KEY ANALYTICAL ASSUMPTIONS

CHAPTER FIVE

2023 Electric Progress Report

Contents

1. Introduction

This chapter describes the forecasts, estimates, and assumptions Puget Sound Energy developed for the 2023 Electric Progress Report (2023 Electric Report). These assumptions span the horizon from 2024-2045 for the 2023 Electric Report. Additional details of the analyses are in Chapter Eight: Electric Analysis and in the related appendices.

This section on electric analysis includes the assumptions we used to create different economic conditions and operational considerations that affect portfolio costs and risks. Inputs included the electric demand forecast, price assumptions for natural gas and CO_2 costs, assumptions about cost and characteristics for existing and generic resources, and transmission considerations. We also included delivery system planning assumptions.

Next, we described electric portfolio sensitivities. Sensitivities start with the optimized, least-cost reference portfolio and change resource assumptions, environmental regulations, or other conditions to examine the effect of each change on the portfolio. We used these sensitivities to help build the preferred portfolio.

Last, we described our considerations for modeling electric supply-side resources as power purchase agreements or ownership agreements in the technology model section.

2. Electric Portfolio Analysis Assumptions

We analyzed a single reference case scenario for this 2023 Electric Report. A single scenario contrasts with a full Integrated Resource Plan (IRP), where multiple scenarios are typically analyzed to test how different economic conditions impact the portfolio optimization results. Instead of numerous scenarios, we used stochastic analysis for this 2023 Electric Report to measure the robustness of the preferred portfolio across a range of economic conditions.

The following section features the primary assumptions for the reference scenario.

2.1. Embed Equity with the Portfolio Benefit Analysis Tool

AURORA, the production cost model software we used for portfolio modeling in this report, is designed to find the lowest-cost portfolio given a set of constraints. Therefore, one of the best ways to influence the results of the AURORA portfolio model is to alter the cost of resources. For example, we incorporated the SCGHG in the AURORA portfolio model as an externality cost, which increases the cost of emitting resources, discouraging the model from including emitting resources in the final portfolio selection. Unfortunately, equity metrics do not have a specified dollar value, like the SCGHG, that we can incorporate into the portfolio model.

We needed another method to embed equity into the portfolio analysis and the 2023 Electric Report, so we created the portfolio benefit analysis tool. This new tool provides a measure of equity-related metrics outside the AURORA model that we can use to inform the portfolio development iteratively.

The portfolio benefit analysis tool is a spreadsheet-based model that relates the relative value added from improving Customer Benefit Indicators (CBIs) with the cost of a given portfolio. The portfolio benefit analysis tool builds on the approach we used in the 2021 IRP to incorporate equity. The tool allowed us to add interested party input to inform our process for the 2023 Electric Report. We anticipate we will continue improving how we incorporate CBIs in portfolio modeling. We describe the methodology we deployed in the portfolio benefit analysis tool in Appendix H: Electric Analysis and Portfolio Model, the portfolio benefit analysis tool Excel workbook that contains the data and the numerical analysis results in Appendix I: Electric Analysis Inputs and Results, and a discussion of the results in Chapter Eight: Electric Analysis.

2.2. Puget Sound Energy Customer Demand

The 2023 Electric Report demand forecast used in the analysis represents an estimate of energy sales, customer counts, and peak demand over 22 years.[1] Significant inputs include the following:

- Demographic changes
- Impacts of climate change
- Information about regional and national economic growth
- Known large load additions or deletions
- Prices
- Seasonality and other customer usage and behavior factors
- Weather

Figure 5.1 shows the electric peak demand and annual energy demand forecasts without the effects of conservation. The forecasts include sales (delivered load) plus system losses, which we represented in average energy demand over the year. The electric peak demand forecast is for a one-hour low temperature in winter at Sea-Tac airport, which we represented in total demand need at peak.

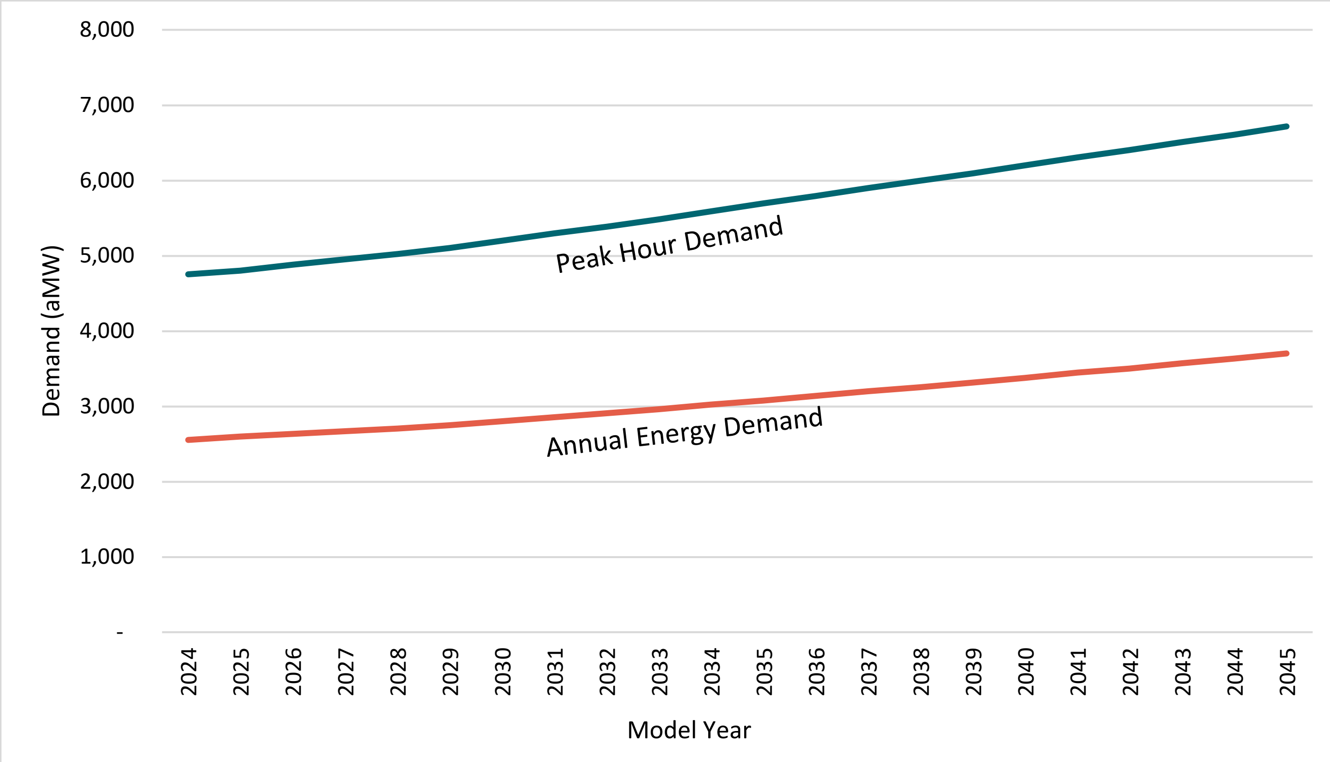
Why don't demand forecasts in rate cases and acquisition discussions match the IRP forecast?

The IRP analysis takes 12 to 18 months to complete. Demand forecasts are so central to the analysis that they are one of the first inputs we develop. By the time the IRP is completed, we may have updated our demand forecast. The range of possibilities in the IRP forecast is sufficient for long-term planning purposes, but we will always present the most current forecast for rate cases or when making acquisition decisions.

➔ See Chapter Six: Demand Forecasts, for a detailed discussion of the demand forecasts and Appendix F: Demand Forecasting Models, for the analytical models used to develop them.

[1] For long-range planning, customer demand is expressed as if it were evenly distributed throughout PSE's service territory, but, demand grows faster in some parts of the service territory than others.

Figure 5.1: 2023 Progress Report Electric Annual Energy and Peak Hour Demand Forecasts



2.3. Natural Gas Price Inputs

For natural gas price assumptions in this 2023 Electric Report, we used a combination of forward-market prices and fundamental forecasts acquired in spring 2022 from Wood Mackenzie.[2]

- Beyond 2030, we used the Wood Mackenzie long-run natural gas price forecasts published in May 2022.
- For 2029 and 2030, we used a combination of forward market prices from 2028 and selected Wood Mackenzie prices from 2031 to minimize abrupt shifts when transitioning from one dataset to another.
- From 2022–2028, we used the three-month average of forward-market prices from May 12, 2022. Forward market prices reflect the price of natural gas purchased at a given time for future delivery.
- In 2029, the monthly price is the sum of two-thirds of the forward market price for that month in 2028 plus one-third of the 2031 Wood Mackenzie price forecast for that month.
- In 2030, the monthly price is the sum of one-third of the forward market price for that month in 2028 plus two-thirds of the 2031 Wood Mackenzie price forecast for that month.

We used three natural gas price forecasts, mid, low, and high, to develop a range of gas prices for the stochastic analysis. However, we used only the mid natural gas prices in the reference scenario for this 2023 Electric Report.

