2023 Clean Energy Plan and Integrated Resource Plan

Addendum: System Need & Portfolio Analysis Refresh

PGE

This document contains forward-looking statements, including those regarding implementation of our business plans, technology transitions, our business, strategies and financial performance, our offerings of new services, and other statements that are not historical fact, and actual results could differ materially from these forward-looking statements. Risk factors that could cause actual results to differ are set forth in the “Risk Factors” section, as well as other sections of our 2022 Annual Report on Form 10-K, available on our website at investors.portlandgeneral.com/financial information/sec-filings, as well as, or in addition to, other filings with the SEC. All forward-looking statements are based on management’s estimates, projections, and assumptions as of the date of filing, and we undertake no obligation to update any such statements.

Portland General Electric Company
Integrated Resource Planning
121 SW Salmon Street
Portland, Oregon 97204

Table of Contents

Figures

Tables

Introduction

The first step in the development of the 2023 CEP/IRP was an estimation of long-term system needs. These needs are calculated as the difference between the system demand for electricity and the supply of existing and contracted generation to meet it. There are two main types of system need:[1,2]

1. *Energy need*: The average amount of system deficit expected over a typical year, expressed in average MW (MWa)
2. *Capacity need*: The resource deficit experienced in times of peak need, expressed in effective capacity (MW)

The 2023 CEP/IRP relies on many input forecasts of both future supply and demand to estimate this need. Since the preparation of the CEP/IRP analysis and its filing in March 2023, several of these forecasts have been updated. The first purpose of this Addendum is to introduce those updates and quantify their impacts on system need. While there are some off-setting effects described below, since the March 2023 filing there has been a sharp increase in nearly all input forecasts resulting in significantly higher system need. Each of the updated input forecasts are detailed in **Chapter 1, Input updates** and the resulting energy and capacity needs are detailed in **Chapter 2, Need changes**.

The second purpose of this Addendum is to reevaluate portfolio analysis based on this updated information. The filed CEP/IRP's portfolio analysis posed several core questions in resource planning. This Addendum asks if the answers PGE provided in the filed CEP/IRP still hold true given the updated input forecasts and the resulting increased estimated system needs. We find those main findings, filed at the end of March, are still valid and now, more supported by these updated input forecasts. In addition, our proposed path to compliance with 2030 emissions targets remains the same. PGE's decarbonization path still requires us to procure sufficient non-emitting energy and capacity resources to systematically reduce fossil fuel generation and purchases associated with Oregon retail load. Our procurement strategies and timing of RFPs will be updated to reflect this increased resource need. This increased resource need also further underscores the critical need to address regional transmission constraints. On-system resources like energy efficiency and community-based

[1] Previous IRPs focused on RPS need as well. However, the non-emitting generation need established by the emission reduction targets in HB 2021 is substantially greater than any applicable RPS constraints. While there was some information in the filed CEP/IRP, this document does not focus on RPS need as it does not drive resource need under any future modeled.

[2] PGE also estimates the flexibility need of the system. The relationship between the flexibility and capacity need is such that only the larger of the two drive resource decisions. Given that the capacity need is significantly higher than the flexibility need, flexibility need is not considered a driver of resource additions within current IRP modeling.

renewable energy (CBRE) resources each are identified as an important part of PGE's resource mix going forward. The increased system need still points to a linear reduction as the most appropriate choice of modeling emissions through 2030. While the size of the incremental resource additions does increase with system need, this Addendum supports the appropriateness of the answers from portfolio analysis and the construction of the Preferred Portfolio, which forms PGE's pathway to 2030 compliance. Similarly, the increase in resources identified in this Addendum do not change the structure of either our Action Plan or our pathway towards 2030. The proposed actions still rely on customer demand-side actions, CBRE acquisitions, increased transmission access, and new resources to meet energy and capacity needs.

Chapter 1. Input updates

Input forecasts create the basis of CEP/IRP estimation of system needs. Since the March 31, 2023 filing, several input forecasts have been updated. Additionally, several methodological changes have been made for this Addendum. These updated input forecasts and methodological changes and magnitudes of their changes are described below.

1.1 Load forecast

Generally, long-term forecasts of load are the first input to be finalized during the development of an IRP. For example, the 2019 IRP (filed in July 2019) finalized its forecast of load in September of 2018. The 2023 CEP/IRP used the March 2022 load forecast for most analysis but did include a sensitivity looking at the December 2022 load forecast as well. In this addendum PGE has updated the load forecast to the June 2023 vintage.

PGE's load forecast methodology includes near term and long-term components, as reflected in Table 99 of Appendix D in the filed CEP/IRP. PGE updates its long-term model specifications during the IRP cycle with periodic updates to the stakeholder audience. These long-term models have not changed as compared to those models presented in the 2023 CEP/IRP.

The near-term load forecast model is updated more frequently, several times each year as new information is available. In the past 18 months, PGE's industrial class load has grown rapidly, at a rate of 10.6 percent in 2022 and 8.3 percent in the first quarter of 2023. The primary driver of PGE's increased load forecast is to reflect rapid industrial growth and growing demand of data centers in PGE's service territory.

In addition, PGE has made several refinements to its near-term load forecast methodology. The data aggregation has been changed to reflect residential dwelling type and non-residential rate schedule groupings rather than previous dwelling and heat type groupings and industry (NAICS) segment non-residential groupings. The new model structure and additional months of data included allow for a simplified approach to capturing the impact of COVID-19. In the commercial models, there is no longer a need for manual indicators, rather economic drivers adequately capture the impact in the historical period.

In March 2022 PGE assumed that the long-term impacts of COVID-19 on residential usage would be one-third of the initial impact. This assumption, along with other decreasing trends in residential use per customer, resulted in a forecasted 4.4 percent decrease in use-per-customer for 2022. As time has passed and more usage data has become available, initial lockdown is now controlled for in the historical period and the uptick since this period is modeled as a permanent shift. Specifically, the early impacts of COVID-19 are captured by indicating the first six months of the pandemic when lockdowns were at their peak and an indicator variable, which begins in April of 2020 and continues into perpetuity, is interacted with weather variables. These interactions account for the change in residential customers' response to weather due to increased time spent at home. This update in assumptions does not change the long-term growth rates of residential customers but rather resulted in a level shift in the near-term usage as we no longer assume a drop in usage due to the unwinding of COVID-19. These changes are summarized in **Table 1** below.

Table 1. Key updates in input assumptions and model structure

	March 2022 Forecast	June 2023 Forecast
Historical Data	Ending January 2022	Ending April 2023
Economic Forecast	OEA February 2022	OEA May 2023
COVID-19	Multiple complex indicator variables Assumption of greater return to pre-pandemic levels for residential customers	Simplified drivers Assumes that status quo has been reached and residential usage will not see a drop off due to return to office
Residential Groups	Dwelling Type & Heat Type	Dwelling Type
Non-residential Groups	NAICS (18 models)	Rate Schedule (5 models)

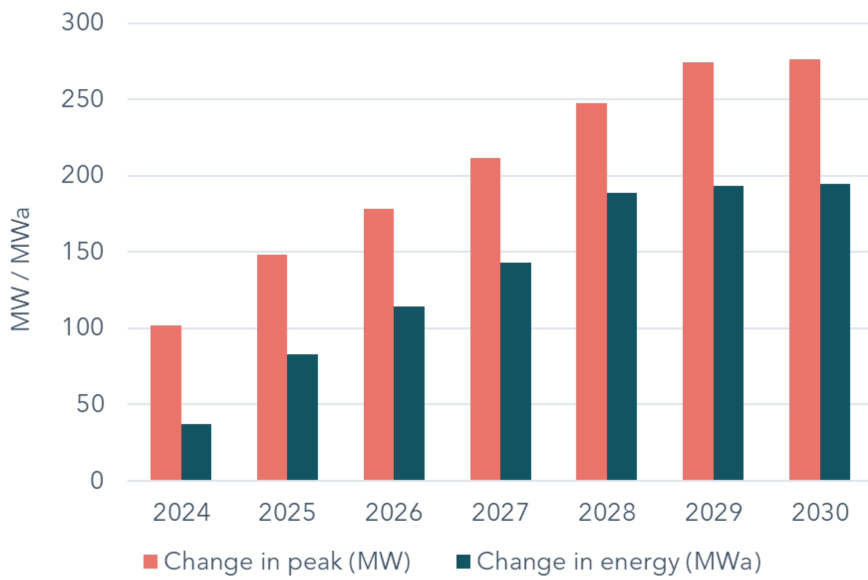
The result of this update is summarized below by replicating the average annual growth rates as shown in **Table 2**. Since only the 5-year portion of the model is updated, these changes are front weighted.

