Appendix H. 2023 IRP modeling details

The 2023 IRP relies on multiple models to create forecasts for power prices, emissions, capacity need, energy need, and more. This appendix provides additional detail on those models.

H.1 Aurora

Aurora is electric market forecasting and analysis software produced and maintained by Energy Exemplar. PGE uses Aurora to simulate wholesale electricity prices and resource dispatch. Within the use of Aurora, we use a separate model for each task: a regional WECC model, described in **Section H.1.1, Aurora – WECC model**, and a PGE-zone-only portfolio model (PZM), described in **Section H.1.2, Aurora PGE Zone Model**.

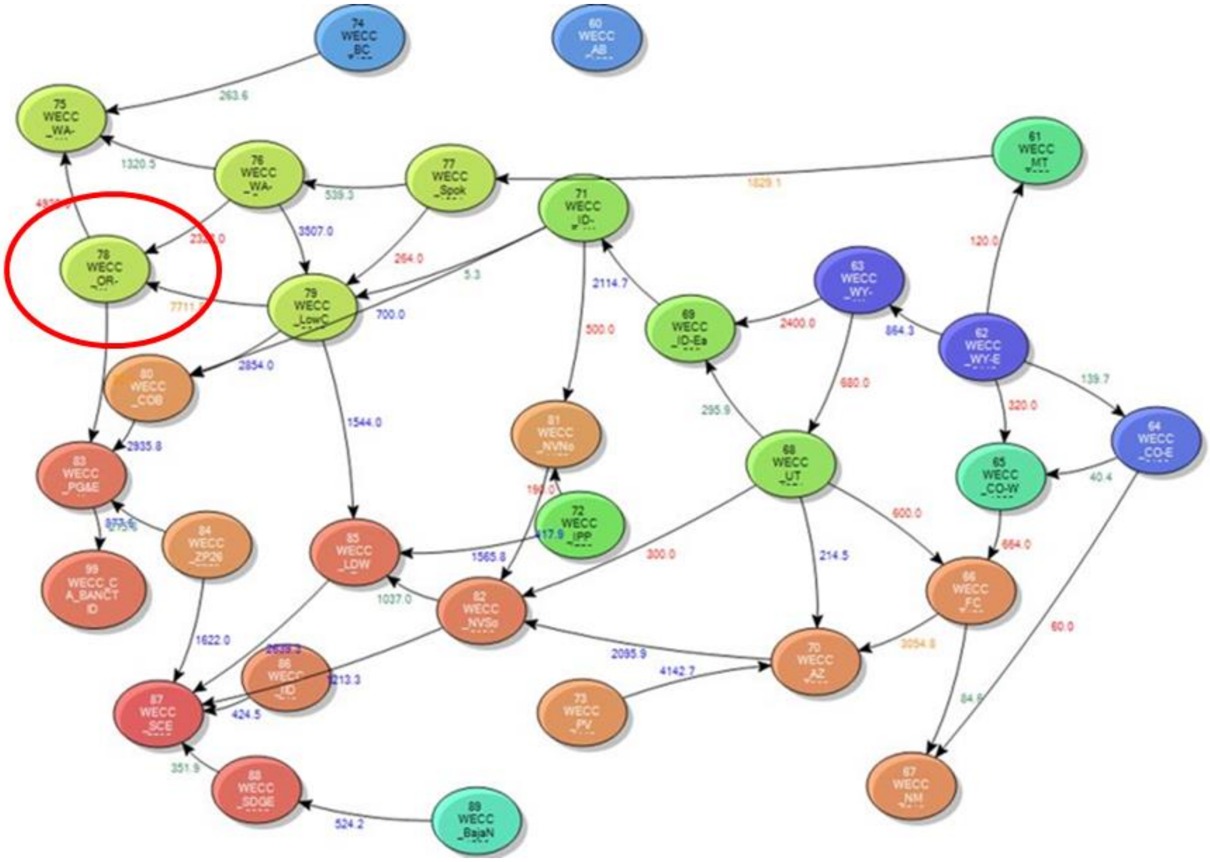
H.1.1 Aurora – WECC model

The Western Electricity Coordinating Council (WECC) model is a regional model provided by the global research consultancy, Wood Mackenzie. PGE input all the assumptions of the 2020H2 WECC model into Aurora as the base case environment for simulation and forecasting. Wood Mackenzie releases long-term forecasts twice a year. PGE updated the wholesale natural gas price forecast with 2022H1 gas price (which was published in June of 2022). In addition to commodity prices, Wood Mackenzie models the following information:

- Load and resources by geographical area. Resources are existing and new additions to meet the forecasted load through 2043.
- Transmission: capacity, constraints, wheeling costs, and carbon hurdle rates. Both existing and transmission lines planned and under construction are modeled.
- Macroeconomic data: environmental costs, inflation, etc.
- Calibration of resource behavior and optimization parameters.

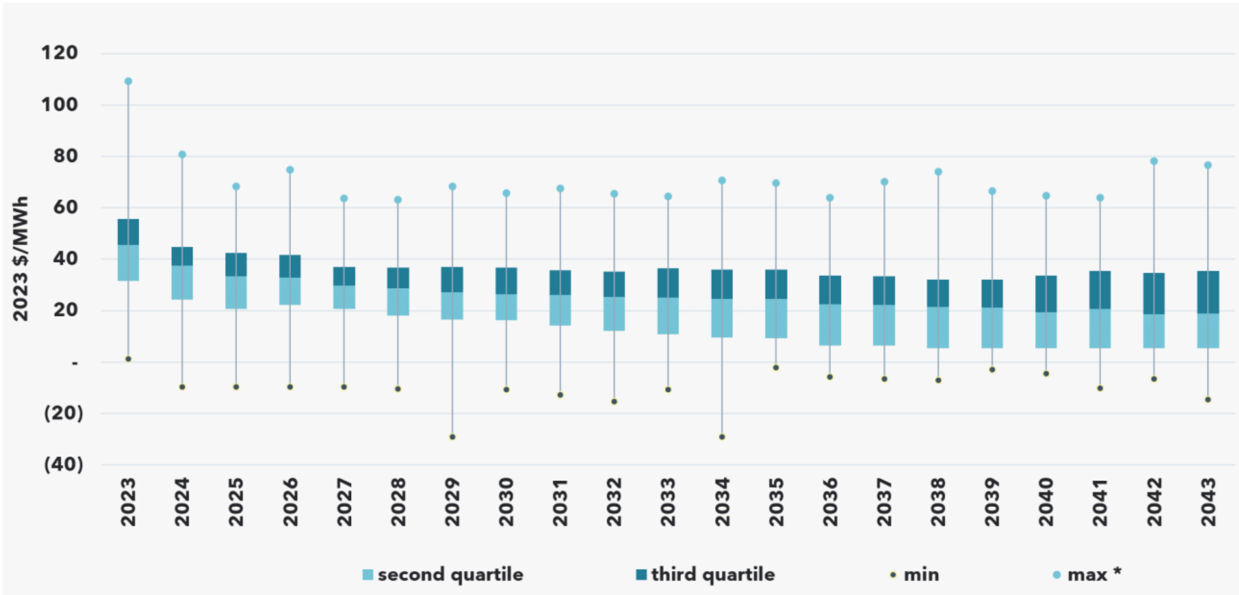
PGE uses the WECC model to forecast hourly electricity prices for the Pacific Northwest. This analysis is a regional simulation where PGE applies Wood Mackenzie's WECC assumptions, such as the growth and reduction of resource technology from 2023-2043, carbon policy, and resource capacity to maintain unbiased input of parameters and resource behavior. **Figure 127** shows the topology modeled in our WECC model: the colored bubbles represent geographical entities for which Aurora forecasts prices, and the lines represent transmission links for imports and exports. The model's objective is to minimize prices for WECC, given constraints on generation and import-exports across zones.

