ITEM NO. 1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
SPECIAL PUBLIC MEETING DATE: March 16, 2020

REGULAR X **CONSENT** ____ **EFFECTIVE DATE** N/A

DATE: February 27, 2020

TO: Public Utility Commission

FROM: Caroline Moore

THROUGH: Michael Dougherty and JP Batmale

SUBJECT: PORTLAND GENERAL ELECTRIC:
(Docket No. LC 73)
Acknowledgement of 2019 Integrated Resource Plan

STAFF RECOMMENDATION:

Acknowledge in part and decline to acknowledge in part Portland General Electric's (PGE or Company) 2019 Integrated Resource Plan (IRP). Commission Staff (Staff) recommends certain actions and additional requirements for inclusion in future resource acquisitions, the IRP update, and future IRPs.

SUMMARY OF STAFF RECOMMENDED ACTIONS

A summary of Staff's recommendations for each of PGE's IRP Action Items is provided below. The Action Items and Staff's recommendations for acknowledgement are discussed in further detail throughout this report. This section also summarizes additional recommendations for future analysis and planning improvements.

CUSTOMER RESOURCE ACTIONS

Action 1A: Seek to acquire all cost-effective energy efficiency (EE), which is currently forecast by the Energy Trust of Oregon (Energy Trust) to be 157 MWa on a cumulative basis by 2025.

Recommendation: Acknowledge subject to the following modifications:

- Energy Trust's baseline EE projections should to be treated like minimums. Before the next IRP, PGE should work with Energy Trust and stakeholders to explore the potential for PGE's portfolio modeling to select incremental energy efficiency that is least cost, least risk, beyond Energy Trust's baseline forecast.
- Before the next IRP, PGE should work with Energy Trust to produce distinct high and low energy efficiency forecasts that do not have predetermined trajectories, but are consistent with the assumptions of the load scenario used.
- Before the next IRP, PGE and Energy Trust should work together to:
    - Study current and forecasted data center load and EE measures; and
    - Consider adoption of the Northwest Power and Conservation Council (NWPCC) EE capacity value modifiers.

Action 1B: Seek to acquire all cost-effective and reasonable distributed flexibility, which is currently forecasted to include approximately 141 MW of winter demand response, 211 MW of summer demand response, 137 MW of dispatchable standby generation, and 4 MW of dispatchable customer storage.

Recommendation: Acknowledge subject to the following modifications**:**

- File a Flexible Load Plan by June 2020 that includes a section on the cost-effectiveness of demand response, and continue working with the Demand Response Advisory Group (DRAG) to identify ways to position the Company to exceed the high end of forecasted demand response, such as considering additional distributed flexibility as a resource in portfolio modeling.
- Provide a status update on key findings from the Flexible Load Plan, Demand Response Test Bed, and DRAG that could impact demand response targets in the IRP Update.

<u>RENEWABLE ACTIONS</u>

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

Recommendation: Not acknowledge the standalone Renewable RFP. Alternatively, if acknowledged, the action list should be conditioned in one of two ways:

- Modify Action 3B Dispatchable Capacity RFP to consider non-dispatchable capacity options; or
- Subject the Renewable RFP to the following conditions:
    - PGE may not submit a benchmark resource to its RFP.

- The cost containment screen must require bids to meet the key cost and performance attributes of the preferred portfolio.
- PGE should engage in a rigorous stakeholder process prior to the selection of an Independent Evaluator (IE) and filing of a draft RFP to determine how the non-dispatchable capacity resources in the Renewable RFP will be considered concurrently with the resources in the dispatchable capacity RFP, such that any resource acquisitions are optimized on a portfolio level.
- The risk of proceeding must remain with PGE unless and until the Commission completes a prudence review and approves cost recovery of any renewable resources acquired under the IRP in rates. Rate recovery may be conditioned or limited to ensure customer benefits remain at least as favorable as IRP planning assumptions, including but not limited to a return of the full value of the Production Tax Credit (PTC) to ratepayers.
- PGE cannot assume it returns the value of the RECs from resources acquired through the RFP to customers. capacity Actions

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

***Recommendation*:** Acknowledge subject to the condition that PGE provide monthly status updates to the Commission on its bilateral capacity procurement efforts.

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

Recommendation: Acknowledge subject to the following modifications:

- PGE must engage in a rigorous stakeholder process prior to the selection of the IE and filing of a draft RFP to:
  - Establish the RFP elements, scoring methodology and associated modeling, including those detailed by Staff in this report
  - Clarify the key attributes of the capacity resources the Company will seek, including the Company's specific dispatchable and/or flexible capacity needs and transmission requirements.
  - Determine how non-dispatchable capacity resources can be considered concurrently with dispatchable capacity resources to ensure resource acquisitions are optimized on a portfolio level.

- PGE must update and refine its capacity needs prior to issuing a capacity RFP.
  - PGE must update its market import assumptions.

  - PGE must update its needs assessment to reflect the outcome of bilateral negotiations, any changes in voluntary products, the Qualifying Facility (QF) forecast, and any changes in the Long Term Direct Access program.

GENERAL IRP COMMENTS

Staff recommends that the Commission's acknowledgement of PGE's IRP is subject to additional conditions related to the following:

- Interim transmission solution
- RPS compliance and banking strategy
- Load forecast
- Non-traditional metrics
- Market energy position (MEP) analysis
- Decarbonization strategy

ENABLING ANALYSES

Staff recommends the following PGE-proposed analyses in the IRP update:

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

Staff recommends the following PGE-proposed analyses prior to the next IRP:

- Transmission-related constraints in portfolio modeling
- Solar integration cost drivers
- Colstrip customer impacts

ADDITIONAL ANALYSES AND RECOMMENDATIONS

Staff recommends the Commission direct PGE to include the following additional analyses in future IRPs and IRP Update as noted below:

- In an IRP update:
  - Emissions forecast update
- Before the next IRP:
  - Market price forecast enhancements
  - The probability of individual futures
  - Discount rate sensitivities for intergenerational equity
  - Flexibility value for hybrid energy and storage resources

DISCUSSION:

ISSUE

Whether the Commission should acknowledge PGE's 2019 IRP, acknowledge specific portions of the IRP with or without certain conditions, or decline to acknowledge the IRP.

APPLICABLE LAW

The Commission adopted least-cost planning as the preferred approach to utility resource planning in 1989.[1] In 2007, the Commission updated its existing least-cost planning principles and established a comprehensive set of "IRP Guidelines" to govern the IRP process. The IRP Guidelines found in Order Nos. 07-002 (corrected by 07-047), 08-339, and 12-013 clarify the procedural steps and substantive analysis required of Oregon's regulated utilities in order for the Commission to consider acknowledgement of a utility's resource plan.[2]

The IRP Guidelines and Commission rules require a utility to file an IRP with a planning horizon of at least 20 years within two years of its previous IRP acknowledgment order, or as otherwise directed by the Commission.[3] Further, the IRP must also include an "Action Plan" with resource activities that the utility intends to take over the next two to four years.[4] The utility's IRP should satisfy the IRP Guidelines and Commission rules for its determination of future long-term resource needs, its analysis of the expected costs and associated risks of the alternatives reviewed to meet its future resource needs, and its near-term Action Plan to achieve the IRP goal of selecting the "portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[5] This is often referred to as the "least cost/least risk portfolio."

The Commission reviews the utility's plan for adherence to the procedural and substantive IRP Guidelines and generally acknowledges the overall plan if it is reasonable based on the information available at the time.[6] However, the Commission explains: "We may also decline to acknowledge specific action items if we question whether the utility's proposed resource decision presents the least cost and risk option

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[1] Order No. 89-507.
[2] Order Nos. 07-002 and 07-047. Additional refinements to the process have been adopted: See Order No. 08-339 (IRP Guideline 8 was later refined to specify how utilities should treat carbon dioxide (CO2) risk in their IRP analysis); Order No. 12-013 (guideline added directing utilities to evaluate their need and supply of flexible capacity in IRP filings).
[3] Order No. 07-002 (Guidelines 1(c) and 3(a)) and OAR 860-027-0400.
[4] Order No. 14-415 at 3.
[5] Order No. 07-002 at 1-2.
[6] *Id.* at 1.

for its customers."[7] The Commission may also provide direction on additional analysis or actions for the next IRP or IRP Update.[8]

Also applicable to review of PGE's 2016 IRP is whether it complies with all of the Commission requirements in its previously acknowledged IRP. For example, PGE's 2013 IRP (LC 56) was acknowledged in Order No. 14-415, but the Commission required several activities, in addition to routine resource planning work, for PGE to undertake and include in its 2016 IRP filing. Thus, in addition to IRP Guideline compliance, Staff reviews whether PGE has complied with the Commission's order in LC 56.

ANALYSIS

Procedural History

Prior to filing the IRP, PGE held several public workshops and a community listening session.[9] On July 19, 2019, PGE filed its 2019 IRP. On August 13, 2019, PGE presented its IRP to the Commission at a Public Meeting. The Company filed its first addendum, the Interim Transmission Proposal, on August 30, 2019. Because of the introduction of this new information shortly before the original September 19, 2019, deadline for Opening Comments, Staff and intervening parties were granted an extension and filed opening comments October 11, 2019. Opening Comments were submitted by Staff and:

- Alliance of Western Energy Consumers' (AWEC);
- Northwest Energy Coalition (NWEC);
- Northwest and Intermountain Power Producers Coalition (NIPPC);
- Oregon Citizens' Utility Board (CUB);
- Renewable Energy Coalition (REC);
- Renewable Northwest (RNW);
- Swan Lake North Hydro, LLC (Swan Lake); and
- U.S. Endowment for Forestry and Communities (US EFC).

Parties participated in a Commissioner workshop on October 31, 2019, which also included a presentation about transmission products and availability by Bonneville Power Administration (BPA).

PGE filed its Initial Reply Comments on November 5, 2019. On November 27, 2019, PGE filed an Updated Needs Assessment. Due to the introduction of new information shortly before the December 3, 2019, deadline for Final Comments, Staff and

[7] *Id.*
[8] OAR 860-027-0400(7), (10).
[9] For more information please see the PGE IRP meetings website: https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning/irp-public-meetings.

intervening parties were granted a second extension and filed Final Comments on December 17, 2019. Final Comments were filed by AWEC, NWEC, NIPPC, CUB, REC, RNW, and Swan Lake.

On January 17, 2020, PGE filed its Final Reply Comments, which included modifications to its Action Plan. This was followed by a Commission Workshop on January 30, 2020, where additional information about the Company's modified Action Items were discussed.

Staff files this memorandum in advance of the March 16, 2020, Special Public Meeting.

As noted by the Commission at the January 30, 2020, Special Public Meeting, a robust IRP process requires a certain degree of fluidity. Staff agrees that IRPs should evolve with new analysis and changing conditions. However, this flexibility must occur with an awareness that parties' ability to comprehensively review the plan will be limited and resolution of significant issues could be shifted to procurement and ratemaking efforts.

Staff's recommendations for acknowledgement are, therefore, designed to keep pace with PGE's evolving resource strategy while preserving the IRP processes' least cost, least risk requirements. Throughout the remainder of this report, Staff makes its recommendations for acknowledgement based on the level of information currently available through discovery, comments, and workshop discussion. Where Staff finds concepts promising but lacking certainty, it does not recommend acknowledgement, but provides recommendations for the least cost, least risk manner to move forward if PGE choses to do so.

Action Plan

The chart below summarizes PGE's final Action Plan items.

<table>
<tr><th colspan="3">Table 1: Summary of 2019 IRP Action Items</th></tr>
<tr><th>Category</th><th>2019 IRP Action Items</th><th>PGE Modifications</th></tr>
<tr><td>Customer Resource Actions</td><td>• Energy efficiency: 157 MWa
• Demand response:
- 141 MW Winter
- 211 MW Summer
• Dispatchable standby generation: 137 MW
• Dispatchable customer storage: 4 MW</td><td>N/A</td></tr>
<tr><td>Renewable Action</td><td>• Issue an RPP in 2020 for up to 150 MWa of Renewable Portfolio Standard (RPS)-eligible renewables online by the end of 2023.
- Must pass a cost-containment screen.
- Must return the value of RECs generated prior to 2030 to customers.
- Must meet the transmission requirements for variable renewables described in PGE's Interim Transmission Solution.</td><td>• Issue an RFP for up 150 MWa of new RPS-eligible renewables without a specified RFP timeline.
• Resource online date extended to the end of 2024.
• Resources will be subject to the following additional conditions:
- Must contribute to meeting PGE's capacity needs.
- Must qualify for the federal Production Tax Credit (PTC) or the federal Investment Tax Credit (ITC).</td></tr>
<tr><td>Capacity Action</td><td>• First, pursue bilateral contracts for existing capacity.
• Second, provide an update on the status of the Company's capacity need following efforts to acquire existing capacity and renewables.
• Third, issue a 2021 RFP for a to-be-determined amount of non-emitting capacity with a to-be-determined COD, if needs remain.</td><td>• Through concurrent processes:
- Pursue cost-competitive agreements for existing capacity in the region.
- Conduct an RFP for non-emitting dispatchable resources that contribute to meeting PGE's 2025 capacity needs.</td></tr>
<tr><td>Additional Procurement Requirements</td><td>PGE has not specified whether it plans to include a benchmark resource for either RFP.</td><td>• Combined, all renewable and capacity procurement actions cannot exceed:
- 150 MWa energy additions; and
- PGE's identified 2025 capacity need, currently forecasted to be 697 MW.</td></tr>
</table>

The following sections describe the proposed Action Items, share the positions of stakeholders and the Company, and provide Staff's recommendation on each item.

Overarching Themes

In this report, Staff will discuss a broad range of topics related to PGE's planning framework and outcomes. It is with complete sincerity that Staff applauds PGE's continued efforts to refine its analysis and recognize the realities of a changing system. Staff finds many of PGE's improvements to be innovative and responsive to major issues raised by PGE's customers, stakeholders, and the Commission in the previous planning cycle. However, there are a key few areas of PGE's analysis that lead Staff to believe that the Company is focusing on the wrong set of risks, leaving ratepayers exposed.

First, there is no doubt that PGE's analysis demonstrates the economic opportunities presented by PTC-eligible wind resources. But, in the push to capture those attributes, the Company put its actual capacity needs on a slower track that could limit the ability to secure cost-competitive non-emitting capacity resources.

In addition, the IRP facilitates an important conversation about decarbonization, but hesitates to put forth a plan beyond building new wind without specifying the attributes that will dictate the extent to which these resources can reduce the need for thermal generation. If PGE is serious about least cost, least risk decarbonization, it will focus on developing a holistic plan includes efforts such as getting ratepayers out of the Colstrip facility before they're left solely responsible for the associated expenses and risks. Staff appreciates PGE's openness to refining its decarbonization strategy, nonetheless.

In short, this push to acquire cheap wind is the outgrowth of a strategy whereby PGE seeks to always be a low-cost seller of power into our regional markets, with ratepayers functioning as the Company's safety-net for any long-term financial risks. Before acquiring new energy resources that may be a better deal than what is available when a more concrete energy need arises, the Company should strongly consider the addition of conditions that link its proposed action to ratepayer protections, resource adequacy, and a more concrete strategy in support of state, local, and other customer goals – like accelerated decarbonization.

