Appendix G. Market capacity study

PGE's resource adequacy model, Sequoia, simulates PGE loads, owned resources, and long-term contracts. The PGE system is modeled as a power island, requiring sufficient owned or contracted resources to meet load every hour. In reality, the PGE system is part of the Western Interconnection. By being part of the Interconnection, PGE can buy and sell power with other entities, optimizing power costs, reducing risk, and potentially using purchased power for resource adequacy.

PGE may be able to buy power on short-term markets from others for resource adequacy needs. However, there may be seasons and hours when buying power is challenging due to competition from other utilities, transmission limitations, and other factors. The Western Interconnection is transforming into a cleaner power system. More wind and solar resources are arriving on the system and thermal dispatchable resources are being retired. New loads are forecasted to arrive from transportation and end use electrification along with high-tech industry (like data centers). As a result, predicting how much power PGE can rely on from the market for resource adequacy in future years is challenging.[454]

To approximate future short-term power market availability during heavy-load hours, the 2023 IRP uses a load-resource balance study for the Northwest region.[455] This study compares existing and committed resources in the Northwest against projected loads and exports to estimate if the Northwest is surplus or deficit in the winter and summer.[456]

G.1 Key input sources and changes

The key study inputs come from the following sources:

- The Power Council's 2021 Power Plan and GENESYS Classic model (as used in the Power Plan) provide the loads, resources, regional power market assumptions (imports from outside the Northwest), and power plant availability assumptions used in the workbook.
- The BPA White Book provides import/export assumptions for the Northwest, the largest being the Columbia River Treaty export.

Compared to the market capacity study in the 2019 IRP Update there have been impactful changes to the assumptions, most notably the usage of climate change model data for load

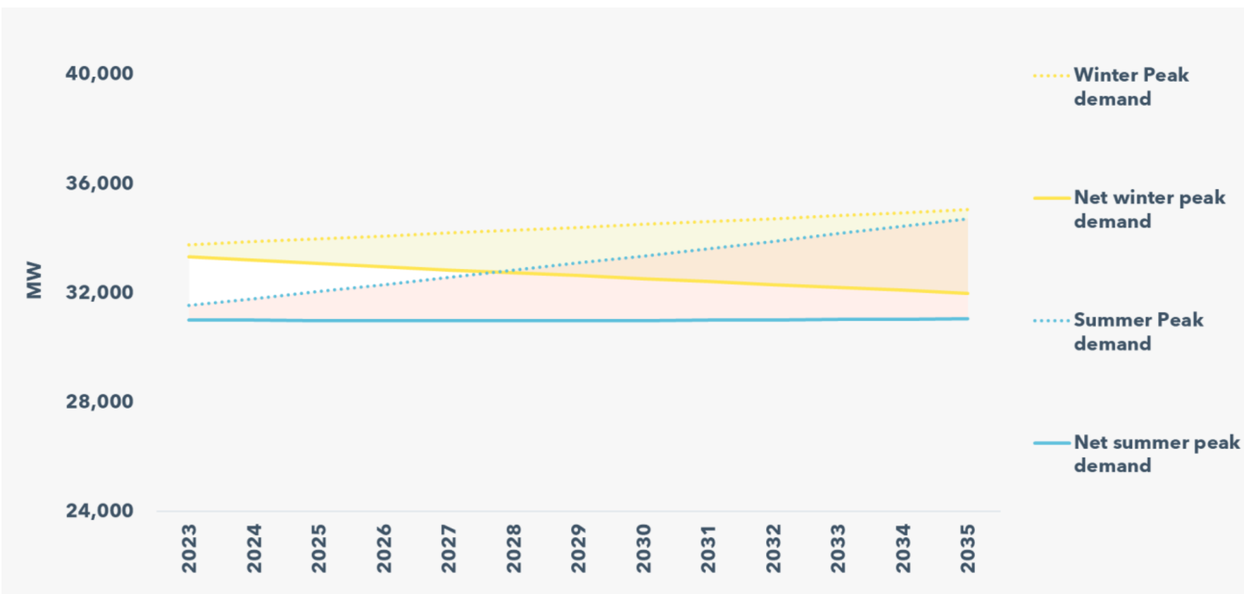
[454] More discussion on the changing west is in **Chapter 4, Futures and uncertainties**.
[455] Heavy-load hours are Monday through Saturday, hours ending 7 through hour ending 22, excluding NERC holidays. Light load hours are all other hours. The Northwest region is roughly ID, OR, WA, and Western MT.
[456] Winter is mid-November through mid-March, and summer is mid-June through September. The workbook used for the analysis originates from the 2019 IRP analysis performed by E3, a consultancy.