Figure 127. Illustrative snapshot of modeled WECC topology



For this analysis, PGE used Aurora version 14.0.1084 with the algorithmic performance optimizer, GUROBI. We simulated hourly prices from 2023 to 2043 for all areas and multiple futures, where we changed input assumptions. The Pacific Northwest is represented by 6 different areas of which Oregon West (highlighted in red in **Figure 127**), was chosen as best representative of the Pacific Northwest prices overall for PGE. Simulated Oregon West hourly prices for each future are then input in PZM and used to dispatch PGE resources. The Reference Case hourly electricity prices are summarized in **Figure 128**.

Figure 128. Reference case hourly electricity price range by year



To account for market uncertainty and volatility, PGE models three gas price futures (reference, high, and low) to capture a range of possible gas prices. The reference forecast is constructed using these components:

- 2023-2026 prices reflect PGE's 2022 Q2 forward gas trading price curve
- 2027 prices are a linear interpolation of 2026 prices and 2028 prices
- 2028-2043 prices are WM 2022 base long-term price forecast

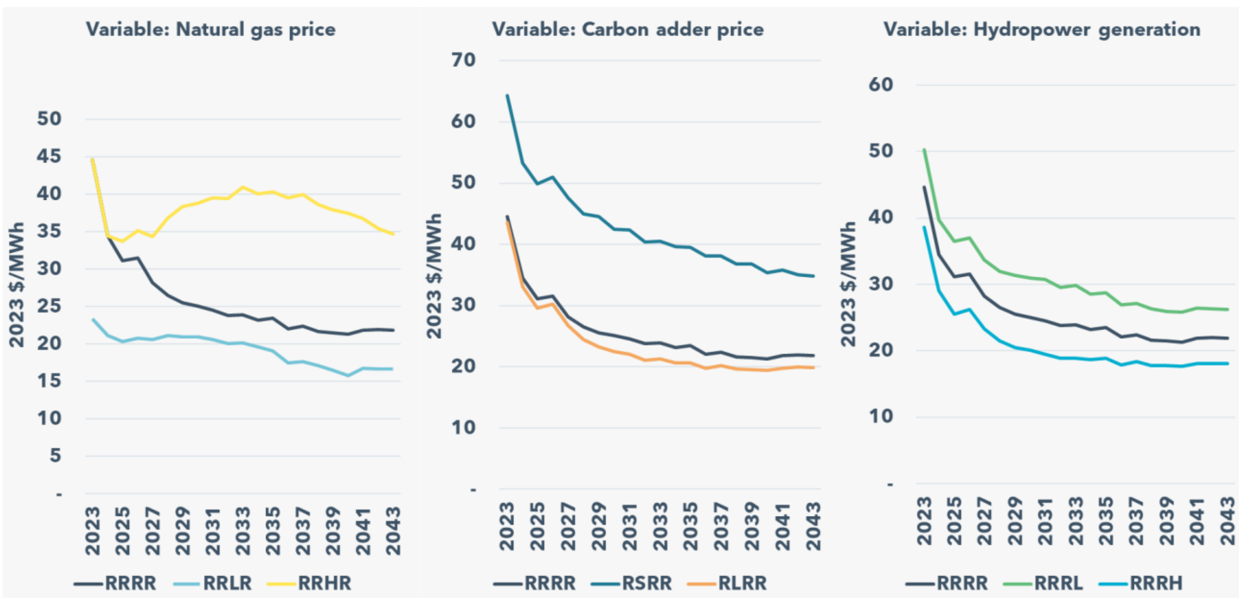
To model low gas price futures, PGE set a natural gas price floor of $2.30 per MMBtu for Henry Hub and applied a proportionate differential basis to other natural gas hubs. This price floor is based on Henry Hub's lowest gas price since 2016, which is approximately $2.30 per MMBtu. Putting a floor of $2.3 per MMBtu approximates a scenario where gas supply has no bottlenecks, and increased exports do not offset the shrinking domestic demand for electricity generation.

The High Gas Price Future applies the highest gas price scenario of the 2021 Annual Energy Outlook (AEO) forecast beginning in 2022. Among the scenarios published for the 2021 AEO, the Low Oil and Gas Supply case results in the highest long-term projection of gas prices. This is an approximation based on the U.S. Energy Information Agency (EIA) assessment of reduced ultimate recovery per well, limited stock of undiscovered resources, and a slow rate of cost-saving technological advancement.

PGE simulated 39 futures by varying four major risk drivers: natural gas prices, carbon price adders, PNW hydropower generation levels, and system commitment/scarcity. The construction of these price futures was discussed in **Chapter 4, Futures and uncertainties.**

The 2023 IRP Reference Case is modeled as a default Aurora setup, reference California Energy Commission (CEC)[464] carbon prices added to carbon-emitting resources in California and Washington and tax carbon prices to carbon-emitting resources in British Columbia and Alberta, reference natural gas price, and reference hydropower generation condition. **Figure 129** shows the impact on the reference prices of the risk drivers that capture commodity and carbon risk: natural gas prices, carbon adders, and hydropower generation. These risk drivers lead to a sustained different price level than the Reference Case and capture a wide range of possible price outcomes.

Figure 129. Wholesale electricity market price comparison between reference and individual variables



In this IRP, PGE added a few futures that proxy a system with increasing demand and supply balancing difficulty. This is because the Western Electricity Coordinating Council (WECC) electricity market transition to largely non-dispatchable resources combined with the still largely unquantifiable impact of climate change on load, wind, and hydro patterns. For these reasons, modeling cannot rely on history or widely adopted methodology. Consequently, PGE employs two Aurora features to incorporate forecast error into an otherwise perfectly balanced system and consider scarcity premiums on prices.

In Aurora, PGE applied the Dispatch Uncertainty table to the Pacific Northwest to mimic operational errors of wind generation forecast and dispatch commitment misalignment. The forecast errors are plus or minus 15 percent of wind nameplate capacity applied randomly to an hour each month. Such a percentage is based on the Wind Integration Study for hour-

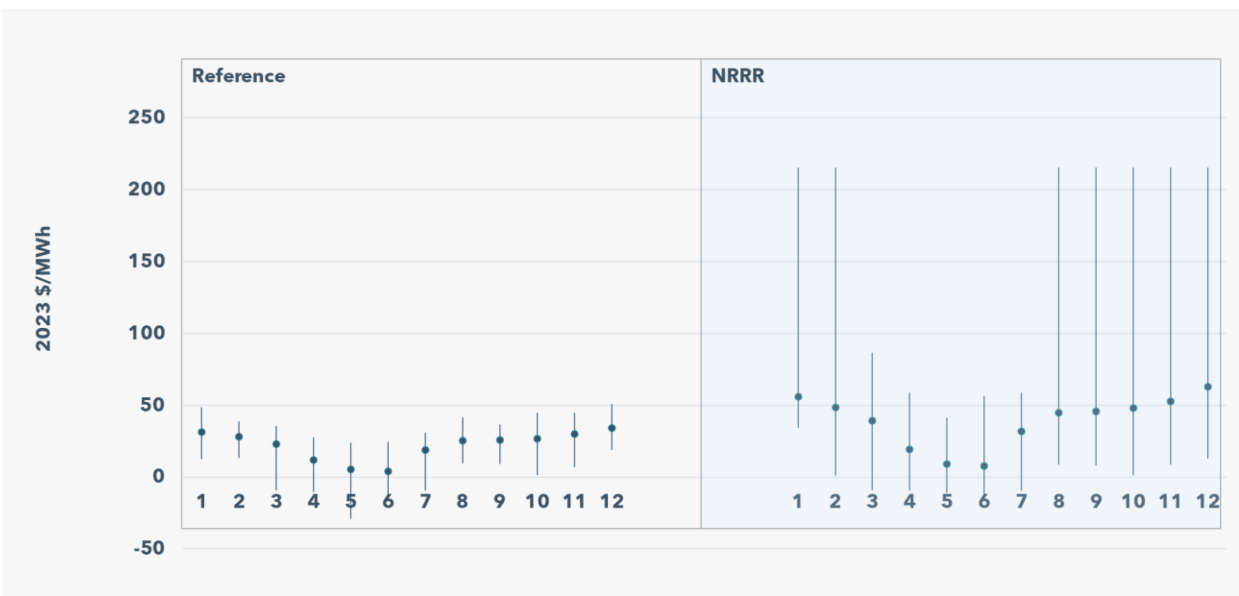
[464] PGE references the California Energy Commission (CEC)'s Integrated Energy Policy Report (IEPR) 2019 carbon price outlook for California. Available at: [TN232922_20200506T151733_Adopted 2019 Integrated Energy Policy Report.pdf]

ahead wind generation error. This error size is adequate to capture net load shocks. We simulated two futures with this characteristic: one in which all other risk inputs are set as Reference Cases and another future that has high gas prices and low hydro conditions. All other zones in WECC are kept with perfect foresight or no forecast error.

