represent the highest 400 hours of PGE capacity need and would serve as assumed curtailed events when analyzing a 400-hour conditional firm product. As demonstrated by **Figure 15**, these hours are coincident with the highest loading hours of BPA's system.

Multiple parties also suggested that PGE rely on historic curtailment when evaluating capacity scoring impacts in the RFP. PGE does not agree with this approach for several reasons, including: (1) there is little to no historic data for conditional firm service as it has not been widely used; and (2) history is likely not a good predictor given the future projections of the transmission system. NIPPC highlights the latter point in its comments, "BPA has declared repeatedly that transmission in the Northwest is increasingly constrained and that BPA will no longer build transmission to solve congestion on its system…"[243] While curtailment information and statements from BPA reflect that conditional firm service has been curtailed approximately 10 hours each year over the last two to three years, PGE's RFP evaluation is aimed at evaluating resources over periods of 20 years or longer. Recent history is unlikely to be a good indicator of the future and it is prudent to evaluate all resources equally under

[243] LC 73 Opening Comments of NIPPC at 11.

the same conditions of what is allowed under their specific transmission arrangements. A shorter-term estimate of curtailment hours may be more appropriate for other forecasting purposes, but evaluation of a long-term resource should be done using assumptions that reflect the long-term risks. Conditional firm reassessment service allows BPA to reassess the number of hours or system conditions on a two-year basis, which may result in increased curtailment hours/conditions or reduced ability to offer service. While PGE cannot accurately predict how transmission service may be curtailed, reassessed, or recalled over a resource's life, it is prudent and reasonable to assess the resource based on its stated number of hours provided by BPA. Additionally, as PGE articulated in the 2019 IRP Addendum and parties recognized in their comments, a primary purpose of the Interim Transmission Solution is learning. As PGE gains experience, particularly with conditional firm service and increasing reliance on shorter-term service, the Company plans to adjust its evaluation methodologies appropriately.

At the October 31, 2019 public meeting, parties also requested further information on PGE's stated preference for number of hours conditional firm service over the system conditions option. PGE continues to believe that the number of hours option is superior to the system conditions option. System conditions can be broadly defined to allow for curtailment under a wide set of possible scenarios whereas the number of hours serves as a limit on such actions. Additionally, if the number of hours has been reached in a given year, BPA's business practice is to convert the conditional firm service to firm for the balance of the year. System conditions does not have this attribute.

As a general matter, both number of hours and system conditions draw from the same overall conditional firm inventory. System conditions and number of hours are two service options for a single transmission product. The cost for either option is the same, and both are subject to the same reassessment conditions and two-year reassessment timing (e.g. all system constraints, not just those identified in the initial study). The number of hours option provides a more robust framework with known limits that better serve to address the inherent risks associated with conditional firm service. Furthermore, as the load serving entity receiving delivery on the transmission service, PGE is the primary entity must manage the operational and financial risk associated with conditional firm transmission service. Given this allocation of risk, it is appropriate for PGE to elect service that best manages curtailment risk particularly when the participating counterparty may elect either service option without impact on cost or availability.

<u>Non-Price Scoring</u>

Non-price scoring is designed to assess the risks and other difficult to quantify elements of a resource. Changing transmission requirements will introduce additional risks to resource procurement as well as additional elements that PGE will initially be unable to quantify. In order to address these, PGE expects to introduce additional non-price scoring components to evaluate transmission service. PGE has not identified specific non-price scoring weightings or point values; they will be proposed and reviewed within an RFP. However, the Company can provide informational detail of likely non-price scoring criteria related to transmission to further discussion within the IRP. As described above, PGE may propose alternative non-price scoring criteria within the RFP but would expect to evaluate similar resource characteristics. **Table 9** contains example non-price categories and a brief explanation of each.

Table 9: Description of example non-price score components

Non-Price Component	Explanation
Conditional Firm Reassessment vs. Conditional Firm Bridge	Bridge service will eventually convert to long-term firm while reassessment will not. PGE expects to assign additional points to bids using bridge service.
Status of Transmission Request(s)	The status of transmission request(s) is expected to differ from bid to bid. PGE expects to award more points to bids that are further along in the process (e.g. have accepted an offer vs. in TSEP initial queue).
Conditional Firm Bridge Expected Conversion	Bridge service remains conditional until the completion of the identified upgrades. Bids with bridge service with nearer term upgrades are expected to receive additional points.
Higher Than 80% Conditional Firm vs. Short-Term Firm	Bidders may elect to procure conditional firm service for more than 80% of the resources nameplate rather than relying on short-term firm. Greater quantities of long-term service provide greater certainty of availability. More points are expected to be awarded to higher levels of long-term service.