2 Wood Mackenzie is a well-known macroeconomic and energy forecasting consultancy whose gas market analysis includes regional, North American, international factors, Canadian markets, and liquefied natural gas exports. Under our agreement with Wood Mackenzie seasonal and annual natural gas price trends are confidential and cannot be shared as part of this report.

2.3.1. Mid Natural Gas Prices

The mid natural gas price forecast uses the three-month average of forward market prices from May 12, 2022, and the Wood Mackenzie fundamentals-based long-run natural gas price forecast published in May 2022. We used the mid natural gas price forecast in the reference case for this 2023 Electric Report.

2.3.2. Low Natural Gas Prices

We developed the low natural gas price forecast using monthly adjustment factors applied to the mid natural gas price forecast. We obtained adjustment factors from the ratio of the low and mid natural gas price forecasts provided in the Northwest Power and Conservation Council's 2021 Power Plan. We used the low natural gas price forecast to develop the stochastic inputs for this 2023 Electric Report.

2.3.3. High Natural Gas Prices

We developed the high natural gas price forecast using monthly adjustment factors applied to the mid natural gas price forecast. We obtained adjustment factors from the ratio of the high and mid natural gas price forecasts provided in the Northwest Power and Conservation Council's 2021 Power Plan. We used the high natural gas price forecast to develop the stochastic inputs for this 2023 Electric Report.

Figure 5.2 illustrates the range of 22-year levelized natural gas prices used in this analysis compared to the 22-year levelized natural gas prices PSE used in the 2021 IRP.

Figure 5.2: Levelized Natural Gas Prices Used in Scenarios, 2023 Progress Report vs. 2021 IRP
(Sumas Hub, 22-year Levelized, Nominal $)

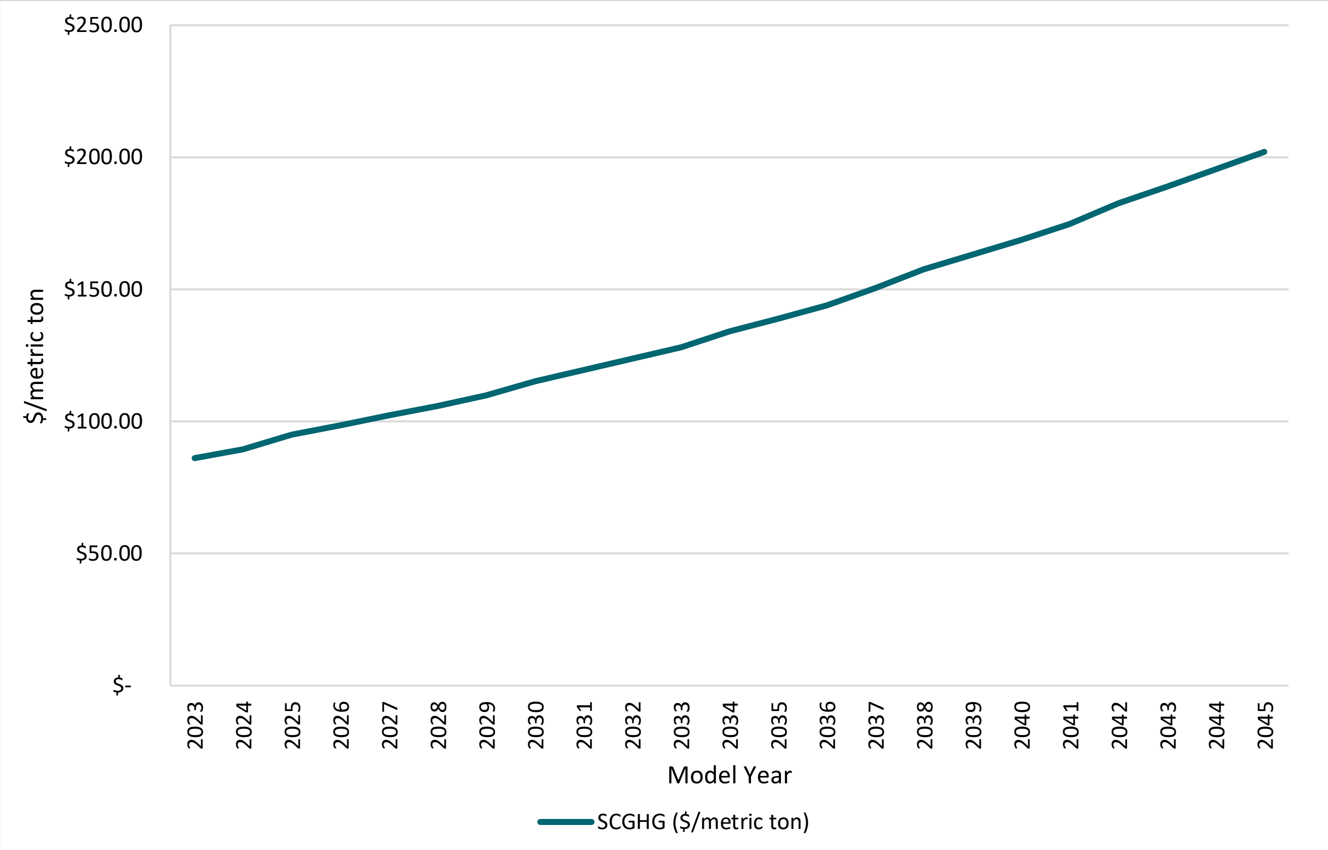
2.4. Carbon Dioxide Price Inputs

We modeled the Social Cost of Greenhouse Gases (SCGHG) and an allowance price for the Climate Commitment Act (CCA) in the 2023 Electric Report. In the following sections, we provide each price's forecasts and applications.

2.4.1. Social Cost of Greenhouse Gases

The SCGHG cited in the Clean Energy Transformation Act (CETA) comes from the Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document, August 2016 update. It projects a 2.5 percent discount rate, starting with $62 per metric ton (in 2007 dollars) in 2020. The document lists the CO_2 prices in real dollars and metric tons. We adjusted the prices for inflation (nominal dollars) resulting in a cost range from $86 per ton in 2023 to $202 per ton in 2045, as shown in Figure 5.3.

Figure 5.3: Social Cost of Greenhouse Gases in the 2023 Progress Report



We applied the SCGHG as a planning adder on emitting resources, so the SCGHG is applied when we optimize build decisions for new resources and retirement decisions for existing emitting resources. The reference case models the SCGHG as a fixed cost adder, which does not impact the dispatch schedule of emitting resources. However, we include a sensitivity that models the SCGHG as dispatch cost.

➔ See Appendix H: Electric Analysis and Portfolio Model for the complete discussion of how we modeled the SCGHG.

2.4.2. Upstream Carbon Dioxide Emissions for Natural Gas

The upstream emission rate represents the carbon dioxide, methane, and nitrous oxide releases associated with natural gas extraction, processing, and transport along the supply chain. We converted these gases to carbon dioxide equivalents (CO_2e) using the Intergovernmental Panel on Climate Change Fourth Assessment (AR4) 100-year global warming potentials (GWP) protocols.[3]

[3] The Environmental Protection Agency and the Washington Department of Ecology direct reporting entities to use the AR4 100-year GWPs in their annual compliance reports, as specified in Table A-1 at 40 CFR 98 and WAC 173-441-040.

For the cost of upstream CO_2 emissions, we used emission rates published by the Puget Sound Clean Air Agency[4] (PSCAA). The PSCAA used two models to determine these rates, GHGenius[5] and GREET.[6] Emission rates developed in the GHGenius model apply to natural gas produced and delivered from British Columbia and Alberta, Canada. The GREET model uses U.S.-based emission attributes and applies to natural gas produced and delivered from the Rockies basin. Table 5.1 provides the results of the GHGenius and GREET models.

Table 5.1: Upstream Natural Gas Emissions Rates

Model	Upstream Segment	End-Use Segment (Combustion)	Emission Rate Total	Upstream Segment CO2e (%)
GHGenius	10,803 g/MMBtu	+ 54,400 g/MMBtu	= 65,203 g/MMBtu	19.9
GREET	12,121 g/MMBtu	+ 54,400 g/MMBtu	= 66,521 g/MMBtu	22.3

Note: End-use Combustion Emission Factor: EPA Subpart NN.

The upstream segment of 10,803 g/MMBtu is converted to 23 lb/MMBtu and then applied to the emission rate of natural gas plants for the SCGHG emissions. We did not apply the upstream emission rate to the CCA allowance price.