In addition, Staff finds that PGE's evolving approach to planning is changing the nature of the IRP. Whether for better or worse, it is clear that the lines are blurring between opportunity and need, and that portfolio analysis is informing less of the resource strategy while the resulting RFP informs more and more.

Ultimately, Staff agrees with PGE and parties that changing system dynamics require a portfolio approach in which a range of diverse resources will be optimized to meet the Company's changing needs. The latest version of PGE's Action Plan comes close to achieving this—with a few required adjustments. Staff looks forward to working with parties to put these planning principles into practice in a least cost, least risk manner.

Demand-side Actions

PGE proposes two customer resource actions in its 2019 IRP:

- **Action 1A. Energy Efficiency (EE):** Seek all cost-effective EE, which is forecasted to be ~157 MWa on a cumulative basis by 2025.
- **Action 1B. Distributed Flexibility:** Seek all cost-effective and reasonable distributed flexibility, which is forecast to include the following cumulative levels by 2025:
    - ~141 MW of winter demand response,
    - ~211 MW of summer demand response,
    - ~137 MW of dispatchable standby generation, and
    - ~4.0 MW of dispatchable customer storage.

1A: Energy Efficiency

The levels of EE forecast in the IRP were developed in conjunction with the Energy Trust of Oregon (Energy Trust). Energy Trust forecasted energy EE savings between 2020 and 2037 and determined that approximately 157 MWa of cumulative cost-effective EE could be acquired in the Action Plan window. In addition, Energy Trust examined an incrementally higher level of EE based on the incremental savings in the achievable deployable forecast above the cost-effective deployable forecast. The Incremental High EE forecast was used in the Low Need Future and projects approximately 10 MWa of incrementally higher EE savings by 2025.[10] In PGE's first round of comments, the Company shared updated EE savings information provided by Energy Trust that indicates a cumulative reduction in savings is approximately 14.7 MWa by year-end 2022.[11]

Parties' Positions

<u>CUB</u>
CUB questions whether PGE and Energy Trust sufficiently explored the energy efficiency potential of data centers given the high potential for savings, and recommended further consideration in future IRPs.[12]

<u>NWEC</u>
NWEC argues that energy efficiency remains the most cost-effective and reliable energy resource available to PGE.[13] NWEC highlights the risk of taking energy efficiency for granted, encourages PGE to consider the EE forecasts as minimum

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[10] PGE 2019 IRP, p. 215.
[11] PGE Reply Comments, p. 44.
[12] CUB Opening Comments, pp. 7-8.
[13] NWEC Opening Comments, p. 2.

targets,[14] and expresses concern over the downward adjustment of Energy Trust's updated EE forecast. NWEC requested additional review of the Energy Trust update.[15]

PGE's Position
PGE argues that separately forecasting EE for data centers is unnecessary, because data center energy efficiency is already included in the suite of programs and measures considered in Energy Trust's forecast.[16]

In response to NWEC, PGE agrees that the Energy Trust EE forecast is should not be considered a minimum or a maximum and that the Company will work with Energy Trust to acquire all cost-effective EE.

In response to suggestions from Staff, PGE agreed to coordinate with Energy Trust to develop two energy efficiency forecasts in addition to the Reference Case. PGE also expressed its openness to considering if and how IRP portfolio analysis could include the selection of additional energy efficiency measures beyond those found to be cost-effective.[17]

Finally, PGE noted in Opening Comments that it would coordinate with Energy Trust to understand the details of the down-rated forecast and implications for the forecast after 2022.[18] However, PGE has not shared any insights into the impact of the new forecast on its EE Action Items in the IRP docket.

Staff's Position and Recommendations
Staff finds that the analysis supplied by Energy Trust to PGE for the 2019 IRP adequately forecasts cost-effective EE savings in the planning horizon. Staff agrees that some of the opportunities for improvement raised by stakeholders are worth exploring in other proceedings and future IRPs, especially around data centers.

Staff appreciates PGE's introduction of the incremental High EE forecast and the Company's commitment to developing three distinct forecasts for future IRPs. Staff emphasizes its position that the EE forecasts' directionality should not be predetermined, but consistent with the assumptions underlying the need future scenarios.

For example, PGE applied its high EE forecast to the low need future to reinforce that the scenario is a lower bound of need. Staff understands PGE's desire to create a distinct high and low need scenario, but finds that a more realistic EE forecast would recognize that there is likely to be less cost-effective EE available in a low load future.

[14] NWEC Opening Comments, p. 3.
[15] NWEC Final Comments, p. 3.
[16] PGE Reply Comments, p. 44.
[17] PGE Final Comments, p. 48.
[18] PGE Reply Comments, p. 44.

Staff agrees with PGE that a range of factors will drive the EE forecast, which is why Staff recommends that the EE forecasts reflect the range of key conditions underlying each need future.

In addition, Staff agrees with NWEC that energy efficiency is a reliable, low-cost, and carbon-free resource.[19] Given the Company's corporate decarbonization goals, Staff finds that it is appropriate to begin exploring the role of least cost, least risk energy efficiency beyond the baseline identified in Energy Trust's forecast. This should include collaborating with the NWPCC to adopt their framework for additional capacity benefits of energy efficiency. This should be completed independent of the work to establish new baseline value(s) for capacity in UM 2011.

Recommendation for Action 1A Energy Efficiency

Staff recommends that the Commission acknowledge PGE's Action Item of acquiring all cost-effective EE through the Action Plan timeframe (~157 MWa) with the following IRP modifications:

- Energy Trust's baseline EE projections should to be treated like minimums. Before the next IRP, PGE should work with Energy Trust and stakeholders to explore the potential for PGE's portfolio modeling to select incremental energy efficiency that is least cost, least risk, beyond Energy Trust's baseline forecast.
- Before the next IRP, PGE should work with Energy Trust to produce distinct high and low energy efficiency forecasts that do not have predetermined trajectories, but are consistent with the assumptions of the load scenario used.
- Before the next IRP, PGE and Energy Trust should work together to:
    - Study current and forecasted data center load and EE measures; and
    - Consider adoption of the Northwest Power and Conservation Council (NWPCC) EE capacity value modifiers.

1B: Distributed Flexibility

PGE worked with Navigant to forecast demand response and dispatchable customer storage—together referred to as distributed flexibility. The distributed flexibility study built upon the potential evaluation in the 2016 IRP to identify the reasonable level of customer adoption that can be expected within the range of cost-effective technical potential.[20] PGE's forecast of reasonable and cost-effective distributed flexibility

[19] Staff Final Comments, p. 40.
[20] PGE 2019 IRP, pp. 128–133.

includes nearly 300 – 400 MW of distributed flexibility on a cumulative basis through 2025, depending on the season:

Table 2: Distributed Flexibility Forecast			
	Low	Reference	High
Winter demand response	73 MW	141 MW	297 MW
Summer demand response	108 MW	211 MW	383 MW
Dispatchable standby generation		137 MW	
Dispatchable customer storage	2.2 MW	4.0 MW	11.2 MW

Parties' Positions

CUB

CUB supports PGE's customer resource actions and notes that the Company's Smart Grid Test Bed pilot is innovative and could bring cost-effective capacity resources onto the system.[21]

NWEC

While complimentary of PGE's Smart Grid Test Bed and plan to acquire all cost-effective and reasonable distributed flexibility, NWEC argues that distributed flexibility requires additional urgency and focus. In Opening Comments, NWEC asserts that the actual achievable potential could be considerably greater than forecasted in the 2019 IRP, and suggests several actions that PGE could take to accelerate distributed flexibility in the Action Plan window: 1) PGE could issue an open-ended RFP for distributed flexibility to test the market for innovative demand-side products; 2) PGE could add a 20 percent stretch goal on top of its distributed flexibility forecasts; and 3) PGE should pay particular attention to overcoming the customer unease and uncertainty observed in customer surveys.[22]

In Final Comments, NWEC expresses comfort with PGE's commitment to continue detailed discussion of how the Company will identify and acquire all cost-effective and reasonable distributed flexibility within the context of a Flexible Load Plan.[23]

RNW

In Final Comments, RNW expresses support for PGE's nuanced approach to forecasting demand-side resources across a reasonable range of futures.[24]

[21] CUB Opening Comments, p. 13.
[22] NWEC Opening Comments, pp. 3-6.
[23] NWEC Final Comments, p. 1.
[24] RNW Opening Comments, p. 3.

PGE's Position
PGE emphasizes that it will pursue all cost-effective and reasonable distributed flexibility and that it intentionally did not specify a target within the Action Plan window to avoid placing limits on demand response growth.[25] PGE acknowledges several key improvements that can facilitate higher levels of distributed flexibility, namely refining the cost-effectiveness methodology and identifying better mechanisms to scale programs.[26] The Company commits to facilitate detailed discussion of these improvements in two ways. First, the Company will file a Flexible Load Plan in 2020 that details current and future implementation practices, as well as program cost effectiveness.[27] In addition, the Company will continue the Demand Response Advisory Group (DRAG).

Staff's Position and Recommendations
Staff agrees that PGE should pursue all cost-effective and reasonable distributed flexibility and appreciates the Company's pioneering efforts to understand and acquire it to date. Staff also appreciates the Company's efforts to refine its modeling of distributed flexibility in the IRP. The Company's analysis suggests that distributed flexibility is PGE's greatest tool to control the extent of its looming capacity shortfall.

However, it remains somewhat unclear the extent to which PGE assesses the value of demand response (DR) as a distributed flexibility tool, especially given the steep drop in DR potential represented in Navigant's forecast. Staff agrees with PGE that "…the most preliminary steps to enable greater penetration levels of DR is include an improved structure to assess cost-effectiveness…"[28] Given this and that Staff is enthusiastic about PGE exceeding its DR goals by 2025, Staff would like PGE to explore the following issues in the forthcoming Flexible Load Plan and as a topic in at least one IRP workshop:

- The use in all calculations of the same base values as those employed for EE, specifically found in UM 1893.[29]
- Reflect the benefit of DR as a zero-emission, dispatchable capacity resource. One such method could be to assign DR a capacity value equivalent to a non-emitting, dispatchable resource, not the current proxy resource.
- Discontinue the use decrementing value assumptions that assume a value of lost service until PGE has the data to establish such a penalty.

[25] PGE Final Comments, p. 50.
[26] Id.
[27] Id.
[28] Ibid., p. 49.
[29] *See* UM 1893, Order No. 19-252, July 31, 2019, pg.10, EE global assumption inputs.

Staff would also note that PGE has several DR pilots running currently with a cumulative budget over $10 Million.[30] It is important that modeling enhancements like the one's undertaken by Navigant, which reduced the potential of DR measures like direct load control, be based on actual evaluated findings from PGE's pilots. Much like the management of other demand-side resources, it is important for DR modeling assumptions to be both transparent and fully vetted by stakeholders using rigorous analysis. PGE's continued use of its DRAG is important in this regard and Staff encourages its continued use.

For all of these reasons and concerns, Staff agrees with PGE that two key areas of improvement can position the Company to adequately leverage distributed flexibility.

<u>Demand Response as a Resource</u>
Staff agrees with the sentiment underlying NWEC's suggestion to issue a distributed flexibility RFP. While it is premature to specify a procurement mechanism, Staff recommends that PGE work with stakeholders to explore whether and how it can consider the addition of least cost, least risk distributed flexibility in portfolio modeling, above the cost-effective baseline.

<u>Flexible Load Plan</u>
Like NWEC and PGE, Staff is comfortable continuing these discussions in the context of the Company's Flexible Load Plan, as long as the Company addresses the modeling and programmatic concerns Staff has raised in the IRP and clearly articulates a feedback mechanism between the Flexible Load Plan and IRP.[31]

Staff recommends that the plan include a section on DR avoided costs and cost-effectiveness methodology that should be vetted by stakeholders prior to use in the next IRP and as part of any future pilot or program design. Staff requests that at least one IRP workshop review the vetted DR avoided costs and cost-effectiveness methodology in time to impact the modeling for the next IRP.

Recommendation for Action 1B. Distributed Flexibility

Staff recommends that the Commission acknowledge PGE's Action Item of acquiring all reasonable and cost-effective distributed flexibility through the Action Plan timeframe (~ 300 – 400 MWa) with the following modifications:

- File a Flexible Load Plan by June 2020 that includes a section on the cost-effectiveness of demand response and continue working with the Demand Response Advisory Group (DRAG) to identify ways to position the Company to

[30] DR pilots include, but are not limited to the following schedules and 2019 budgets: Schedule 4 ($2.5 Million), Schedule 5 ($2.6 Million), Schedule 6 ($2.7 Million), Schedule 13 ($2.5 million)
[31] Staff Final Comments, pp. 40 – 43.

exceed the high end of forecasted demand response, such as considering additional distributed flexibility as a resource in portfolio modeling.

- Provide a status update on key findings from the Flexible Load Plan, Demand Response Test Bed, and DRAG that could impact demand response targets in the IRP Update.

Supply-side Actions

PGE proposes three concurrent supply-side actions its 2019 IRP. PGE separates these items into Renewable Actions and Capacity Actions. Staff believe that PGE should approach these as an interrelated set of supply-side actions. Therefore, Staff approaches them as such in the following sections:

- **Bilateral Capacity (#3A):** Pursue cost-competitive agreements for existing capacity in the region.
- **Dispatchable Capacity RFP (#3B):** Conduct an RFP for non-emitting dispatchable capacity resources.
- **Renewable RFP (#2):** Conduct an RFP for up to approximately 150 MWa of new RPS-eligible resources that contribute to meeting PGE's capacity needs by the end of 2024.
- **Additional Procurement Requirements:** The combined capacity contribution of all procured dispatchable capacity resources (Actions #3A and #3B) and all new renewable resources (Action #2) will not exceed PGE's identified 2025 capacity need, currently forecasted to be 697 MW. The combined energy additions from new non-emitting dispatchable capacity resources (Action #3B) and new renewable resources (Action #2) will not exceed approximately 150 MWa.

Evolution of Supply-side Actions
Staff appreciates PGE's responsiveness to Stakeholder discussion and changing planning conditions throughout the 2019 IRP. The Company was open to refreshing its analysis and making adjustments to its Action Plan as necessary. This section provides a summary of key developments in PGE's supply-side actions over the course of this IRP.

<u>Needs Assessment</u>
PGE performed an updated needs assessment in November 2019, which resulted in a net increase of the Company's 2025 reference case capacity need from 685 MW to 697 MW. This is based on the net effect of incorporating subscribed Green Tariff resources and new QF contracts, which reduced its capacity need by 40 MW in the 2025 reference case; and, a 52 MW increase in capacity need driven by an updated

econometric load forecast. Staff notes that roughly 350 MW of this need is driven by capacity contracts that expire in 2024 and 2025.[32]

The updated needs assessment also resulted in an increase in the 2025 the reference case energy shortage to market from 109 MWa to 121 MWa under the traditional load resource balance.[33]

Procurement Activities

PGE's IRP initially relied on a four-step approach to meet the needs identified above, that prioritized resource acquisitions in the following order:

1. Pursue bilateral capacity contracts upon IRP acknowledgment;
2. Procure up to 150 MWa of RPS-eligible renewable resources with a 2020 RFP;
3. Update the Company's needs assessment following steps 1 and 2;
4. Fill any remaining capacity needs with a non-emitting capacity RFP in 2021.