The default Wood Mackenzie database models a cycle of four different wind years, 2016-2019. The same error pattern is applied to the four wind years. The impact on annual average simulated wholesale electricity prices is generally moderate. Still, the volatility triggered by such an error is very different and much higher than the Reference Case, see **Figure 130**. The bar represents the range between minimum and maximum hourly prices for the month of 2031. The dot is the average monthly price.

For many hours, the model could not find resources to meet demand as the spare capacity was not committed and triggered the price cap of $1000 per MWh. The instances of $1000+ prices were so frequent that we reduced the price cap to $250 per MWh in these futures. Capping the price at $250 per MWh reflected the price experienced during the 2000 energy crisis, providing a likely scenario.

Figure 130. Intra-month hourly price volatility with dispatch uncertainty in 2030



Scarcity premium is a significant component of procurement economics. When resource capacity is scarce, the marginal cost of dispatch becomes higher since more expensive resources get dispatched to meet the load. These dispatched resources' associated maintenance and operational costs add to the scarcity premium. Typically, they are modeled in long-term models like Aurora because of their strong dependence on short-term zone-specific conditions. However, PGE agreed with stakeholders in the public process that occasional scarcity might be a characteristic of WECC given the uncertainty both on resource generation and load going forward. PGE proxied such premiums with the startup cost of thermal plants. In Aurora, PGE activated an Uplift Logic in which the startup cost of thermal plants is added to the dispatch cost. This cost is spread across the online hours of the thermal plants and consequently reflected in the electricity prices. We activated this logic for all hubs in the PNW and on-peak hours. This adder does not affect the annual average level of wholesale prices much. Volatility is shown in **Figure 131** for the year 2030, but price caps in this future are not triggered. The bar represents the range between minimum and maximum hourly prices for the month of 2030. The dot is the average monthly price.

Figure 131. Intra-month hourly price volatility with scarcity premiums: year 2030

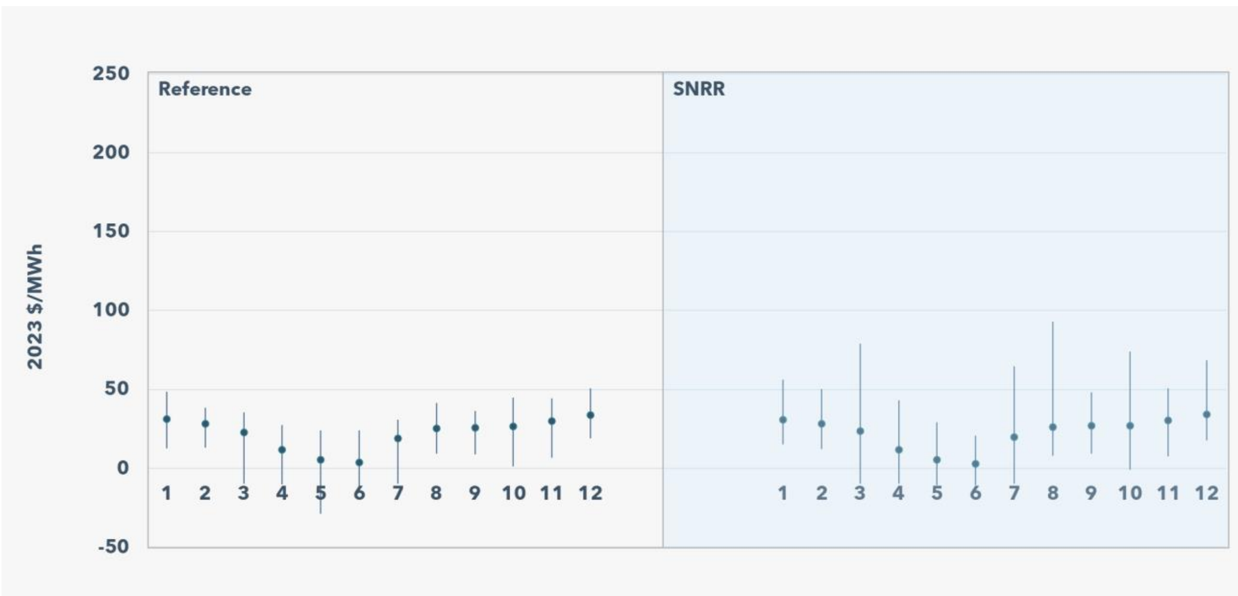


Table 121, **Table 122**, and **Table 123** show the annual average wholesale electricity prices simulated for all 39 futures.

Table 121. Average annual wholesale electricity prices for PNW by future (2023 $/MWh)

Year	NRHH	NRHL	NRHR	NRRH	NRRL	NRRR	RLHH	RLHL	RLHR	RLLH	RLLL	RLLR	RLRH	RLRL	RLRR	RRHH
2023	39.2	51.3	45.3	39.1	51.1	45.3	37.7	49.0	43.6	18.5	25.3	22.3	37.7	49.0	43.5	38.7
2024	28.8	39.9	34.5	28.7	39.8	34.4	28.0	37.8	33.1	16.4	23.4	20.0	28.1	37.6	33.1	29.0
2025	27.5	39.1	33.2	25.3	36.6	30.9	26.7	36.8	31.9	15.4	22.4	18.9	24.7	34.1	29.6	27.7
2026	31.3	43.1	37.2	28.0	39.2	33.3	28.6	38.7	33.8	16.2	22.6	19.2	25.5	34.8	30.2	29.6
2027	29.6	41.8	35.6	24.2	35.0	29.5	27.6	37.5	32.7	15.7	22.3	18.9	22.3	30.8	26.7	28.6

Year	NRHH	NRHL	NRHR	NRRH	NRRL	NRRR	RLHH	RLHL	RLHR	RLLH	RLLL	RLLR	RLRH	RLRL	RLRR	RRHH
2028	31.1	44.5	37.5	22.0	33.2	27.7	29.5	39.5	34.7	15.8	22.6	19.2	20.5	28.4	24.5	30.8
2029	31.7	45.6	38.6	20.5	32.1	26.1	30.5	41.0	36.1	15.3	22.3	18.8	19.4	27.1	23.2	31.7
2030	35.3	50.5	42.3	22.5	35.3	28.3	30.8	41.1	35.8	15.1	21.8	18.4	18.8	26.1	22.4	32.5
2031	34.9	50.5	42.4	21.1	35.3	26.8	31.4	42.2	36.8	14.8	21.7	18.2	18.4	26.0	22.0	33.0
2032	33.9	48.9	41.2	20.0	32.3	25.3	31.5	41.8	36.3	14.1	20.7	17.3	17.6	24.9	21.1	33.3
2033	34.2	49.0	41.1	19.3	30.6	24.7	32.6	43.3	37.8	14.3	20.9	17.3	17.7	25.0	21.3	34.4
2034	37.4	51.6	43.8	21.0	32.7	26.2	32.3	42.2	37.1	14.1	20.2	17.0	17.3	24.1	20.6	34.3
2035	36.3	50.5	43.1	21.0	32.4	26.2	32.8	42.1	37.3	13.8	19.4	16.4	17.6	24.1	20.6	34.4
2036	35.0	48.5	41.2	19.1	29.5	23.8	32.4	41.7	36.8	12.9	18.1	15.3	16.9	23.0	19.8	33.7
2037	34.5	47.4	40.7	19.0	28.4	23.5	32.8	42.0	37.3	13.2	17.9	15.4	17.3	23.3	20.2	34.5
2038	36.3	49.9	43.0	20.6	31.1	25.5	31.6	40.6	36.2	12.7	17.6	15.0	16.8	22.7	19.7	33.2
2039	35.0	47.8	41.0	20.0	30.5	24.7	31.3	40.2	35.8	12.2	16.9	14.5	16.7	22.6	19.6	32.6
2040	33.0	45.4	38.8	18.8	28.0	23.2	30.4	39.5	35.2	11.7	16.5	13.9	16.6	22.6	19.4	31.7
2041	31.8	43.9	37.8	18.8	27.9	23.0	30.1	39.2	34.4	12.5	17.3	14.6	17.0	23.2	19.7	31.4
2042	34.2	47.5	40.8	21.6	32.3	26.4	28.7	38.0	33.2	12.6	17.6	14.9	17.0	23.5	19.9	30.2
2043	33.2	45.4	38.6	21.3	31.9	26.7	28.4	36.9	32.4	12.4	17.2	14.6	17.0	23.0	19.8	29.8