2.4.3. Climate Commitment Act Allowance Price

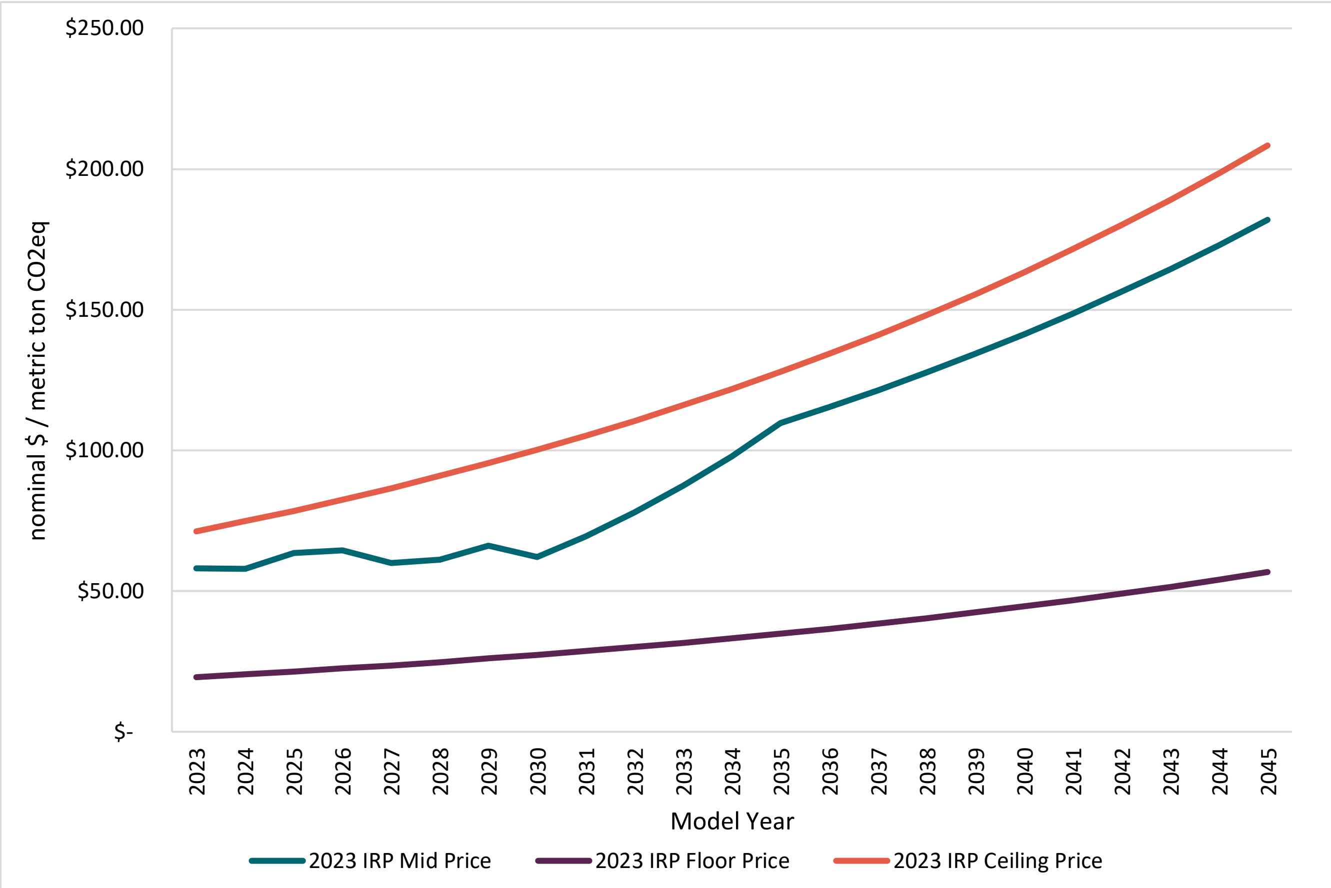
The Washington State legislature passed the CCA in 2021; it goes into effect in 2023. The CCA is a cap-and-invest bill that places a declining limit on the quantity of greenhouse gas emissions generated within Washington State and establishes a marketplace to trade allowances representing permitted emissions. The resulting market establishes an opportunity cost for emitting greenhouse gases. We added an emission price to greenhouse gas emissions in the electric price forecast model for emitting resources within Washington State to model this opportunity cost. In the price forecast model, we only added the emission price to Washington State emitting resources to ensure the model reflects any change in dispatch without impacting that of resources outside Washington State not subject to the rule. To accurately reflect all costs imposed by the CCA, we added a hurdle rate on transmission market purchases to the PSE portfolio model to account for unspecified market purchases using the CCA price forecast at the unspecified market emission rate 0.437 metric tons of CO_2eq per MWh (RCW 19.405.070).[7]

Figure 5.4 shows the emission prices we used to model the CCA allowance price, an ensemble of two price forecasts from the Washington Department of Ecology (Ecology) and the California Energy Commission (CEC). Ecology issued an analysis of the CCA, which included estimated allowance price forecasts across a range of program and market assumptions.[8] We suggest a linkage to the California carbon market is a likely scenario; therefore, we adopted an ensemble pricing scheme that begins with pricing at the rate specified by the Ecology CA Linkage 2030 case, then

4 Proposed Tacoma Liquefied Natural Gas Project, Final Supplemental Environmental Impact Statement, Ecology and Environment, Inc., March 29, 2019.
5 GHGenius. (2016). GHGenius Model v4.03. Retrieved from http://www.ghgenius.ca.
6 GREET. (2018). Greenhouse gases, Regulated Emissions and Energy use in Transportation; Argonne National Laboratory.
7 RCW 19.405.070
8 Preliminary Regulatory Analyses for Chapter 173-446 WAC, Climate Commitment Act Program

transitions to the CEC 2021 Integrated Energy Policy Report[9] allowance price forecast for the remainder of the modeling horizon.

Figure 5.4: Climate Commitment Act Allowance Pricing in the 2023 Progress Report



2.5. Climate Change

This 2023 Electric Progress Report is the first time Puget Sound Energy has included the influence of climate change on demand and hydroelectric conditions in the Pacific Northwest (PNW) in an electric progress report. We adapted inputs incorporating climate change from the NPCC's 2021 Power Plan analysis. As the basis for their analysis, the NPCC evaluated 19 climate change scenarios developed by the River Management Joint Operating Committee (RMJOC)[10], Part II, and selected three scenarios representing a range of possible climate outcomes. Puget Sound Energy adopted these same three climate change scenarios:

- CanESM2_RCP85_BCD_VIC_P1, coded as A.
- CCSM4_RCP85_BCD_VIP_P, coded as C.
- CNRM-CM5_RCP85_MACA_VIC_P3, coded as G.

[9] 2021 Integrated Energy Policy Report (ca.gov)
[10] https://usace.contentdm.oclc.org/digital/collection/p266001coll1/id/9936

The three climate change scenarios we adopted uniquely impact the PNW load and hydroelectric input assumptions. Incorporating these disparate impacts into a single deterministic forecast presented significant modeling challenges. Therefore, the 2023 Electric Progress Report analysis averaged the effects of each climate change scenario to develop a single climate change case, which retains trends in all three climate change scenarios.

➔ For more information on assumptions for incorporating climate change, see Chapter Six: Demand Forecast.

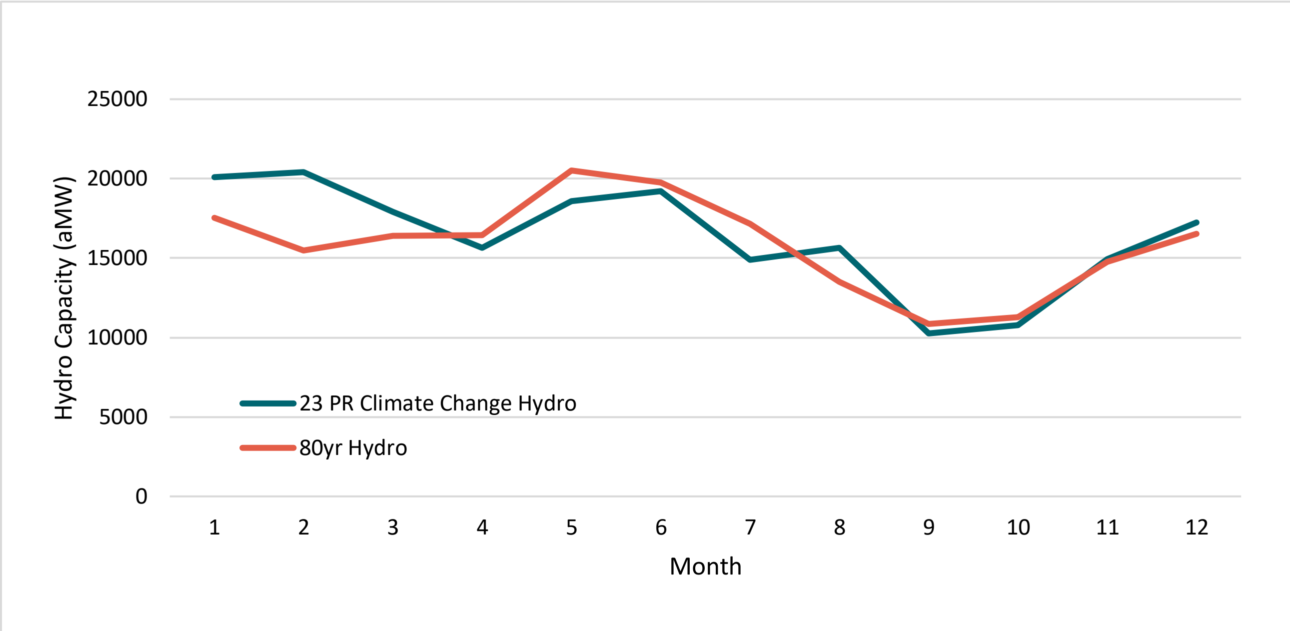
2.5.1. Hydroelectric Assumptions

We adapted the climate change hydroelectric forecast from the regional demand forecast created by the NPCC for the 2021 Power Plan. The hydroelectric forecast represents an average of all three climate change scenarios and an average of the hydroelectric conditions for the 30-year timespan of the climate change scenarios. We calculated hydroelectric capacity based on expected hydroelectric output from the GENESYS[11] regional resource adequacy model using streamflow data representative of the climate change scenarios.