and hydropower inputs.[457] These changes lead to higher loads and lower hydropower generation in the summer, and lower loads and higher hydropower generation in the winter. This study indicates that surplus power is available in the winter but not in the summer. This conclusion differs from the 2019 IRP Update analysis that saw zero market power available in the winter Reference Case and limited power available in the summer. The change in findings is largely due to moving to climate change model data.[458]

G.2 Load and demand side resource assumptions

The load assumptions in the study are based on the 2025 load input file to the GENESYS Classic model and uses the average one-hour peak load for winter and summer. Using this starting point, the load scales up and down based on the 2021 Power Plan growth trends. Power Plan data are used to estimate the amount of energy efficiency and demand response in the analysis as well. **Figure 124** shows the load projections (dashed lines), demand side measure impacts (in shading), and net peak loads for this study (solid lines). The winter net load forecast experiences load decay, whereas the summer net load forecast is mostly flat.

Figure 124. Peak load forecasts



[457] Load and hydro assumptions are from the Power Council, which switched to climate change data for their 2021 Power Plan.
[458] The Power Council has additional discussion on how changing from historical data to climate change data impacted adequacy in their GENESYS classic modeling. Part of that discussion can be found here:https://nwcouncil.app.box.com/s/t40vm814w7qu86uzc00a5jckyofq72zh

G.3 Supply-side resource assumptions

The resources in this study come from the Power Council's resource database.[459] Only existing and firmly committed supply-side resources are in the analysis.[460] Resources are derated from nameplate values to their effective capacity values based on Power Council estimates.[461] One of the most significant adjustments occurs with hydropower, which is derated to its minimum 10-hr sustained peaking level in the climate change record.[462] The supply-side resource capacity contributions for summer and winter 2026 by fuel type are in **Table 116**.

Table 116. 2023 resource capacity contribution (MW)

	Summer	Winter
Hydropower (10-hr)	15,013	21,431
Natural gas	8,782	8,939
Coal	4,429	4,487
Nuclear	1,017	1,035
Wind	2,114	917
Solar	736	544
Other	694	694

One driver of Northwest resource adequacy challenges is coal unit retirements. **Table 117** explores how Northwest coal units are assumed to retire in the next decade. A change to the schedule would impact the study results. There are some changes in assumptions from the 2021 Power Plan in this study as shown in **Table 117**.

Table 117. Major coal power plants in the Northwest

Unit	Study Assumption	2021 Power Plan Assumption
Hardin	Retired	Retired
Colstrip 1	Retired	Retired

[459] Additional information available at: https://www.nwcouncil.org/energy/energy-topics/power-supply/
[460] Resources assumptions for this analysis were mostly frozen in spring 2022.
[461] Additional information available at: https://nwcouncil.app.box.com/s/k12r8hry1ofogeqxgjw8spgnv2n55lvm
[462] Ten-hour sustained peak derived from data in the GENESYS model. Compared to the 2019 IRP Update values, there is an extra ~3,600 MW of hydropower in the winter, and ~400 MW less in the summer.

Unit	Study Assumption	2021 Power Plan Assumption
Colstrip 2	Retired	Retired
Boardman	Retired	Retired
Centralia 1	Retired	Retired
N Valmy 1	Offline for NW in 2021	Offline for NW in 2021
N Valmy 2	Retiring end of 2025	Retiring end of 2025
Centralia 2	Retiring end of 2025	Retiring end of 2025
Colstrip 3	Offline for NW in 2030	Retiring end of 2035
Colstrip 4	Offline for NW in 2030	Retiring end of 2035
Bridger 1	Converting to gas	Retiring end of 2023
Bridger 2	Converting to gas	Retiring end of 2028
Bridger 3	Online	Online
Bridger 4	Online	Online

G.4 Import and export assumptions

Beyond loads and resources, the workbook takes key imports and exports into account. Export assumptions are from the BPA White Book. The Columbia River Treaty Canadian entitlement is the primary export in the workbook. Import assumptions come from the Power Council, with resource availability from outside the region (as included in the GENESYS Classic Model) being the primary import (winter only).[463] All Northwest located IPP resources are assumed to be fully available in the winter and are limited to 2,500 MW in the summer. **Table 118** shows import, export, and IPP assumptions in 2023 for winter and summer.