Table 122. Average annual wholesale electricity prices for PNW by future (2023 $/MWh)

Year	RRHL	RRHR	RRLH	RRLL	RRLR	RRRH	RRRL	RRRR	RSHH	RSHL	RSHR	RSLH	RSLL	RSLR	RSRH	RSRL
2023	50.3	44.6	19.2	26.9	23.3	38.6	50.3	44.6	56.4	72.0	64.4	37.3	48.9	43.3	56.4	72.0
2024	39.7	34.4	17.1	25.2	21.1	29.0	39.7	34.5	46.0	60.5	53.4	34.1	46.1	40.5	45.7	60.4
2025	39.3	33.7	15.9	24.8	20.3	25.5	36.5	31.1	44.4	59.9	52.2	32.8	45.3	39.1	42.4	57.4
2026	41.0	35.1	16.9	24.9	20.8	26.2	37.0	31.5	46.5	61.6	54.5	34.2	46.0	40.3	43.7	57.7
2027	40.4	34.3	16.6	25.0	20.6	23.3	33.7	28.2	45.4	60.8	53.3	33.2	45.4	39.6	40.1	53.9

Year	RRHL	RRHR	RRLH	RRLL	RRLR	RRRH	RRRL	RRRR	RSHH	RSHL	RSHR	RSLH	RSLL	RSLR	RSRH	RSRL
2028	43.4	36.8	16.9	26.2	21.1	21.5	32.0	26.5	47.1	62.0	55.2	33.4	45.4	39.6	38.1	50.9
2029	45.2	38.4	16.3	26.6	20.9	20.5	31.3	25.5	47.9	63.8	56.4	32.9	45.2	39.1	37.2	50.0
2030	46.0	38.8	16.3	26.5	20.9	20.1	30.9	25.0	47.7	63.7	56.0	32.4	44.5	38.4	36.2	49.1
2031	47.1	39.5	15.9	26.5	20.6	19.5	30.8	24.5	49.0	64.8	57.1	32.3	44.4	38.5	35.9	48.5
2032	46.6	39.4	15.4	25.4	20.0	18.8	29.5	23.8	47.7	63.7	55.8	30.5	42.8	36.5	34.1	46.9
2033	48.2	41.0	15.4	25.7	20.1	18.9	29.8	23.9	49.1	65.1	57.2	30.7	42.6	36.5	34.3	46.8
2034	46.6	40.1	15.4	24.5	19.6	18.6	28.6	23.2	48.9	63.8	55.9	30.2	41.6	35.8	33.8	45.7
2035	46.8	40.4	14.9	23.9	19.0	18.9	28.7	23.5	48.9	63.7	56.0	29.7	40.8	35.0	33.9	45.6
2036	46.1	39.5	14.0	22.0	17.5	17.9	26.9	22.0	47.8	63.0	55.6	27.9	39.0	33.5	32.1	44.2
2037	46.0	40.0	14.3	21.7	17.6	18.4	27.2	22.4	47.8	62.4	55.2	27.5	38.3	33.0	32.1	43.8
2038	44.4	38.6	13.8	21.1	17.1	17.8	26.3	21.6	46.2	60.4	53.5	26.5	37.1	31.9	31.0	42.7
2039	43.8	37.9	13.3	20.3	16.5	17.7	26.0	21.4	45.8	59.9	53.0	25.9	36.3	31.2	31.0	42.3
2040	43.0	37.5	12.8	19.5	15.8	17.7	25.9	21.3	43.9	58.7	51.2	24.3	34.7	29.5	29.5	41.6
2041	42.6	36.8	13.5	20.7	16.7	18.1	26.5	21.9	43.3	57.8	50.7	25.0	35.2	30.1	30.0	41.5
2042	41.0	35.4	13.7	20.5	16.7	18.1	26.3	22.0	41.4	55.7	48.5	24.3	35.1	29.6	29.1	40.9
2043	40.1	34.7	13.5	20.3	16.7	18.1	26.2	21.8	41.0	54.5	47.6	24.5	34.3	29.3	29.4	40.5

Table 123. Average annual wholesale electricity prices for PNW by future (2023 $/MWh)

Year	RSRR	SRRH	SRRL	SRRR	SRHR	SRHL	SRHH
2023	64.3	40.7	52.9	47.1	47.2	52.8	40.8
2024	53.3	30.5	41.6	36.4	36.1	41.7	30.5
2025	49.9	26.8	38.4	32.7	35.5	41.3	29.1
2026	51.0	27.5	39.0	33.1	36.6	43.0	31.1
2027	47.7	24.3	35.3	29.6	36.2	42.5	30.1
2028	44.9	22.5	33.4	27.7	38.5	45.4	32.4
2029	43.6	21.4	32.8	26.8	40.3	47.5	33.3
2030	42.5	21.0	32.5	26.2	40.9	48.2	34.0
2031	42.4	20.3	32.1	25.4	41.2	49.1	34.2
2032	40.4	19.6	30.8	24.7	40.9	48.5	34.4
2033	40.5	19.8	31.2	24.9	42.8	50.2	35.6
2034	39.6	19.4	30.0	24.1	41.7	48.5	35.4
2035	39.5	19.6	30.3	24.3	42.1	48.8	35.5
2036	38.1	18.7	28.2	23.3	41.1	48.0	35.4
2037	38.1	19.3	28.2	23.5	41.6	47.7	36.1
2038	36.8	18.7	27.4	22.7	40.6	46.1	34.8
2039	36.8	18.5	27.0	22.4	39.9	45.5	34.3
2040	35.4	18.5	26.9	22.4	39.4	44.8	33.3
2041	35.8	19.0	27.5	22.9	38.4	44.4	33.0
2042	35.0	18.9	27.4	23.0	37.0	42.7	31.6
2043	34.8	19.0	27.2	22.8	36.2	41.8	31.1

H.1.2 Aurora PGE Zone Model

The Aurora PGE Zone Model (PZM) is used to simulate the economic dispatch of existing PGE and candidate new resources. Inputs to the model are:

- Variable costs and operating characteristics of PGE existing resources, power plants, and contracts, generally matching those of the 2022 annual update tariff (AUT) November 15 filing. An exception is planned maintenance and forced outages that represent our best estimate of plant's long-term performance instead of the snapshot of the test year of AUT.
- Fuel prices match those of the WECC model except for Colstrip, for which we have more detailed assumptions
- Carbon dispatch adders matching those of the WECC model
- Electricity hourly wholesale prices for the Pacific Northwest are simulated with the WECC model.

Aurora simulates PGE existing dispatchable generation resources, contracts, and new resources using economic dispatch based on electricity prices and associated risk variable inputs consistent with each price future. When economically dispatched, resources will generate when resource dispatch cost is lower than the electricity market price and will not generate when market purchases are cheaper.

