BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 73

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2019 Integrated Resource Plan Update	Staff's Comments

Introduction

The purpose of these Comments is to draw the Commission's attention to key issues in PGE's IRP Update and raise any preliminary concerns about PGE's acknowledgement request. A goal of Staff's review is to ensure that updates affecting the May 1, 2021 update of avoided cost prices can be vetted by all interested stakeholders.

OAR 860-027-0400 requires each utility to file an IRP Update that: describes actions taken to implement the action plan and changes since the acknowledgement order, and justifies deviations from the action plan. The IRP Update is due to be filed on or before the one-year anniversary of the acknowledgment order. Per OAR 860-027-0400(8), "The energy utility may request acknowledgment of changes, identified in its update, to the IRP action plan."

The Commission acknowledged PGE's 2019 IRP at a March 16, 2020 special public meeting, and that decision was memorialized in Commission Order No. 20-152, issued on May 6, 2020. PGE's IRP Update was filed on January 29, 2021.

PGE, on page 2 of the IRP Update, states that "the IRP Update does not propose any changes to the acknowledged 2019 IRP action plan." PGE requests acknowledgement of its IRP Update. This request is made, not under OAR 860-027-0400, but in reference to Order No. 18-145 in Docket LC 66. PGE intends to make a May 1, 2021 filing to update its avoided costs prices based on the updated values in its IRP Update. Per Order No. 18-145, acknowledgement of the IRP Update docket will not guarantee the avoided cost input values will be accepted, nor does acknowledgement of an IRP Update establish avoided cost rates.[1] In Docket LC 66, Staff found that the avoided cost input values appeared appropriate. Here in LC 73, PGE is proposing changes to the effective load carrying capability (ELCC) values that significantly affect the avoided cost prices, thus in lieu of recommending acknowledgement of the IRP Update, Staff might continue to examine the avoided cost input values in the May 1 avoided cost update filing.

In response to Administrative Law Judge Rowe's request, PGE made a supplemental filing on February 5, 2021 detailing the aspects of the IRP Update that affect avoided cost prices. As filed, these updated values would lower the avoided cost prices for solar by 17 percent for standard pricing and 8 percent for renewable pricing and have smaller impacts on baseload and wind prices.[2] The decreased avoided costs prices are primarily the result of lower marginal ELCC values for solar.

Key Items from the IRP Update

Status report on acknowledged actions and order requirements

Customer Actions

PGE and Energy Trust have been working together to update the energy efficiency forecast for the 2022 IRP. In the IRP Update, PGE did not change its forecast of the quantity of energy efficiency to

[1] *In the Matter of Portland General Electric Company, 2016 Integrated Resource Plan,* Docket LC 66, Order No. 18-145, Appendix A at 6 (May 1, 2018).

[2] *In the Matter of Portland General Electric Company, 2019 Integrated Resource Plan*, Docket LC 73, PGE 2021 IRP Update, Supplemental Filing at 6 (February 5, 2021).

be acquired. In response to Staff's information request, PGE states that for its next IRP it can work to make a methodological change to incorporate in its energy efficiency forecast the potential to acquire additional, non-cost-effective, energy efficiency.[3]

Capacity and Renewable Actions

PGE notes that the Commission's Order No. 20-153, at 26, directed the Company to justify procurement using two separate RFPs or a single RFP. "Currently, PGE expects to propose a single solicitation for renewable and non-emitting capacity resources."[4] Staff agrees with this approach because it allows for the most thorough modeling of non-emitting capacity resources. Staff looks forward to finding out before the end of this IRP Update process when the RFP process will begin.