Table 2. Reference Case top down econometric 20-year AAGR (2023-2042)

Vintage	Total Energy	Peak	Residential	Commercial	Industrial
March 2022	1.2%	0.8%	0.5%	0.0%	3.5%
June 2023	1.6%	1.1%	0.6%	0.0%	3.9%

Aggregated, these changes lead to significantly higher forecasts of system needs. The magnitudes of these changes in both energy and capacity (in MWa and MW) are displayed below in **Figure 1**.

Figure 1. March 2022 to June 2023 load forecast changes



1.2 Distributed energy resources

PGE continues to experience growth of distributed energy resources (DERs) on the system driven by strong customer demand and favorable federal, state, and local policies. Like the load forecast described in **Section 1.1, Load forecast**, the DER forecast is a key input to CEP/IRP analysis at the start of the modeling workflow. Like the load forecast, the 2023 CEP/IRP used the March 2022 vintage of the DER forecast that was filed in the DSP Part 2 for most analyses.[3]

The most notable changes in policy that affect the DER forecast since the vintage used in the filing of the 2023 CEP/IRP are the Inflation Reduction Act (IRA) and Oregon's adoption of the Advanced Clean Cars II rule.[4] This section presents results from our most recent DER forecast update.

[3] Like the load forecast described in **Section 1.1**, the Low, Reference, and High Need Futures leveraged the March 2022 DER forecast vintage, but additional sensitivity cases were conducted with additional DER growth as described in Section 6.10.22 of the 2023 CEP/IRP.

[4] The 2023 CEP/IRP accounted for IRA influence on supply-side technology cost changes driven by the legislation. PGE did not include explicit accounting of the IRA impacts on DER until the forecast update described in this section. However, some of the DER sensitivity cases in the 2023 CEP/IRP did account for large DER growth.

1.2.1 DER forecast update overview

AdopDER is PGE's enterprise DER modeling tool used to forecast DER adoption and calculate expected load impacts for critical PGE business functions. PGE uses the tool to forecast DER growth and potential impacts from the bottom-up, aggregating site-level adoption up to the feeder and ultimately the bulk power system level. The tool is consistently used to inform DSP forecasting, the CEP/IRP, corporate load forecasting, and various other PGE functions about the expected impact stemming from customer DER adoption and consequent changes to overall system energy demand patterns.

AdopDER is a unique hybrid model for assessing DER growth, leveraging top-down customer growth estimates determined by the corporate load forecast, and pairs this with bottom-up insights about customer behavior and DER resource availability to inform an overall picture of DER adoption. For more information on AdopDER and how it interacts with the corporate load forecast, see Section 3.5 of the DSP Part 2.[5]

The full suite of potential impacts of the IRA on DER adoption will take more time to assess and understand as the longer-term provisions and supply-chain responses come into clearer focus, such as onshore manufacturing incentives and requirements. Our DER forecast update focuses on the most near-term elements within the legislation that impact our forecast methodologies.[6] However, across all DER types we do see a steady increase over time in terms of adoption following this update. The main areas of change were:

- Transportation electrification update: reflecting passage of Oregon DEQ's Advanced Clean Cars II rule and the EV tax incentives in the IRA, as well as updated DMV registrations and econometric forecast calibration
- Solar PV and storage update: reflecting recent acceleration of PGE's interconnection queue and changes in IRA regarding the Investment Tax Credit (ITC)
- Building electrification update: reflecting increased incentives stemming from policy changes such as the IRA

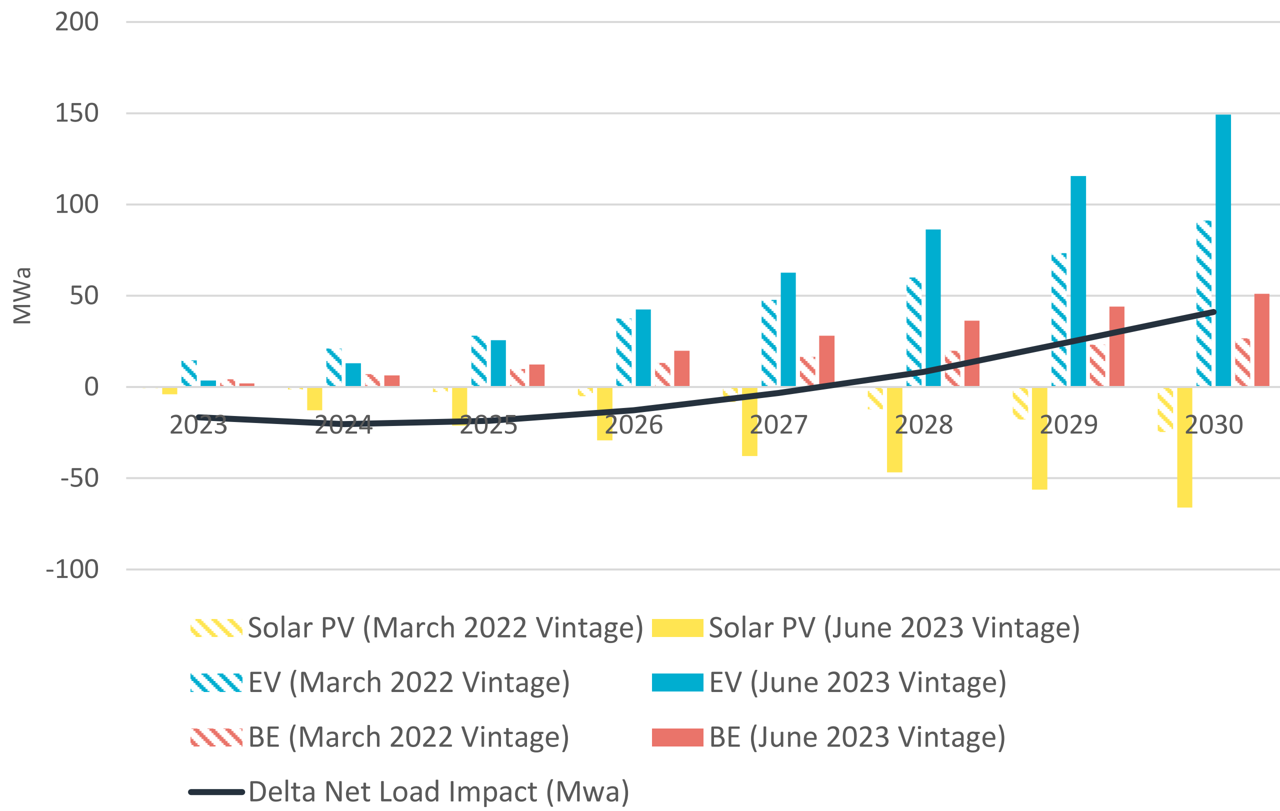
[5] DSP Part 2 is available at: https://downloads.ctfassets.net/416ywc1laqmd/2Fr2nVc4FKONetiVZ8aLWM/b209013acfedf1125ceb7ba2940bac71/DSP_Part_2_-_Full_report.pdf

[6] This DER forecast update includes only solar PV, transportation and building electrification. Demand response (DR) programs, including distributed standalone storage, are not reflected here. Because these resources are modeled in the technical achievable potential within the IRP, changes to the selection of those resources are addressed through portfolio modeling.

1.2.2 DER forecast results

Figure 2 shows the high-level DER changes by category from the March 2022 DER forecast vintage that informed most of the 2023 CEP/IRP analysis compared to the updated June 2023 DER forecast vintage.[7] The net annual energy impact is a decrease until 2027 and a net increase beginning in 2028.[8]

Figure 2. Aggregated forecasted distributed energy resource changes



In the initial years, the forecast is slightly reduced compared to the previous forecast used in the CEP/IRP because of the updated customer adoption and near-term market trends that were recalibrated, while longer-term the growth in electrification is partially offset by an increase in the solar adoption forecast. In aggregate, the combined DERs will add 41 MWa of

[7] Note these MWa represent incremental additions starting from the base year of the forecast (2022) in order to separate from the DER that are effectively embedded in the corporate load forecast. Therefore, they do not represent the total DER on the system.

[8] This is strongly influenced by the solar PV update, which has the highest percentage change between the forecast vintages, though in the longer term less energy impact compared to electrification. The relatively higher change in the distributed solar forecast is due to the combined influence of adding IRA incentives as well as accounting for the recent uptick in rooftop solar applications that continued throughout 2022 even before the passage of the IRA.

additional load to our baseline corporate load forecast by 2030, increasing overall energy need.

Although the impact of DERs that add load (e.g., transportation electrification) or generation (e.g., distributed solar) can offset each other from an average annual energy demand perspective, integrating these growing DERs interconnected to the distribution grid will require careful planning and integration to minimize system costs and maximize their potential for shifting load and providing additional grid services as discussed in PGE's DSP Part 2.