In its Final Comments, PGE made several modifications to change the four steps into a more fluid portfolio approach. The revised approach is driven by the following developments:

- Renewable RFP
    - PGE updated its portfolio analysis following the extension of the Federal PTC on December 20, 2019.[34] Based on this analysis, PGE modified its Renewable RFP to seek resources online by the end of 2024, one year later than its original Action Item.
    - PGE relaxed the urgency of the Renewable RFP by removing the specific 2020 release date, but did not specify a timeline to release the RFP. PGE states that this RFP can occur concurrently with a capacity RFP.[35]

- Dispatchable Capacity RFP
    - PGE accelerated the timing of its Capacity RFP to be concurrent with the Bilateral Capacity Action. This was done in response to parties' concerns that the prioritization of the other two supply-side actions prior to the Capacity RFP did not align with the timing of the Company's capacity

[32] PGE 2019 IRP, p. 25.
[33] PGE Response to OPUC IR No. 179, Attachment M.
[34] House Resolution 1865 extended eligibility for wind generation facilities to receive the PTC by one year and returned the PTC value to 60 percent. PGE and Staff's reading of this change indicates that resources online by the end of 2024 will be eligible for this incentive. Previously, PGE's modeling assumed that resources online by the end of 2023 would receive the PTC and it would be at 40 percent.
[35] PGE Final Comments, p. 2.

need and the lead-time required for the pumped-storage resources in the preferred portfolio.

- PGE also revised its Capacity RFP to be specific to dispatchable capacity to "differentiate the resources pursued through this action from those non-dispatchable non-emitting resources that would also contribute capacity to the system through the Renewable RFP but would not meet PGE's needs for dispatchable and flexible resources."[36]

3A: Bilateral Capacity Action

PGE proposes to pursue agreements for existing capacity in the region to meet a portion of the Company's forecasted 2025 capacity needs. The Company has not specified a target acquisition level, but states that these resources must be cost-competitive and would be bound by the requirement that supply-side actions cannot collectively exceed 150 MWa or PGE's identified 2025 capacity need.

Parties' Positions
No parties oppose PGE's Bilateral Capacity Action Item.

PGE's Position
PGE argues that pursing mid-term bilateral capacity allows the Company to make the best use of existing resources in the region, is flexible to the uncertain magnitude the 2024-2025 capacity need, allows the Company time to better understand large-scale energy storage systems, and captures the benefits of additional technological progress in the storage sector.[37]

At the January 30, 2020, Commission Workshop, PGE provided an update on its bilateral negotiation process. PGE is currently engaged in bilateral solicitation for mid-term capacity resources. Subsequent to a Commission order acknowledging the pursuit of bilateral contracts, the Company will receive offers and commence negotiations. PGE has partnered with a third-party marketer to encourage broad participation by counterparties. Before initiating acquisition of any resource more than 80 MW and five years in length, therefore subject to the competitive bidding rules under Chapter 860, Division 89, the Company plans to file a waiver of the competitive bidding requirements under OAR 860-089-0100(2) with the Commission.

Staff Position and Recommendations
Staff supports this action as part of a balanced portfolio approach to meeting its forecasted range of capacity needs. If the market permits, mid-term capacity contracts

[36] Id., p. 9.
[37] PGE 2019 IRP, p. 219.

will create a longer runway to develop a portfolio of non-emitting dispatchable capacity resources without precluding opportunities to acquire new cost-effective resources that are currently available, including long lead time resources that are in the preferred portfolio. To the extent possible, PGE should look to stagger bilateral contract start dates and terms so as to avoid and/or mitigate a large capacity cliff, especially beginning in 2025.

In keeping with Commission Order No. 17-386, PGE should provide updates on the status of its bilateral solicitation and progress toward executing agreements, including the key attributes of these agreements.[38]

Recommendation for Action 3A. Bilateral Capacity

Staff recommends that the Commission acknowledge PGE's Bilateral Capacity Action Item to pursue cost-competitive agreements for existing capacity in the region to meet a portion of the Company's forecasted 2025 capacity needs.

Staff recommends that the Commission direct PGE to provide monthly or more frequent updates on the key attributes of the opportunities for bilateral negotiation.

3B: Dispatchable Capacity RFP

PGE seeks to issue an RFP for non-emitting dispatchable resources to meet a portion of its forecasted 2025 capacity need, concurrently with the Bilateral Capacity Action (3A) and Renewable RFP (2). Because PGE accelerated the timing of this Action Item in its Final Comments, the specific RFP schedule, resource attributes, elements, scoring, and modeling are unknown. What is known is that this action would be bound by the requirement that the three supply-side actions cannot collectively exceed 150 MWa and PGE's identified 2025 capacity need. Further, PGE estimates an indicative lower bound of approximately 250 MW of capacity contribution from the existing and new capacity procurement activities based on the capacity need in the Low Need Future and the anticipated contribution of renewables.[39]

Parties' Positions
Parties have not had the opportunity to submit written comment since PGE modified the timeline and specified the requirement for the dispatchability of this Action Item. However, CUB, RNW, and Swan Lake's Final Comments suggest that PGE consider conducting a capacity RFP concurrently with its bilateral capacity efforts.[40,41,42]

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[38] Commission Order No. 17-386, p.17.
[39] PGE Final Comments, p. 9.
[40] CUB Final Comments, pp. 7-8.
[41] Swan Lake Final Comments, pp. 1 -11.
[42] RNW Final Comments, p. 7.

CUB, NWEC, and RNW also note the risks associated with new thermal resources and express support for the Company's decision to limit any capacity resource acquisitions to non-emitting capacity. [43,44,45]

<u>AWEC</u>
AWEC argues that PGE has overstated its capacity need. In addition to concerns about the industrial load forecast, AWEC finds that PGE is understating the availability of imports from the Mid-Columbia (Mid-C) and California-Oregon Border (COB) market hubs to meet it peak needs.[46] Further, AWEC notes that PGE's assumptions are not consistent with other similarly situated utilities in the region.[47] Notwithstanding these concerns, AWEC asserts that, if the Company issues an RFP, it should be designed to meet its capacity need and be conducted concurrently with bilateral capacity efforts.[48]

PGE's position
PGE was initially hesitant to seek new capacity resources before acquiring existing capacity resources, securing new PTC eligible wind resources, and further refining its forecasted need through 2025.[49] The Company was also hesitant to commit to a new resource given the anticipated cost declines, short lead times, and modularity of batteries.[50]

PGE considered stakeholders' concerns that the staged approach was focusing on the wrong priorities and would limit its ability to secure the cost-competitive, non-emitting capacity resources in its preferred portfolio in time to meet its 2025 needs.

In its Final Comments, PGE "acknowledged that [its] objectives could be met through appropriately designed concurrent processes" and proposed to align its Capacity RFP with its other resource procurement efforts.[51]

PGE notes that this strategy:

> [R]etains the flexibility for PGE to adjust as information is gained about the market through the bilateral negotiation and RFP processes and to procure long-lead time resources in the non-emitting Capacity RFP if the Company can pair them with short-term contracts to meet interim capacity needs.[52]

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[43] CUB Final Comments p. 7.
[44] NWEC Final Comments, p. 2.
[45] RNW Final Comments, p. 7.
[46] AWEC Final Comments, Attachment A, pp. 4-7.
[47] Ibid., Attachment A, p. 5.
[48] Ibid., p. 9.
[49] PGE Final Comments, p. 9.
[50] PGE Opening Comments, p. 15.
[51] PGE Final Comments, p. 8.
[52] Ibid., p. 9.

While the preferred portfolio—updated to reflect the PTC extension—identifies 200 MW of pumped storage and 37 MW of 6-hour batteries in 2024, the Company has not yet specified the resources or key dispatchable capacity attributes it will seek.[53] Staff understands that this is due to the Company's original expectation to establish these details with stakeholders in 2021.

In addition, PGE disagrees with AWEC's concerns and finds that its Market Capacity Study, performed by E3 in 2018, is reasonable, and that it is not appropriate to change its analysis based on other utilities' assumptions.[54]

Staff's Position and Recommendations

Staff is supportive of PGE's proposal to develop a Capacity RFP concurrently with its Bilateral Capacity efforts. Staff agrees with PGE and other stakeholders' focus on optionality and flexibility and finds that concurrent efforts strike a suitable balance between the risk of inaction and the risk of overbuilding.

Staff reiterates the benefit of creating a longer, more flexible runway to develop a least-cost, least-risk portfolio of non-emitting capacity resources. The asset life, operational characteristics, and ability for a utility to meet 300 – 700 MW of capacity need with current battery technology remains relatively unknown. Staff finds PGE's revised approach better reflects the reliability risks of a just-in-time capacity approach along with exposure to price and carbon risks if PGE misses its opportunity to secure cost-competitive, non-emitting resources that may be available in the near-term.

<u>The Capacity RFP requires a rigorous procurement process.</u>

Due to the original timing of the capacity RFP, PGE has not provided enough detail to move forward with a streamlined RFP process.[55] PGE affirms this in its Final Comments and notes that, "PGE plans to open an IE RFP design docket in 2020 for capacity resources following acknowledgment of the IRP."[56]

Staff reiterates its appreciation for PGE's responsiveness in adjusting the Capacity RFP. The trade-off is that this leaves uncertainty about PGE's approach to seeking a least cost, least risk portfolio of capacity resources. In line with the competitive bidding rules, PGE must conduct a rigorous stakeholder process and file a proposal for the RFP design, scoring, and associated modeling prior to engaging the Independent Evaluator

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[53] PGE Response to OPUC IR No. 008, Attachment B, updated January 17, 2020.
[54] PGE Final Comments, p. 16.
[55] Under OAR 860-089-0250(2)(a), PGE is not obligated to seek Commission approval of the RFP scoring and modeling before filing a draft RFP if the RFP design, scoring methodology, and associated modeling process were included as part of the Commission-acknowledged IRP.
[56] PGE Final Comments, p. 26.

(IE). This will ensure that the IE has sufficient Commission guidance to perform its duties.

Staff provides the following non-exhaustive list of issues that PGE must address through its initial RFP stakeholder process, and welcomes additional discussion with PGE and stakeholders. In addition to scoring details, PGE must establish:

- The key attributes of its capacity resource need. This may include both an upper limit for procurement and clearly articulated capacity attributes it seeks, including flexibility and dispatchability requirements.
- Commercial online date requirements and a clear demonstration of long lead time resource eligibility, or an alternative proposal for the incorporation of long-lead time resources.
- Whether cost containment screens should be used.
- Detailed transmission requirements and a justification for how the requirements should or should not vary across resources.
- Eligibility for various hybrid renewable plus storage resources configurations.
- How dispatchable and non-dispatchable resources can be considered concurrently to ensure that any new resources acquired are optimized on a portfolio level. This is addressed in more detail in the Renewable RFP discussion.

PGE must update its capacity needs assessment, including its market import assumptions, prior to seeking new resources.
Staff agrees that the Company's modeling of its system's reliability needs in RECAP is mostly reasonable. PGE's range of capacity needs are wide enough that replacing its 350 MW of expiring contracts with cost competitive contracts could keep the company resource sufficient in a low need future without additional action

That said, Staff agrees with PGE and other stakeholders that it should proceed cautiously and remain as flexible as possible in light of the evolving circumstances during this process. Specifically, as suggested by PGE, the Company needs to refine its 2025 capacity need before issuing an RFP.

Staff sees merit in exploring AWEC's concerns about regional market import assumptions before finalizing the capacity needs sought to be met with the resources from the Capacity RFP. Staff also agrees with AWEC that PGE falls short of other regional utilities in modeling a reasonable level of market purchases that can reduce its need is compelling and should be explored. As AWEC notes, it might be more reasonable to assume that utilities in the Northwest will utilize some level of imports to serve customer loads in both winter and summer, at least over the next five years.

Staff also finds that PGE should update its 2025 capacity needs to reflect the following developments:

- A revised estimate of imports from the WECC;
- Insights from the existing capacity efforts;
- Insights from its Flexible Load Plan and other distributed energy resource efforts;
- Any developments in the Voluntary Renewable Energy Tariff and Community Solar programs;
- Qualifying Facility contracts; and
- Any changes to the Long Term Direct Access program.

Recommendation for Action 3B. Dispatchable Capacity RFP

Staff recommends the Commission acknowledge that PGE's 2025 capacity need of up to 697 MW, but condition acknowledgement of the issuance of a Dispatchable Capacity RFP on completion the following actions prior to filing a draft RFP:

- PGE must engage in a rigorous stakeholder process prior to the selection of the IE and filing of a draft RFP to:
  - Establish the RFP elements, scoring methodology, and associated modeling, including those detailed by Staff in this report.
  - Clarify the key attributes of the capacity resources the Company will seek, including the Company's specific dispatchable and/or flexible capacity needs and transmission requirements.
  - Determine how non-dispatchable capacity resources can be considered concurrently with dispatchable capacity resources to ensure resource acquisitions are optimized on a portfolio level.

- PGE must update and refine its capacity needs prior to issuing a capacity RFP.
  - PGE must update its market import assumptions.
  - PGE must update its needs assessment to reflect the outcome of bilateral negotiations, any changes in voluntary products, the QF forecast, and any changes in the Long Term Direct Access program.

2: Renewable RFP

PGE also seeks to acquire up to 150 MWa of new RPS-eligible resources separately from its Dispatchable Capacity RFP. PGE requires that these resources be eligible for the federal PTC or ITC and, "contribute to meeting its capacity needs" by 2024."[57]

The preferred portfolio—updated to incorporate the one-year PTC extension—identifies the following wind additions between 2024 and 2025:

- 41 MWa of Gorge Wind in 2024;
- 109 MWa of Montana Wind in 2024; and
- 100 MWa of Washington Wind in 2025.[58]

PGE explains that it has captured the key attributes of its top performing portfolios, but has not further specified the characteristics of these resources in its RFP to provide:

> [F]lexibility across renewable technologies and locations while leveraging the analytical methodologies in the IRP to fairly evaluate benefits to the system…to identify those resources that provide the best value for customers.[59]

In its IRP, PGE has clearly distinguished this action from its capacity actions. The Company notes that the addition of renewable resources will have some impact on its capacity needs, but the only characteristics that PGE is explicitly seeking through this RFP are energy and RPS eligibility. In other words, this Action Item was identified to leverage expiring federal tax incentives to reduce the Company's exposure to market price risk.[60] Resources solicited under this RFP could meet PGE's capacity needs, but it is unclear to what extent and how cost-effectively the resources may do so. For this reason, PGE proposes several RFP conditions to mitigate the risk that the market price hedge won't play out in ratepayers' favor:

- **Cost containment screen:** As agreed upon in the context of PGE's 2016 IRP, PGE will not select bids where the costs outweigh the levelized benefits.[61]
- **REC value mechanism:** PGE will lower the near-term cost of the renewable resources by returning the value of the RECs generated prior to its 2030 RPS need.[62]

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[57] PGE Final Comments, p. 7.
[58] PGE Confidential Response to AWEC IR No. 003, Attachment C.
[59] PGE 2019 IRP, p. 216.
[60] Id.
[61] Id.
[62] Id.