[463] This is often referred to as imports from the Southwest in Power Council analysis. Additional imports could potentially be available depending on the load/resource balance in other parts of the West and transmission expansion to other regions (for example, transmission expansion into Canada could potentially bring more power to the Northwest during certain hours).

Table 118. 2023 imports/exports/NW IPPs (MW)

	Summer	Winter
Imports	16	2,565
Exports	1,564	1,143
NW IPPs	2,500	2,716

G.5 Planning reserve margin assumptions

Planning reserve margins account for operating reserves, load deviations from extreme weather, forced outages (or higher than expected levels of forced outages), and other factors. This analysis uses three planning margins, 10 percent, 12.5 percent, and 15 percent. The three margins set the high (10 percent), reference (12.5 percent), and low (15 percent) market power assumption cases.

G.6 Results

Figure 125 and **Figure 126** show the load resource balance for the Reference Case summer and winter estimates. Note the step down in coal resources following 2025 and 2029.

Figure 125. Northwest summer peak load/resource balance

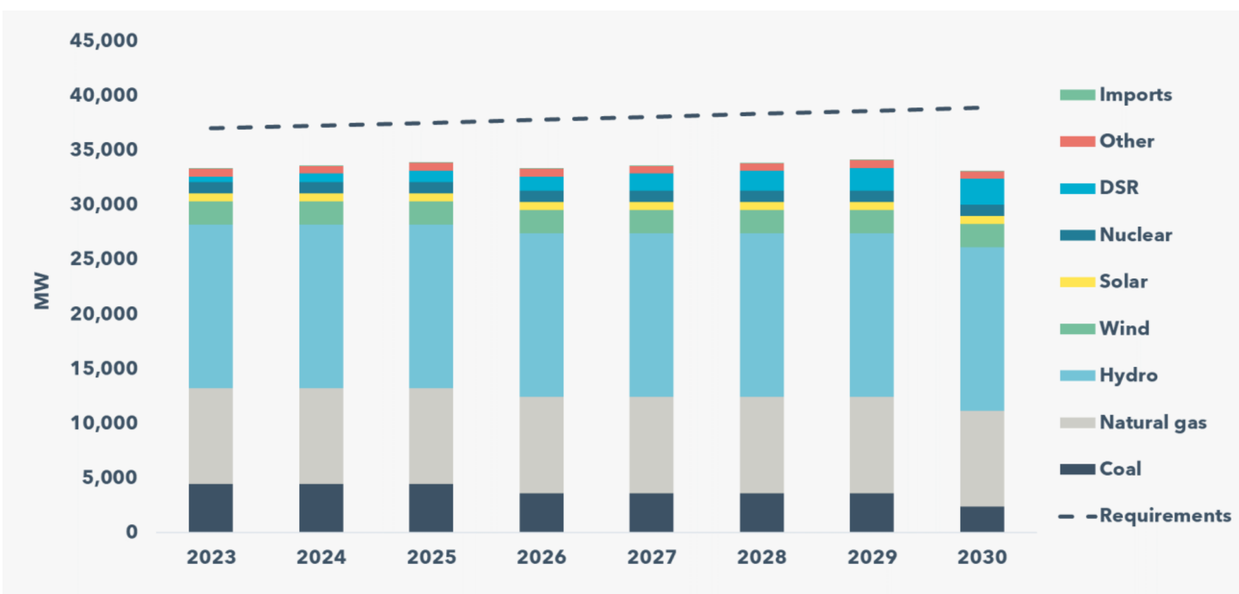
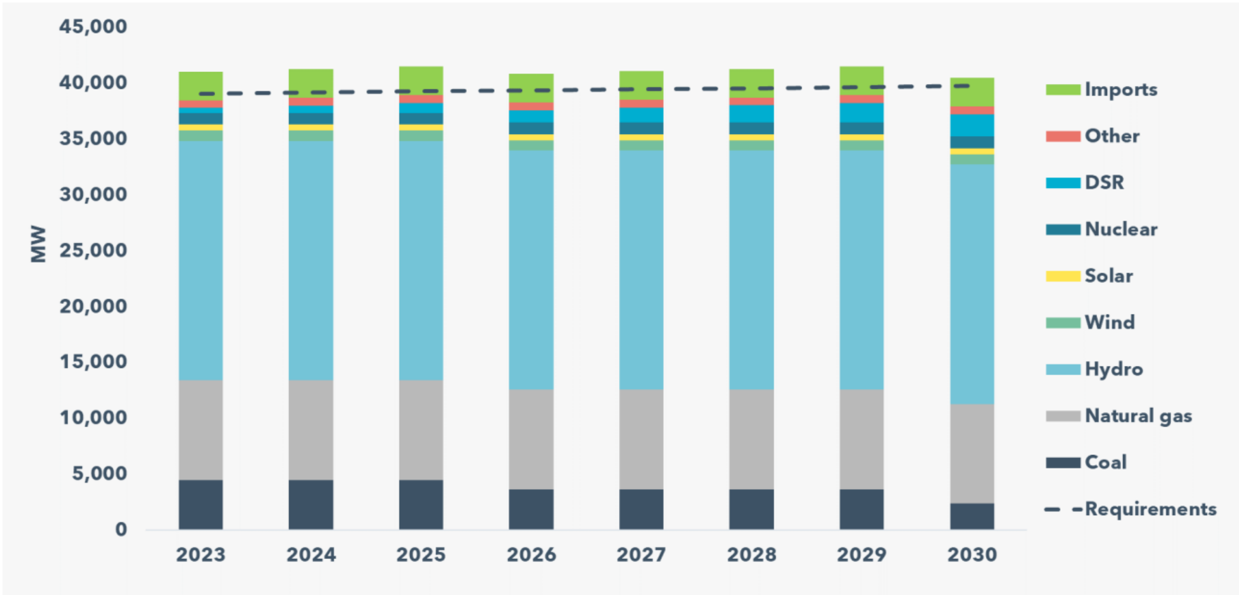