1.3 2021 All-Source RFP

The 2021 All-Source RFP began with acquisition targets of 500 MW of capacity and up to 150 MWa of energy to meet the 2025 resource adequacy deficit.[9] The energy target was later increased to up to 250 MWa in the UM 2166 docket, and the capacity target decreased to 388 MW.[10]

The 2023 CEP/IRP was published before the conclusion of the 2021 All-Source RFP. To avoid adding incremental resources to fill need that would be met with resources acquired in that RFP, the CEP/IRP relied on a proxy set of resources in its analysis. By the filing of the CEP/IRP the company did have certainty of one resource (the Clearwater wind project), which is included in its analysis. The remainder of the RFP proxy included sufficient solar and stand-alone storage to meet the remaining RFP acquisition targets (this amounted to 410 MW of generic solar resource and 400 MW of four-hour batteries). These resources are included in the projected energy load-resource balance displayed in the filed CEP/IRP's Figure 42.

In May 2023 PGE announced the conclusion of the 2021 RFP. In addition to Clearwater Wind, the RFP acquired three four-hour battery projects totaling 475 MW. The difference between the RFP proxy and the actual resources acquired in the 2021 All-Source RFP are displayed in **Table 3**.

Table 3. 2021 RFP proxy vs actual 2021 All-Source RFP acquisitions

2023 CEP/IRP 2021 RFP proxy		2021 RFP procurement	
Resource	Nameplate MW	Resource	Nameplate MW
Clearwater Wind	311	Clearwater Wind	311
Proxy solar	410	Troutdale 4-hr battery	200
4-hr battery	400	Seaside 4-hr battery	200
		Evergreen 4-hr battery	75

[9] UM 2166, page 1 & 2: https://edocs.puc.state.or.us/efdocs/HAA/um2166haa173953.pdf
[10] UM 2166, Order 22-315, page 5.

Updating from the RFP proxy to using the actual projects has three primary impacts on the PGE planning models:

1. *Energy need increases:* The need to acquire non-emitting energy resources, like wind and solar, increases as fewer renewables were acquired than included in the proxy.
2. *Winter capacity need decreases:* The additional battery (75 MW more in the actual than the proxy) provides more winter capacity than the proxy solar resources.[11]
3. *Summer capacity need remains:* The additional capacity provided by the increased storage is roughly offset by the reduction in capacity from the RFP proxy's solar.

1.4 Storage resources

Throughout the cycle of charging and discharging a battery, some energy is lost from the roundtrip efficiency of the battery system. As the energy lost by current quantities of storage is not substantial, PGE has not previously accounted for them in energy need accounting. However, as large quantities of batteries are planned to be added to the system, the losses are projected to be non-trivial. For this Addendum energy losses have been added for the 475 MW of RFP storage resources and the 23 MW of existing storage PPAs. Losses were calculated using simulated average annual capacity factors from Aurora of -1.4 percent for the 4-hr storage proxy resource.[12] Accounting for energy losses from storage results in an increase in energy need on average by 7 MWa per year. The capacity need model (Sequoia) already has incorporated storage losses into need and ELCC calculations; as a result no adjustments are needed to the capacity need values for storage losses.

1.5 Qualifying facilities update

The 2023 CEP/IRP uses qualifying facility inputs (facilities contracted under PGE's Schedule 201 or Schedule 202) that were updated in December 2022. From December 2022 to June 2023 there have been changes to qualifying facilities that have resulted in an approximately 161 MW nameplate net decrease of generation resources. The majority (160 MW) of this change is due to solar qualifying facilities terminating their contracts with PGE (the remaining 1 MW is from correcting IRP input errors).

[11] Those solar resources were assumed to use conditional-firm transmission, which reduced their capacity contribution values.
[12] The market simulation that creates these capacity factors (Aurora PZM model) limits storage cycling to an average of once per day on an annual basis.

The impact to PGE's planning models of switching to updated qualifying facility inputs is increased need for non-emitting resources and increased need for capacity resources in both the summer and winter.

1.6 Methodological corrections

1.6.1 Thermal output

The 2023 CEP/IRP uses the Aurora PZM model (PZM) in conjunction with the intermediary GHG model to determine how much energy can be retained from CO_2e emitting sources for retail load service. For this Addendum two corrections were made in the PZM:

1. Minimum heat rates in PZM were adjusted for several existing thermal plants (Beaver, Carty, Coyote, and Port Westward 1)
2. The nameplate capacity associated with Beaver was corrected

These corrections altered how those resources are economically dispatched in PZM, and this impacted how much energy is estimated to be retained from CO_2e emitting sources for retail load service. The impact of these changes is shown in **Table 4** which displays differences between the Addendum values and the 2023 CEP/IRP values for CO_2e associated energy retained for retail load service (Reference Case price future (RRRR)). The changes in owned generation, which are primarily changes associated with Beaver, are mostly balanced by market unspecified purchases. In year 2030, the total change in energy retained for retail load service from CO_2e emitting sources is two MWa fewer than in the CEP/IRP.

Table 4. Changes to energy retained for retail load service from CO2e emitting sources

RRRR	Beaver	Carty	Coyote	PW1	PW2	Colstrip (20%)	Market Unspec.	Other	Total
2024	(34)	0	2	(1)	0	0	39	(2)	6
2025	(31)	4	4	1	1	2	25	(0)	5
2026	(18)	5	4	4	1	3	2	0	2
2027	(11)	3	2	2	1	2	1	0	1
2028	11	(2)	(1)	(1)	(1)	(1)	(7)	(1)	(3)
2029	6	(1)	(0)	(1)	(0)	(0)	(5)	(1)	(2)
2030	5	(1)	(0)	(1)	(0)	0	(4)	(1)	(2)

Table 5 shows the annual CO_2e emissions in the Preferred Portfolio from the Addendum and the 2023 CEP/IRP. Note that there is no change in the retail load service CO_2e emissions values (both documents use the same CO_2e glidepaths).

Table 5. CO2e from retail load service and total emissions (retail + wholesale)

All values in million metric tons of CO_2e						
	Retail load CO_2e			Total (retail + wholesale) CO_2e		
Year	2023 CEP/IRP	Addendum	Difference	2023 CEP/IRP	Addendum	Difference
2024	5.31	5.31	0.00	7.17	7.17	0.00
2025	5.05	5.05	0.00	6.91	6.84	(0.07)
2026	4.36	4.36	0.00	6.75	6.63	(0.12)
2027	3.68	3.68	0.00	6.71	6.60	(0.11)
2028	2.99	2.99	0.00	6.71	6.81	0.09
2029	2.31	2.31	0.00	6.43	6.50	0.08
2030	1.62	1.62	0.00	4.42	4.50	0.08

1.6.2 Light load hour market

The 2023 CEP/IRP adequacy model (Sequoia) includes a light load hour market for resource adequacy calculations. The total quantity modeled available from this market varies between 400-999 MW depending on load, with higher load days (which are associated with more extreme weather) seeing less availability than lower load days. The hours that define the light load hour market in the 2023 CEP/IRP were carried over from the 2019 IRP Update and are hour ending 23 to hour ending 6 Pacific Standard Time, Monday through Saturday. However, light load hours are more commonly defined as hour ending 23 to hour ending 6, Prevailing Time.[13] The difference in those two definitions mostly impacts summer adequacy modeling since summer months occur during Pacific Daylight Time (rather than Pacific Standard Time). PGE tested the capacity impact of moving the light load hour market to match Prevailing Time for the months of April through October and saw a 15 MW decrease in summer capacity need and a zero change in winter capacity need, for year 2026.[14] This shift in light load hour market availability was built into this Addendum and only impacts the capacity need values (not the energy need values).[15]

There is a need to better understand power market availability at a more refined level than the traditional heavy load and light load hour split. For example, the Power Council chose to redefine heavy and light load hours for modeling purposes in the 2021 Power Plan due to

[13] Light load hours typically include holidays as well, however holidays are not specified in Sequoia's market setup.
[14] The months of March and November were left in standard time. This was done since adequacy issues in those two months are likely due to cold weather which is more likely in early March or late November, time periods that are mostly in standard time.
[15] The full set of summer years were rerun for this Refresh. The full winter adequacy years were not rerun after test years (reference case years 2026 and 2030) showed zero change. This change only impacts the winter market in October, a month that typically has few (if any) adequacy challenges in the model.

changing market dynamics.[16] For future resource adequacy work, the CEP/IRP team will work internally with market facing teams to discuss which hours market power will most likely be available.

1.6.3 Annual Revenue-requirement Tool

PGE developed its Annual Revenue-requirement Tool (ART) as part of the 2023 CEP/IRP. ART is the final step in the analysis workflow and leverages data from several upstream models including the intermediary GHG model (iGHG). PGE identified an error in the data that is transferred between the iGHG model and ART. Specifically, PGE identified that costs associated with market purchases that are then sold in the wholesale market were not included in the data sent to ART. However, the benefits associated with these wholesale sales on the revenue requirement were included. Thus, previous ART results partially undercounted costs associated with market purchases that remain constant across portfolios with the same decarbonization glidepath.