Since its 2019 IRP acknowledgement, PGE acquired a major capacity resource by negotiating a power purchase agreement (PPA) with the Douglas County Public Utility District (PUD). Douglas County is to the east of Wenatchee, WA. Staff is inquiring about the specifics of this PPA, for example, the extent to which the agreement allows the Douglas County PUD to address their own capacity needs with the PPA resources. In the IRP Update, PGE describes that its 186 MW capacity need decrease in the 2025 reference case is primarily due to its acquisition of the PPA from the Douglas County PUD.[5]

Enabling Analyses, Studies and Additional Requirements

PGE also describes its separate Colstrip Enabling Study, which examines the accelerated depreciation of its share of that coal plant. Although PGE's exit from the plant would remove the plant's estimated 281 MW of capacity, PGE found that "there could be economic benefits to removing Colstrip from PGE's portfolio earlier than the end of 2034." And PGE suggests that Montana wind projects utilizing the Colstrip transmission system could help offset the capacity loss.[6] PGE evaluated Colstrip scenarios such as separate accelerated depreciation dates for its share of two units. Although a date of 2025 was also evaluated, most recently, PGE recommends accelerated depreciation to the end of 2027. The robustness of the 2027 recommended date will be further tested in PGE's next IRP.

PGE includes a sensitivity for if the Green Energy Affinity Rider (GEAR) subscribed an additional 138 MW; this sensitivity became a reality subsequent to the IRP Update.[7] The Company used a placeholder resource to approximate 12 MW of reduced capacity need due to the GEAR addition.[8]

Need and position assessments

PGE provides a June 2020 updated load forecast. PGE regularly updates its load forecasts in order to use more recent data. Additionally in its June 2020 forecast, the Company contemplates the impacts of COVID-19. In response to Staff's information request, PGE provided the manual

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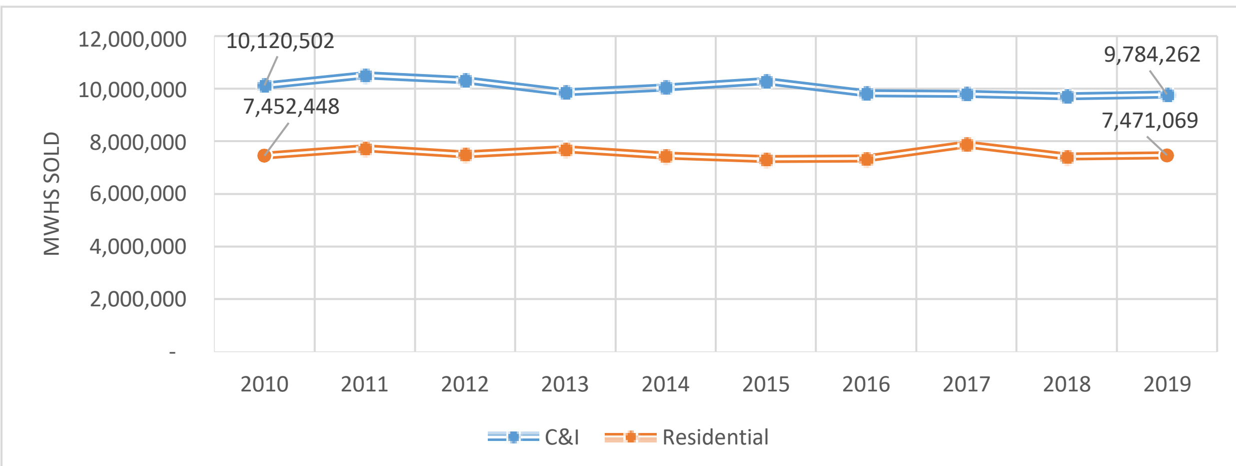
[3] *See* PGE's response to Staff IR 203.
[4] PGE's IRP Update at 16.
[5] PGE's IRP Update at 35, where 697 MW – 511 MW = 186 MW.
[6] *See* PGE's 2020 Colstrip Enabling Study at 1 and 20.
[7] *See* In the Matter of Portland General Electric Green Tariff Filing, Docket UM 1953,
[8] *See* PGE's response to Staff IR 193.

adjustments to its load forecast made in an attempt to encompass the impacts of COVID-19, however Staff is concerned that the logic of the manual adjustment made by the Company is difficult to follow. PGE describes the manual adjustments as a temporary approach due to lack of data. [9] As a general rule, Staff recommends against manual adjustments outside of the load forecasting model. Going forward, Staff recommends that PGE continue its attempt to find suitable econometric data on COVID-19 impacts, such as the novel traffic volumes data discussed at PGE's October 28, 2020 IRP Roundtable.[10]

PGE's IRP Update forecasts an increase in overall load growth from the acknowledged 2019 IRP. As shown in Figure 1, this increase is not necessarily in keeping with historic sales trends since 2010.