We held the average hydroelectric forecast fixed for all the modeled years. Figure 5.5 presents the climate change hydroelectric forecast compared to the 80-year historic hydroelectric average forecast we used in the 2021 IRP. The forecasts are similar, but the climate change forecast trends toward more hydroelectric generation in the winter and less generation for the remainder of the year. This plot represents the PNW average hydroelectric capacity; trends for individual hydroelectric facilities will vary.

[11] https://www.nwcouncil.org/2021powerplan_genesys-model/

Figure 5.5: Pacific Northwest Climate Change Hydroelectric Forecast, Average of All Hydroelectric Facilities



2.6. Electric Price Inputs

We must create a wholesale electric price forecast as an input to the portfolio model to represent the wholesale power market. In this context, electric price does not mean the rate charged to customers; it means the price to PSE of purchasing (or selling) one megawatt (MW) of power on the wholesale market, given the prevailing economic conditions. This wholesale electric price forecast is an essential input since market purchases make up a substantial portion of PSE's existing electric resource portfolio.

Creating a wholesale electric price forecast requires performing WECC-wide AURORA model runs. The AURORA database starts with inputs and assumptions from the Energy Exemplar 2020 WECC Zonal database v1.0.1. We then include updates such as regional demand, natural gas prices, CO_2 prices, clean energy policies, and resource retirements and builds.

Figure 5.6 presents the annual average electric price forecast used in the 2023 Progress Report.

➔ See Appendix G: Electric Price Models for a detailed description of the methodology used to develop wholesale electric prices

Figure 5.6: Mid-C Wholesale Electric Price Annual Average Price Forecast Over Time (Nominal $/MWh)

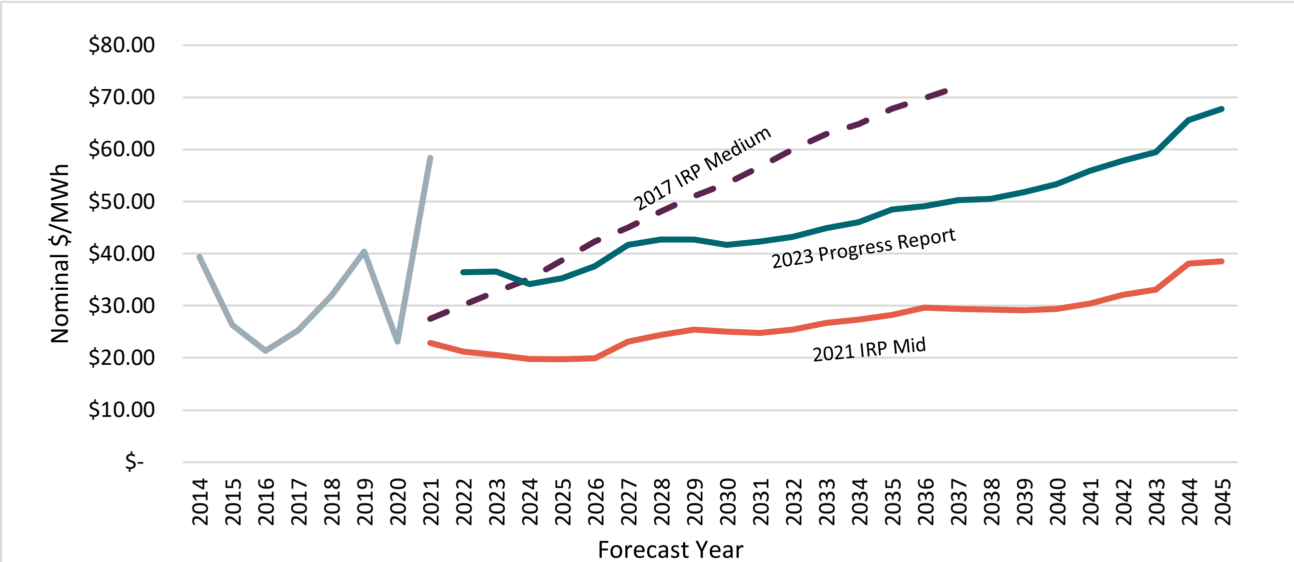
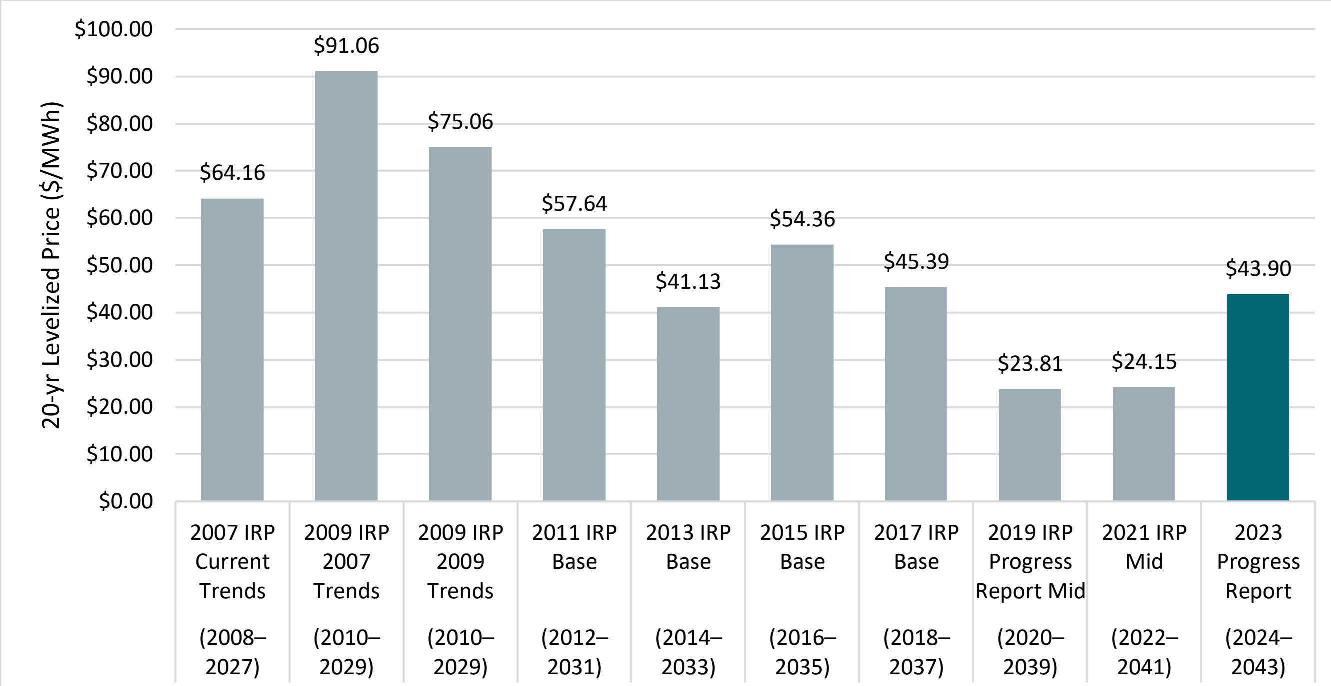


Figure 5.7 compares the 2023 electric price forecast to past IRP electric price forecasts. In previous IRPs, the downward revisions in forecast power prices corresponded to those in natural gas prices. In the 2021 IRP, the large increase in renewable resources in the region required by new clean energy regulations drives much of the downward revision in forecasted power prices. The 2017 IRP base scenario included CO_2 as a tax, whereas the 2021 IRP includes the social cost of greenhouse gases as an adder to resource decisions. The increase in electric prices in the 2023 Electric Progress Report is from several significant model updates, including increased natural gas prices, increased storage resources, revised methodology on clean energy policy modeling, and the addition of carbon allowance pricing from the CCA.

➔ Please find more details on the impacts of these updates in Appendix G: Electric Price Models.

Figure 5.7: Comparison of 2023 20-year Levelized Electric Prices Compared to Past IRPs ($/MWh)



2.7. Electric Resource Assumptions

We modeled the following generic resources as potential portfolio additions in this IRP analysis.

➔ See Appendix D: Generic Resource Alternatives, for detailed descriptions of the supply-side resources listed here and Appendix E: Conservation Potential Assessment and Demand Response Assessment, for detailed information on demand-side resource potentials.