- **Transmission solution:** PGE will increase the likelihood of cost-competitive bids by adding flexibility to its long-term firm transmission requirements for renewable resources on a pilot basis.

Previous Commission Guidance
Staff finds it valuable to preface discussion of the Renewable RFP with the Commission's recent guidance on similar action items. In PGE's 2016 IRP, the Commission provides a lengthy discussion of the difficult balance between cost and risk in a changing industry, and outlines several principles upon which a utility must justify the size and timing of a resource procurement in an IRP.[63]

The Commission did not obviate the opportunity for a utility justify a new resource that is tied to an economic opportunity rather than a specified capacity, energy, or RPS compliance shortage. The Commission suggests that if a utility identifies such an action as least cost, least risk, it must demonstrate that it provided full consideration of short-term impacts and long-term risks.[64]

The Commission expressed concerns with how utilities characterize need and assess risks associated with timing and resource size, but recognized the potential value of time-limited opportunities for PTC benefits.[65] The Commission also advised that, "in reviewing an Action Plan, we will continue to look to see how individual action items fit into a comprehensive integrated strategy for meeting customer needs and whether the risks are appropriately shared between ratepayers and shareholders."[66]

In PacifiCorp's 2016 IRP, the Commission weighed the same complex issues. The Commission recognized the, "uncertainties that may persist beyond project commercial operation date (post-COD risks), such as project performance, tax policy changes, and resource value relative to market."[67] Consequently, the Commission conditioned acknowledgement of PacifiCorp's renewable action items to, "ensure customer benefits remain at least as favorable as IRP planning assumptions."[68]

As PTC expiration looms, the appropriate balance of near-and long-term costs and risks remain at hand. All the while, the same uncertainties remain and new planning questions continue to emerge, such as the appropriate characterization of an energy shortage when variable and thermal resource dispatch are evolving. Staff seeks to make recommendations related to this Action Item that carry both the core IRP principles and the Commission's recent guidance forward for the benefit of ratepayers.

[63] Commission Order No. 17-386.
[64] Ibid., p. 3.
[65] Commission Order No. 18-044, p. 6.
[66] Commission Order No. 17-386, p. 14.
[67] Commission Order, 18-138, p. 8.
[68] Id.

In addition, Staff finds that PGE made a clear and deliberate effort to justify its 2019 IRP renewable action in a manner that aligns with the Commission's 2016 IRP guidance. In the following sections, Staff will note areas in which PGE appears to have met or fallen short of this guidance.

Parties' Positions

AWEC

AWEC does not recommend acknowledgement of the Renewable RFP and expresses deep frustration with what it perceives as PGE's disregard for the Commission's IRP guidelines and 'basic exercise' of integrated resource planning.[69] AWEC's concerns with the Renewable RFP center on a misalignment with the Company's identified need and flawed portfolio modeling.

CUB

Following PGE's updated needs assessment, CUB recommends acknowledgement of the Renewable RFP.[70]

NWEC

NWEC supports the Renewable RFP and notes the hedging benefit that early action provides against natural gas and market prices.[71] NWEC also supports PGE's condition to return the value of RECs to customers prior to the 2030 RPS shortage.[72]

RNW

RNW supports PGE's plan to meet a portion of its energy, capacity, and RPS needs through renewable procurement and notes that market reliance can bring both costs and risks.[73] RNW argues that PGE specified the appropriate level of resource attributes in the Renewable RFP and that it is not practical or in the spirit of IRP guidelines to identify a specific resource for the RFP.[74]

AWEC, NIPPC, NWEC, RNW, and REC also provide recommendations related to the RFP's transmission requirements. These issues are addressed in a dedicated General IRP Comments section.

PGE's Position

PGE maintains that its portfolio modeling continues to demonstrate that near-term renewable procurement is part of a least cost, least risk long-term resource strategy. The Company's justification for this Action Item falls into two categories.

[69] AWEC Final Comments, pp. 1 – 2.
[70] CUB Final Comments, p. 7.
[71] NWEC Opening Comments, p. 4.
[72] Ibid, p. 4.
[73] RNW Final Comments, pp. 7 – 9.
[74] Ibid., p. 6.

First and foremost, PGE's portfolio modeling suggests a significant economic opportunity associated with PTC-eligible renewable resources.[75] Portfolios optimized to minimize variants of short-and long-term cost and risk add between 175 MWa and 550 MWa of PTC-eligible wind in the near-term. These portfolios show over $1 billion in reference case benefits compared to portfolios constrained not to add renewables in the Action Plan window. PGE eliminated these portfolios from consideration to limit the near-term cost and long-term risk associated with energy additions that are not needed to meet a near-term shortage. The resulting preferred portfolio, which was constrained to limit renewable resource additions to 150 MWa of before 2024 and 250 MWa total before 2025, still shows $885 million of benefits in the reference case compared to the delayed renewables portfolio.[76] This improves by $86 million when the model is updated to account for the PTC extension.[77]

Second, PGE argues that new renewable resources, "leverage federal tax credits to secure low-cost renewables to meet our near-term energy and capacity needs while making steady progress toward meeting long-term RPS needs and greenhouse gas (GHG) goals." [78]

PGE performed several analyses to test assumptions underlying these benefits. PGE argues that across sensitivities, portfolios that add wind continue to perform better than those that do not.[79] PGE's analysis also suggests that the benefits are directly linked to the availability of tax credits.[80]

PGE generally refers to the 150 MWa limitation in response to Staff and AWEC's concerns about the timing and size of PGE's Renewable RFP. Parties were originally concerned that a 2023 renewable resource addition did not align with the identified 2024-2025 capacity need and the company's long energy position demonstrated in the traditional load-resource balance. In Final Comments, PGE notes that relaxing the urgency of its Renewable RFP to reflect the PTC extension alleviates this tension.[81]

Staff's Positions and Recommendations

Before expanding on these issues, Staff notes that PGE's continued willingness to explore the costs and risks of this Action Item is much appreciated by Staff and parties. The Company has been responsive to stakeholder discussion and open to considering modifications that mitigate risks to ratepayers.

[75] PGE 2019 IRP, p. 216.
[76] Ibid., p. 190.
[77] PGE Final Comments, pp. 30 – 33.
[78] PGE 2019 IRP, p. 214.
[79] PGE Reply Comments, pp. 30 – 33, updated with PGE errata filing, December 5, 2019.
[80] PGE Opening Comments, pp. 32, updated with PGE errata filing, December 5, 2019.
[81] PGE Final Comments, p. 5.

Staff does not recommend acknowledgement of a standalone RFP for Renewable Resources.

As noted previously, Staff recommends acknowledgement that PGE has some amount of 2025 capacity need and should engage in activities designed to procure non-emitting capacity resources during the Action Plan window. Given the value of federal tax incentives in PGE's portfolio analysis, Staff agrees with PGE, AWEC, and RNW that these resources are a potential least cost, least risk option to help meet a portion of the Company's identified capacity needs. Further, Staff greatly appreciates the Company's thoughtfulness in relaxing the urgency of the renewable action in light of the PTC extension. Staff agrees with PGE that this better aligns the renewable resource procurement strategy with the Company's capacity needs, which reduces risk and near-term costs to ratepayers.

Similar to AWEC, Staff finds that there is still considerable risk in the Company's plan to separately and specifically seek resource attributes for which the Company does not have material near-term need. The Company has not identified an unmanageably short energy position—it ranges from 147 MWa long to 255 MWa short across need futures.[82] PGE also confirms through sensitivity analysis that this procurement is not designed to meet an RPS shortage, which it does not anticipate until at least 2030.[83] What PGE has identified is an opportunity to hedge today's renewable energy resource economics against a range of potential market price futures.

Staff appreciates RNW and NWEC's comments about the benefits of considering market exposure risk. Staff agrees that this should be considered when evaluating the size and timing of new resources, but finds that this risk cannot take precedent over capital investment risk at a time of uncertainty about the impact of decarbonization on the long-term value of wind resources in the region. When a resource is sought for reliability or compliance, ratepayers have to bear capital investment risk and the utility should look for least cost, least risk size and timing of resource actions to do so. However, when an RFP is specifically targeted to address market price exposure, the balance of long-and near-term costs and risk is less straightforward.

In evaluating whether PGE has appropriately balanced capital investment and market price exposure risks with its separate Renewable RFP, Staff finds the following major risks are not adequately considered:

- **Potential to overbuild:** Risk that the Company will not optimize renewable and dispatchable capacity bids through separate solicitations.
- **Near-term resource performance**: Risk that the resources acquired will not produce the energy and capacity benefits modeled in the IRP. And—regardless

[82] PGE Response to OPUC IR No. 179, Attachment M.
[83] PGE Updated Needs Assessment, p. 8.

of whether they produce the benefits modeled— the risk that the resources acquired will limit PGE's ability to secure a better deal on future resources due to technological advancements, future policy, and market forces, such as a high regional wind build out that depresses market prices when the wind is blowing.

- **Modeling flaws:** Concern that elements of the portfolio modeling underlying the Renewable RFP action are speculative and arbitrary. These flaws obscure whether the size and timing of PGE's Renewable RFP adequately balances the long-term risks to customers.

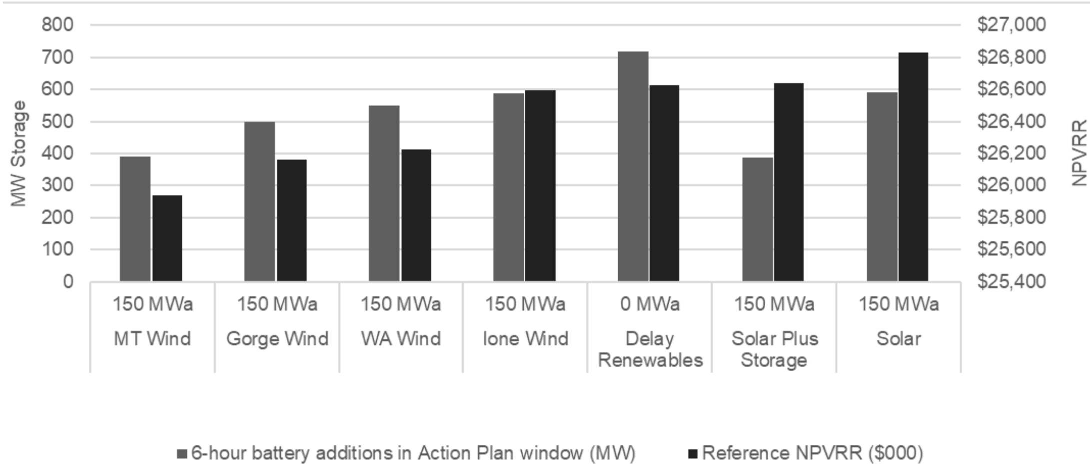
In the following sections, Staff elaborates on these risks and, in the event the Company chooses to proceed, note opportunities for PGE to address the risks if it moves forward with a separate Renewable RFP.

<u>A separate renewable RFP will expose ratepayers to the risk of overbuilding at the portfolio level.</u>

In the previous sections, Staff outlined several risks associated with an RFP specifically designed to mitigate market exposure. This, however, does not mean that PTC and ITC-eligible renewables should not be considered as least-cost resources to meet a portion of PGE's capacity needs. It means that these resources need to be considered in a least cost, least risk manner that does not expose ratepayers to the risk of overbuilding at a portfolio level.

Examination of PGE's renewable resource portfolios shows that the optimal dispatchable capacity resources—as well as the portfolio's performance—is closely linked to the attributes of the renewable resources acquired. For example, the portfolio constrained to add 150 MWa of Gorge Wind requires 50 MW fewer in storage capacity additions and provides $64.5 million of additional benefits compared to adding 150 MWa of Washington Wind.

Figure 1: Renewable Resource Portfolio Additions[84]



However, the Washington Wind proxy resource performs notably better than the Gorge Wind on an energy and net resource value basis (roughly 22 percent). This enforces Staff concern that separately pursuing energy resources based on the forecasted energy value places ratepayers at an even higher risk of overbuilding across resources.

Table 3: Renewable Resource Values

Proxy Resource	Capacity Factor	COD 2024 LCOE[85]	Energy Value	Flexibility Value	Capacity Value	Net Cost/ (Value)
		2020 $/MWh				
Montana Wind	43%	$45	$52	$0	$10	($18)
Washington Wind	43%	$40	$51	$0	$5	($16
Gorge Wind	41%	$43	$49	$0	$7	($14)
Ione (Oregon) Wind	33%	$55	$49	$0	$4	$1

If the Company chooses to move forward with a separate RFP, it should clearly articulate how it will consider the non-dispatchable renewable resources concurrently with dispatchable capacity so that resource additions are optimized across portfolios.

[84] PGE 2019 IRP, Appendix H, pp. 328 – 333.
[85] Staff updated the PTC value in PGE's LCOE calculation to reflect the PTC extension for COD 2024 resources.

<u>Pursuit of the market hedge relies of the performance of proxy resources in uncertain long-term conditions.</u>
Staff agrees with AWEC that modeling is, "inherently unreliable when the resource need is long-term rather than short-term, and acting on this modeling now puts all of the risk of inaccurate assumptions on customers."[86] Staff raised similar concerns in PGE's 2016 IRP and finds that these concerns translate when the benefits are based on uncertain long-term conditions. In this section, Staff outlines several key risks and uncertainties associated with renewable resource performance.

- *Cost in a High Tech Future*

Staff believes that the impact of regional decarbonization efforts on the value of wind over long term is uncertain. A glut of variable generation resources in the region could depress market prices and dampen the economic opportunity of PGE-owned renewables. In addition, there is uncertainty surrounding the rate of renewable technology improvement, the emergence of new cost-effective carbon-free technologies, and whether the PTC or new incentives will persist.

In response to stakeholder discussion in the 2016 IRP, PGE's 2019 IRP reflects this risk in the Cost in a High Tech Future metric.[87] In PGE's words, this metric examines the risk of regret in a future with rapid advancement and deployment of clean technologies."[88] This analysis addresses market prices and existing technologies, but does not capture policy risk and new technologies..

PGE's modeling indicates that the preferred portfolio could cost $17 – $921 million more than not adding renewables now in the High Tech Future.[89,90] The IRP seems to downplay this risk, including the fact that the preferred portfolio's is only $3 million away from being screened out for the Cost in a High Tech Future metric.[91]

Acquiring any resources based on these uncertainties is risky. If PGE moves forward with a separate Renewable RFP, it must ensure that it is getting a good enough deal on that resource to justify the risk. PGE relies on its 150 MWa energy limit and proposed cost-containment screens to balance the near-term rate impacts. Staff finds that PGE could do more capture the benefits modeled in the preferred portfolio by enhancing its

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[86] AWEC Final Comments, p. 8.
[87] The PGE 2019 IRP, p. 187, states that this metric measures the NPVRR of the portfolio in a future where renewable and storage technology improves along the higher trajectory and market prices reflect the High WECC Buildout.
[88] 2019 PGE IRP, p. 187.
[89] Id.
[90] PGE Response to OPUC IR No. 181.
[91] The threshold for the Cost in High Tech Future screen is $15.350 million NPVRR. The preferred portfolio is $15.347 billion.

cost containment screens to ensure the key attributes of portfolio modeling will be achieved.