Figure 1: PGE Annual MWH Sold, OPUC Stat Book

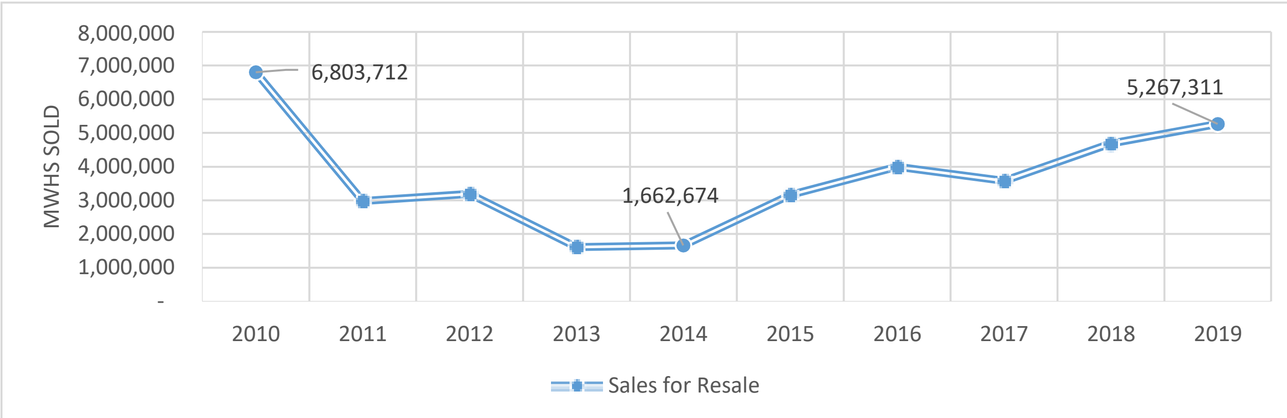


Staff looks forward to working with PGE between now and the 2022 IRP to better understand how recent developments have reversed historic trends in annual load growth.

In PGE's load forecast, related to capacity, in the 2050 reference case, summer peak demand increases by 124 MW due to the load forecast update.[11] Related to energy, PGE describes that, "in the outer years, the net market shortage increased, primarily due to the increased load forecast."[12] Staff appreciates the clarifications in PGE's response to DR 187 regarding the non-comparability of net market shortage in IRP planning and operational "sales for resale." Regardless, as shown in Figure 2, the recent trend for PGE has been increasing sales to market.

[9] *See* PGE's response to Staff IR 183.
[10] *See* PGE IRP Roundtable Meeting #20-6, October 28, 2020 slide deck at 9.
[11] PGE's IRP Update at 27, where 4308 MW – 4184 MW = 124 MW.
[12] PGE's IRP Update at 37.

Figure 2: PGE Annual MWH Sold for Resale, OPUC Stat Book



Sales to market is only one part of an overall net position. Staff looks forward to working with PGE prior to the next IRP to understand the strategy and risks associated with resource acquisitions along with market purchases and sales to meet future load growth.

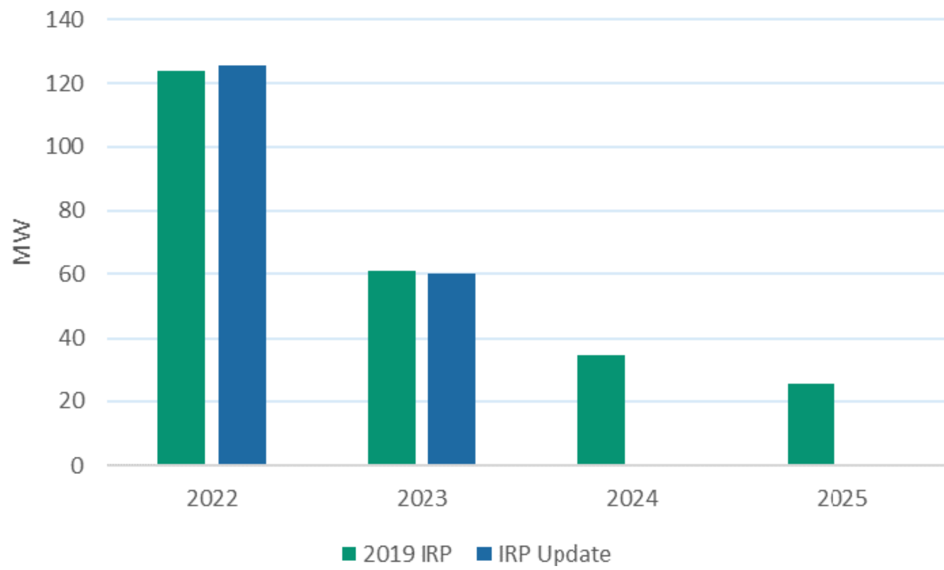
PGE updated the baseline portfolio to include 93 MW of community solar resources. Some of these additions were offset by reductions in PURPA resources due to the Community Solar Settlement Agreement.[13]