2.7.1. Demand-side Resources

Demand-side resources contribute to meeting energy-need by reducing demand. An integrated resource plan includes both supply- and demand-side resources. We accounted for the contribution that demand-side programs make to meeting resource needs as a reduction in demand for the IRP analysis. Demand-side resources include energy efficiency measures (also referred to as conservation), generation efficiency measures, and distribution efficiency measures.

Energy Efficiency Measures

Energy efficiency measures reduce the level of energy used to accomplish a given amount of work. We group the wide variety of energy efficiency measures available into three categories: retrofit programs that have shorter lives; lost opportunity measures that have longer lives, such as high-efficiency furnaces; and codes and standards that drive down energy consumption through government regulation. Codes and standards impact the demand forecast but have no direct cost to utilities. Energy efficiency also includes small-scale electric distributed generation, such as combined heat and power.

Generation Efficiency

Generation efficiency comes from improvements at PSE generating plants.

Distribution Efficiency

Distribution efficiency comes from voltage reduction and phase balancing. Voltage reduction is reducing the voltage on distribution circuits to reduce energy consumption. Phase balancing can reduce energy loss by eliminating total current flow losses.

2.7.2. Distributed Energy Resources

Distributed Energy Resources (DER) are small, modular energy generation and storage technologies installed on the distribution systems rather than the transmission system. Distributed Energy Resources are typically under 10 MW and provide a range of services to the power grid. These resources include wind, solar, storage, and demand response technologies and may be networked to form Virtual Power Plants (VPPs). We included demand response, distributed solar, and distributed storage programs as generic DERs in this 2023 Electric Report.

Demand Response

Demand response resources are like energy efficiency in that they reduce customer peak load, but unlike energy efficiency, they are also dispatchable. These programs involve customers curtailing load when needed. The terms and conditions of demand response programs vary widely.

Distributed Solar Generation

Distributed solar generation refers to small-scale rooftop or ground-mounted solar panels close to the customer's load source. We modeled distributed solar as a residential-scale resource in western Washington. We summarize the capacity factors for solar resources modeled in Table 5.2. Consulting firm DNV provided the solar production profile data used in the AURORA model.

Table 5.2: Distributed Solar Capacity Factors

Solar Resource	Configuration	Capacity Factor (annual average, %)
DER Ground Solar	Residential-scale, fixed-tilt, ground mounted	17
DER Rooftop Solar	Residential-scale, fixed-tilt, rooftop mounted	17

Distributed Battery Energy Storage

Distributed battery energy storage systems refer to small-scale lithium-ion battery installations close to the customer's load. We modeled distributed storage as a residential-scale, three-hour duration battery with a nameplate capacity of 5 MW.

Non-wires Alternatives

We consider non-wires alternatives when developing solutions to specific, long-term needs identified in the transmission and distribution systems. The resources we study benefit from the capacity to address system deficiencies while supporting resource needs. We can deploy them across the transmission and distribution systems, providing flexibility in addressing system deficiencies. The non-wires alternatives we considered during the planning process include energy storage systems and solar generation.

2.7.3. Supply-side Resources

Supply-side resources provide electricity to meet the load. These resources originate on the utility side of the meter and include wind, solar, pumped hydroelectric energy storage, battery energy storage, hybrid resources (combination of wind, solar, and battery), combustion turbines, and advanced nuclear small modular reactors (SMR). The following section describes the supply-side resources applied to this 2023 Electric Report.

Wind

We modeled wind in seven locations throughout the northwest United States, including eastern Washington, central Montana, eastern Montana, Idaho, eastern Wyoming, western Wyoming, and offshore Washington. A summary of capacity factors for each wind resource is in Table 5.3. Consulting firm DNV provided the wind production profile data used in the AURORA model.

Table 5.3: Wind Capacity Factors

Wind Resource	Capacity Factor (annual average, %)
British Columbia	40.9
Eastern Washington	37.2
Central Montana	41.3
Eastern Montana	47.7
Idaho	15.0
Eastern Wyoming	46.4
Western Wyoming	36.1
Offshore Washington	42.1

Solar

We modeled solar as a centralized, utility-scale resource at several locations throughout the northwest United States and as a distributed, residential-scale resource in western Washington. A summary of the capacity factors for utility scale solar resources modeled is in Table 5.4. Consulting firm DNV provided the solar production profile data used in the AURORA model.

Table 5.4: Solar Capacity Factors

Solar Resource	Configuration	Capacity Factor (annual average, %)
Idaho	Utility-scale, single-axis tracker	27.3
Eastern Washington	Utility-scale, single-axis tracker	25.0

Solar Resource	Configuration	Capacity Factor (annual average, %)
Western Washington	Utility-scale, single-axis tracker	20.2
Eastern Wyoming	Utility-scale, single-axis tracker	28.9
Western Wyoming	Utility-scale, single-axis tracker	30.0

Energy Storage

Energy storage encompasses a range of technologies capable of converting kinetic energy into stored potential energy for later use. Energy storage removes the need for electricity generation to match the energy demand instantaneously. As such, energy storage can help to mitigate some of the challenges associated with variable energy resources such as wind and solar. A wide variety of energy storage technologies exist and span a range of development conditions from theoretical to commercially available. We discuss the current status of several storage technologies in Appendix D: Generic Resource Alternatives. We modeled a subset of commercially mature and well-characterized storage technologies for this 2023 Electric Report, including two-hour, four-hour, and six-hour lithium-ion batteries and eight-hour pumped hydroelectric storage. Generic Resource Alternatives. We modeled a subset of commercially mature and well-characterized storage technologies for this 2023 Electric Report, including two-hour, four-hour, and six-hour lithium-ion batteries and eight-hour pumped hydroelectric storage.

Baseload and Peakers

Baseload generators are designed to operate economically and efficiently over long periods of time, defined as more than 60 percent of the hours in a year.

Peaker is a term used to describe generators that can ramp up and down quickly to meet spikes in need. Unlike baseload resources, they are not intended to operate economically for long periods of time.

Hybrid Resources

In addition to stand-alone generation and energy storage resources, we modeled hybrid resources, which combine two or more resources at the same location to take advantage of synergies between the resources. We modeled three types of hybrid resources: eastern Washington solar + four-hour lithium-ion battery, eastern Washington wind + four-hour lithium-ion battery, and eastern Washington wind + solar + four-hour lithium-ion battery.

Baseload Thermal Plants

Baseload thermal plants or combined-cycle combustion turbines (CCCT) are F-type, 1 x 1 engines with wet cooling towers. We assumed they would generate 348 MW plus 19 MW of duct firing and be in PSE's service territory. We designed and intended these resources to operate at base load, defined as running more than 60 percent of the hours in a year.

Frame Peakers

Frame peakers or simple-cycle combustion turbines (SCCT) are F-type, wet-cooled turbines. We assumed they would generate 237 MW and be in PSE's service territory. We modeled these resources with either natural gas or an alternative fuel as the fuel source.

Recip Peakers

Recip peakers, or reciprocating engines, are small 18.2 MW engines with wet cooling located in PSE's service territory. We modeled these resources with either natural gas or an alternative fuel as the fuel source.

Alternative Fuels

In addition to natural gas, this 2023 Electric Report includes low-carbon alternative fuels, including hydrogen and biodiesel. Given current incentives in the Inflation Reduction Act,[12] green hydrogen fuel may become cost-effective compared to natural gas after accounting for the social cost of greenhouse gases and the impacts of the CCA. Biodiesel may also provide a viable, low-carbon alternative fuel for capacity resources during peak critical hours.

➔ We provide a description and the modeling assumptions used for these alternative fuels in Appendix I: Electric Analysis Inputs and Results.

Advanced Nuclear Small Modular Reactor

We modeled advanced nuclear (SMR) for the first time in the 2023 Electric Report. An SMR is a cluster of relatively small nuclear reactors at the same site that share land and infrastructure, although each reactor may be operated independently. The reactor technology is similar to that used in nuclear-powered submarines. While the exact specifications for SMR systems can vary, we chose to model this resource with a configuration of up to a 50MW module for this 2023 Electric Progress Report.

➔ We provide a complete description of SMR technology in Appendix D: Generic Resource Alternatives.

2.8. Electric Resource Cost Assumptions

We sourced generic resource capital cost assumptions from the National Renewable Energy Laboratory (NREL) 2022 Annual Technology Baseline (ATB)[13] for most resources in the 2023 Electric Report, consistent with our Clean Energy Implementation Plan (CEIP). This method is different from the approach we took in the 2021 IRP, which used different generic resource cost assumptions. The NREL did not include reciprocating peaker technology in the 2022 ATB; therefore, we sourced capital cost data for this generic resource from the U.S Energy Information Administration's (EIA) Annual Energy Outlook (AEO) for 2022 (2022 AEO).

Interconnection costs are not included as part of the capital cost for generic resources in the 2022 ATB or 2022 AEO and can account for a significant portion of the capital cost of some resource types. We added interconnection cost

[12] https://www.congress.gov/bill/117th-congress/house-bill/5376/text
[13] https://atb.nrel.gov/electricity/2022/technologies

estimates to each resource type based on the spur line length needed to interconnect each generic resource to the transmission grid to account for this omission.