Contract Requirements

As a general matter, when PGE enters into a commercial contract with a counterparty for construction or long-term delivery of a resource, PGE seeks to appropriately assign risks to the counterparty to protect PGE's customers from failure to perform or other unforeseen circumstances. This principle extends to delivery and transmission risk. PGE believes that they can mitigate some of the delivery risk via the product requirements outlined in the Interim Transmission Solution. However, transmission risk will continue to exist, particularly with conditional firm and short-term service.

As detailed in the 2019 IRP Addendum, PGE is proposing a change from historical practice, which allowed assignment of transmission rights to PGE. Proposed assignment of conditional firm service will be more carefully considered.[244] As an alternative PGE may consider managing and using transmission rights of the counterparty, but not becoming the transmission contract holder. PGE may

[244] 2019 IRP Addendum at 6.

continue to allow for assignment provided that risks to PGE and customers are limited and otherwise offset by the counterparty.

PGE also identified other contractual considerations within the 2019 IRP Addendum, such as requiring the exploration of converting conditional firm to long-term firm. However, as PGE noted in the Addendum, "The Company would not explicitly require that conditional firm service be converted to LTF service regardless of cost."[245] Currently, PGE does not plan to impose these costs solely on the bidder, but instead is seeking to ensure that opportunities to upgrade the quality of transmission service are made available to the Company and its customers. PGE recognizes that the specific terms and conditions governing responsibility are subject to negotiation and does not believe it is appropriate to attempt to provide such details in this forum when they are unknown at this time. PGE also identified its expectation to:

> Address the increased deliverability risk by more clearly assigning deliverability responsibility to the supplier through more robust contract terms. Generally, these terms would address the quality of transmission procured for output above the level supported by long-term transmission, changes to the terms and conditions of the conditional firm service, minimum production guarantees, and failure to perform provisions should short-term transmission products not be available or the Bonneville Power Administration (BPA) cease to offer conditional firm service.[246]

Again, PGE is not seeking to saddle bidders with unrealistic contract provisions or unmanageable requirements. Instead the Company is proactively identifying areas of change that will need to be addressed and reviewed in the RFP contracting process. PGE seeks to ensure that any negotiated contract adequately addresses the reasonable realm of possible changes so as to remove ambiguity and manage risk.

As a practical matter, commercial counterparties are generally unwilling to incur meaningful transmission risks and PGE should not expect that fundamental limitations associated with the availability of transmission products can all be overcome through creative contracting with a willing counterparty. Instead PGE has proposed the Interim Transmission Solution to allow for the procurement of additional renewable resources that would otherwise be limited and to create the time and space to evaluate the additional risks faced by PGE and its customers associated with non-long-term firm products.

[245] *Id.* at 5.
[246] *Id*.

8. Other Topics

8.1. Boardman

Parties' Comments

Staff, in Recommendation 17, recognizes that the federal Regional Haze program has at times required generators to install Selective Catalytic Reduction (SCR) technology.[247] In this same recommendation, Staff also suggested that emissions control technology investments for utilizing torrefied biomass at Boardman may potentially be avoided if the plant were "operated significantly fewer hours in a year than the Boardman coal plant historically operated."[248] Staff also recommended "a stakeholder workshop within the IRP docket to discuss the potential for sustainably harvested biomass capacity at the Boardman plant."[249] The US Endowment for Forestry and Communities, which filed comments highlighting their sustainably harvested biomass product, advocated for continued testing of torrefied biomass at the Boardman facility and asserted that the fuel replacement could lead to "possible decommissioning of extant pollution control equipment at Boardman."[250]