PGE hired the consultant E3 to forecast the amount of capacity available to purchase on the market: "a theoretical amount of capacity that for planning purposes, we assume can be secured on an hour-ahead basis in constrained conditions without any prior contractual rights."[14] E3 found that the region faces an anticipated capacity deficit in 2021 in the winter base case and 2026 in the summer base case.[15] An important change in the IRP Update is PGE's finding that it cannot rely on market purchases in the summer beginning in 2024 instead of 2026. PGE made this finding by updating E3's study to include resource retirements and additions found in the Northwest Power and Conservation Council's June 2020 generating resources project database.

Figure 3, reproduced from IRP Update page 31, shows the decrease in summer, on-peak market capacity purchases available to PGE:

[13] See PGE's IRP Update at 30: "The settlement agreement was filed by PGE in Docket No. ADV 1112 on May 15, 2020."
[14] PGE's IRP Update at 30.
[15] *See* IRP at 646 (Appendix E page 35).

Figure 3: Comparison of Summer On-Peak Market Capacity Assumptions

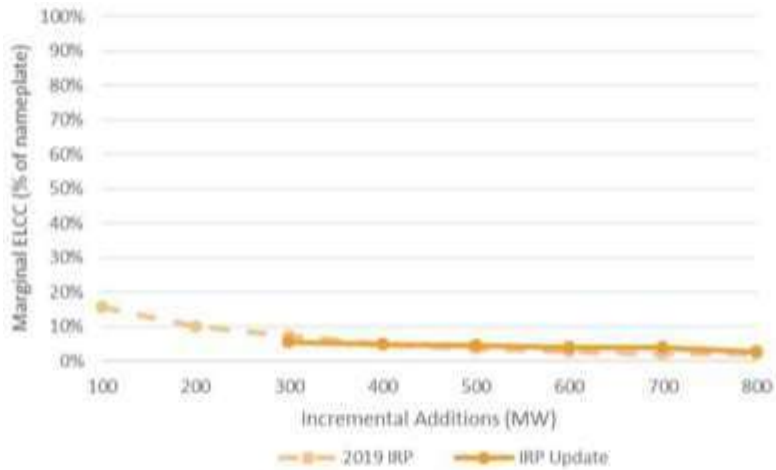


Staff's IRP Final Comments recommended that "PGE should monitor and report on its market capacity assumptions as part of any RFP and in the 2021 update to LC 73, as market conditions may encourage the building of more generation resources regionally."[16] Indeed, it appears that regional resource retirements have increased the regional need for capacity, especially in the summer.

PGE has replaced its RECAP loss-of-load-probability model with the new Sequoia model that the Company developed internally. The Company uses its loss-of-load probability model to assess capacity need and to assign capacity contribution values to resources. Staff finds the Company's process rationale for switching to the Sequoia model to reduce the need for outboard adjustments compelling. PGE also states that its Sequoia model introduces more sophisticated modeling of energy limited resources and interactive effects between resources. Simultaneous to the introduction of the Sequoia model, changes in the load and resource balance have changed capacity contributions. By running a baselining exercise, the Company has demonstrated that most of the changes in capacity contribution are due to the addition of similar resources on the system such that subsequent additions of resources with similar characteristics have decreased marginal benefits. For example, the declining marginal value of solar is shown as the downward sloping lines in Figure 4, which is reproduced from PGE's response to Staff IR No. 189:

[16] LC 73, Staff Final Comments December 17, 2019 at 15.