Staff also notes that PGE's introduction of multiple technology learning curve rates is a great improvement. Still, Staff agrees with NWEC that additional work needs to be done to identify the appropriate basis to establish these learning rates. If PGE's assumptions are too conservative, they will underrepresent the High Tech Future Cost risk.

- *Wind Performance*

Capacity factor sensitivities provided in PGE's Reply Comments indicate that the wind acquisition in the preferred portfolio provides a $400 - $600 million benefit to ratepayers over delayed resource acquisition, even when the capacity factor is as low as 24 – 32 percent.[92] At the same time, the preferred portfolio loses roughly $1.3 billion in benefits when the capacity factors are adjusted to this level.[93]

In the 2016 IRP, the Commission did not initially acknowledge PGE's near-term renewable acquisition, in part because the Company's analysis did not sufficiently consider intergenerational equity considerations.[94] In the 2019 IRP, PGE provides an intergenerational equity analysis that compares the balance of near-and long-term impacts of resource acquisition in 2023 versus 2026. Staff finds some of the assumptions arbitrary, but generally agrees with PGE that the rate impact differential is rather small between 2023 versus 2026. However, this analysis does demonstrate substantially different near-term outcomes when comparing the rate impacts of an owned resource; to a PPA resource on the magnitude of 0.12 cents/kWh near-term rate impacts for an owned acquisition, while the PPA structured acquisition has a near-term rate impact of 0.04/kWh respectively.

If the Commission acknowledges this Action Item, Staff finds it important to consider whether near-term costs and performance risks should be limited further by conditioning acknowledgement on the use of a PPA structure in the Renewable RFP. The PPA structure can limit near-term cost and allows ratepayers to share these performance risks with the PPA counterparty. In other words, under a PPA structure, ratepayers will only be responsible for the costs of the energy that's delivered to the system.

Staff notes that the added risks placed on the PPA counterparty could be reflected in the PPA price, which Staff finds 1) can be mitigated through cost containment; and 2) is an acceptable tradeoff for mitigating some of the performance risk and near-term costs.

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[92] Based on PGE Response to OPUC IR No. 174.
[93] Id.
[94] Commission Order No. 17.386, p. 15.

In addition, PGE can ensure the Renewable RFP is closely linked to, if not a part of, the Dispatchable Capacity RFP.

- *Securing Production Tax Credits*

Renewable size and timing analysis demonstrates that near-term renewables are only a net benefit when the PTC can be captured.[95] Therefore, Staff recommended in comments that, if the Commission acknowledges a 2020 renewable RFP, the Company should be required to return the full forecasted value of the PTC and ITC to customers.[96] Staff clarifies for its final recommendations that it does not propose a specific ratemaking action in the IRP. Staff provides this recommendation to confirm the circumstances in which acknowledgment of the Action Item may be reasonable and highlight the importance of fully utilizing PTC and ITC credits to realize the benefits of early action.

<u>Portfolio modeling flaws undercut PGE's projections of future net benefits.</u>
In addition, Staff agrees with AWEC that PGE appears to have predetermined the attributes of its Renewable RFP when developing its portfolio modeling. This would be less problematic if the predetermined 150 MWa as the upper bound—which PGE describes as a major risk mitigator in its renewable procurement strategy—was not also selected in an arbitrary manner.

Staff agrees that PGE's portfolio analysis demonstrates that portfolios that add more renewables in earlier years perform better. Staff also agrees that the portfolios constrained to add 150 – 250 MWa will add the full amount allowed under the constraint and still perform better across cost and risk metrics than portfolios that do not add renewables. However, Staff is concerned by the idea that 150 MWa as an upper bound was informed by anything but the fact that PGE decided to constrain nearly all of its portfolios remaining after optimized portfolios were screened out to add 150 MWa of renewables in the near term. The ones that it did not constrain to specifically add 150 MWa were simply constrained to add 50 – 100 MWa more or less in the near-term.[97]

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[95] PGE Reply Comments, p. 32, updated with PGE errata filing, December 5, 2019, as described by Staff's Final Comments, pp. 20 – 22.
[96] Staff Final Comments, pp. 21 – 22.
[97] After the optimized portfolios were removed from consideration due to the size of near-term energy additions, PGE was left with two types of portfolio: Renewable size and timing portfolios that examine the cost and risk of 0, 50, 100, 150, 200, and 250 MWa additions of renewable energy by 2023, 2024, or 2025; and resource-specific portfolios that examine the addition of each proxy resource and are all specifically constrained to add 150 MWa of renewable resources. Specifically, the portfolios designed to test wind, solar, biomass, and geothermal are constrained to add 150 MWa of these resources by 2025, and the portfolio designed to test the addition of gas plants and storage are also constrained to specifically add 150 MWa of Washington Wind in 2023.

In its Final Comments, PGE admits that some additional subjectivity underlies the energy addition thresholds and explains that the Company's decisions are rooted in the Market Energy Position (MEP).[98] PGE explains that the 150 MWa limit reflects a "persistent market reliance of over 250 MWa in almost all futures," minus a 100 MWa buffer to account for the possibility of lower loads, new resources from voluntary programs, and existing capacity contracts that include energy.[99] Staff confirms that the MEP is above 250 MWa in 52 of the 54 market price futures; however, 250 MWa does not seem to represent a significant breaking point across MEP estimates, such as the minimum (224 MWa), tenth percentile (326 MWa), or any of the actual MEP values.[100]

Overall, Staff agrees that imposing a procurement limit helps mitigate a range of important risks to ratepayers. Additionally, it is possible that 150 MWa is an appropriate size. However, as noted by the Commission in PGE's 2016 IRP, the burden of proof to justify the proposed energy acquisition limit falls on the Company. PGE has not provided sufficient justification for Staff to consider this a sufficient mitigation tool. In the event the Commission acknowledges this Action Item, Staff proposes additional conditions that may alleviate some of this concern.

<u>PGE's REC proposal creates additional planning risk.</u>
In addition to the 150 MWa limit and cost containment screen, PGE proposes to mitigate near-term costs by returning the value of RECs generated by any new renewable resources to ratepayers prior to PGE's identified 2030 physical RPS shortage. Staff notes two issues with this proposal: one functional and one procedural.

Functionally, REC banking is an important tool set forth in statute that allows PGE to smooth the blockiness of resource procurements and defer the need to build future resources for RPS compliance allowing ratepayers to benefit receive the RPS compliance value from renewable generation for which they have already paid.

PGE's proposal to arbitrage the RPS compliance value with unbundled REC value misaligns costs and risks to ratepayers. Staff noted in PGE's 2016 IRP, RECs are not likely to generate much market value.[101] Staff finds that this is not on par with the value of deferring large capital investment costs. As a result, PGE's proposal would create future planning risks by eliminating this tool and skewing future IRP analyses to add more resources earlier.

Procedurally, the Commission decided in the 2016 IRP that, "Staff may request that we open a docket on mechanisms for delivering value from incremental RECs to customers

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[98] PGE Final Comments, p.5.
[99] Ibid., p. 6.
[100] PGE Response to Staff IR No. 008, Confidential Attachment A.
[101] *See* LC 66, Staff Comments Filed December 1, 2017, p. 10.

in a public meeting at a later date."[102] Staff notes that to date, Staff has not requested that such a docket be opened. Planning mechanisms to specifically address REC treatment and valuation for RPS-eligible resources have not been identified other than what is in existing guidance for IRP development. However, dockets are pending address RPS planning, reporting, and banking requirements, which may affect the manner in which RECs and REC banks are managed. [103]

The industry has reached the stage at which utilities are adding renewable resources as least-cost, least risk resources irrespective of RPS need. As such, utility REC banks are growing and key questions are arising about banking strategy and stranded costs across multiple dockets. Staff discusses REC banking issues, as well as recommendations to address these broader issues holistically, in the RPS Compliance and Banking Strategy Section.

PGE must engage in additional stakeholder process prior to issuing a renewable RFP. On December 11, 2019, the Administrative Law Judges assigned to this docket issued a memorandum requesting stakeholders and PGE to address two detailed questions on the application of the OPUC's new rules for resource procurement by PGE. Question 1 asked:

Regarding a RFP for RPS-eligible resources:

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

In Final Comments, Staff indicated that PGE had not addressed these criteria fully and outlined the following issues required further discussion:

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

[102] Commission Order No. 18-044, p. 2.
[103] *See* for example Docket Nos. AR 610, 616, and 617 RPS Rulemakings, in addition to PGE's 2019 IRP and UE 370.

- Explanation of how the RFP will assess the financial impacts of renewable PPAs and renewable benchmark resources.[104]

PGE's Final Comments indicated that it provided the correct level of information to prepare parties to engage in the RFP process.[105] PGE does not find that the Company should provide all of the information contained in a draft RFP, such as the detailed scoring information as suggested by NIPPC.[106]

Staff agrees that PGE does not need to provide a full draft RFP in the IRP to satisfy the Commission's competitive bidding rules. The function of the RFP information in the IRP is to provide enough detail regarding the design, modeling, and scoring elements to determine if PGE can move forward with an accelerated process for review of a draft RFP. In response to AWEC's comments, Staff does not find that complete agreement on the construction of RFP elements is required to move forward to the more detailed RFP development process.

Staff has commented on the misalignment of the attributes sought through the Renewable RFP and the Company's needs. Given the adjustments made to PGE's supply side actions, PGE must engage in a process with stakeholder to determine how PGE will concurrently conduct its non-dispatchable capacity and dispatchable capacity solicitations to optimize its additions across both resources. PGE may be embarking on new territory with this portfolio approach to supply-side actions and, per the concerns raised in this report, needs to refine its risk, ensure that it has specified the correct attributes, requirements, and scoring criteria to mitigate cost and risk to ratepayers and avoid overbuilding resources. In addition, the Company must resolve the tension between the transmission requirements for non-dispatchable and dispatchable resources as detailed further in the dedication transmission section of this report.

<u>Conclusion</u>

PGE makes a reasonable case for low-cost renewables to meet a portion of its identified capacity need. However, PGE's separate Renewable RFP is not designed to seek these attributes and exposes ratepayers to avoidable risks. Due to the evolution of this IRP docket, PGE has not had the opportunity to develop the mechanisms necessary to mitigate these concerns and demonstrate the Renewable and Capacity

[104] Staff Final Comments, p. 33.
[105] PGE Final Comments, p. 26.
[106] NIPPC Final Comments, pp. 14 – 19.

RFPs can be optimized at a portfolio level. Therefore, Staff cannot recommend acknowledgement of the separate Renewable RFP at this time.

If the Commission chooses to acknowledge a renewable procurement, Staff recommends conditioning the Action Item so that PGE conducts its RFP in a manner that will only select resources that:

- Minimize performance risks and near-term costs borne by ratepayers through a PPA structure (no benchmark resource);
- Offer a legitimately good deal by capturing the attributes demonstrated in IRP modeling;
- Are best positioned to meet PGE's capacity needs cost-effectively; and
- Are optimized on a portfolio level with dispatchable capacity additions.

Recommendation for Action 2 Renewable RFP

Staff does not recommend acknowledgement of the standalone Renewable RFP, but in the event the Commission acknowledges the Action Plan, Staff recommends conditioning acknowledgment on adoption of one of two least cost, least-risk pathways that PGE could move forward with a renewable resource action:

1. Modify Action 3B Dispatchable Capacity RFP to consider non-dispatchable capacity options; or
2. Subject the Renewable RFP to the following conditions:
    - PGE may not submit a benchmark resource to its RFP.
    - The cost containment screen must require bids to meet the key cost and performance attributes of the preferred portfolio.
    - PGE should engage in a rigorous stakeholder process prior to the selection of an Independent Evaluator (IE) and filing of a draft RFP to determine how the non-dispatchable capacity resources in the Renewable RFP will be considered concurrently with the resources in the dispatchable capacity RFP, such that any resource acquisitions are optimized on a portfolio level.
    - The risk of proceeding must remain with PGE unless and until the Commission completes a prudence review and approves cost recovery of any renewable resources acquired under the IRP in rates. Rate recovery may be conditioned or limited to ensure customer benefits remain at least as favorable as IRP planning assumptions, including but not limited to a return of the full value of the Production Tax Credit (PTC) to ratepayers.
    - PGE cannot assume it returns the value of the RECs from resources acquired through the RFP to customers. General IRP Comments

GR1: Interim Transmission Solution

Overview

Due to the nature of PGE's system, transmission is a major consideration in resource acquisitions. PGE filed a proposal for an Interim Transmission Solution to support the 2019 IRP's Renewable RFP as an addendum to the 2019 IRP on August 30, 2019. The proposed solution is a five-year provisional program, specific to renewable resource procurement processes conducted between 2019 and 2024. PGE intends to utilize this solution until it can develop a more permanent strategy to appropriately balance the cost and risk of integrating renewable resources.[107] The key restrictions on the renewable resources in this provisional program are the following:

- Applicable only to newly procured variable renewable resources pursuant to an IRP Action Plan or in support of voluntary renewable programs.
- "Eligible transmission service" consists of one or a combination of the following products:
  - Long-Term Firm (LTF) transmission service;
  - Conditional Firm Bridge (CFB) transmission service with a Number of Hours curtailment option;
  - Conditional Firm Reassessment (CFR) transmission service with a Number of Hours curtailment option.
- Eligible transmission service is required for at least 80 percent of the maximum output of the facility.
- PGE continues to require that output be delivered to PGE's system, not a market hub.[108]

PGE confirms that it will employ its scoring methodology based on non-quantifiable aspects centered on risk and uncertainty, such as the difference in long-term availability between CFB and CFR service, and states that transmission will play a role in the determination of capacity value.[109] The Company will reflect curtailment impacts and long-term transmission for less than the full output depending on the type of transmission service paired with the project, in addition to what appears to be coincidence with peak.[110]

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

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[107] PGE's 2019 IRP Addendum – Interim Transmission Solution, p. 1.
[108] Ibid., p. 5.
[109] Ibid., p. 6.
[110] PGE specifies this as "appropriate hours" and makes several references to peak system needs throughout the document. See PGE's 2019 IRP Addendum – Interim Transmission Solution, page 6.

PGE."[111] Further, the Company will weigh the scoring based on PGE's determination of capacity value, which will ultimately be tied to the type of transmission service included in the project offer. The Company also explains that it will introduce a non-price scoring assessment that will assign higher non-price scores to bids that have greater shares of long-term service and long-term firm service.[112]

Parties' Opening Comments

<u>NIPPC</u>

NIPPC argues that PGE's transmission solution is not sufficiently detailed to move forward with a faster-tracked RFP process under the Commission's competitive bidding rules and finds that the interim solution will still restrict the ability of bidders to successfully compete in the RFP. NIPPC finds that PGE should provide details about *how* the different eligible transmission service types will be scored. NIPPC highlighted the following transmission-related concerns.