The PZM outputs are sources of inputs to ROSE-E for all price futures across all years. ROSE-E inputs new resources' capacity factor and energy value, existing resources' variable costs and energy value, and existing portfolio's baseline resource costs and baseline net contract costs from PZM, the set of PZM outputs to ROSE-E includes total annual variable costs, annual net market purchases, resource dispatch, and energy value for new and non-carbon emitting resources. The dispatch results of the thermal units in various price futures from the PZM are provided to the Intermediary GHG model, described in greater detail in **Appendix H.2, Intermediary GHG model**.

H.2 Intermediary GHG model

PGE buys and sells power on the wholesale market for various reasons, including risk mitigation and net variable power cost reduction. Incorporating HB 2021 into planning requires differentiating between energy and associated emissions used to serve retail load, and energy and emissions used for wholesale market sales. To accomplish this, the 2023 IRP uses an Excel-based intermediary GHG model.

The intermediary GHG model focuses exclusively on GHG emitting generation. Its objective is to allocate GHG emitting power to retail load service and to wholesale sales. The model takes inputs from:

- Aurora for thermal units, based on economic dispatch and various price futures
- Historical data for market transaction patterns
- The Oregon DEQ for GHG intensity values from emitting sources (tons / MWh)

Using these inputs, the model creates estimates for how much power PGE can retain from each specific source to meet retail load under different GHG constraints. Total power plant dispatch ratios and historical sales patterns determine the amount of each resource retained for retail load service, keeping similar ratios across fuel types. For example, historically, PGE keeps a greater percentage of natural gas generation for retail load service than coal generation. Resultingly, in the model, natural gas generation is kept for retail load service at a higher rate than coal. Inside fuel classes (natural gas, coal, etc.) the ratio of power retained for retail load service is the same across resources. An example of this is in **Table 124**, using power plants Beaver and Carty and focusing on the year 2027. In this example, 77 percent of the plant output for both Beaver and Carty is kept for retail load.[465]

Table 124. Example retail/wholesale energy breakout in 2027

Resource	Total MWh	Retail MWh	Retail %
Carty	2,477,916	1,901,681	77%
Beaver	563,811	432,698	77%

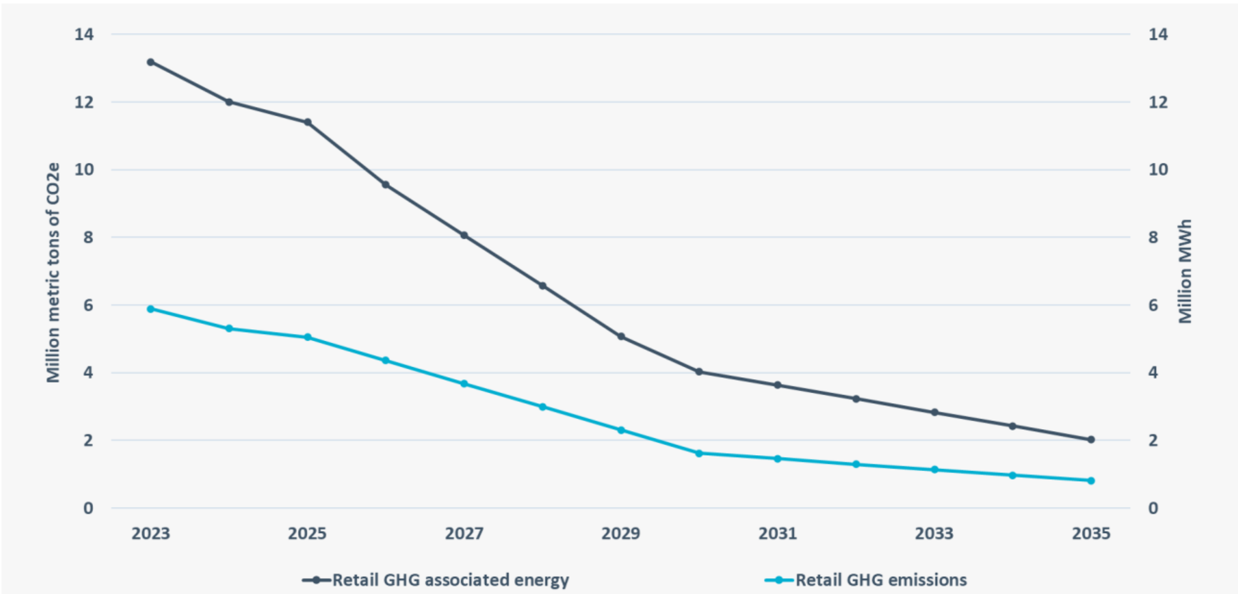
In the example shown in **Table 124**, the total MWh values are determined by the Aurora model, which provides the thermal plant inputs to the intermediary GHG model. The model then reduces the amount of generation retained for retail load (in this case down to 77 percent) while taking other resource emissions and GHG targets into consideration.[466] The generation not retained for retail load is assumed to be sold into the wholesale power market.

The primary output of the intermediary GHG model is the total amount of generation from GHG emitting resources retained for retail load.[467] This information helps set the energy

[465] Example data, actual values used in the IRP may differ.
[466] The 2023 IRP uses five different GHG glidepaths (targets). More information on the glidepaths is in **Chapter 5, GHG emissions forecasting**.
[467] Distributed system generation resources are not in the GHG model or IRP energy position. These resources typically dispatch under emergency conditions. Inclusion of DSG resources at 2022 dispatch levels was tested in the GHG model and resulted in a 2030 annual energy position change of under 0.1 MWa.

position for ROSE-E, the IRP capacity expansion model. An example of this is in **Figure 132** which shows GHG emitting resource energy and emissions retained for retail load service. More discussion on the model is in **Chapter 5, GHG emissions forecasting**.

Figure 132. Retail load GHG emissions and associated energy (Reference Case)



H.3 Sequoia

This section provides a brief overview of the Sequoia model and focuses on changes made to Sequoia since the 2019 IRP Update.[468] For more detailed information about the model, see Appendix K of the 2019 IRP Update.

H.3.1 Overview

Sequoia runs stochastic simulations to test the PGE system for resource adequacy, perform Effective Load Carrying Capability (ELCC) studies, and examine GHG emissions. It pairs different load and resource profiles to test the power system under a wide range of conditions. A typical test simulates 50,000 weeks per season (summer/winter) to provide a

[468] 2019 IRP update with appendix K at p.75, available at: https://assets.ctfassets.net/416ywc1laqmd/1PO8IYJsHee3RCPYsjbuaL/b80c9d6277e678a845451eb89f4ade2e/2019-IRP-update.pdf

broad set of load and resource combinations. The model runs on an hourly timestep, with 50,000 weeks equating to 8.4 million hours.[469]

The Sequoia model runs each week independently. It starts with an initial draw of seven sequential historical days. From those days, it extracts three key inputs: the month, if the days are a weekday or a weekend, and the daily load bin (the load bin tells the model how high loads are). Using this information, Sequoia builds a synthetic week. The key pieces of the week are:

- Water year, which sets the weekly energy budget and hourly generation max/min for large hydropower projects. The model uses the same water year for the entire week. The water year data come from a historical 30-year record, with the data being specific by month.
- Load profile. The load profile changes daily and aligns with the initial draw data by month, weekday/weekend, and load bin. The load data use 30 historical temperature profiles to create variations.
- Wind/solar profile. The wind/solar profiles, which are independent by project, change daily and align to the initial draw data by month and load bin. Matching the load bin values to the wind/solar profile links temperature to wind/solar generation outputs.
- Thermal generation availability is set using stochastic forced outage rates and mean-time-to-repair inputs. Thermal generation can also vary by month, with higher generation available in colder months due to air density.
- Storage resources start the week 100 percent charged, this a change from the 2019 IRP update that started storage at a 50 percent charge level. Storage resources charge and discharge as needed, with perfect foresight, and are limited to one cycle per day.
- Power market inputs vary by month, time of day, and load bin. More information on power market inputs is in **Appendix G, Market capacity study**.
- Other inputs, like demand response programs and run-of-river hydropower, enter the model via month-hour shapes (which use hourly shapes that vary by month and weekday/weekend) or monthly blocks (the resource output varies by month).