Figure 4: Comparison of Solar ELCC Curves



Only a small portion of the capacity contribution changes are attributable to the change from the RECAP model to the Sequoia model. Vetting the Sequoia model outputs is one of Staff's top priorities for the next IRP. The ELCC values from the Sequoia model impact the avoided costs prices, so Staff is investigating the reasonableness of the ELCC changes. Broadly, this development is oddly juxtaposed to the IRP Update's lack of on-peak summer market capacity in 2025. Staff looks forward to understanding the relationship, or lack thereof, between no summer, on-peak market capacity but a reduced ELCC – and thus capacity value – of new solar before the next IRP.

Wholesale market electricity prices

PGE updated its natural gas forecast inputs (by using more recent forward market prices and Wood Mackenzie forecasts and US Energy Information Agency (EIA) forecasts) and updated carbon price forecast inputs (by using a more recent California Energy Commission Report). PGE also changed an assumption by delaying carbon prices implementation from 2021 to 2022.

In PacifiCorp's RFP process, Staff has expressed serious concerns that an assumption of steady growth in wholesale electricity prices could prove to not materialize thereby greatly increasing the risk of being long to market.[17] In this PGE IRP Update, PGE has modestly decreased its forecasted growth in wholesale electricity market prices. Staff has asked an information request about the sensitivity of wholesale electricity market prices to potential surplus regional energy supply. As PGE, Staff, and stakeholders prepare for the upcoming RFP and the next IRP, Staff would like explore the topic of wholesale electricity prices in much greater granularity. This could include attempting to develop analysis comparing actual vs. forecasted (a) net load variances and (b) market prices to determine the extent to which PGE's proposed resources are at risk of under-recovery.

[17] *See* In the Matter of PacifiCorp application for approval of 2020 all-source request for proposal, Docket UM 2059, Staff's Comments on Market Price Sensitivity December 8, 2020.

Resource economics

Resource economics affect the May 1, 2021 avoided cost prices update. Administrative Law Judge Rowe requested PGE to make a supplemental filing to describe generally how the IRP Update will impact avoided cost prices. In its supplemental filing, PGE states that "[updated interconnection costs] have a minimal impact on avoided cost rates."[18] PGE left its financial parameters, such as inflation, unchanged since its acknowledged IRP. Updated ELCC values have the biggest impact on avoided costs prices.

The reproduced table below shows some of PGE's ELCC value changes (note that this is not an apples-to-apples comparison because PGE's new Sequoia model measures ELCC values relative to perfect capacity, so the current avoided cost column below would be a bit lower on a perfect capacity basis):

Table 1. Marginal ELCC Values

Resource	Current Avoided Cost	2019 IRP Update
Gorge Wind	28.6%	25.0%
Solar	15.8%	5.5%
SCCT	99.7%	95.5%

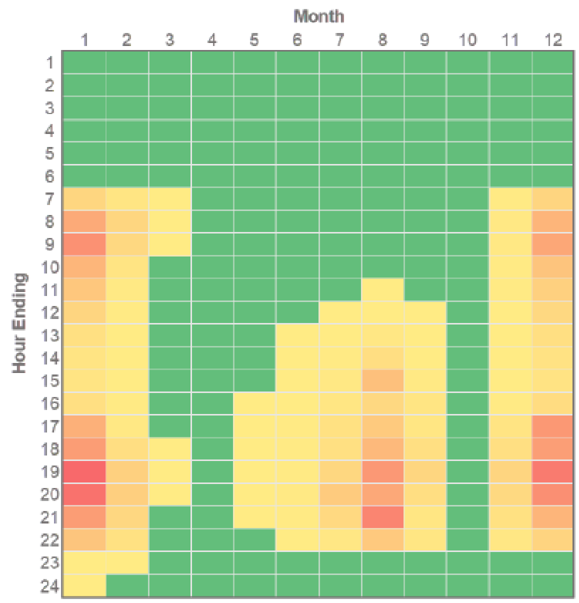
PGE explains that "the decline in the marginal ELCC value for solar is primarily due to approximately 200 MW of additional solar resource in the Baseline Portfolio since the analysis for the 2019 IRP."[19]

Relying on data requests and review of outputs from the Company's Sequoia model, Staff is investigating whether it is appropriate for the ELCC of solar to fall so sharply, so quickly. PGE computes the marginal ELCC of solar at 5.5 percent. This value is about 17 times smaller than the ELCC of a single-cycle combustion turbine (SCCC) at 95.5 percent.