These unaccounted costs associated with market purchases from both specified and unspecified sources are highest in 2024 and reduce over time as dependence on market purchases that contain emissions reduces in each decarbonization glidepath. Thus, the change in overall revenue requirement is largest in 2024 and reduces over time.

This change does not impact the comparison between portfolios that have the same glidepaths such as the annual price impact comparison between the different energy efficiency portfolios. However, since the change has the highest impact on early years such as 2024 and 2025, the rate of change of the normalized revenue requirement ($/MWh) decreases. In other words, rates increase at a less-steep rate compared to the graphs provided in the filed IRP.

[16] The Power Council, for purposes of the 2021 Power Plan, defined heavy load hours “as hours ending 7 pm through 10 pm on weekdays; light load hours are all others.” https://www.nwcouncil.org/2021powerplan_cost-and-benefits-energy-efficiency-resources/

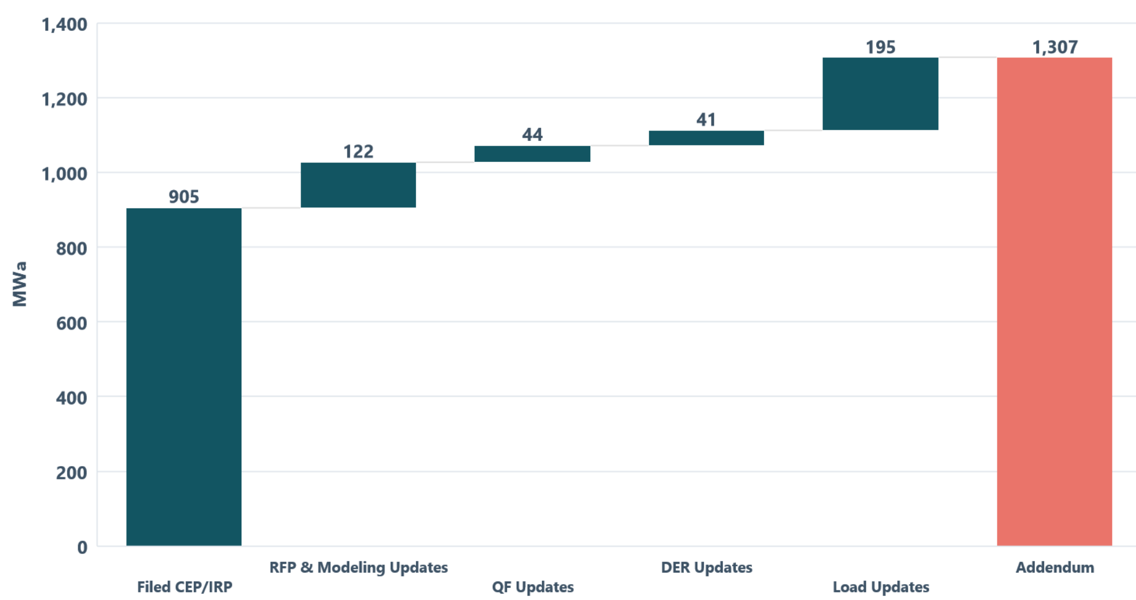
Chapter 2. Need changes

The resulting changes to energy and capacity needs from the updates to input forecasts and modeling changes are described below.

2.1 Energy need

Energy need describes PGE's resource needs in terms of the balance between the average amount of electricity demanded and supplied each year. Since the 2023 CEP/IRP, PGE's estimate of energy need has changed due to updates to the factors described in **Chapter 1, Input updates**.[17] The drivers of change behind each of these updates are described in previous sections. The incremental impact of each update and the resulting updated 2030 Reference Case energy need are shown in **Figure 3**. The combined impact of the updates increases PGE's forecasted 2030 Reference Case energy need from 905 MWa to 1307 MWa.

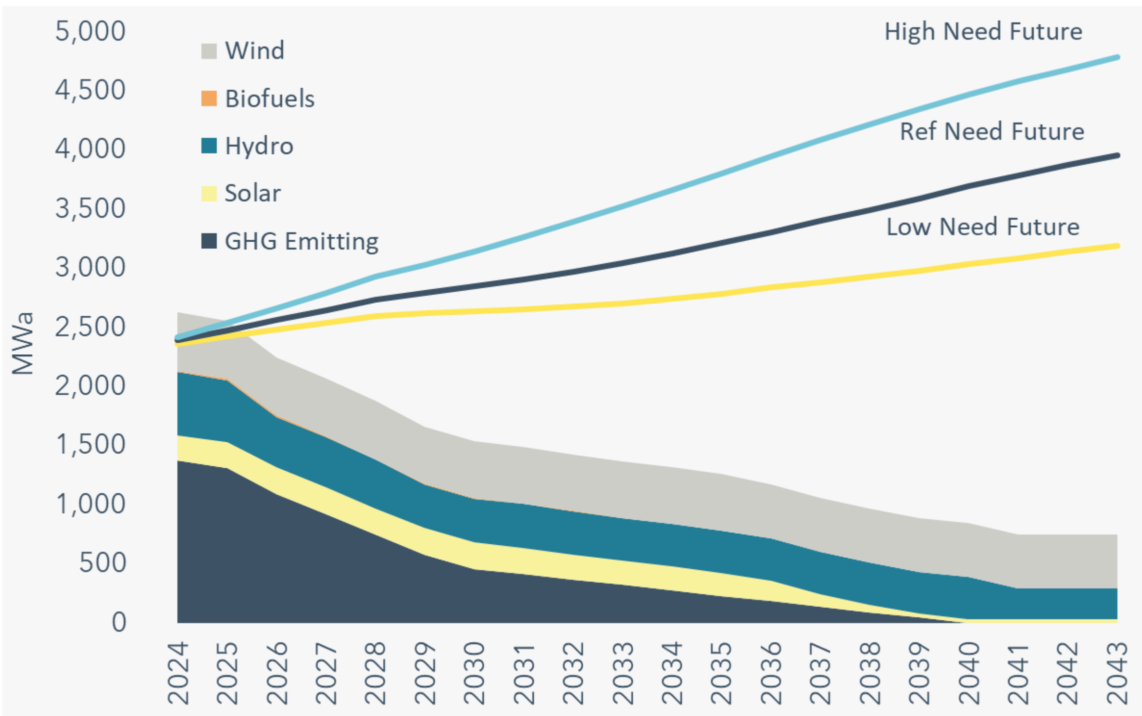
Figure 3. Incremental impacts of updates on 2030 Reference Case energy need



[17] In addition to the changes described in **Chapter 1** an adjustment was made to the forecast of community solar in PGE's energy accounting to improve alignment with PGE's capacity modeling in Sequoia, which resulted in a small increase (1.7 MWa) in 2030.

Figure 4 shows PGE's updated energy-load resource balance, which compares the forecast of Oregon retail load and the amount of energy allowed to serve retail load, assuming a linear decarbonization glidepath. The energy available to serve retail load is the combination of energy from GHG-emitting sources retained for retail sales and the total energy from non-emitting sources. The quantity of allowed energy does not include new supply-side resources outside of those from the 2021 RFP and the continued acquisition of energy efficiency, demand response and other demand-side resources. Before any additional incremental resource additions, Reference Case retail load is expected to surpass the allowed energy on PGE's system starting in 2026.

Figure 4. Energy-load resource balance in linear GHG glidepath in Reference Case future[18]



[18] For convenience of display, the negative energy associated with storage is represented in **Figure 4** as an increase in load.

2.2 Capacity need

Capacity needs describe the effective capacity, in MW, required to achieve a resource-adequate power system. These estimates come from PGE's resource adequacy model, Sequoia.

The impact of the changes that have occurred from when CEP/IRP assumptions were locked to this Addendum is a net increase in the need for resources that provide effective capacity. The elements that create this changing need are broken out for summer and winter in **Figure 5** and **Figure 6** below for the year 2028 (the year targeted by the CEP/IRP Action Plan). Note that some updates impact one season more than the other. For example, moving from 2021 RFP proxies to the actual resources selected reduces the need for winter capacity but has little impact on summer capacity need. For both winter and summer, the largest driver of increased capacity need is the updated load forecast. In 2028, the 1-in-2 peak forecast, on an annual basis, is roughly 250 MW higher in the Addendum than in the CEP/IRP.