Table 125 visually represents part of the process previously outlined for one week in Sequoia.

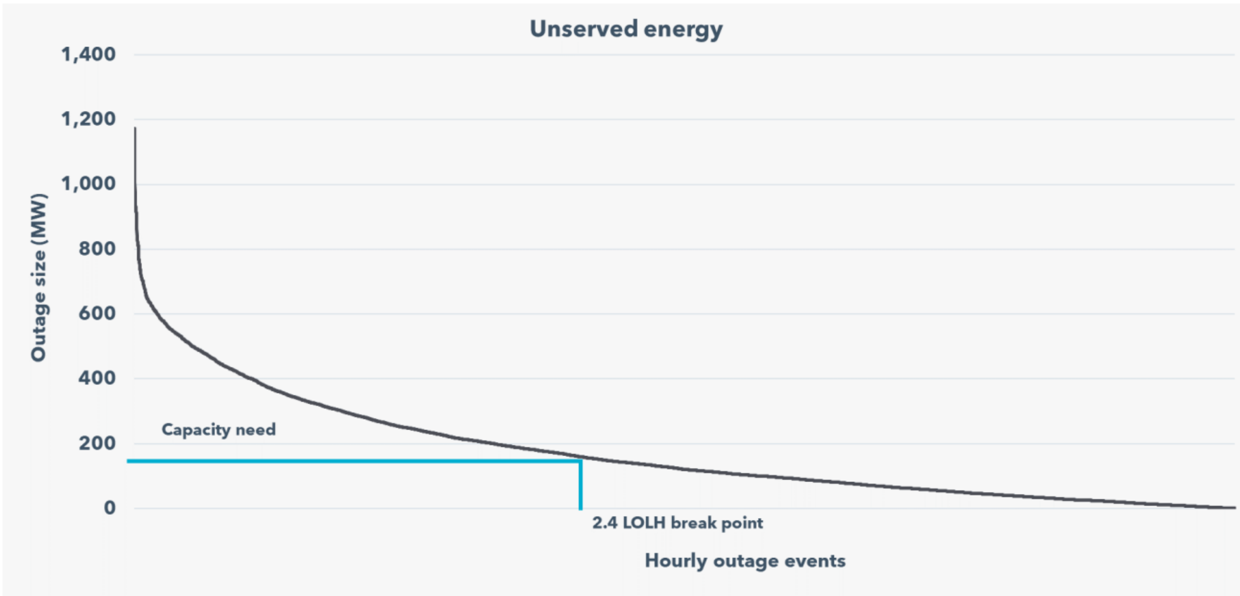
[469] 50,000 weeks are tested per year/season for capacity needs and to establish ELCC values. To reduce model runtime capacity needs in some years after 2030 are interpolated.

Table 125. Sequoia week creation example

Start date	Month	Load bin	Weekday	Water year	Biglow	Bakeoven	Load	Thermal resources
8/5/1997	8	5	1	2003	8/6/2005	8/11/2014	8/30/2007	Resource generation varies by month and by forced outage rate.
8/6/1997	8	5	1	2003	8/25/2016	8/3/2014	8/7/1981	
8/7/1997	8	5	1	2003	8/5/2010	8/10/2014	8/13/1992	
8/8/1997	8	3	1	2003	8/22/2005	8/24/2014	8/30/1991	
8/9/1997	8	4	0	2003	8/1/2005	8/9/2012	8/24/2019	
8/10/1997	8	5	0	2003	8/21/2011	8/26/2011	8/8/1987	
8/11/1997	8	5	1	2003	8/31/2004	8/19/2014	8/18/1981	

As the model runs, it tabulates when outages occur. Each outage enters a loss-of-load log, ranking outages from largest to smallest. The model then calculates the number of outage hours allowable to meet the 2.4 Loss of Load Hours (LOLH) target. It finds this value on the x-axis and outputs the corresponding capacity value on the y-axis. This value is the effective capacity needed to achieve an adequate system. If the system is already adequate, the value is zero. An example of this calculation is in **Figure 133** – in this case, the system needs around 200 MW of capacity.

Figure 133. Sequoia capacity need calculation example



PGE uses the Sequoia model to calculate resource ELCC values, using the following steps:

- The model runs once to establish a base system capacity need
- The model runs again with a new resource added and produces a new capacity need
- The difference in capacity need between the base system and the system with the new resource added determines how much effective capacity the resource contributes
- The effective capacity value is divided into the resource nameplate value to calculate the ELCC

This approach is similar to how the Northwest Power and Conservation Council determined resource capacity contributions in the 7th Power Plan (the Council calls this approach associated system capacity contribution or ASCC).

H.3.2 Sequoia input model changes since the 2019 IRP Update

Updates have been made to the Sequoia data inputs since the 2019 IRP Update. Select updates are in **Table 126**.

Table 126. Select input related Sequoia changes since 2019 IRP Update

Item	Update
Pelton/Round Butte	Hydropower contract renewed
Core load forecast	Updated spring 2022
Electrification loads	Updated summer 2022
Temperature years	Year 2021 included
Existing western solar profile	Updated with NREL data
Forced outage rates	Updated spring 2022
Qualifying facilities online	Updated spring 2022
DER inputs	Updated summer 2022
Power market availability	Updated market analysis
Run-of-river hydropower	Updated with BPA/Corps data
2021 Proxy RFP portfolio	Included

H.3.3 Other Sequoia model changes since the 2019 IRP Update

Since the 2019 IRP Update, Sequoia has undergone several non-input-related changes. They include:

- Running the model seasonally rather than annually. A seasonal ELCC provides more information for resource additions during portfolio analysis. With many resources, ELCC values differ by season. Using a seasonal approach can help ROSE-E, the capacity expansion model, better evaluate resource options and resource adequacy on a seasonal level. For example, Gorge wind tends to have higher ELCC values in the summer than winter. Resultingly, ROSE-E may see more value from Gorge wind if summer capacity needs are more prevalent than winter, and less value if winter needs are more prevalent than summer.

- Running the model to analyze GHG emission. Via an approach suggested by E3, a consultancy, Sequoia can provide insights into GHG emissions on the PGE system. **Appendix I, C-level analysis** discusses how the model runs for GHG emissions.
- Starting storage resources fully charged at the start of the week. More discussion regarding this change is in **Appendix J, ELCC sensitivities**.

H.4 ROSE-E

ROSE-E is a capacity expansion model that identifies resource additions across potential futures and years using information about PGE's capacity and energy need, operational and regulatory requirements, the current portfolio of resources, and technical and economic characteristics of new resource options. ROSE-E will select a portfolio of resources that satisfies the constraints imposed while minimizing the chosen objective. A full description of the model parameters and mathematical implementation can be found in Appendix I of the 2019 IRP.[470] This appendix focuses on changes and improvements made to ROSE-E since the 2019 IRP.

PGE has approached portfolio design in this IRP as a one-stage process where optimization and scoring have been combined into a single process that is focused on building a portfolio that allows PGE to comply with HB 2021. The previous IRP used a two-stage approach to create a variety of near-term portfolios based on alternative objective functions while minimizing Net Present Value Revenue Requirement (NPVRR) over the study period for any given near-term build.

H.4.1 Input data

Changes and improvements have been made since the 2019 IRP to methodology associated with some of the inputs that ROSE-E receives from other PGE models.

Existing resources

The source of information on PGE's existing resources has evolved since the 2019 IRP because of the new planning paradigm associated with HB 2021. To forecast PGE's future energy position, ROSE-E utilizes a load-resource balance (LRB) model (**Section 6.5, Energy need**). Energy from non-GHG emitting resources in the LRB is determined by estimated capacity factors. Energy from thermal plants and GHG-associated market purchases are

[470] In the matter of Portland General Electric Company, 2019 Integrated resource plan, Docket No. LC 73, Order No. 20-152, available at: https://apps.puc.state.or.us/orders/2020ords/20-152.pdf

estimated using the Intermediary GHG model. More information in **Section H.2, Intermediary GHG model**.