Staff is continuing to explore this change and appreciates that the Company provided Staff a narrative description of the capacity contribution changes in response to Staff IR 189. In Docket No. UM 2011, General Capacity Investigation, some stakeholders have expressed difficulty with the black-box nature of loss-of-load probability models like Sequoia. For example, visually looking at PGE's updated loss-of-load expectation heatmap in Figure 5, reproduced from IRP Update page 36, shows that there remains visual expectations of loss-of-load during solar generation daylight hours:

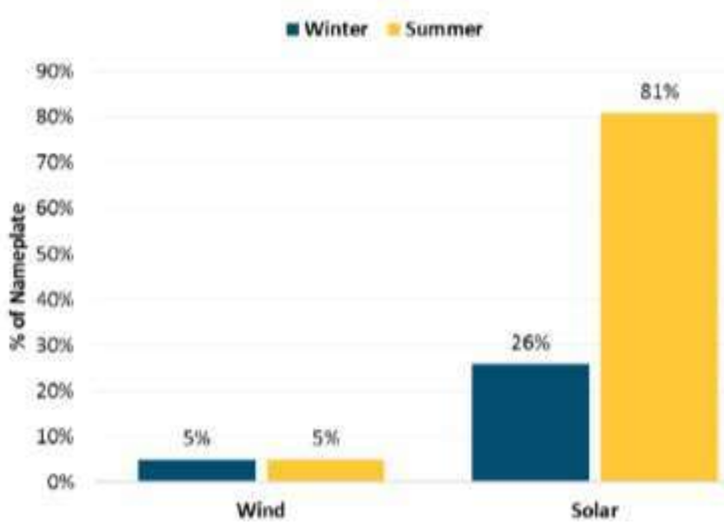
[18] PGE IRP Update – Supplemental Filing at 5.
[19] PGE IRP Update – Supplemental Filing at 3.

Figure 5: Reference case Loss-of-load expectation heatmap for 2025



PGE begins to justify the apparent visual usefulness of solar capacity in contrast to its low ELCC value by noting that "while the loss-of-load expectation heatmaps can be useful for understanding the hourly and seasonal nature of the probability of loss of load events, the heatmaps are limited in the information that they provide… the shading does not indicate information about the quantity of capacity needed."[20] Nonetheless, Staff remains concerned as, for example, PGE's computation is drastically lower than Consultant E3's figure in IRP External Study E, which is reproduced as Figure 6 (E3's study identifies the Northwest Power and Conservation Council as the source for the values):

Figure 6: Seasonal ELCC for wind and solar resources as a fraction of their nameplate capacity



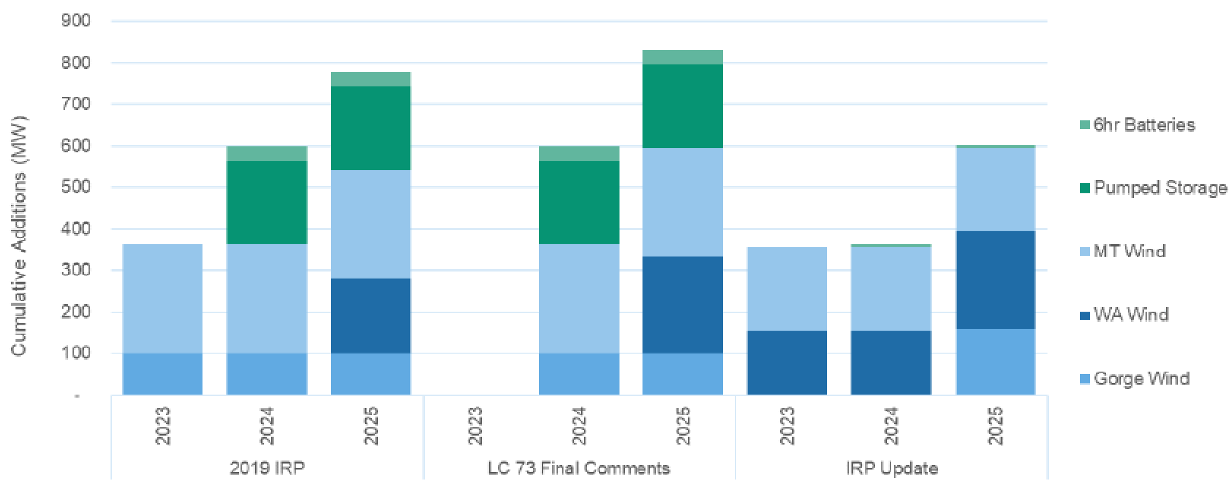
[20] PGE's response to Staff IR 189.