Figure 5. Summer 2028, changes in capacity need

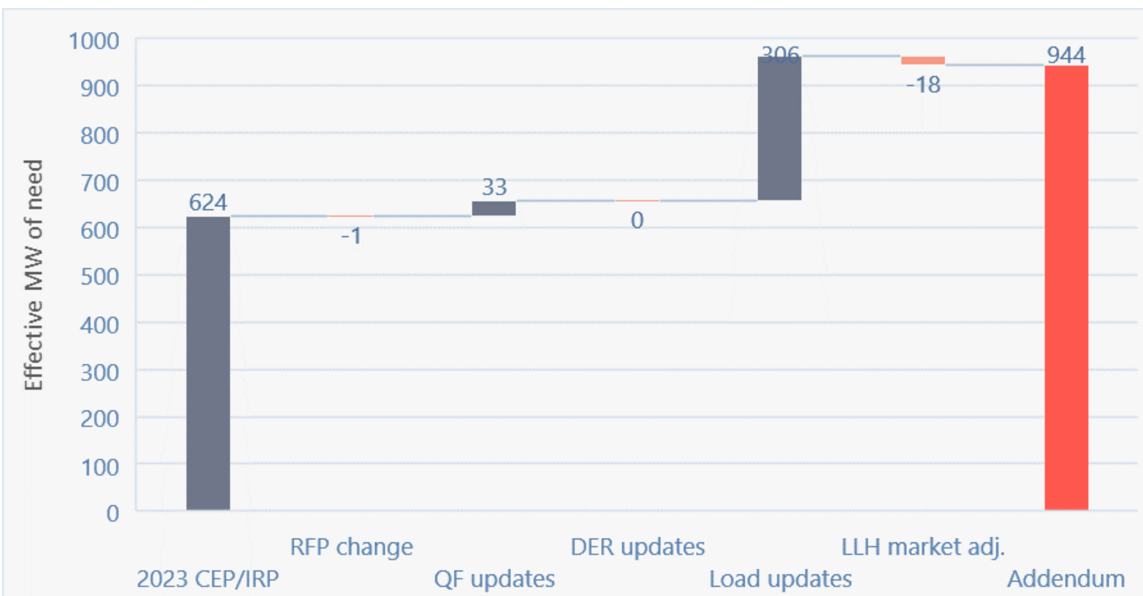


Figure 6. Winter 2028, changes in capacity need

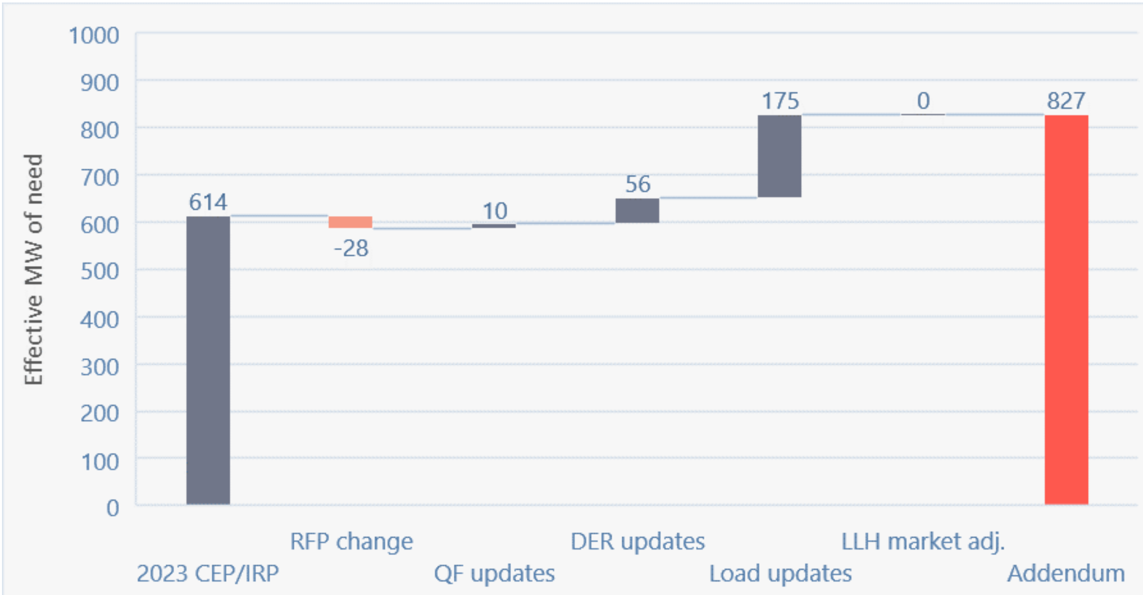
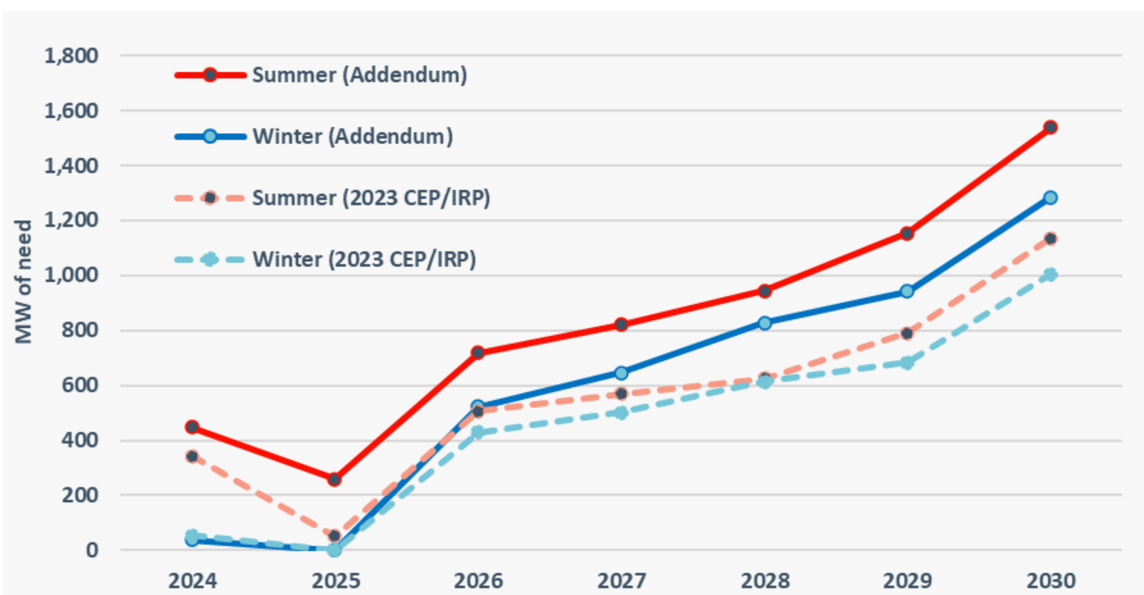


Figure 7 shows the CEP/IRP capacity need and the Addendum values for year 2024 through 2030. Need increases over time due to load growth, contract expirations, and resource exits. Need increases sharply in 2026 due to expiring contracts, and again in 2030 due to the assumption that PGE will stop taking power from Colstrip at the end of 2029.

Figure 7. Capacity need comparison



Chapter 3. Portfolio analysis

PGE reevaluated portfolio analysis based on the updated estimates of need provided in **Chapter 2, Need changes** and methodological change described in **Section 1.6, Methodological corrections**. Additionally, we made two portfolio analysis corrections discussed earlier in the CEP/IRP docket.[19] The changes to portfolio analysis are described below, then the results to all changed inputs to all modeled portfolios and the Preferred Portfolio follow after.

3.1 Hybrid and pumped storage resources

As mentioned in PGE's Round 0 comments, PGE has identified (with the help of RNW and Swan Lake and Goldendale) two corrections to make in portfolio analysis.

The first correction addresses the failure to make pumped hydro storage available for selection in the Preferred Portfolio. PGE agrees that pumped hydro should not be included as an emerging technology and has made it available for selection in the Preferred Portfolio in this refreshed analysis. In this analysis, the full 2000 MW of known potential projects in the region (Swan Lake 400 MW, Gordon Butte 400 MW and Goldendale 800 MW) is made available for selection in the Preferred Portfolio starting in 2028.

The second correction addresses an error in the capacity factors of hybrid resources (solar plus storage) used in portfolio analysis in the filed CEP/IRP. The error, which only affected hybrid resources, resulted in capacity factors that were 33 percent to 40 percent of what they should have been. As a result, the potential energy benefits of hybrid resources were underestimated in modeling. This refresh of portfolio analysis uses the corrected hybrid capacity factors. **Table 6** shows both the corrected capacity factors, used in this analysis, and the capacity factors used in the filed 2023 CEP/IRP.