- PGE could do more to allow increased flexibility in transmission requirements. Particularly, NIPPC argued that PGE should allow "some" level of non-firm transmission and "some" level of short-term firm beyond the currently proposed 20 percent maximum in its interim solution. NIPPC requests that the Commission require PGE to perform analysis of how much curtailment risk is acceptable.[113]
- PGE is withholding 350 MW of transmission in the form of deferred service. Because PGE is able to defer the start date of transmission service on BPA's system by requesting deferrals, this suggests that there is additional "idle" capacity that PGE is not releasing for third-party use, thereby limiting the ability of independent power producers to compete with PGE in an RFP.[114]
- PGE does not address freed-up transmission rights as a result of the Boardman retirement. More specifically, when a generation resource retires, the transmission capacity associated with that resource also "retires," effectively freeing up capacity on the transmission system. NIPPC claims that these "freed-up" rights (585 MW of Point-to-Point transmission service) are not addressed by PGE.[115]
- PGE needs to do additional analysis on the Energy Imbalance Market (EIM) transmission dispatch. With additional products being developed, such as EDAM and DAME, NIPPC argues that not enough analysis has been done to understand the impacts of these additional products and that PGE should off on

[111] PGE's 2019 IRP Addendum – Interim Transmission Solution, p.11.
[112] Id.
[113] NIPPC Final Comments, p. 3.
[114] Ibid., pp. 2-6.
[115] Ibid., pp. 6-7.

acquiring any new long-term transmission rights associated with new generation.[116]

- There is not enough information in the Interim Transmission Solution addressing diversity of resources and that the Company should consider combining multiple bids in different zones to optimize resource variety.[117]

AWEC

AWEC agrees with NIPPC that PGE does not provide information about how the transmission service types will be scored, but also cautions that requiring too much detail about RFP scoring could compromise the parties' review of the IRP and the RFP.[118] AWEC is not opposed to the level of detail provided in the IRP, but finds that the RFP information in the IRP should be informational only and that the Commission should not acknowledge RFP scoring methodology in this IRP.[119]

RNW

RNW argues that PGE should allow non-firm transmission products for projects in its RFP.[120] RNW believes that curtailments are rare and there is not significantly more risk associated with using non-firm transmission for the last 20 percent of a project's output.[121] RNW also encourages PGE to consider reducing the percentage of long-term firm transmission needed because deliverability of a resource using firm transmission has diminishing returns.[122] Finally, RNW reiterates that PGE should consider contractual mechanisms to make its transmission rights available to third-party bidders.[123]

NWEC

NWEC agrees with PGE that renewable resources must have sufficient transmission to deliver output to load rather than being forced to curtail or shut off but also notes that system performance might be improved by allowing renewable output availability less than 100 percent of the time.[124] NWEC also appreciates PGE's discussion around complementary value from combinations of resources, namely the insight that value from renewable resources is augmented by diverse geographic location type of generation.[125]

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[116] Ibid., pp. 7-9.
[117] Ibid., pp. 9-10.
[118] AWEC Final Comments, pp. 14-17.
[119] Id.
[120] RNW Final Comments, pp. 1-2.
[121] Ibid., p. 2.
[122] RNW Final Comments, pp. 4-5.
[123] Ibid., p. 5.
[124] NWEC Final Comments, p. 4.
[125] Id.

PGE's Position
Regarding RFP design, PGE insists that the level of detail it provides in the IRP is sufficient and that comprehensive information about non-price scoring elements is more appropriately reviewed within an RFP approval proceeding.[126]

PGE disagrees with RNW and NIPPC's assessment about the level of risk with non-firm transmission and notes that historical curtailment patterns may not be appropriate predictors of future curtailment.[127] PGE continues to maintain its position that it will not offer "system conditions" conditional firm reassessment service as part of an RFP bid and that it also will not allow non-firm products above the proposed 20 percent in the Interim Solution.[128]

Regarding the idea that PGE apply its own transmission rights to third-party projects, PGE reiterated that this would shift the uncertainty and cost associated of maintaining its rights on to PGE and customers for the benefit of hypothetical projects.[129] Though PGE appreciates NIPPC's proposal regarding resource diversity and transmission, overall, PGE repeatedly stated that it believes many of the specifics the parties have requested are best addressed in an RFP docket, not the IRP.[130]

Staff Position and Recommendations
Staff is pleased that the Company introduced a proposal to broaden the diversity of transmission products it is willing to accept. That said, Staff finds that the details on eligibility and the scoring methodology insufficient to understand whether this proposal will in fact increase likelihood that PGE received a range of successful bids. Staff provided list of requests for PGE to address, including discussion of tradeoffs of types of resources, transmission paths to be utilized, and net contributions of blended wind regimes.[131]

Given the state of transmission availability in the region, Staff does, however, have sufficient information to be concerned that PGE resources are likely to score higher. PGE has indicated in its interim proposal that bids with higher quality transmission will get higher scores. Thus, a lower-cost bid with conditional firm transmission may not be selected in favor of a higher-cost bid with lower quality transmission. There is simply not enough information about the scoring methodology to know what to expect.

In addition, parties raised the question of what PGE will do with the transmission rights associated with the Boardman closure. PGE explained at the January 30, 2020, Special Public Meeting that there are high costs associated with retaining or renewing these

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[126] PGE Final Comments, pp. 20-28.
[127] Ibid., pp. 21-22.
[128] Ibid., p. 22.
[129] Ibid., p. 23.
[130] Ibid., pp. 24-26.
[131] See both Staff Opening Comments, p. 42, and Staff Final Comments, p. 39.

rights and indicated that it would not be acceptable to continue paying for them for the sake of allowing a third party developer to export power across its system. However, Staff notes that if PGE were to retain or renew these rights for its own RFP bid, it would assume those costs anyway; they would just not be used to transport third-party resources. This lends itself to the question of whether the Commission should allow ratepayers to assume additional risk so that third parties can lean on PGE's transmission system. This would ultimately depend on reliability risks to ratepayers, economic viability of the third-party bid, relative costs, and whether the quality of a third party bid is high enough to justify any ratepayer risks.

This level of detail cannot be answered at this time and will only be answered through the rigorous RFP process recommended by Staff under Actions 2 and 3B.

The generation PGE proposes to acquire in its Action Plan cannot serve load without transmission. Because PGE has not specified the performance attributes of its resource acquisitions, the ability to secure least cost, risk renewable resources will be heavily informed by the access these types of resources have to eligible transmission. The Company should make known its scoring methodology as soon as possible in any RFP docket it intends to file.

Recommendation GR1 Interim Transmission Solution:

If PGE moves forward with an RFP that includes renewable resources, the Commission should require PGE to incorporate the following modified elements from Staff's comments into its initial application:

- The Company must explain how it intends to score transmission service when it initially files its RFP. This includes qualitative and quantitative weighing. The Company must outline its rubric and explain how it will score transmission products. Exact values/formulas should be provided. The discussion should be supported by an appendix explaining what PGE relied on in making its cost and risk projections, and how those calculations were specifically made. PGE should make straightforward, lay audience explanations in the initial application on what it is trying to achieve and how and why it has confidence in particular resources or sub-regional sourcing of resources. This should be backed up with an appendix that gets more technical and detailed. The application should include how the methodology will align with Bonneville Power Administration's TSR Study and Expansion Process (TSEP) process.
- The Company should explain how it will weigh tradeoffs between resource quality, cost, and transmission capacity, including available transfer capability (ATC). This discussion should include but not be limited to explaining how it will score tradeoffs of lower quality wind (or other resources) with existing ATC vs. higher quality resources with incremental transmission capacity build.

- The Company should discuss how it will score net contribution made by blending diverse regime wind profiles. If resource diversity (both geographic and resource type) the Company should provide an explanation as to why it will not be considering resource diversity in its RFP.
- The Company should discuss how it will score partnerships or partial share of larger wind projects that can lower cost and risk for PGE ratepayers. If partnerships will not be considered, the Company should provide an explanation as to why it will not be considering partnerships in its RFP.
- The Company should discuss how it will weigh specific transmission paths and average flowgate impacts of project bids. This discussion must explain how PGE has or would acquire each needed transmission resource or right.
- Material changes such that the RFP is different from what was reviewed in the IRP must be brought to the Commission's attention.

GR2: RPS Compliance and Banking Strategy

Overview

PGE introduced a new strategy to meet future RPS needs in this IRP: physical compliance. As part of this strategy, PGE relies on the regular addition of new renewable resources to meet increasing RPS needs starting in 2027.[132]

If this RPS compliance strategy and its subsequent renewable resource acquisitions are acknowledged, PGE's next RPS "shortage" will be in 2030.[133] In that year, PGE will have a REC bank of 25 million eligible RECs, which is four times the RPS obligation. The REC bank will continue to grow almost every year until it reaches 42 million RECs in 2040 when the RPS reaches 50 percent, and is still four times the RPS obligation.[134] Following 2040, PGE begins to net deplete the REC bank by about 1 million RECs per year through the end of the 2050 planning horizon.[135]

The industry should celebrate the fact that it has reached a point where PGE proposes to add RPS renewable resources as an economic opportunity irrespective of RPS need.[136] However, the combination of physical compliance and renewable additions not driven by compliance results in PGE accruing a massive REC bank that persists throughout the long-term planning horizon.

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[132] PGE 2019 IRP, p. 179.
[133] PGE Final Comments, p. 41.
[134] PGE Response to Staff IR No. 008, updated January 17, 2019.
[135] Id.
[136] PGE 2019 IRP, p. 201.

Parties' Positions

CUB

CUB expressed concerns about the accuracy of PGE's RPS need and the new glide path to renewable resource acquisition related to the overall load forecast being overstated.[137] CUB stated that its concerns about PGE's strategy to RPS need were largely satisfied by PGE's responses.[138]

NWEC

NWEC was generally supportive of PGE's new RPS physical compliance strategy.[139]

RNW

RNW found the approach to RPS need reasonable. RNW asserted that PGE's strategy to meet its RPS obligation through physical compliance reflected, "…sound risk management.." and the analysis of benefits firmly established that PGE's physical compliance strategy was least cost, least risk.[140] RNW also felt that PGE adequately addressed Staff's concerns about the impact of VRET programs on the Company's energy and capacity needs.[141]

AWEC

AWEC expressed strong concerns about the physical RPS compliance requirement that PGE places on portfolios beginning in 2027. AWEC's opposition to PGE's renewable Action Item and RPS physical compliance strategy stems from three concerns:

- Forecasted long-term benefits do not outweigh the lack of near-term need or represent least cost, least risk planning;[142]
- PGE's glide path analysis shows that PGE is always *physically* long on RPS compliance;[143] and
- The use of the REC bank and unbundled RECs are not properly maximized to avoid overbuilding resources.[144]

PGE's Position

PGE stated that, "requiring physical RPS compliance is the most appropriate method of aligning with the public policy objectives of SB 1547."[145] Regardless, PGE went to some length in its comments to address stakeholder concerns. PGE did additional modeling of scenarios to prove the economic benefit of near-term renewable acquisitions and a

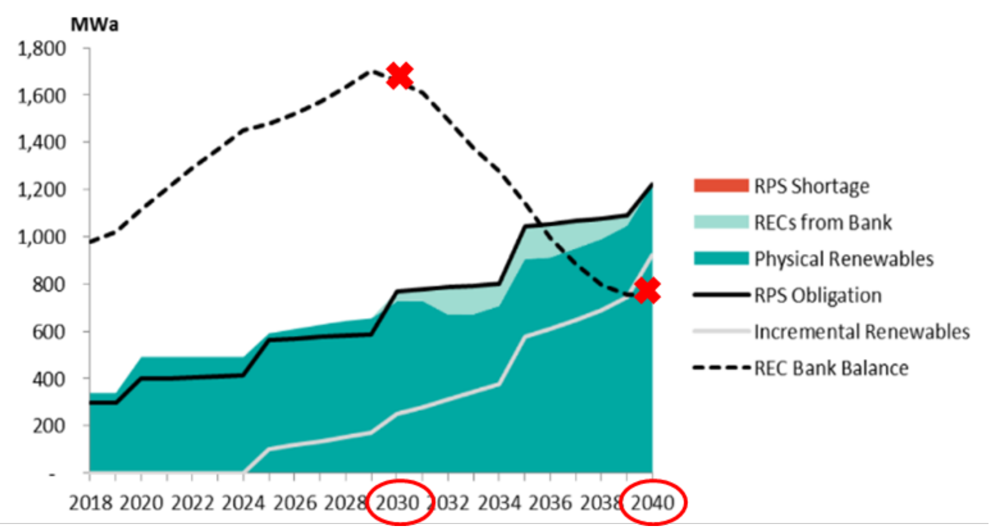
[137] CUB Opening Comments, p. 3.
[138] CUB Final Comments, p. 7.
[139] NWEC Final Comments, p. 1.
[140] RNW Final Comments, pp. 9-10.
[141] Ibid., p. 10.
[142] AWEC Final Comments, p. 9-10.
[143] Ibid., p. 10-11.
[144] Ibid., p. 10-13.
[145] PGE Reply Comments, p. 50.

physical compliance strategy.[146] While PGE's Final Comments stated their openness to exploring different strategies to utilize its REC bank, PGE did not commit to reflecting this in its IRP modeling.[147]

In terms of unbundled RECs, PGE claims that it should not model the use of unbundled RECs 1) because the market is too hard to forecast (but apparently not hard enough not to decide to sell perfectly good RPS RECs) and 2) because it could require them to buy incremental RECs that it doesn't need because it already acquired enough renewables.

Staff's Position and Recommendations
PGE's proposed physical compliance strategy is a large departure from the last IRP. In LC 66, PGE proposed a mix of RECs and near-term resource acquisitions to create a glide path for long-term RPS compliance, as shown in the figure below. [148]

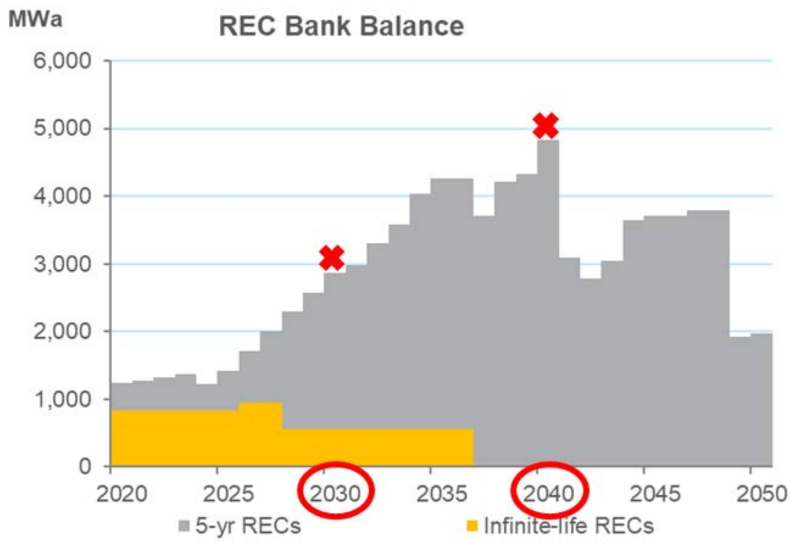
Figure 2: PGE 2017 Proposed Renewable Glide Path



PGE's proposed shift to a physical compliance strategy in the 2019 IRP nearly doubles the forecasted REC bank size by 2030, and by 2040 the REC bank is about seven times larger than the glide path proposed in 2017.[149] For perspective, PGE will have roughly four times as many RECs in its bank than its reference case load forecast in 2040. This means PGE could have enough RECs stored up—already paid for by ratepayers—to meet eight years' worth of its 50 percent RPS obligation.[150]

[146] Ibid., pp. 49 – 53.
[147] PGE Final Comments, p. 52.
[148] *See* LC 66, PGE Revised Renewable Action Plan, Nov. 9, 2017, pg. 21.
[149] PGE 2019 IRP, p. 202.
[150] Ibid., Updated Needs Assessment, p. 3.