Figure 126. Northwest winter peak load/resource balance



In years with a power surplus PGE is assigned a share of the extra MWs. The share is based on the ratio of PGE's peak load to the Northwest region's peak load – roughly 10 percent. For example, if there is a 1,000 MW surplus, PGE's share is around 100 MW. For simplicity, and due to uncertainty regarding future loads and resources, the surplus values from 2023 through 2025 are averaged together, rounded to the nearest 50 MW, and used as the power market assumption in years 2023 through 2025. The average of the 2026 through 2035 surplus values are used as the power market assumption in year 2026 forward. The resulting heavy-load-hour market assumptions for the Reference Case are in **Table 119** and **Table 120**.

Table 119. Reference case 2023 IRP HLH market capacity

	2023	2024	2025	2026	2027	2028	2029	2030
Ref. Summer (HLH)	0	0	0	0	0	0	0	0
Ref. Winter (HLH)	200	200	200	150	150	150	150	150

The 2023 IRP has three market forecasts, low, reference, and high. They differ by planning reserve margin. The low case (lowest market availability) uses a 15 percent planning margin, the reference-case 12.5 percent, and the high case 10 percent. In all three cases, summer market power is zero. Winter market power availability varies by planning margin and year.

Table 120. High, reference, and low HLH market estimates

2023 IRP	2025 and earlier	2026 forward
High Summer (HLH)	0	0
High Winter (HLH)	300	250
Ref. Summer (HLH)	0	0
Ref. Winter (HLH)	200	150
Low Summer (HLH)	0	0
Low Winter (HLH)	150	50

G.7 Light load hour and shoulder season market assumptions

Unlike the heavy load hour (HLH) assumptions for winter and summer, the light load hour (LLH) and shoulder season assumptions are not based on a supply and demand balance study. For the spring and fall, 200 MW of HLH market power are assumed to be available in all years in the Reference Case. During light load hours in all months and years, a range of market power availability of 999 MW to 400 MW is used. The value declines as load increases (for example, during the highest load days there are 400 MW of LLH market available, during the lowest load days there are 999 MW available).

G.8 Limitations

The Power Council's Power Plans are produced every five years. Resultingly, the data and assumptions that underpin this market power assessment can fall behind the pace of public policy. Additionally, this assessment, a peak hour load/resource balance snapshot, is simplistic and does not take net load, flexibility challenges, transmission, and other factors into consideration. Going forward, PGE will seek more sources of data and more sophisticated approaches for assessing regional power market availability in IRPs and other planning work.

There may be a future opportunity to link IRP power market availability assumptions to work done by the Western Power Pool via the Western Resource Adequacy Program (WRAP). The WRAP was not sufficiently advanced to be used in this IRP cycle. PGE will consider using data from the WRAP to inform the market capacity study in future planning cycles.

Lastly, the estimates from this study are for long-range planning and are not at the detail needed for shorter-term operation applications.