Table 6. Average annual capacity factors of hybrid proxy resources

	Update (corrected)	Filed CEP/IRP (with error)
Christmas Valley Hybrid 1	28.6%	9.5%
Christmas Valley Hybrid 2	29.2%	11.7%
McMinnville Hybrid 1	22.3%	7.4%
McMinnville Hybrid 2	23.0%	9.2%

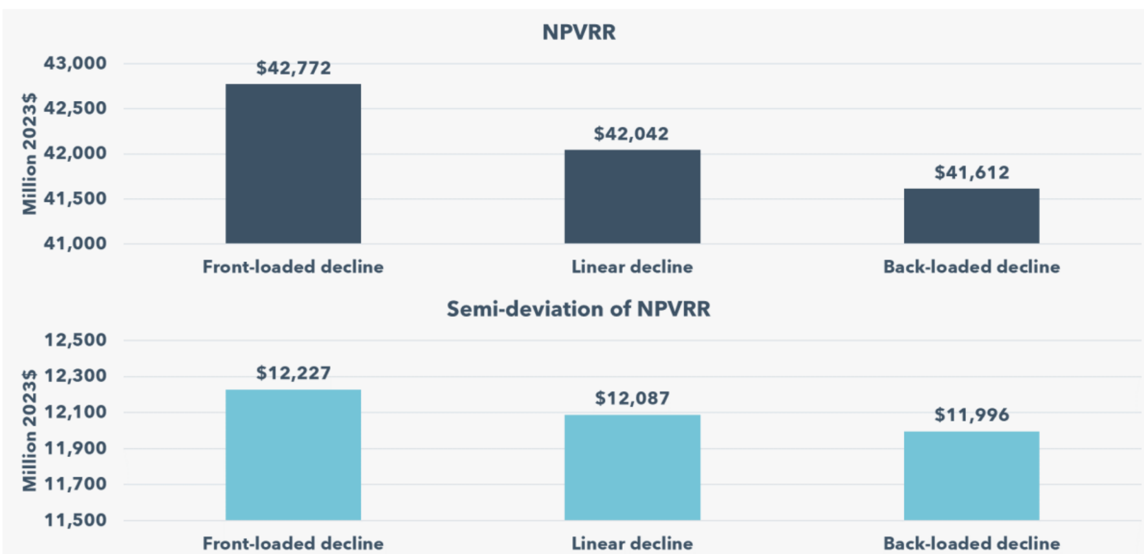
[19] See Section 3.6, Pumped hydro characteristics and Section 11.6, Hybrid resources of PGE's Round 0 comments. Available here: https://edocs.puc.state.or.us/efdocs/HAC/lc80hac102443.pdf

3.2 Portfolio analysis

Portfolio analysis in the 2023 CEP/IRP was organized around several key questions in resource planning. After incorporating the updated input forecasts, the findings regarding those key questions are robust to the updates and have not changed.

Decarbonization glidepath: Refreshing estimates of system needs provides supporting evidence that the linear decline still represents the best balance between decarbonization and portfolio cost and risks. Comparison of the cost and risk metrics of the decarbonization glidepath portfolios shows that, consistent with the results in the filed CEP/IRP, the cost and risk of the 'Linear decline' portfolio falls in between those of the 'Front-loaded decline' and 'Back-loaded decline' portfolios (**Figure 8**). While the back-loaded decline produces lower portfolio cost and risk metrics, it still has drawbacks associated higher cumulative emissions and procurement risk from waiting to procure the resources necessary for HB 2021 compliance. Conversely, while the front-loaded decline produces lower cumulative emissions, it brings higher costs than the linear glidepath.

Figure 8. Cost and risk metrics of decarbonization glidepath portfolios



Transmission need: Increasing system resource need exacerbates the need for transmission to move off-system generation to load. The informational portfolio with no transmission upgrades ('No Upgrades') displays the estimated first year where PGE would not be able to add sufficient resources without some increase in transmission availability.[20] This date is displayed in **Table 7** which compares the 'No Upgrade' portfolio results from the filed CEP/IRP to the updated results. The first year of transmission need has shifted from 2029 to 2028, and the size of the need in 2030 has increased from 768 MW to 1,658 MW.

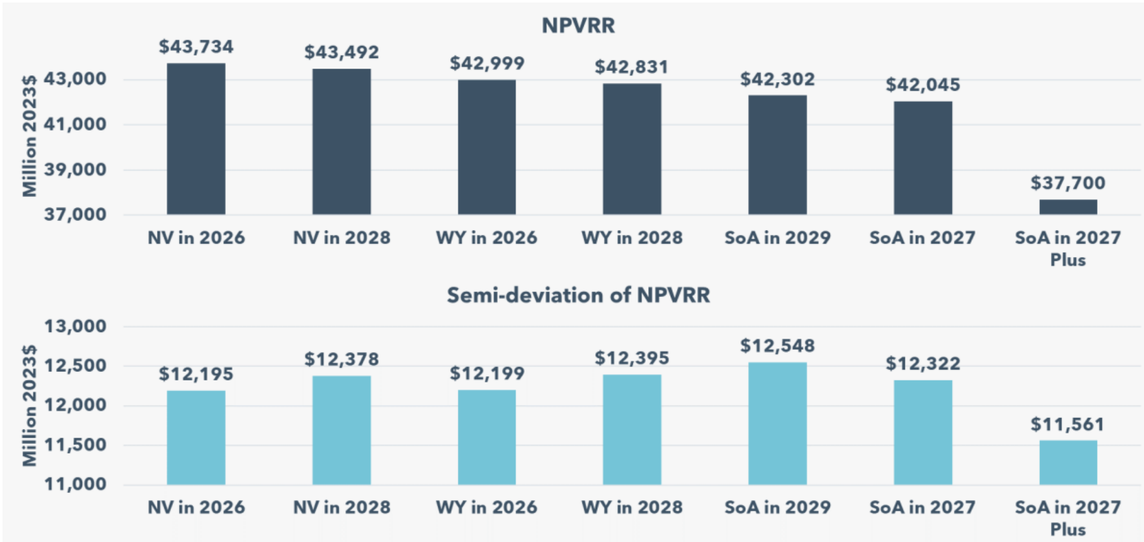
Table 7. Estimated Reference Case transmission need

	Estimated transmission need (MW)	
Year	**2023 CEP/IRP**	**Updated Results**
2026	0	0
2027	0	0
2028	0	355
2029	159	1,051
2030	768	1,658
2035	3,005	4,568
2040	7,468	9,403

Additional Transmission Resources: Having access to a wider geographic area of resources leads to decreased cost and risk. Consistent with the findings in the filed CEP/IRP, the 'SoA in 2027 plus' portfolio, which allows access to the largest amount of transmission resources, produces the lowest cost and risk amongst the transmission timing portfolios (**Figure 9**). These results demonstrate the benefits of having more transmission options available. Both 'SoA in 2027' and 'SoA in 2029' have lower cost than the WY and NV transmission expansion portfolios, reinforcing the finding of value in pursuing options to upgrade the existing transmission system to expand access to renewable resources in the PNW. These findings reaffirm the inclusion of all available transmission options in the Preferred Portfolio.

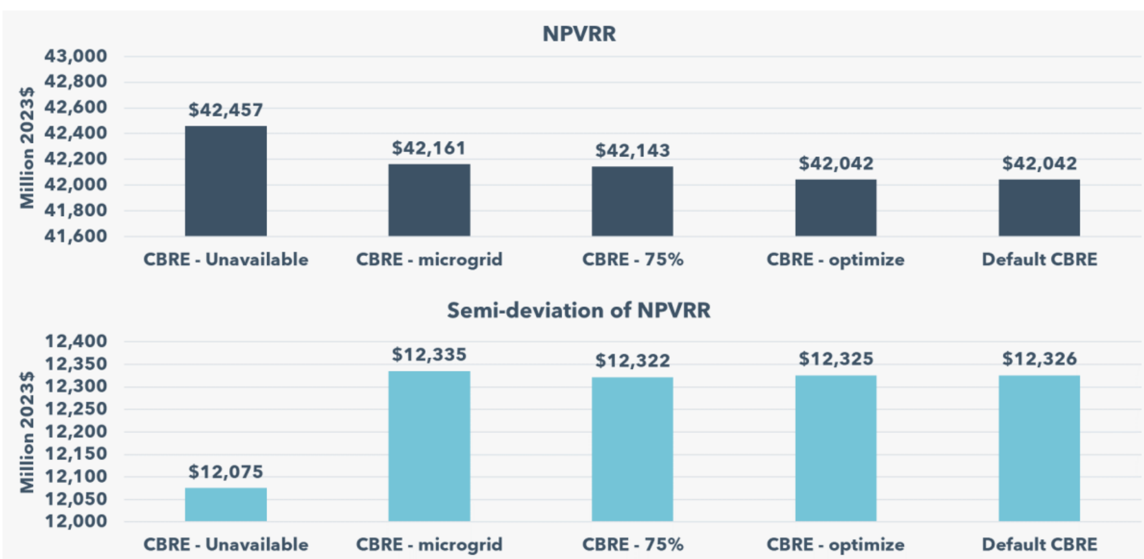
[20] The portfolio is considered informational because it does not represent an actionable set of resource actions for PGE. It does provide a useful demonstration that the current forecasts of transmission capacity are insufficient to meet system needs.