We expect generic resource capital costs to decline as technology advances push costs down. The declining cost curves applied to different resource alternatives come from the 2022 ATB. The 2022 ATB provides three cost curves for each resource: low, mid, and constant technology cost scenarios. We selected the mid-technology cost scenario for the IRP cost curves, representing the most likely future cost projection.

We sourced generic resource O&M costs from the 2022 ATB for all generic resource technologies except thermal technologies. We sourced generic CCCT and frame peaker fixed O&M from averaging our existing costs, as reported in the 2021 FERC Form 1s. We adopted the fixed O&M that were reported for the Port Westward 2 facility as the generic reciprocating peaker fixed O&M.[14] We adopted variable O&M from the CAISO Variable Operations and Maintenance Cost Review, Final Proposal.[15]

The 2022 ATB did not provide O&M costs for most hybrid configurations presented in the 2023 Electric Report. We combined the fixed O&M for each component within the hybrid system to calculate these costs and used the respective capacities to generate a weighted average. The 2022 ATB provided a fixed O&M cost associated with a solar plus four-hour li-ion battery storage hybrid system, which is higher than the weighted average. Though the literature indicated this O&M was based on stand-alone solar and battery fixed O&M, NREL did not present the precise method of combining these costs in the 2022 ATB. To maintain consistency with other hybrid systems in the 2023 Electric Report, we used a weighted average for the solar plus battery storage hybrid resource. We show all hybrid resource fixed O&M as a time series.

➔ See Appendix D: Generic Resource Alternatives, for a more detailed description of resource cost assumptions, including transmission and natural gas transport assumptions.

Table 5.5 summarizes generic resource cost assumptions.

Table 5.5: New Resource Generic Cost Assumptions

IRP Modeling Assumptions (2020 $)	Nameplate (MW)	First Year Available	Fixed O&M ($/kW-yr)	Variable O&M[1] ($/MWh)	CAPEX ($/kW)[2]	Intercon-nection[2,3]	Total[2]
CCCT	348	2024	22.67	6.16	963	22	987
Frame Peaker	237	2024	9.52	1.02	879[4]	26	944
Recip Peaker	219	2024	14.53	1.16	2019	26	2045
WA Utility Solar East & West	100	2024	19.35	0.00	1074	156	1230
Idaho Utility Solar	400	2026	19.35	0.00	1074	463	1537

14 https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/home
15 https://stakeholdercenter.caiso.com/StakeholderInitiatives/Variable-operations-maintenance-cost-review

IRP Modeling Assumptions (2020 $)	Nameplate (MW)	First Year Available	Fixed O&M ($/kW-yr)	Variable O&M[1] ($/MWh)	CAPEX ($/kW)[2]	Intercon-nection[2,3]	Total[2]
WY Utility Solar East & West	400	2026	19.35	0.00	1074	463	1537
DER Solar — Rooftop and Ground-mounted WA West	5	2024	25.48	0.00	2,287	0	2,287
Offshore Wind	100	2030	70.78	0.00	4,137	590	4,728
BC Wind	100	2024	41.79	0.00	1,308	422	1,730
WA Wind	100	2024	41.79	0.00	1,308	156	1,464
MT Wind	100	2024	41.79	0.00	1,308	1,164	2,472
ID Wind	400	2026	41.79	0.00	1,308	463	1,772
WY Wind	400	2026	41.79	0.00	1,308	463	1,772
Pumped Storage — WA, OR, Closed Loop, 8-hour	100	2029	17.82	0.51	3,404	506	3,910
Pumped Storage — MT Closed Loop 8-hour	100	2029	17.82	0.51	3,404	198	3,602
Battery 2-hour Li-Ion	100	2024	20.12	0.00	746	58	804
Battery 4-hour Li-Ion	100	2024	32.76	0.00	1,256	58	1,314
Battery 6-hour Li-Ion	100	2024	45.49	0.00	1,765	58	1,823
DER Batteries 3-hour	5	2024	98.06	0.00	3,923	0	3,923
Wind + Battery	150	2024	38.35	0.00	1,093	217	1,310
Solar + Battery WA	150	2024	23.39	0.00	976	170[5]	1,147
Wind + Solar + Battery WA	250	2024	30.69	0.00	932	257[5]	1,190
Biomass	15	2024	151.00	5.80	4,332	573[5]	4,906
Advanced Nuclear SMR	50	2028	114.00	2.84	10,918	13	10,930

Notes:

1. Variable O&M costs do not include the cost of fuel for thermal resources.
2. Capital Costs, Vintage 2023. CAPEX (capital expenditures) required to achieve commercial operations of a generation plant. CAPEX may vary by resource type.
3. Interconnection costs consist of the transmission, substation, and natural gas pipeline infrastructure. The interconnection cost of offshore wind only includes onshore interconnection, and we included marine cable costs in the capital cost of the resource.
4. Frame peaker CAPEX includes costs for on-site biodiesel storage
5. Wind + Battery and Solar + Battery resources received a 40 percent interconnection cost-benefit, and the Wind + Solar + Battery resource received a 55 percent interconnection cost-benefit.

➔ See Appendix D: Generic Resource Alternatives for cost curve charts broken out by renewable, energy storage, and thermal resource type. See Appendix D: Generic Resource Alternatives for cost curve charts broken out by renewable, energy storage, and thermal resource type.

2.9. Flexibility Considerations

The 2023 Electric Report flexibility study reflects the financial impacts of the sub-hourly flexibility analysis in the portfolio analysis. Different resources have different sub-hourly operational capabilities. Even if the portfolio has adequate flexibility, various resources can impact costs and how the portfolio operates. For example, batteries could avoid the dispatch of thermal plants form ramping up and down.

For the sub-hourly flexibility analysis, we used a model called PLEXOS. First, we created a current portfolio case based on PSE's existing resources. We started the current portfolio case by making a simulation that reflects a complete picture of PSE as a Balancing Authority (BA) and our connection to the market. We represented PSE's Balancing Authority Area (BAA) load and generation on a day-ahead and real-time, 15-minute basis. We also included opportunities to make purchases and sales at the Mid-C trading hub in hourly increments and the Energy Imbalance Market (EIM) in 15-minute increments. For this analysis, we simulated 2029 for both hour-ahead and real-time and then took the difference in total portfolio cost between the two simulations.

We tested the impact of a range of potential new resources, each individually added to the current portfolio. If the dispatch cost of the portfolio with the new addition is lower than the existing portfolio case cost, we identified the cost reduction as a benefit of adding the new resource.

Table 5.6 shows the cost savings associated with each resource. For example, a CCCT has a cost savings of $5.17/kW-year. We applied these cost savings back to the fixed O&M of the generic resource as a reduction to the cost.

Table 5.6: Sub-hourly System Flexibility Cost Savings

Resource	Flexibility Cost Savings ($/kW-yr)
CCCT	5.17
Frame Peaker	9.65
Recip Peaker	28.14
Lithium-ion battery 2-hour	7.43
Lithium-ion battery 4-hour	47.21
Lithium-ion battery 6-hour	8.58
Pumped Storage Hydroelectric 8-hour	2.82
Demand Response	19.39

➔ See Appendix H: Electric Analysis and Portfolio Model, for a detailed description of the methodology used to develop the flexibility benefit.

2.10. Regional Transmission Constraints

Transmission constraints are a set of limits imposed on the IRP portfolio model, which seeks to model real-world transmission limitations within the WECC. These constraints include capacity limitations, transmission losses, and transmission costs.

2.10.1. Transmission Capacity Constraints

Transmission capacity constraints have become a vital modeling consideration as we transition away from thermal resources and toward clean, renewable resources to meet the goals of CETA. In contrast to thermal resources such as CCCTs and frame peakers, which we can generally site in locations convenient to transmission, produce power at a controllable rate, and dispatch as needed to meet shifting demand, renewable resources are site-specific and produce power intermittently. The limiting factors of renewable resources have two significant impacts on the power system: 1) we must acquire a greater quantity of renewable resources to meet the same peak demand as thermal resources, and 2) the best renewable resources to meet PSE's loads may not be located near our service territory. A wind farm in one location will produce a different amount of power than the same wind farm in another place. This situation makes it essential to consider whether there is enough transmission capacity to carry power from remote renewable resources to our service territory.

2.10.2. Assumptions

To model transmission capacity constraints, we created eight resource group regions and set limits on the generation capacity built in each region. We based resource group regions on the geographic relationships of the generic resources modeled in the 2023 Electric Report. Table 5.7 summarizes the resource group regions and the generic resources available in each group.