Baseline portfolio

Total variable costs and annual net market purchases for the Baseline Portfolio are generated by the Aurora PGE Zone simulation and factor into portfolio costs and energy-related constraints in ROSE-E. To follow the established DEQ emission methodology, market sales and market purchases are estimated using data from Aurora in conjunction with the Intermediary GHG model, which is used to determine the amount of GHG-associated energy that is retained to serve Oregon retail load, and how much is available for wholesale market sales.

Temporal granularity

The temporal granularity of certain inputs has been increased to add realism to model assumptions or provide additional modeling flexibility.

Resource adequacy

To foster reliable portfolios, ROSE-E utilizes data from Sequoia that defines the amount of accredited capacity needed to maintain a reliable system, which is defined as LOLE of 2.4 hours per year (see **Chapter 6, Resource needs**). In the 2019 IRP, capacity need data was defined at the annual level.[471] To capture the difference more accurately in system needs throughout the year, the capacity need is calculated seasonally (summer and winter) in Sequoia. ROSE-E must build sufficient resources to be adequate in both seasons. Effective Load Carrying Capability (ELCC) of new resource options is also calculated seasonally in Sequoia.

Flexibility value

Flexibility values have previously been static throughout the study period and can now vary across all years of the analysis. Flexibility value of storage resources was calculated for years 2026 and 2030. In ROSE-E the 2026 value is linearly interpolated for the years 2027 - 2029, and the 2030 value is linearly interpolated from 2031 – 2043. See **Ext. Study-IV, Flexibility study** for a detailed description of flexibility values.

[471] In the matter of Portland General Electric Company, 2019 Integrated resource plan, Docket No. LC 73, Order No. 20-152, available at: https://apps.puc.state.or.us/orders/2020ords/20-152.pdf

New types of resource options

Portfolio analysis in the 2023 IRP includes three types of resource options that have not been included in previous IRPs. The following describes these new types of resource options.

Non-cost-effective EE and DR

As in the 2019 IRP, cost-effective Distributed Energy Resources (DERs) are accounted for as reductions in forecasted load, as described in **Appendix D, Load forecast methodology**. In this IRP, Energy Efficiency (EE) and Demand Resources (DR) that do not meet the cost-effectiveness criteria have been added as new resource options to be considered for selection by the model alongside supply-side options in portfolio analysis.

CBREs

Three types of community-based renewable energy (CBRE) resources are included as resource options in portfolio modeling. More information about CBREs is provided in **Section 7.2, Community-based renewable energy (CBRE)**.

Transmission expansion

Three options to expand transmission capacity are available for selection in the model. These options are described in detail in **Section 9.4.1, Proxy transmission options identify transmission need.**

Generic Resources

The model has access to two generic non-emitting resources (Generic Capacity and Generic VER). These resources give the model sufficient access to energy and capacity to meet system needs that would otherwise be infeasible in a transmission-constrained environment. The generic resources are priced slightly higher than the most expensive supply-side resource available to the model.

H.4.2 Constraints

In addition to the four constraints identified in the 2019 IRP, constraints have been added to accommodate new planning requirements or issues of increasing relevance.

Emissions

All ROSE-E portfolios are subject to an GHG emissions constraint that limits portfolio emissions to levels that comply with HB 2021 emissions targets. Except in the case of portfolios designed specifically to test the impact of alternative GHG reduction glidepaths, emissions targets are defined using the linear glidepath (**Section 5.3, Components of IRP emissions reporting**). The generation from existing PGE thermal plants made available in ROSE-E is limited to levels that produce emissions up to the levels associated with HB 2021 targets each year. The allocation between plants is determined by economic dispatch up to the emissions limit in each price future (**Section 5.3, Components of IRP emissions reporting**). Because the GHG budget is fully utilized up the GHG emissions reduction glidepath with the dispatch of PGE-owned thermals and GHG-emitting contracts/market purchases, gaps between energy needs to serve retail load and energy allowed to serve it must be made up through the building of new non-emitting resources, without the option to utilize market purchases beyond what is accounted for in the Intermediary GHG emissions model.

Transmission

A new constraint imposes limits on transmission availability to move energy from new off-system resources to PGE's system. Previous IRPs assumed all proxy resource builds would be able to deliver their energy to PGE's system. In the 2023 IRP, we incorporated the current contractual transmission landscape by assigning an inventory of transmission availability for each resource that limits the total quantity of each resource that can be built. Resource inventories are quantified in MWs of available transmission capacity (ATC) defined by zones, with cross-zonal impacts accounted for in the calculation of inventory quantity. Therefore, resource builds within a given zone do not impact the availability of transmission in other zones.[472] Resource transmission zones and the methodology used to determine available transmission inventories are described in **Section H.7, BPA transmission in ROSE-E**.

Each resource zone has an inventory of available firm transmission and an inventory of conditional firm transmission availability.[473] On-system resources do not have transmission limitations and do not impact the inventories of other resources.[474]

[472] For example, Gorge Wind and Wasco Solar are both in the Gorge transmission zone, which has 190 MW of LTF ATC. So, building 1 MW of either Gorge Wind and Wasco Solar reduces the LTF ATC of the Gorge zone to 189 MW, but does not impact the ATC of either a) the ATC of other transmission zones or, b) the CF ATC of the Gorge zone.
[473] Resources available with firm transmission generally have higher ELCC values than those with conditional firm transmission (as described in **Appendix K, Tuned system ELCCs**).
[474] Storage resources and CBREs are considered on-system.

H.5 LUCAS

H.5.1 LUCAS – Levelized fixed-cost revenue requirement tool

The Levelized Utility Cost Aggregator System (LUCAS) is a tool used to calculate revenue requirements for the fixed costs of new supply-side resources and PGE-owned resources. LUCAS is an Excel-based model. Significant inputs to LUCAS include:

- Financial assumptions. PGE's cost of capital required return, long-term inflation, tax rates (federal, state, and property), federal investment tax credits, and the Modified Accelerated Cost Recovery System (MACRS) schedule.
- PGE-owned resources. PGE's book and tax depreciation, economic life, deferred tax, fixed O&M, scheduled capital additions, and fixed gas transportation costs.
- Supply-side resources. Includes overnight capital costs, fixed operations & maintenance (O&M), project life, decommissioning costs, and plant operating parameters. As applicable, LUCAS captures fixed costs for gas transportation and wheeling.

For a given resource, LUCAS calculates the total fixed costs for each year, the net present value of those costs across the project's life, and the real-levelized cost. Outputs from LUCAS include real-levelized fixed costs for each resource option by commercial operation date (COD) and capital cost trajectory. These data are passed to ROSE-E for determination of the fixed component of portfolio costs and evaluation of resource economics.

H.5.2 Long-term financial assumptions

As required by Guideline 1a of Order No. 07-002, PGE's estimated after-tax marginal weighted average cost of capital of 6.25 percent serves as a proxy for the long-term cost of capital to discount future resource costs. PGE bases this estimate on information available as of Q1 2022. **Table 127** contains other relevant financial assumptions.

Table 127. 2023 IRP long-term financial assumptions

Component	Percent
Composite Income Tax Rate	27.5%
Incremental Cost of Long-Term Debt[475]	3.9%
Long-Term Debt Share of Capital Structure	50.0%

[475] The incremental cost of long-term debt is based on an average of three-year forward 30-year borrowing costs as of March 2022 (i.e., the cost of 30-year debt in 2022, 2023, and 2024).

Component	Percent
Common Equity Return	9.5%
Common Equity Share of Capital Structure	50.0%
Weighted Cost of Capital	6.7%
Weighted After-Tax Discount Rate	6.2%
Long-Term General Inflation	2.1%

H.6 Annual Revenue-requirement Tool (ART)

The Annual Revenue-requirement Tool (ART) is an Excel-based tool used to estimate the annual revenue requirement ($'s) and the normalized annual revenue requirement ($/MWh) impact for a set of portfolios. ART was developed in addition to ROSE-E and the differences between the two models are listed in **Table 128**.