PGE's Response

As stated in PGE's response to LC 73 OPUC Data Request No. 133, for the purposes of air quality permitting, emissions for the Main Boiler at Boardman are reduced to zero for all pollutants once coal fired operations are ceased by December 31, 2020, consistent with state of Oregon Regional Haze rules found in OAR 340-223-0030. At that point, permitting the Main Boiler to operate on torrefied biomass would be functionally equivalent to permitting a newly built facility. PGE has included the installation of SCR technology in our preliminary Boardman biomass air quality analysis. This SCR assumption is connected to the expected Prevention of Significant Deterioration (PSD) pre-construction permitting requirements that would likely apply to the plant upon re-permitting, and not solely for compliance with the federal Regional Haze program. Based on our preliminary air quality analysis, even with extremely limited hours of operation of the Main Boiler on torrefied biomass (in the range of 70-100 hours per year[251]), PSD pre-construction permitting requirements would likely be triggered. And to comply with the Best Available Control Technology (BACT) requirements under the PSD permitting program, the expected NOx emission limit for the Main Boiler would likely only be achieved with the installation of post combustion emissions controls such as an SCR or Selective Non-Catalytic Reduction (SNCR).

PGE filed an update to the Boardman decommissioning plan on November 1, 2019 under Docket No. UE 230. In this filing, PGE discusses an option to further assess potential future uses for Boardman and its associated equipment consistent with our greenhouse gas reduction and clean energy

[247] LC 73 Opening Comments of Staff at 29.
[248] *Id*.
[249] *Id*.
[250] LC 73 Opening Comments of US Endowment for Forestry and Communities at 2.
[251] Assuming a single startup/shutdown and operating load between 63 percent and 100 percent.

commitments. PGE will provide updates on developments related to this effort within future IRPs and/or IRP Updates.

8.2. Climate Change Adaptation

Parties' Comments

Staff proposed as part of Recommendation 10 that PGE develop and submit a climate adaptation plan within the 2019 IRP Update.[252]

PGE's Response

PGE supports the suggestion from Staff to create a long-term climate change adaptation plan, and we look forward to working with Staff and stakeholders to begin developing this analysis. Due to the complexity of such an effort, PGE suggests that this be included as an enabling study for the next IRP, rather than an addition to the 2019 IRP Update. This process could potentially leverage previous work from our 2015 Climate Change Study, our 2018 Decarbonization Roadmap, as well as current regional efforts to develop climate change models led by the Northwest Power and Conservation Council and other entities.

In their comments, Staff noted that PGE should consider how "factors such as population growth, severe weather, hydro flows, temperature increases, and air conditioning penetration could interact to change the costs, risks, and strategies associated with reliably serving peak load."[253] PGE clarifies that these factors have been considered in the 2019 IRP analysis through the application of load growth scenarios, hydro generation scenarios, and technology penetration scenarios. Though these varied drivers of cost and risk provide a reasonable bandwidth of potential futures for IRP analysis, they are not explicitly combined to reflect the specific goal of climate change adaptation because this is beyond our planning scope as it is currently defined.

9. Conclusion

In the 2019 IRP, PGE introduced new approaches and methodologies to address the substantive concerns that the Commission and stakeholders raised in evaluating the 2016 IRP, with a focus on addressing uncertainty, optionality, flexibility, customer decisions, and decarbonization. In some cases, these new approaches introduced additional complexity and new insights. PGE appreciates the efforts that stakeholders made to provide feedback on these approaches in the public roundtable process and to provide for a thorough review of PGE's approach within LC 73. Parties' comments encompassed a wide range of substantive topics. In these comments, PGE aimed to provide additional information and analysis where requested, to describe PGE's perspective on topics where it may differ from parties' comments, to give an indication of when and how PGE plans to provide additional information or analysis, and to update the Action Plan to provide for better assurances that actions will be aligned with customers' best interests.

[252] LC 73 Opening Comments of Staff at 17-19.
[253] *Id.* at 18.

As described in these comments, the additional analysis and consideration conducted to date continues to support the primary components of the Action Plan. However, PGE is proposing two conditions to the Action Plan to address Staff concerns that the Renewable Action as originally proposed may not adequately reflect the key attributes of resources in the preferred portfolio and to ensure that long-lead-time resources have the opportunity to participate in the non-emitting capacity RFP. In addition, PGE proposed to conduct three Enabling Analyses to support future IRPs, which will address: (1) transmission-related constraints; (2) climate adaption; and (3) solar integration cost drivers. PGE also committed to update the needs assessment in November 2019, hold a stakeholder workshop on the intergenerational equity analysis, and provide additional information on Colstrip when it becomes available.

PGE continues to approach the central questions of the 2019 IRP with a focus on rigorous analysis, consideration of market realities, and input from the Commission and stakeholders in order to achieve the best balance of cost and risk. 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 its 2019 IRP at its January 28, 2020 public meeting.