Figure 9. Cost and risk metrics of transmission timing portfolios



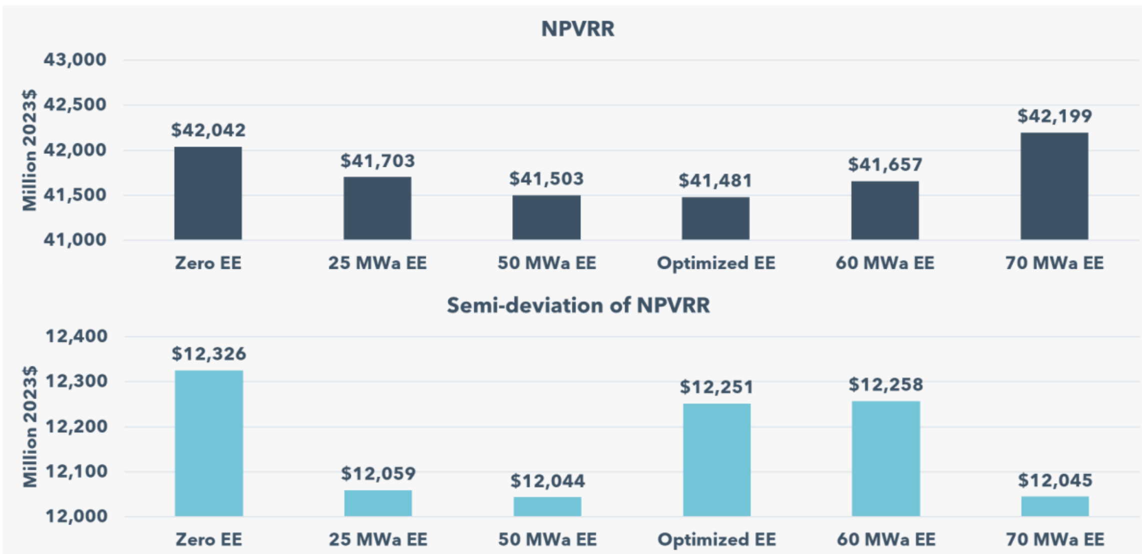
Community-Based Renewable Energy: The addition of CBREs to PGE's system lower portfolio cost and the full potential of 155 MW are added when the model is able to optimize their selection. Consistent with findings in the filed CEP/IRP, the 'CBRE – optimize' and 'Default CBRE' portfolios, which both add the full 155 MW of CBRE resources, produce the lowest costs. This finding demonstrates potential for CBREs to lower costs in a transmission-constrained environment, while maximizing the provision of community benefits (**Figure 10**). Consistent with these updated results, the full 155 MW of CBREs are included in the Preferred Portfolio.

Figure 10. Cost and risk metrics of CBRE portfolios



Energy Efficiency: The increased need increases the value of non-emitting generation resources. As in the filed CEP/IRP, additional quantities of EE can lower long-term cost and risk. The optimized EE portfolio elects to add 53 MWa of additional EE. As shown in **Figure 11**, increasing the amount of EE added decreases costs up to a point, suggesting that there are additional quantities of EE beyond those identified as cost-effective using avoided cost outputs from the 2019 IRP update that can help meet energy needs while lowering long-term portfolio costs.

Figure 11. Cost and risk metrics of EE & DR portfolios



However, as detailed in the filed CEP/IRP there are near-term cost impact implications associated with EE that must be taken into consideration. **Figure 12** shows that relative to a portfolio without any additional EE, including additional EE results in higher near-term cost pressure. PGE notes that the increase in dependence on both transmission market access resources and generic resource because of higher resource needs, reduce the relative increase in near term cost stemming from energy efficiency. Thus, compared to the analysis that was filed in the CEP/IRP, we see a smaller increase in near-term cost especially in 2029 and 2030. Since the underlying phenomenon that ties the addition of EE to increase near term rate pressure is policy based, the directional insights do not vary from the filed CEP/IRP. Reiterating the policies that drive this interaction, first, unlike other assets the additional EE is not financed or securitized, so the full cost is incurred before the generation starts. Second, EE decreases retail sales which leads to increased costs per unit of sales. Aggregated, these two effects lead to much higher near-term cost increases than the relevant comparators. While these policies have been in place for many years, the fast ramp in acquisition required exacerbates the near-term impacts of these policies. PGE recognizes that different rate mechanisms could reduce the influence of the near-term price impact. As a result of the findings, the Preferred Portfolio does not include additional EE beyond the amount found to be cost-effective using avoided cost outputs developed from the 2019 IRP.

Figure 12. Yearly costs per MWh for additional EE portfolios

3.3 Preferred Portfolio

The cumulative resource additions from 2024 through 2030 in the Preferred Portfolio are shown in **Table 8**. Notable outcomes of the resource build include:

- The updates to energy and capacity need forecasts resulted in a larger resource build (and associated cost and risk metrics) in the Preferred Portfolio.
- The correction to hybrid capacity factors has resulted in the model shifting to selecting hybrid resources rather than standalone storage and solar. 1010 MW of hybrid resources are added through 2030.
- All 800 MW of available transmission expansion are selected by 2030. This includes 400 MW of WY wind and 400 MW of NV solar.

- The model must now rely on 251 MW of the Generic VER resource in 2030 to meet needs.
- Pumped hydro storage is not added in the 2024-2030 timeframe. The full 2000 MW of available pumped hydro are added in 2040.

Table 8. Cumulative resource buildout in Preferred Portfolio (MW)

	2024	2025	2026	2027	2028	2029	2030
Wind	0	0	690	1090	1128	1528	1528
Solar	0	0	0	0	0	153	400
Hybrid	0	0	299	299	869	1010	1010
Battery Storage	0	0	0	0	0	0	0
Pumped Hydro Storage	0	0	0	0	0	0	0
CBREs	0	0	66	85	110	133	155
WY Tx	0	0	0	0	0	400	400
NV Tx	0	0	0	0	0	153	400
Generic VER	0	0	0	0	0	0	251
SoA Tx	0	0	0	400	400	400	400
Additional EE & DERs	0	0	0	0	0	0	0
Non-GHG-Emitting Contract Extension	0	0	200	200	200	200	200
Cost-effective EE (MWa)*	30	60	90	120	150	183	216
Cost-effective DR*	133	162	183	199	211	218	228
Clearwater Wind **	311	311	311	311	311	311	311
Seaside Storage **	0	0	200	200	200	200	200
Troutdale Storage **	0	200	200	200	200	200	200
Evergreen Storage **	0	75	75	75	75	75	75

***** Contributions reduce need
****** 2021 RFP resources

The cost and risk metrics of the Preferred Portfolio are displayed in **Figure 13**. The increased need and resulting increase in resource additions resulted in an increase in cost and risk associated with the Preferred Portfolio. The 20-year NPVRR of the Preferred Portfolio in the updated results is $36.96 billion. The increased resource needs found in the results of this analysis using updated need forecasts reinforces the key findings from the filed CEP/IRP that the binding nature of decarbonization and transmission constraints necessitates an approach to pursue all feasible avenues of resource additions.

Figure 13. Cost and risk metrics of the Preferred Portfolio

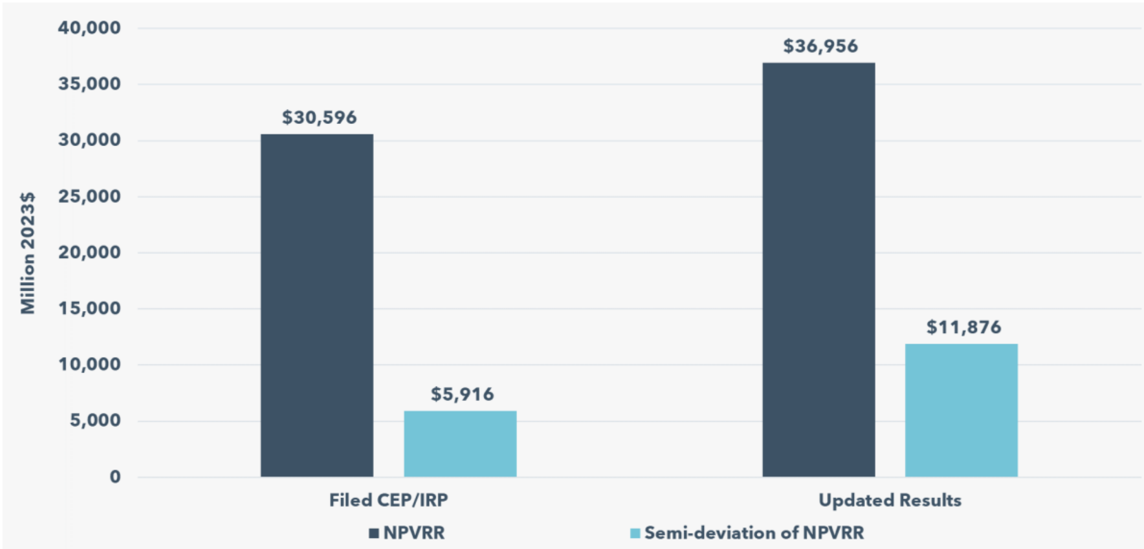
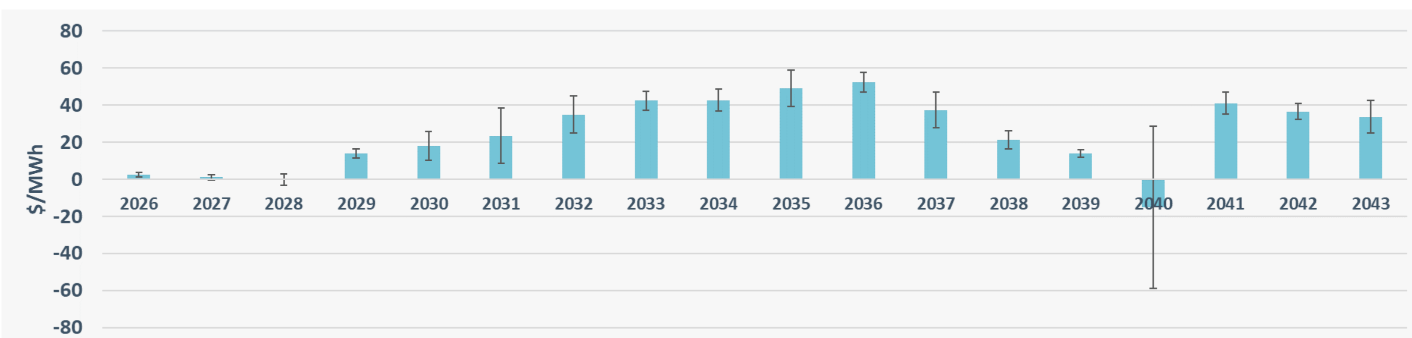