Table 5.7: Resource Group Regions and Generic Resources Available in Each Region

Generic Resource	PSE Territory[1]	Eastern Washington	Central Washington	Western Washington	Southern Washington / Gorge	British Columbia	Montana	Idaho & Wyoming
CCCT	X							
Frame Peaker	X							
Recip Peaker	X							
WA Solar East — Utility Scale		X	X		X			
WA Solar West — Utility Scale	X							
Idaho Solar — Utility Scale								X
WY Solar East — Utility Scale								X
WY Solar West — Utility Scale								X
DER WA Solar — Rooftop	X							
DER WA Solar — Ground	X							
WA Wind		X	X		X			
BC Wind						X		
MT Wind East							X	
MT Wind Central							X	
ID Wind								X
WY Wind East								X
WY Wind West								X
Offshore Wind				X				
Pumped Storage		X	X		X			
Battery 2-hour Li-Ion	X							
Battery 4-hour Li-Ion	X							
Battery 6-hour Li-Ion	X							
Solar + battery		X			X			
Wind + battery		X			X			
Solar + wind + battery		X			X			
Wind + pumped storage							X	
Biomass	X			X				
Advanced Nuclear SMR		X						

Note:

1. Not including the PSE IP Line (cross Cascades) or Kittitas area transmission, which is fully subscribed

We based capacity limits on our experience with available transmission capability (ATC) on the Bonneville Power Administration's (BPA) system, the results of BPA transmission service requests (TSRs), recent BPA TSR Study and Expansion Process (TSEP) Cluster Studies (2020, 2021, & 2022), regional transmission studies by Northern Grid, and dialogue with regional power sector organizations. Transmission planning, building, and acquisition are complex processes with various possible outcomes; therefore, we developed a range of plausible transmission limits and timelines for each region. To structure these ranges, we organized the transmission limits into tiers; uncertainty increases from tier to tier based on our ability to acquire that quantity of transmission.

The tiers include:

- **Tier 1:** Transmission capacity that we could likely acquire in 2023–2025. This transmission capacity draws primarily from repurposing our existing BPA transmission portfolio.
- **Tier 2:** Transmission capacity that we could acquire in 2025–2030 but is less certain than Tier 1. This transmission capacity adds new transmission resources to our portfolio. Tier 2 includes all Tier 1 transmission.
- **Tier 3:** Transmission capacity that we could acquire beyond 2030. Acquisition of Tier 3 transmission is less certain than Tiers 1 and 2. Capacity added in Tier 3 would likely come from adding long lead-time, major transmission system upgrades, or new transmission resources to PSE's portfolio. Tier 3 includes all Tier 1 and 2 transmission.
- **Tier 4:** Tier 4 represents a generally unconstrained transmission system.

In this report's reference case, we modeled transmission limits by tier with increasing transmission limits over time. By 2040, transmission will be unconstrained. In the context of this report, unconstrained transmission signifies there is enough time to acquire or build new transmission resources to match the resource mix provided by the model.

Table 5.8 summarizes the transmission limits by tier for each resource group region.

Table 5.8: Transmission Capacity Limitations by Resource Group Region (Added Transmission MW by Tier)

Resource Group Region	Tier 1 (by 2025)	Tier 2 (by 2030)	Tier 3 (by 2035)	Tier 4 (by 2040)
PSE territory (a)	(b)	(b)	(b)	(b)
Eastern Washington	640	2,310	2,510	Unconstrained
Central Washington	250	600	850	Unconstrained
Western Washington	0	100	635	Unconstrained
Southern Washington/Gorge	340	2,010	2,390	Unconstrained
British Columbia	200(c)	200(c)	200(c)	Unconstrained
Montana	0	400(c)	400(c)	Unconstrained
Idaho and Wyoming	0	400	600	Unconstrained
TOTAL	1,430	6,020	7,585	Unconstrained

Notes:

a. Not including the PSE IP Line (cross Cascades) or Kittitas area transmission, which is fully subscribed.
b. Not constrained in the resource model, assumes adequate PSE transmission capacity to serve future load.
c. Indicates we rounded transmission constraints to align with generic resource capacity ranges.

The rationale for each transmission capacity limitation by resource group region follows.

Eastern Washington

Through BPA Cluster Study requests, we may obtain 150, 600, or 650 MW for transmission to the Lower Snake River region for Tiers 1, 2, and 3, respectively. By co-locating a 150 MW solar resource at an existing wind facility, we could add 150 MW of Tier 1 transmission. We may acquire an additional 340 or 1,230 MW for Tiers 1 and 2, respectively, of third-party BPA transmission from developer submittals and resource retirements.

Central Washington

We may obtain 250, 500, or 750 MW of transmission for Tiers 1, 2, and 3, respectively, using a portion of the existing 1,500 MW of Mid-C transmission we currently use for market purchases for dual purposes. An additional 100 MW of transmission may be available in Tier 1 to deliver Kittitas area solar via the Grant County PUD system.

Western Washington

We assume no additional transmission is available in Tier 1. Tier 2 may add 100 MW of BPA transmission after the TransAlta purchased power agreement (PPA) expires in 2025. Tier 3 may add 335 MW of dual-purpose transmission to prioritize renewable generation from the Mint Farm CCCT region. Tier 3 may add 200 MW of third-party transmission rights from developer submittals, resource retirements, or offshore wind development.

Southern Washington / Gorge

We may obtain 340 or 1,230 MW for Tiers 1 and 2, respectively, of third-party BPA transmission rights from developer submittals or resource retirements. Tiers 2 and 3 may also add 330 MW of dual-purpose transmission (Tier 2 100 MW, Tier 3 230 MW) to prioritize renewable generation co-located with the Goldendale CCCT.

British Columbia

We may obtain up to 160 MW of long-term transmission from BC Hydro by 2025. Any additional transmission between PSE and British Columbia would require a transmission study and likely system upgrades.

Montana

We may obtain 370 MW for Tier 2 of transmission from repurposing transmission freed up by removing Colstrip Units 3 & 4 from the PSE portfolio.

Wyoming / Idaho

Puget Sound Energy may pursue transmission capacity on the Boardman-to-Hemingway (B2H) and Gateway West projects, adding 400 or 600 MW of transmission for Tiers 2 and 3, respectively.

Puget Sound Energy Territory

For the 2023 Electric Report, we assumed that the PSE system in western Washington is unconstrained. This assumption does not include PSE IP Line (cross Cascades) or Kittitas area transmission, which is fully subscribed. This assumption holds because of a robust delivery system planning approach and the resulting long-range delivery system infrastructure plan, including transmission and distribution system upgrades.

2.10.3. Transmission Loss Constraints

Transmission loss constraints model energy lost to heat as power flows through the transmission line. Many factors, including distance, line material, and voltage, impact the magnitude of transmission line losses. The BPA assumes a flat 1.9 percent line loss across its transmission network. A line loss study conducted between PSE and the Colstrip substation found the line loss to be approximately 4.6 percent. Lacking a similar study for transmission to Wyoming and Idaho, we assumed a similar loss given the similar distance. Table 5.9 summarizes the transmission line losses assumed by the resource group region.

Table 5.9: Average Transmission Line Losses by Resource Group Region

Resource Group Region	Line Loss (%)
Eastern Washington	1.9
Central Washington	1.9
Western Washington	1.9
Southern Washington/Gorge	1.9
British Columbia	1.9
Montana	4.6
Idaho and Wyoming	4.6

2.10.4. Transmission Cost Constraints

Transmission cost is another factor used in the PSE portfolio model to constrain resource-build decisions. Transmission costs include a fixed component measured in dollars per kilowatt per year ($/kW-year) and a variable component measured in dollars per megawatt-hour ($/MWh). Fixed transmission costs include wheeling tariffs and balancing service tariffs, among others. Wheeling tariffs will vary by region depending on the number of wheels required to return power to our service territory. Balancing service tariffs vary by resource type; wind balancing service tariffs are usually more expensive than solar balancing serving tariffs, given the greater inter-hour variability of wind resources. Variable transmission costs are primarily composed of spinning and supply reserve requirement tariffs and may include other penalties or imbalance tariffs. Table 5.10 summarizes fixed and variable transmission costs by generic resource type.

We based the wheeling tariffs from Idaho and Wyoming on tariff service over Gateway West, Boardman to Hemingway, and the BPA main grid. For transmission cost modeling, we assumed the cost of three wheels (PacifiCorp, Idaho Power, and BPA) with a reduction to two wheels (PacifiCorp and BPA) after the Gateway West segments are fully completed (estimated 2030 according to PacifiCorp IRP).