Figure 3: PGE 2019 IRP Preferred Portfolio REC Utilization[151]



Staff appreciates all of the additional analysis conducted by PGE on issues related to RPS need and its physical compliance strategy. However, we agree with AWEC that this approach overstates the near-term need for PTC wind in an effort to help bolster the more long-term and thus less concrete benefits related to the economic opportunity argument associated with this resource. In this sense, we disagree with the analysis of NWEC, RNW, and CUB.

PGE presents analysis clarifying that the model can still choose to use banked RECs. However, the physical compliance requirement means that the use of banked RECs cannot actually defer the model's decision to add new resources—it simply determines which RECs are most cost-effective to retire. To this end, if renewables are projected to be so much cheaper than banked or unbundled RECs, then Staff is left wonder why the physical compliance requirement was necessary in the first place.

Staff asserts that the value of the banked RECs – and to that end unbundled RECs – is to defer the need for resource acquisition to comply with RPS. That is why these mechanisms were included in Senate Bill (SB) 838 and retained in SB 1547. If PTC wind is that beneficial financially, let it compete with all other resources to meet actual needs, like PGE's capacity shortfall in 2025.

Staff reiterates its initial position that PGE must consider the use of unbundled RECs and a more reasonable use of the REC bank that PGE's ratepayers have built-up by

[151] PGE Response to Staff IR No. 008, updated January 17, 2019.

paying for renewable acquisitions. Staff does not find PGE's argument against the use of unbundled REC's compelling. PGE has been utilizing nearly 20 percent unbundled RECs in its annual RPS compliance for many years now. If need be, PGE can use their historic data and market relationships to develop low, medium, and high price sensitivities for unbundled RECs in future IRPs.

Further, there are direct and indirect costs to ratepayers associated with banked RECs accumulating from resources acquired solely based on economic opportunity (e.g., direct: overbuilding a resource; indirect: carrying costs associated unused RECs). When banked RECs exceed the actual load or can meet 100 percent of the RPS requirements for several years in a row, PGE should seek to use these RECs to some degree or the Commission should seek to return some near-term benefit to ratepayers.

Finally, Staff finds value in exploring AWEC's assertion that PGE may be required to over-procure energy resources to cover the RPS obligation of VRET participants with bundled RECs. Until VRET customer load exceeds 20 percent of PGE's load, the Company can mitigate this issue with unbundled RECs. Staff is concerned that a physical compliance strategy would remove this option. As more individuals and communities seek to go 100 percent renewable or until the Legislature mandates that PGE be 100 percent renewable, unbundled RECs may not solve the entire problem. Staff's recommendation to explore this issue further with stakeholders is provided in recommendation AR8.

Recommendation GR2 RPS Compliance and Banking Strategy:

Staff recommends that the Commission decline to acknowledge PGE's physical compliance strategy and direct PGE to:

- Not model a physical compliance requirement in the next IRP;
- Require PGE to model a reasonable amount of banked RECs, like in LC 66, as part of any revised RPS need forecast in upcoming RFPs or the 2019 IRP update;
- Require PGE to model the use up to 20 percent unbundled RECs to meet RPS as part of any revised RPS need forecast in upcoming RFPs or the 2019 IRP update;
- In the next IRP, develop and perform a sensitivity on the preferred portfolio that uses 20 percent unbundled RECs; and
- Open a contested case to determine how to best return value to ratepayers from accumulated unused RECs.

GR3: Load forecast

Overview
PGE used three overarching elements, each with its own methodology, to develop the load forecast for this IRP. These elements are:

- An enhanced top-down econometric forecast;
- Energy efficiency forecast from Energy Trust;
- Customer Distributed Energy Resources (DER).

Per the order in PGE's last IRP, the Company completed a study of load forecasting and also conducted workshops and undertook activities designed to improve their load forecast.[152] PGE's enhanced econometric forecast in the 2019 IRP, combined with other forecasts, projected an overall annual average growth rate of 1 percent for the reference case.[153] This was a slight revision downward from the 2016 IRP and 2016 IRP Update where the annual average growth rate was 1.2 percent and 1.1 percent, respectively.[154]

For the 2019 IRP, the annual average growth rate by customer type was as follows:

Customer Type	Reference Case, Forecasted Annual Average Load Growth[155]
Residential	0.1 %
Commercial	0.5 %
Industrial	1.9 %

As part of this IRP, PGE also filed an updated needs assessment in November 2019. The load forecast was revised slightly upwards after incorporating updated inputs from the Oregon Office of Economic Analysis.[156] In addition, PGE provided sensitivity analysis that accounted for the impact of voluntary programs, like VRET and Community Solar.[157]

The inclusion of the customer DER forecast was new to this IRP.[158] Staff appreciates PGE's transparent efforts to develop and incorporate this novel forecast into its overall projection of future need.

[152] *See* LC 66, Commission Acknowledgement Order No. 17-386, October 9, 2017, pg. 19.
[153] PGE 2019 IRP, Table 4-6, p. 102.
[154] *See* LC 66 2016 IRP Update, March 8, 2018, Table 2, pg. 15.
[155] PGE 2019 IRP, pp. 90 – 91.
[156] PGE Updated Needs Assessment, modified by the December 11, 2019 errata filing, p. 3.
[157] Ibid, pp. 8-10.
[158] PGE was directed to develop this forecast in Order No. 17-386, p. 19.

Parties' Positions

CUB

Noting the central importance of accurate load forecasts to avoid overestimating future need, CUB's comments explored the following four factors that could lead to an elevated 2019 IRP industrial load forecast:

- Direct Access customers – PGE's model should account for new and existing large customers that are likely to leave the system.
- VRET – Voluntary programs should be modeled as reductions to the load forecast.
- Energy efficiency of data centers – The growth of this load drives PGE's industrial demand and more aggressive energy efficiency should be studied.
- Use of economic drivers – Explore the use of alternative economic drivers more reflective of PGE's service territory.

AWEC

AWEC sought the removal of new load Direct Access (NLDA) from PGE's 2019 industrial forecast. AWEC argued that without an adjustment downward for NLDA the Company would overbuild resources.[159] Further, AWEC reiterated its evidence for and recommendation that PGE treat Direct Access as a resource option to avoid incremental capacity additions.[160]

RNW

RNW generally expressed support of PGE's load forecasting approach.[161]

NWEC

NWEC reminded PGE of the need to accurately account for the future growth of electric vehicles, both in its load forecast and as a demand-side resource that could support future grid flexibility.[162] NWEC also expressed a broad concern for "further work" regarding PGE's approach to forecasting Direct Access loads and future with a proliferation of microgrids.[163]

PGE's Position

PGE noted that its econometric load forecast has performed well in a benchmark survey of utilities by Itron.[164] PGE also recognized all parties' desire to better consider Direct Access in the Company's load forecast. However, PGE responded that its current approach sufficiently captures the impact of long-term Direct Access (LTDA) on

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159 AWEC Final Comments, Attachment A, pp. 1-2.
160 Ibid., p. 5.
161 RNW Final Comments, p. 7.
162 NWEC Opening Comments, p. 5.
163 Ibid, p. 6.
164 PGE Reply Comments, p. 40.

forecasted load. PGE also addressed concerns raised by Staff and NWEC regarding the impact of EVs on the load forecast. PGE noted that the adoption of EVs in the Action Plan window does not drive capacity procurements and defended its approach to modeling rates of EV adoption. Finally, the Company expressed an openness to exploring alternative economic drivers for the industrial load and in the next IRP.

Staff's Position and Recommendations
Overall, the load forecast for this IRP appears sound, but future improvements should be considered for both the next IRP and the upcoming RFP.

Staff appreciates the improvements over the last IRP and the steps taken by PGE to address stakeholder concerns in this IRP. The improvements necessitated by Order No. 17-386, and those taken independently by PGE, should remain in place.

Staff appreciated PGE's willingness to adopt CUB's recommendation to explore the drivers used in future industrial load forecasts. This exploration should be built into the upcoming planning cycle so that the dialogue impacts the next IRP.

With regards to Direct Access, Staff generally agrees with both CUB and AWEC that PGE's current approach should be enhanced. At a minimum, more sensitivities should be conducted around the modeling of LTDA and NLDA to develop scenarios for the cost-of-service load forecast that results from PGE's current process. The observation that overall industrial load growth for PGE's customers (1.9 percent) is greater than the growth of LTDA customers (1.6 percent) points to a need for more analysis of sensitivities.

Staff agrees with AWEC that docket UM 2024 would be the most appropriate forum to explore treating Direct Access as a resource option in future IRPs.[165] With the Phase 1 schedule for UM 2024 recently set for Opening Comments on March 16, 2020, Staff looks forward to hearing from all stakeholders on this important topic.[166]

Finally, Staff agrees strongly with CUB's description of the necessity for load forecasts to be as accurate as possible to avoid overbuilding resources.[167] With this in mind, Staff would note that comparing and truing-up forecasts to reflect actual observations can be a powerful, iterative tool to improve forecast accuracy.

In the second quarter of 2020, PGE will be sharing its retail sales and net metering additions. The retail sales numbers can provide a window into load growth by customer type. As Staff pointed out in its Opening Comments, PGE's forecasted annual average

[165] AWEC Final Comments, p. 5.
[166] *See* UM 2024 Ruling on Procedural Schedule, Feb. 21, 2020.
[167] CUB Opening Comments, pp. 10 – 11.

load growth of 0.5 and 1.9 percent for commercial and industrial customers stands in contrast to recently observed annual growth rates.

Figure 4: Historic Commercial and Industrial Load[168]

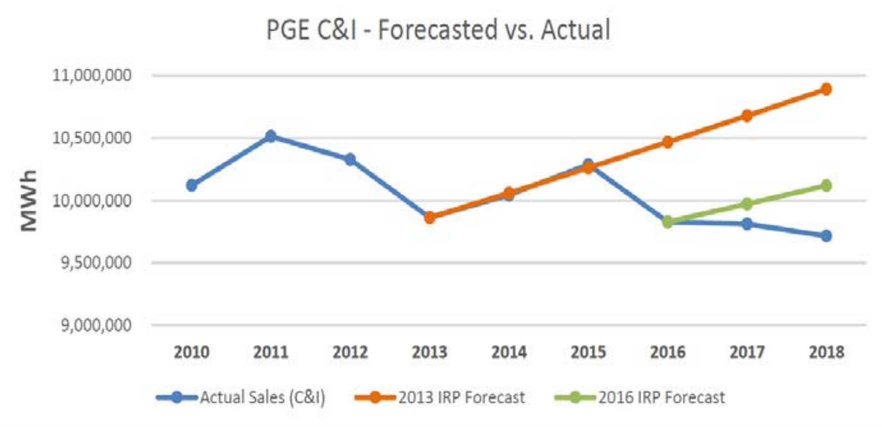
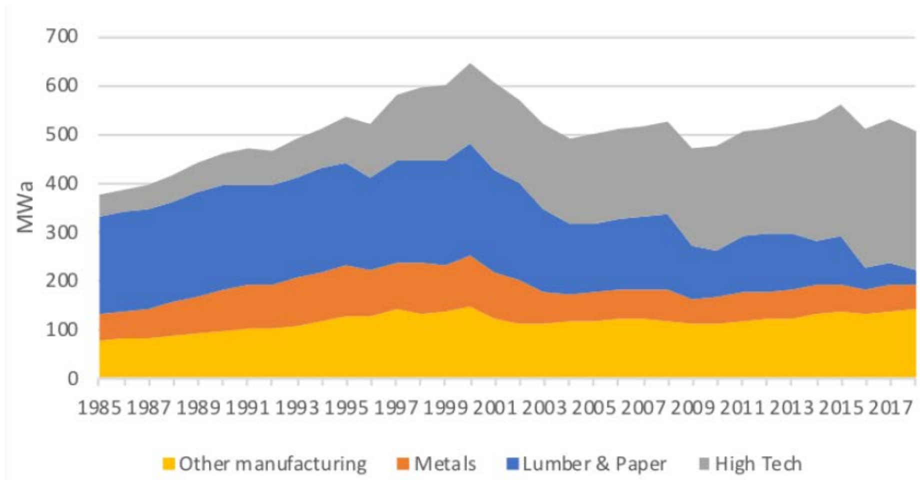


Figure 5: Industry Mix in PGE's Service Area[169]



Also, when comparing PGE's forecast for distributed solar to actual net metered solar installations, there is a possibility that PGE's high forecast could actually be the reference case. Using the average rate of growth for distributed solar installations from the years 2016-2018, PGE's forecasted penetration rate would be closer to

[168] Staff Opening Comments, p. 21.
[169] PGE 2019 IRP, p. 92.

300 MW-ac.[170] PGE's current reference case scenario for distributed solar installations is approximately 200 MW-ac in 2030.[171]

Given that PGE will be conducting bilateral negotiations and launching one to two RFPs in the second quarter of 2020, there is the ability to improve the Company's load forecasts by incorporating observed 2019 sales and solar installations into the econometric model and DER forecast, respectively.

Recommendation GR3 Load Forecast:

Acknowledge PGE's load forecast subject to the following modifications:

- Work with stakeholders to explore the drivers used in future industrial load forecasts and sensitivities around Direct Access customers. This work should be built into the upcoming planning cycle so that the dialogue impacts the next IRP.
- Report to stakeholders on actual 2019 sales by customer class and 2019 DER installments (RE 45), showing trends over the past five years, and discuss possible adjustments to the load forecasts from this data that adjusts the load forecasts used bilateral negotiations and any RFP acknowledged by this IRP.

GR4: Non-traditional metrics

Overview

PGE introduced non-traditional scoring metrics in the 2019 IRP to account for risks not captured with the traditional cost, variability, and severity metrics.[172] These metrics include greenhouse gas (GHG) emissions, criteria pollutant emissions, cost in a carbon-constrained future, cost in a high-tech future, near term cost, and energy additions through 2025.[173] As noted by PGE and RNW, these metrics were developed through a robust stakeholder process.

In the 2019 IRP, PGE used the non-traditional metrics to screen portfolios out of consideration prior to examination of non-traditional metrics. Portfolios were excluded based on failing a single metric. For six of the seven non-traditional metrics, PGE excluded any portfolio that performed one-standard deviation worse than the mean. For the Energy Additions Through 2025 metric, all portfolios adding more than 250 MWa of energy are excluded.

PGE screened out about half of the portfolios originally considered. This includes all of the optimized portfolios which, as intended through optimization, perform best on

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[170] *See* PGE Report on Net Metering, RE 45, Compilation of annual installations from 2016, 2017, and 2018 reports.
[171] PGE 2019 IRP, p. 99.
[172] Ibid., p. 186.
[173] Id.

traditional cost and risk. Following the application of the screens, PGE evaluated the remaining portfolios for traditional cost and risk.