Figure 14 shows the difference in annual price impact between the Preferred Portfolio that was filed in CEP/IRP and the Preferred Portfolio developed in this Addendum. The increase in costs across the years is the direct result of the increase in resource additions stemming from the increased resource need driven by the different factors identified in **Chapter 2, Need changes**.[21,22]

Figure 14. Price impact difference between filed CEP/IRP and Addendum Preferred Portfolio



[21] The methodological correction identified in **Section 1.6.3** is addressed and factors within the **Figure 14**. However, its impact is minor relative to the change in price impact resulting from the addition of new resources
[22] The reduction in cost in 2040 is a function of the large addition of batteries, which based on the current treatment of the 30% ITC, lowers the first year's cash flow. The associated large range highlights the relationship between ownership structures and tax credits as they affect cash flows.

Table 9 is an update of Table 2 of the filed CEP/IRP, providing a summary of total resource actions from 2023 through 2030. It shows incremental new resources added by year (it does not show resource losses). It includes IRP Preferred Portfolio resources and non-CEP/IRP resource actions (2021 RFP resources, qualifying facility resource additions, GFI solar additions, etc.).[23] **Table 9** also include PGE's retail load service GHG emissions glidepath from 2023 through 2030.

Table 9. Preferred Portfolio resource pathway through 2030 (incremental additions)

Values in nameplate MW	2023	2024	2025	2026	2027	2028	2029	2030
DR (cost-effective)	24	26	25	19	14	11	8	9
EE (cost-effective)	31	30	30	30	30	31	33	33
Storage	0	0	275	200	0	0	0	0
Solar & wind	30	734	69	700	410	48	563	508
Hybrid	0	0	0	299	0	570	141	0
CBRE	0	0	0	66	19	25	23	22
Transmission (Tx) market access	0	0	0	0	0	0	553	247
Contract extension	0	0	0	200	0	0	0	0
GHG glidepath (MMTCO2e)	5.9	5.3	5.0	4.4	3.7	3.0	2.3	1.6

Table 10 shows incremental resource actions from year 2031 through 2043. It also includes PGE's retail load service GHG emissions glidepath from 2031 through 2043.

Table 10. Preferred Portfolio resource pathway 2031-2043 (incremental additions)

Values in nameplate MW	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
DR (cost effective)	11	8	9	8	5	11	7	7	7	1	6	11	3
EE (cost effective)	34	34	32	31	29	28	25	23	19	16	15	11	9
Storage	0	32	100	100	100	100	68	100	100	2100	0	0	0
Solar & wind	522	347	341	363	469	500	500	500	500	500	483	255	225
Hybrid	0	0	0	0	0	0	0	0	0	0	0	0	0
CBRE	0	0	0	0	0	0	0	0	0	0	0	0	0
Tx market access	0	0	0	0	0	0	0	0	0	0	0	0	0
Capacity	0	0	0	18	134	135	256	500	500	500	0	0	0
GHG glidepath (MMT CO2e)	1.5	1.3	1.1	1.0	0.8	0.6	0.5	0.3	0.2	0.0	0.0	0.0	0.0

[23] As a result of including non-CEP/IRP and non-RFP resources the values in this table will differ from those in **Table 8**. For simplification purposes, generic VER resources and 5 MW of qualifying facility biomass are included in the wind & solar values.

Conclusion

This Addendum has incorporated several updated CEP/IRP input forecasts and reevaluated portfolio analysis on the resulting calculations of system need. Results have provided additional support to the answers proposed to the main questions posed by portfolio analysis:

- A linear decline is an appropriate method to model emission reductions through 2030
- Addressing congestion across BPA's system (especially across the South of Allston flowgate) is necessary to maintain reliability and add sufficient off-system resources to meet energy needs
- Acquiring generation beyond the traditional geographical footprint of PGE's resources is an effective strategy to reduce long-term system cost and risk, particularly in higher-need futures
- CBRE resources could be an effective means of reducing long-term system cost, risk, and emissions while maximizing community benefits
- Additional quantities of EE (above the cost-effective forecasts from the ETO) reduce long-term system cost and risk. However, under the current policy and cost structures this additional EE has a significant near-term price impact.

The increased resource need could warrant updating the resource acquisition targets in the Action Plan. Those potential updated values are presented below in **Table 11**:

Table 11. Potential updates to Action Plan resource targets

		2023 CEP/IRP	LC 80 Addendum
Customer actions	Acquire all cost-effective energy efficiency	150MWa Cumulative 2024-2028	Unchanged
	Incorporate customer demand response	211 MW summer & 158 winter by 2028	Unchanged
CBRE action	Issue RFP for all available and qualifying CBRE resources	66 MW by 2026	Unchanged
Energy action	Conduct one or more RFPs to acquire sufficient energy to position PGE to meet the forecasted 2030 need	181 MWa (905 MWa / 5 total years) per year through 2028 (543 MWa in Action Plan window)	**261** MWa (**1307** MWa / 5 total years) per year through 2028 (**783** MWa in Action Plan window)
Capacity action	Conduct one or more RFPs to acquire sufficient capacity to meet forecasted 2028 needs	624 MW summer & 614 MW winter	**944** MW summer & **827** MW winter

		2023 CEP/IRP	LC 80 Addendum
Transmission actions	Pursue options to alleviate congestion on the South of Alston (SoA) flowgate	n/a	Unchanged
	Explore options to upgrade the Bethel-Round Butte line (from 230 to 500 kV)	n/a	Unchanged

These resource targets in the Action Plan form the basis of need projections going forward. However, this Addendum supports the notion that resource need estimates are not static. Instead, they will be constantly updated throughout the LC 80 docket and beyond as new input forecasts, resource information, and methodological changes are incorporated. This is especially applicable for the current RFP, whose resource acquisition targets will be updated with refreshed forecasts of system needs going forward. This constant updating is not a new process: the capacity needs used in the 2021 All-Source RFP were updated six times either between its initiation (April 2021) and its last filing (May 2022) in the RFP docket (UM 2166) and other regulatory filings. These updates were triggered by updated input forecasts like updated load forecasts and projected resource changes (such as the extension of the Pelton-Round Butte contract). The results of the 2023 CEP/IRP were an important but static consideration in how the Company plans to meet its long-term system needs. However, PGE expects the forecasts of long-term supply and demand that create system need to be continuously evolving, and the Company is committed to working with its public stakeholders and the Commission to continue updating forecasts when and where appropriate.

PGE also recognizes that there remain important questions in resource planning that warrant further investigation in the LC 80 docket. The Company is working to clearly articulate its long-term transmission needs and how the transmission components of the Action Plan fit in to its wider resource acquisition strategy. PGE is also looking to assess what options exist to leverage the opportunities of additional EE beyond the forecasted acquisition of cost-effective measures provided by ETO.

These questions highlight the challenge of acquiring sufficient resources to meet HB 2021’s emission reduction targets both reliably and affordably. PGE is committed to working with its public stakeholders and the Commission to determine the best set of resources to achieve those three goals. This Addendum reflects our willingness to ensure this conversation is supported by the most appropriate information possible.