Table 128. Differences between ROSE-E and ART

	ROSE-E	ART
Costs:	Existing and new resource related fixed, variable, and integration costs based on 100% PPA assumption	Existing and new resource related fixed, variable, and integration costs based on different ownership structures
Benefits:	Includes all resource benefits such as - energy value, flexibility value, RCBI	Only includes monetary benefits of wholesale market sales when generation is higher than load
Other:	All values are expressed in levelized terms which may not reflect actual yearly costs due to ownership structure and tax credit implications	All values are based on expected impact each year of the planning horizon, and are representative of the cost changes associated with existing and incremental generation

Figure 134 and **Figure 135** show a simplified version of the governing equation within ART to assess the annual revenue requirement or price impact.

Figure 134. Estimating the annual price impact ($)

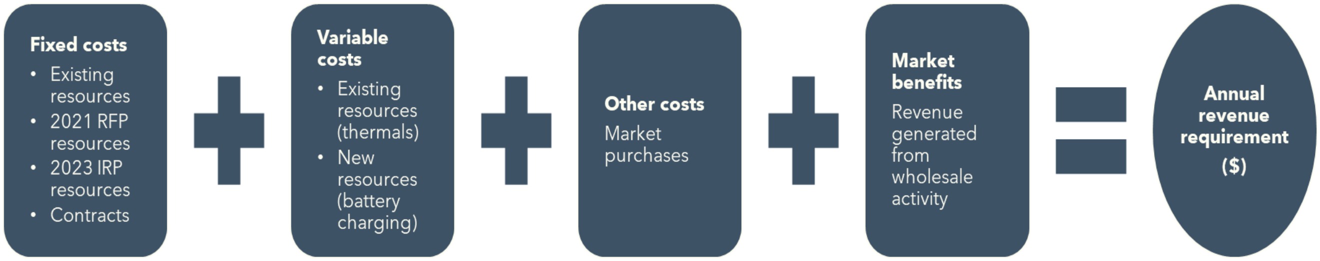
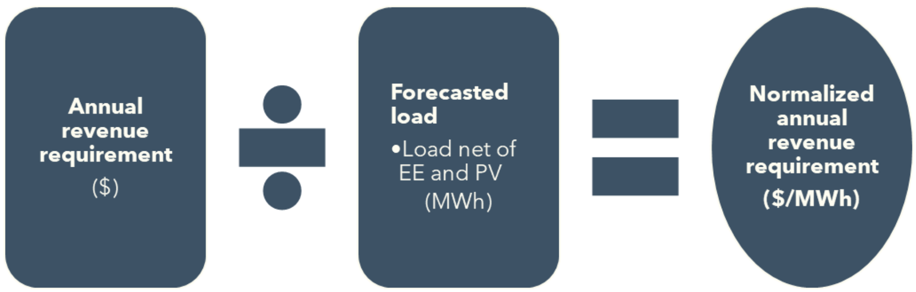


Figure 135. Estimating the annual normalized price impact ($/MWh)



Each component of **Figure 134** and **Figure 135** along with their corresponding source is detailed in the following:

- **Fixed costs** in ART represent the aggregate impact of fixed costs stemming from each of the following:
  - Existing resources – The fixed costs of existing resources include costs such as the capital carrying costs, depreciation, taxes, demand response program cost, and costs of Energy Trust programs. These are aggregated and sourced from the LUCAS model (**Section H.5, LUCAS**).
  - Contracts – Cost of Qualifying Facilities are calculated on a $/MWh basis within Aurora and included within ART. Additionally, costs of other contracts are aggregated and sourced from LUCAS.
  - 2021 RFP proxy resources – For the 2021 RFP, costs of PGE's Clearwater Wind project are included from 2024. Costs of the remainder of the 2021 RFP start in 2025 and are estimated through proxy solar and battery resources. PGE assumes 100 percent PPA for these resources.
  - 2023 IRP – The magnitude and timing of resources is sourced from ROSE-E (**Section H.4, ROSE-E**), while cost streams for both ownership and power purchase agreement (PPA) assumptions are sourced primarily from LUCAS.

- **Variable costs** in ART include the cost of running thermal units which primarily include fuel costs and the cost of charging batteries. Both of these costs come from the Aurora PGE zone model (PZM).
- **Other costs** include purchases PGE makes from the spot market for both specified and unspecified sources. These are calculated within the intermediary GHG model (**Section H.2, Intermediary GHG model**).
- **Market benefits** represent the benefits from wholesale sales which are calculated in part within the intermediary GHG model and through the load resource balance output from ROSE-E. These benefits are calculated yearly using yearly average prices.
- **Forecasted load** represents the load in MWh net of load reducing DERs including energy efficiency and rooftop solar.

The limitations of and assumptions used in ART are as follows:

- ART only include generation related costs and does not include costs from the rest of the company such as grid modernization, administration & general (A&G), wildfire mitigation, or PGE transmission & distribution costs. Additionally, generation costs include both actuals and proxy costs. Proxy costs and associated operating characteristics may not be reflective of costs or project capabilities seen in future RFPs. Thus, ART does not reflect actual or expected customer prices and applying percentages to these changes will not represent actual customer price changes over time. Instead, ART provides directional impact of resource actions and another dimension when comparing portfolios.
- All costs are noted in nominal terms
- Yearly prices are highly sensitive to assumptions of generic resources costs
- Results are specific for the Reference Case scenario (reference need, reference prices, reference cost future)
- Assumes Colstrip exit in 2029
- Assumes the following Reference Case conditions:
  - Ownership – 50 percent PPA and 50 percent PGE ownership of all new resources and 100 percent PPA for the remaining 2021 RFP proxy resources. This impact affects tax credit allocations and payment schedule.
  - Energy efficiency and demand response costs are not securitized or financed, and impact customer prices in year one.
  - All tax incentives are monetized.

H.7 BPA transmission in ROSE-E

Through engagement with stakeholders, it was determined that PGE would incorporate transmission-related assumptions and modeling in this 2023 IRP. Availability of capacity on BPA's transmission system was included as a resource build constraint in ROSE-E. The amount capacity available on BPA's system was quantified through a review of BPA's published TSR Study and Expansion Process reports (TSEPs) from 2016-2021.[476] BPA has stated that TSRs made starting in 2022 will only be granted service once upgrades are complete.[477] Transmission capacity on BPA's system that is subject to upgrades is not included in the calculated available inventories.

TSRs (Transmission Study Requests) made prior to the 2022 TSEP that point to PGE's system were used to quantity the availability of BPA transmission to access PGE's system, according to the following criteria:

- Requested transmission service associated with TSRs in 'study' status are categorized as available conditional firm (CF) transmission.
- Requested transmission service associated with TSRs in 'confirmed' status are categorized as available long-term firm (LTF) transmission.

This inventory is used in ROSE-E as a constraint on the quantity of resource that can be built in different resource zones, as described in **Section H.4.2, Constraints**. Available inventory by zone used in ROSE-E is shown in **Table 129**, and the resource zone of each proxy resource is shown in **Table 130**.

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[476] Available at: https://www.bpa.gov/energy-and-services/transmission/acquiring-transmission/tsep
[477] With the exception of 80 MW of transmission capacity for offshore wind BPA identified in the 2022 TSEP as available without upgrades, which is included in ROSE-E transmission inventories (**Table 129**).

Table 129. Transmission ATC by Resource Zone

Resource Zone	LTF	CF	Total
Christmas Valley	490	510	1000
Gorge	190	388	578
McMinnville	10	0	10
Montana	0	0	0
Offshore	0	80	80
SE Washington	0	150	150
Total	690	1128	1818

Table 130. Transmission Zones of Proxy Resources

Transmission Zone	Proxy Resource
Christmas Valley	Solar_CV
Christmas Valley	CV_Hyb_1
Christmas Valley	CV_Hyb_2
Gorge	Wind_Gorge
Gorge	Solar_Wasc
McMinnville	Solar_Mcm
McMinnville	MCMN_Hyb_1
McMinnville	MCMN_Hyb_2
Montana	Wind_MT
Offshore	Wind_Off
SE Washington	Wind_SEWA