As described above, vetting the Sequoia model outputs is one of Staff's top priorities. Additionally, the information requests submitted by Renewable Energy Coalition (REC) to PGE will help Staff explore the issue. Staff specifically desires to explore further whether PGE's capacity contribution values are dependent on its choice of the reference year 2025 for its modeling.[21]

Portfolio analysis

PGE's preferred portfolio has significantly changed since its acknowledged IRP, as shown in Figure 7, which is reproduced from IRP Update page 52:

Figure 7: Mixed full clean action plan window resource additions



To understand the significant changes to the preferred portfolio, Staff met with PGE on February 23, 2021. PGE talked with Staff to provide an overview of the sensitivity of the preferred portfolio to production tax credit (PTC) changes. The significant change is to replace procurement of batteries and storage with wind in the near term. In an information request to PGE, Staff asked: if the PTC is extended again, is the optimal renewable addition delayed? In its response, PGE states that "the availability of the PTCs is an influential component in this determination [of the optimal type, size, and timing of all resource additions]."[22] Staff expresses a concern that because the ELCC of storage is greater than that of wind, the Company is obtaining less capacity per MW of nameplate resource size. Staff recommends that this issue be addressed in coordination with review of PGE's RFP, specifically, if storage and battery bid prices are lower than assumed in PGE's IRP, then procurement of storage and batteries might again become preferred. Staff is also concerned about the risk of potential future capacity shortfalls in the region. Staff is working to understand how PGE's PPA with the Douglas County PUD affects the portfolio optimization.

[21] *See* PGE's response to Staff IR 204.

[22] PGE's response to Staff IR 197.

As in the IRP, PGE's caps are binding of 150 MWa of additional renewable resources in 2023-2024 and no more than 250 MWa through 2025. PGE states that without the caps, its ROSE-E model would optimize by acquiring a significant amount of additional renewable resource MWs.[23]

PGE discusses the emissions in the preferred portfolio and Staff is working with the Company on how it assesses climate risks. Staff is supportive of PGE's focus on emissions for its next IRP and finds PGE's progress thus far aligns well with the goals of Governor Brown's Executive Order 20-04.

Finally, in data request No. 210 Staff asked if PGE would be willing to explore the impact of investment decisions on energy burden for low- to moderate- income customers. We appreciated the Company's forthright response. PGE agreed that energy burden was a very important topic, but that ultimately an IRP is not the appropriate forum for such a discussion.

Staff believes that recent developments create a space within the IRP to begin to discuss this topic. First, EO 20-04 directed the PUC to "exercise its broad statutory authority" to balance reducing GHG with other issues such as mitigating energy burden. More importantly, the Commission decision in UE 370, Order No. 20-321, opened the possibility of such a discussion between stakeholders in an IRP. Specifically,

> We recognize that IRP and RFP processes may not be an appropriate forum for detailed review of cost recovery mechanisms, but we reaffirm that considerations of risk allocation may be relevant to our acknowledgment decisions and consistent with the IRP guidelines' mandate that "risk and uncertainty must be considered." In all IRPs and RFPs, we expect customer rate impacts and risks associated with a preferred portfolio of resources to be identified and well understood, and we expect utilities to engage in discussion of portfolio alternatives to mitigate customer risks.

Staff recognizes that this does not resolve the issue of "where" to best discuss energy burden and future investment decisions. Further, Staff understands that this IRP Update is not the best venue. However, Staff raises this issue now so that stakeholders and PGE can begin the discussion of how to best fold this important topic into the next IRP and RFP processes per Order No. 20-321.