Parties' Positions
No parties expressed concerns with the non-traditional screens. NWEC and RNW expressed support for the use of the screens.[174,175]

PGE's Position
PGE affirms that the non-traditional screens were developed through a robust stakeholder process and focuses any further discussion on the fact that the screens do not change portfolio modeling's indication that near-term renewable additions are beneficial to ratepayers.[176]

In addition, PGE notes that non-traditional screens should not be used in the RFP scoring process, but that the Cost in a High Tech Future risk is already captured by the use of the IRP wholesale market price futures in scoring bids.[177]

Staff's Position
Staff finds that PGE was successful in developing its non-traditional metrics with stakeholders. The metrics proved very useful in comparing portfolios based on contemporary risks that are not fully captured by the traditional cost and risk metrics.

While supportive of the metrics themselves, Staff is concerned about the blunt manner in which PGE implemented this tool. Staff found that this was less severe, because the major limiting screen was placing an upper bound in near-term additions. Staff agrees that, at some point in portfolio modeling, it was important to test this.

However, if the majority of the Company's top performing portfolios were eliminated from consideration based on relative performance to other portfolios based on a single one of the other metrics, Staff would likely take issue with the modeling assumptions or development of the screens.

Staff encourages PGE to work with stakeholders to refine its use of the metrics and consider how it can facilitate comparison of top performing portfolios across all metrics with more nuance and flexibility.

In addition, Staff appreciate PGE's comments on the use of non-traditional screens in RFP scoring. Staff finds that the non-traditional risks are important considerations in RFP development, but these risks can be addressed through other mitigation tools that

[174] NWEC Final Comments, p. 1.
[175] RNW Opening Comments, p. 5
[176] PGE Reply Comments, pp. 24-27.
[177] PGE Final Comments, pp. 27-28.

Staff proposed for the standalone Renewable RFP, such as the enhanced cost containment.

Recommendation GR4 Non-traditional Metrics:

Non-traditional screens cannot be used to screen portfolios prior to considerations of traditional cost and risk. PGE should continue to refine the non-traditional metrics with Staff and stakeholders so that they can be more nuanced.

GR5: Market Energy Position (MEP) Analysis

Overview
PGE's MEP study models economic dispatch of PGE's resources under 54 future scenarios designed to represent potential variations in economic factors, including gas prices, carbon prices, and load. The MEP compares PGE's economic dispatch to three different expected load or "need" futures to demonstrate how much energy PGE expects it will buy on the market in each future, assuming no incremental resource actions beyond efficiency and DERs.

In its portfolio modeling, PGE uses the MEP in two ways. First, PGE uses it to constrain out-year resource acquisitions to avoid a persistently long market position.[178] In addition, PGE uses the MEP to loosely inform an upper bound on energy additions in the near term, which in turn informs the upper limit on the proposed Renewable RFP.[179]

Parties' Positions
RNW supports the MEP.[180]

CUB finds that the MEP is a step in the right direction, but encourages PGE to do more to consider the interaction of regional markets and resource dispatch in the IRP.[181]

PGE's Positions
In comments, Staff and PGE have engaged in extensive discussion about whether PGE has used its MEP to quantify a resource need or energy shortage.

PGE states that it has not used the MEP to quantify its need, but to limit its ability to pursue an economic opportunity. The Company further states that it plans to host discussions with Staff and stakeholders in the next IRP cycle to consider opportunities to improve the terminology and reporting of information related to energy in future IRPs.[182]

[178] PGE Final Comments, p. 17.
[179] Id.
[180] RNW Final Comments, p. 9.
[181] See both CUB Opening Comments, p. 12 and CUB Final Comments, p. 5.
[182] PGE Final Comments, p. 17.

Staff Position and Recommendations
Staff appreciates the open discussion of this topic with PGE, and it has helped Staff clarify its final position as follows:

Staff is less concerned about the use of the MEP as an upper bound for the glide path analysis after considering PGE's arguments, but hopes that the proposed stakeholder discussions prior to the next IRP consider if there are more nuanced approaches to placing an upper limit on resource additions than PGE used in its IRP's modeling.

Staff also agrees with CUB that markets may have increasing implications for modeling resource dispatch and the consideration of opportunity and need. Staff encourages PGE to work to consider how the next IRP can better reflect these implications.

Staff continues to caution against the use of the MEP to quantify an energy resource need or deficit. In recent IRPs, the Commission has suggested that in addition to resource need, economic opportunity may be a reasonable justification for a resource addition. A true resource need is expected when the company will no longer have sufficient resources in the stack to serve its load, regardless of resource cost or market prices. The traditional load and resource balance study (LRB) is an appropriate way to determine the year when a utility has a true need to acquire new resources, since it considers the full potential energy output of existing utility resources, rather than the economic dispatch of resources in response to market prices.

Acquiring a resource in advance of need can be risky for ratepayers in a number of ways which aren't fully accounted for in IRP portfolio modeling. Early acquisition can take away the planning flexibility to seize an opportunity to secure a better resource that becomes available unexpectedly, or the opportunity to respond to unexpected changes in market prices or other economic variables in the interim. The traditional energy LRB, which identifies the last possible year when the company could acquire a new resource and still serve load reliably, is an accurate way to identify the year of a resource need.

The MEP is not a sufficiently accurate way to determine resource need if PGE has any dispatchable energy resources in its portfolio. For example, consider a potential future where regional market energy and market capacity are abundant, and market prices remain very low. PGE has 950 MWa of dispatchable CCCT generation available (approximately the combined MWa of Carty, Coyote Springs, and Port Westward).[183] In this future, PGE would meet load mostly with non-dispatchable, low-variable-cost renewables and market purchases, avoiding CCCT generation because of its higher variable costs. The Market Energy Position analysis would indicate that PGE was short to market, but this should not be mistaken for a need to procure new energy resources. PGE would still have 950 MWa of dispatchable energy resources sitting idle, waiting to be used when market prices increase above their variable cost. In this scenario, it would

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[183] PGE 2019 IRP, p. 275.

be incorrect to use the MEP to quantify a resource need, since it would indicate that PGE should procure new energy resources, instead of utilizing the 950 MWa of idle, existing resources on its system.

PGE's IRP explains that a MEP study with a high level of market purchases represents risks to customers through the potential for high market prices.[184] Staff agrees but finds the MEP study to be inadequate to accurately quantify these risks, because it does not consider the potential to increase the dispatch from existing PGE-owned or -controlled resources.

In summary, Staff appreciates the MEP study as an informative look at the Company's potential future energy position. Staff simply recommends the MEP not be used to quantify a resource need, and discourages use of the terminology 'shortage to market' to describe the MEP, as it does not necessarily represent an energy shortage.[185] Because the 2019 IRP does not rely on the MEP to justify resource procurement, Staff's words of caution regarding the MEP do not have major implications for this IRP.

Recommendation GR5 Market Energy Position:

Prior to the next IRP, PGE should work with stakeholders to:

- Continue to use the MEP in portfolio modeling to manage the market position of its portfolios and provide the traditional LRB as a means of determining if there is a capacity or energy shortage.
- Work with Stakeholders to consider opportunities to improve the terminology and reporting of MEP information related to energy in future IRPs. This should include whether PGE can take a more nuanced approach to placing an upper limit on resource additions than PGE used in its near-term portfolio modeling.
- Include a regional market analysis to identify the impacts of regional market developments on PGE's resource needs and options.

GR6: Decarbonization Strategy

Overview

PGE's 2019 IRP states a corporate goal to decarbonize its energy supply as cost-effectively as possible.[186] In Opening Comments, Staff recognized the challenges PGE faces in aligning the Commission's long-term planning process with its decarbonization goals, but criticized the Company for treating a standalone wind investment as a proxy for a fully articulated decarbonization strategy.[187] Staff pushed back on PGE's narrative and suggested that, if the Company wishes to bring its corporate decarbonization goals

[184] PGE 2019 IRP, p. 112.
[185] See Figure 4-18, PGE 2019 IRP p. 111.
[186] 2019 PGE IRP, p. 22.
[187] Staff Opening Comments, pp. 17-19.

into its planning framework, it must present a holistic strategy to meet its goals in a way that minimizes cost and risk for ratepayers.

Over the course of this IRP, parties have engaged in helpful discussion related to decarbonization. Staff appreciates this discussion and encourages PGE to continue down this path.

Parties' positions

CUB

CUB states that it is important and least risk to decarbonize the electric grid in a way that does not threaten reliability.[188]

RNW

RNW encouraged PGE to continue evaluation of accelerated depreciation and early retirement of the Colstrip Units.[189]

Swan Lake

Swan Lake supported acquisition of non-emitting resources and encouraged PGE to recognize the risks of sooner than anticipated plant closures.[190]

PGE's Position

Throughout the IRP, PGE expressed openness to considering approaches to least cost, least risk decarbonization, including, but not limited to:

- **Colstrip:** PGE performed multiple analyses considering early exit from its share of Colstrip Units 3 and 4. These analyses continue to indicate increasing benefits of early exit, particularly under the latest fuel supply contract.[191] As a result, PGE has committed to identify its commercial options for early exit and analyze the customer rate impacts of these options.[192]
- **Boardman:** PGE agreed to provide updates on Boardman decommissioning and the opportunity to continue use of Boardman using dispatchable, non-GHG emitting energy or capacity technologies within future IRPs and/or IRP Updates.[193]
- **Climate adaptation:** PGE agreed to update its climate adaptation study to consider the impacts and interactive effects of climate change on its loads and resources.[194]

[188] CUB Final Comments, p. 7.
[189] RNW Final Comments, pp. 11-12.
[190] Swan Lake Final Comments, p. 26.
[191] PGE Final Comments, pp. 31 – 34.
[192] Ibid., p. 34.
[193] Ibid., p. 53.
[194] See both PGE Reply Comments p. 90, and PGE Final Comments p. 10.

- **Demand-side actions:** PGE has agreed to consider additional demand-side resources above the cost-effective baseline.[195]
- **Portfolio analysis:** PGE modeled a GHG and cost optimized portfolio and included multiple emissions-related screens.[196]
- **Decarbonization study:** PGE provided a deep decarbonization study as an enabling analysis in this IRP.[197]

Staff's Position and Recommendations
Staff appreciates PGE's goals and willingness to explore more comprehensive planning approaches. Staff is encouraged by PGE's commitment to explore commercial options to exit Colstrip consistent with its IRP analysis. Staff is concerned that PGE ratepayers could be the last customers left responsible for a stranded asset. Staff recommends that PGE pursue an aggressive timeline for these efforts and provide quarterly updates to Staff on the progress.

Staff also appreciates PGE's introduction of the GHG and cost optimized portfolio and non-traditional screens. The energy additions in the portfolio eliminated it from robust discussion, but Staff notes that this portfolio resulted in a very similar resource strategy to the Minimize Average Long-term Cost portfolio.[198] In the next IRP, Staff hopes that PGE will continue to build on this analysis such that parties and the Commission can understand the extent to which a least cost, least risk decarbonization portfolio would or would not be costlier and riskier than the top performing portfolios.

In addition to the commitments above, Staff recommends that PGE work with stakeholders before the next IRP to determine whether portfolio modeling can consider thermal resource retirements.

Finally, Staff expects that developments in community-driven renewables will occur before the next IRP. Staff sees these as opportunities to accelerate its goals in partnership with its customers. However, Staff is also concerned that these efforts could create undue costs, risks, and reliability issues for all ratepayers if not planned for properly. Staff recommends that PGE include an update on these efforts in the IRP Update. This can include potential loads committed to community renewable or decarbonization goals, timelines, and targets.

[195] PGE Final Comments, p. 15.
[196] Ibid, p. 180 and 187.
[197] Ibid., External Study A. Deep Decarbonization Study beginning p. 375.
[198] Ibid., p. 186.

Recommendation GR6 Decarbonization Strategy:

If PGE wishes to reflect its corporate decarbonization goals in its planning framework, PGE should consider the following additional efforts as part of a holistic least cost, least risk decarbonization strategy prior to the next IRP:

- Conduct its proposed Colstrip rate impact analysis, providing quarterly updates to Staff and moving as quickly as possible.
- Work with stakeholders to continue to improve how portfolio modeling can present a least cost, least risk decarbonization strategy to be compared to traditional top performing portfolios.
- Enhance PGE's portfolio modeling to consider thermal resource retirements, or other GHG mitigating measures, in portfolio analysis.
- Include a discussion of community-driven decarbonization efforts in the IRP Update.

Additional Analysis and Recommendations

Parties have identified several additional areas to enhance PGE's approach to resource planning. The discussion of these issues benefitted this IRP and will improve future planning efforts. Staff finds that there is general agreement on these issues across parties and, therefore, recommends that PGE continue to pursue the areas of continued improvement as summarized in Table 4 below.

Table 4: Additional Analysis and Recommendations

Category	Final Staff Recommendation	PGE Response
IRP improvements: Staff recommendation that the Commission acknowledge a requirement that PGE work with stakeholders to make the following improvements before the next IRP:		
AR 1. Market price forecasts	Refine resource build out and carbon price assumptions in the market price forecasts.	Agreed
AR 2. Probabilities	Enhance PGE's consideration for the probability of individual futures in portfolio modeling.	Agreed
AR 3. Intergenerational equity	Explore the use of discount rate sensitivities as a measure of intergenerational equity.	Agreed
IRP update: Staff recommends that the Commission acknowledge a requirement that PGE provide the following in an IRP update:		
AR 4. Emissions forecast	Update the Emissions forecast after PGE completes any supply side actions.	Agreed

In addition, parties raised important consideration for issues that are more appropriately addressed in other dockets. Staff provides its recommendations for the dockets in which parties can raise these issues, if desired, in the table below.

Table 5: Matters to be Addressed in Other Dockets

Category	Final Staff Recommendation	PGE Response
Other dockets: Staff recommends that parties can raise concerns about the following in:		
AR 5. Energy Efficiency Capacity	Further refinement of the capacity value of energy efficiency in UM 1893, as highlighted in NWEC's comments.	Agreed
AR 6. Direct Access	Planning for Direct Access load and capacity in UM 2024.	Agreed
AR 7. QFs	Planning for future and expiring QFs in UM 2038, per the concerns expressed by REC.[199]	Agreed
AR 8. Green Tariff	The potential for Voluntary Renewable Energy Tariffs to cause PGE to overbuild bundled energy resources in UM 1953, as raised by AWEC. [200]	Not addressed

Conclusion

Staff appreciates the thorough participation of all parties and commenters to this docket as well as PGE. Staff's specific recommendations as to Guideline compliance, Order No. 14-415 compliance, each Action Item, and General Recommendations for PGE's 2019 IRP are found at the beginning of this report.

PROPOSED COMMISSION MOTION:

Acknowledge in part and decline to acknowledge in part PGE's 2019 Integrated Resource Plan and adopt certain actions and additional requirements for inclusion in future resource acquisitions, the IRP update, and future IRPs.

[199] REC's Opening and Final Comments focus on the Company's treatment of QFs both in its IRP needs assessment and in the course of business. In the context of planning, REC recommends that PGE account for a more realistic rate at which QFs come online and renew or enter new contracts with PGE at the end of their current contracts. Staff genuinely appreciates REC's recommendations and is interested in further exploring these issues UM 2038.

[200] See the RPS Compliance and Banking Strategy section of this Staff report for more information.