GHG Emissions and Response to EO 20-04

Staff issued data requests to understand more about how the Company is assessing climate related risks. Staff recommends that the Company produce a Climate Change Risk Report to be included in the next IRP. The report should include, at a minimum, the Company's process for identifying, assessing, and managing climate-related risks and how it integrates these risks into its overall risk management. It should also include additional detail regarding GHG emissions. Regarding climate risk evaluation and assessment in the Company's IRP, financial reporting, and other business practices, the report should:

[23] *See* PGE's IRP Update at 55.

1. Describe the metrics and/or methods that the Company uses to evaluate climate-related financial and operational risks covering investments in and returns from generation;
2. Describe the methods used in considering financial and operational risk mitigation from non-generation activities that make the system more flexible and efficient, (such as investments in smart networks and customer solutions); and
3. Indicate which metrics and/or methods are used to track climate-related transition risks, physical risks, and catastrophic or "tail" risks.

Further, in response to EO 20-04, Staff will be seeking additional, and in some cases more granular portfolio emissions data in the next IRP. Staff looks forward to working with the Company to identify the best ways to uncover and understand pathways to meet GHG emission reduction targets with this additional information. Staff hopes to see at least some of the following items included in the next IRP:

- A model and description of the necessary changes to the IRP Preferred Portfolio operations and resource mix to meet various emissions targets (both the Company's and where different, those in EO 20-04) and to reliably serve load.
- If hourly dispatch and emissions data are available, production of a 12 x 24 matrix of gross (not net) GHG emissions. If not available, a description of the challenges to producing a 12 x 24 matrix of gross (not net) GHG emissions using select portfolios from the IRP in select years.
- Estimates of the Company's carbon intensity per customer in select years.
- Load duration curves for select years that detail the estimated 8,760 hourly operation costs and emissions.
- Emissions associated with annual "sales for resale" from fossil fuel sources.

Avoided Cost Data for Qualifying Facilities in the IRP Update

As described above, the updated ELCC values have one of the largest impacts on avoided cost prices. PGE describes that also affecting avoided costs prices are updates to the simple-cycle combustion turbine (SCCT) net energy value, interconnection costs, and updated combined-cycle combustion turbine (CCCT) annual generation and starts.[24] The reproduced table below presents the estimated combined effect on avoided costs prices:

[24] *In the Matter of Portland General Electric Company, 2019 Integrated Resource Plan*, Docket LC 73, PGE 2021 IRP Update, Supplemental Filing at 2 (February 5, 2021).

Table 2. Initial Estimated Change to Avoided Cost Pricing from 2019 IRP Update

Resource	Standard	Renewable
Base Load	2%	2%
Wind	-2%	0%
Solar	-17%	-9%

The avoided costs prices compute the revenue requirement of an SCCT by summing the costs and subtracting the revenues. In Staff's work with the UM 1728, in the matter of PGE updates to Schedule 201 qualifying facility (10 MW or less) avoided cost, workpapers it appears that the net energy value change in the IRP update changes the revenue requirement by about one one-thousandth of a percent and the impact of avoided cost prices is similarly small. PGE describes that the updated interconnection costs have a minimal impact on avoided cost rates.[25] Also from the UM 1728 workpapers, CCCT starts cost about $15,000 in 2021 and increase in cost due to inflation. All else equal, more starts increases the costs of operating a CCCT. In aggregate during 2021 to 2050, PGE's IRP update increases the number of forecasted starts over the 30 year period. Else equal, when a CCCT operates more hours, its fixed costs are spread over additional MWh. PGE's IRP update decreases the CCCT aggregate generation during 2021 to 2050. Because the resource is more expensive to operate, the CCCT generation and starts updates likely increase avoided cost prices slightly.

Next Steps

Staff will be filing its final Staff Report on April 6, 2021 with its recommendations. In the meantime, Staff will be working to address the issues raised in the comments above.

This concludes Staff's comments.

Dated at Salem, Oregon, this 10th of March, 2021.

/s/ Max St. Brown

Max St. Brown
Renew Resource Analyst
Policy & Economic Analysis

[25] Ibid at 4.