Table 5.10: Transmission Costs by Generic Resource Type (in 2020 $)

Generic Resource	Fixed Transmission Cost ($/kW-year)	Variable Transmission Cost ($/MWh)
CCCT	0.00[a]	0.00
Frame Peaker	0.00[a]	0.00
Recip Peaker	0.00[a]	0.00
WA Solar East — Utility-scale	27.80	0.26
WA Solar West — Utility-scale	5.24	0.26
Idaho Solar — Utility-scale	57.66	0.26
WY Solar East — Utility-scale	101.12[b]	0.26
WY Solar West — Utility-scale	101.12[b]	0.26
DER WA Solar — Rooftop	0.00[a]	0.26
DER WA Solar — Ground-mount	0.00[a]	0.26
WA Wind	31.21	0.26
BC Wind	61.69	0.26
MT Wind — East	59.10	0.26
MT Wind — Central	59.10	0.26
ID Wind	61.07	0.26
WY Wind East	97.31[b]	0.26
WY Wind West	97.31[b]	0.26
Offshore Wind	31.21	0.26
WA/OR Pumped Storage	22.58	0.26
MT Pumped Storage	50.47	0.26
Battery 2-hour Li-ion	0.00[a]	0.00
Battery 4-hour Li-ion	0.00[a]	0.00
Battery 6-hour Li-ion	0.00[a]	0.00
Solar + Battery	27.80	0.26
Wind + Battery	31.21	0.26
Solar + Wind + Battery	31.21	0.26
Wind + Pumped Storage	59.10	0.26
Biomass	22.58	0.26
Advanced Nuclear SMR	22.58	0.26

Notes:

a. Fixed transmission cost is not applied because we assumed the resource would be built within the PSE service territory.

b. Wyoming transmission cost reflects wheel through Idaho Power territory, reduction in cost modeled in 2030 when Gateway West transmission becomes available. See Appendix H: Electric Analysis and Portfolio Model for further details on modeled transmission cost.

2.11. Electric Delivery System Planning Assumptions

Puget Sound Energy uses a structured approach to developing infrastructure plans that support various customer needs, including effective DER integration. Our process and the associated planning assumptions are in Figure 5.8 and Table 5.11, respectively.

Figure 5.8: Delivery System Planning Operating Model

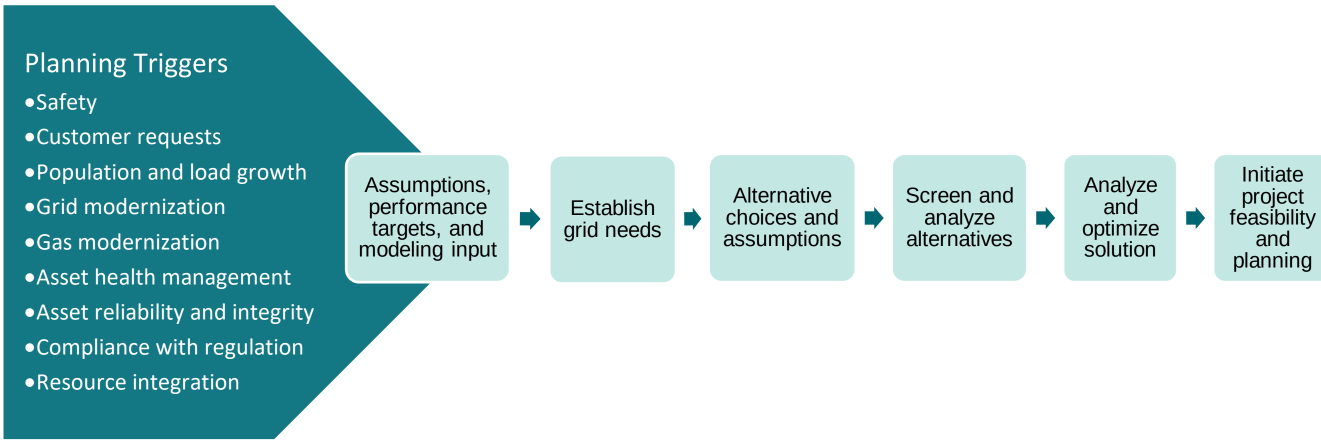


Table 5.11: Delivery System Planning Assumptions

Assumptions	Description
Demand and Peak Demand Growth	Uses county-level demand forecast applied based on historic load patterns of substations with known point loads adjusted for
Energy Efficiency	Highly optimistic 100% targets included (PSE benchmarking with peers in 2021)
Resource Interconnections	Interconnection requests with completed Large/Small Generator Interconnection Agreements included
Aging Infrastructure	Known concerns included in the analysis
Interruptible / Behavior-based Rates	Known opportunities to curtail during peak included
Distributed Energy Resources	Known controllable devices are included (most current solar and battery systems are not controllable to manage peak reliably to date)
System Configurations	As designed
Compliance and Safety Obligations	Meet all regulatory requirements, including NESC, NERC, and WECC, along with addressing voltage regulation, rapid voltage change, thermal limit violations, and protection limits

2.11.1. Delivery System Planning Non-wires Alternatives Forecast

We included a distributed energy resources forecast in the 2023 Electric Report that evaluates where we identified DERs as a potential non-wires solution for meeting delivery system needs. We then extrapolated the forecast based on load growth assumptions. As needs arrive on the planning horizon, further analysis relative to specific values and potential will test these assumptions.

The non-wires alternatives we considered during the delivery system planning (DSP) process include demand response, targeted energy efficiency, energy storage systems, and solar generation, among others. We considered these resources independently and as part of hybrid resource combinations with traditional infrastructure improvements to optimize the solution. Initial analyses suggest that cost-effective solutions align with needs primarily driven by capacity or resiliency. As we continue integrating DER into system solutions, we must answer critical questions about DER's operational flexibility and associated cyber-security considerations.

We used the following assumptions to develop a DER forecast to solve identified system needs over the 0-to-10-year time frame.

- Based on industry knowledge and consultant input for summer needs, we determined 3 to 4 MW was a reasonable size for utility-scale photovoltaic (PV).
- Due to the practical sizing of DER solutions, we did not consider projects with needs larger than 20 MW.
- We applied average historical percentages to determine energy efficiency, demand response, and energy storage potential.

We used the same assumptions for needs identified in the 10- to 20-year timeframe but extrapolated the value based on the load forecast (i.e., years with lower forecasted load growth would require fewer, smaller-scale projects to meet system needs versus years with larger forecasted load growth). We made additional considerations to account for the planning process. We assumed the needs we identified before 2023 would take two to three years to complete based on a new planning process and the learning curve associated with implementing new technologies. We assumed the needs identified after 2023 would be built when it first appeared on the system as the planning process matures and we gain experience siting DER. Figure 5.9 presents the forecast of DER resources added to the system as non-wires alternatives.

Figure 5.9: Forecasted DER Installation by Year and Type

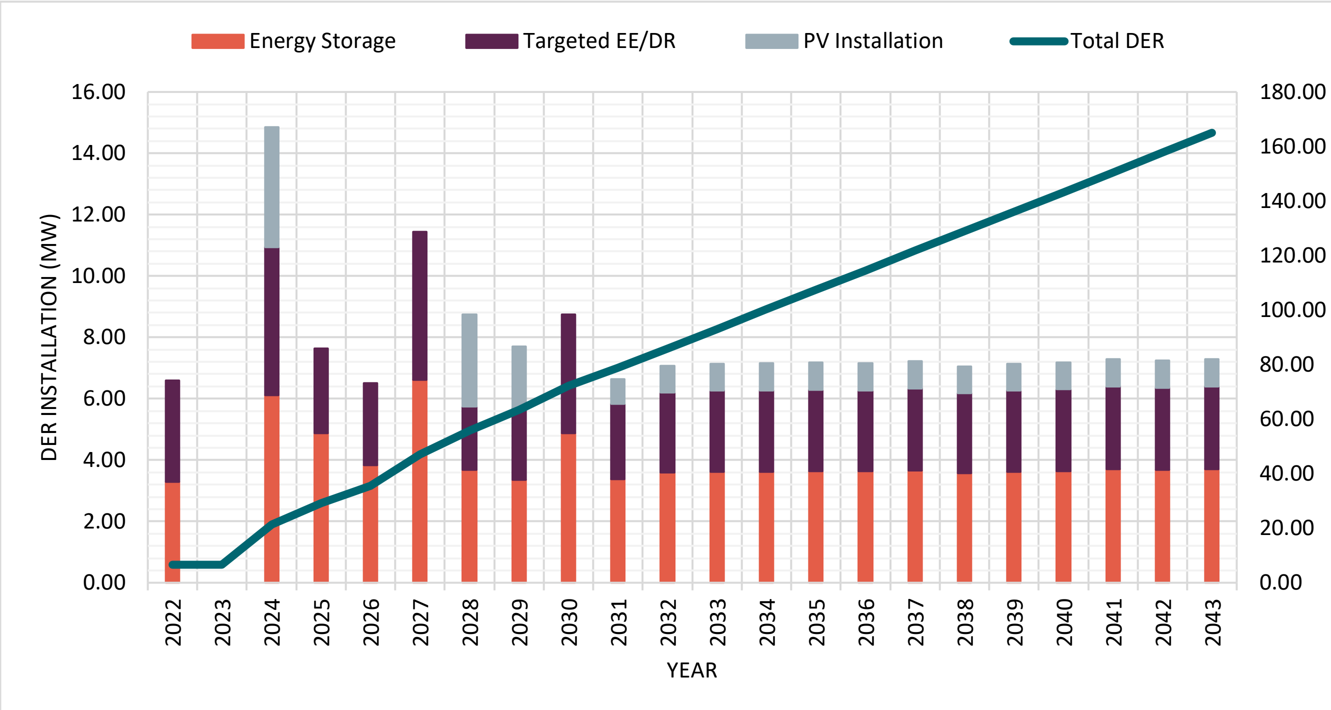


Table 5.12 presents the projected transmission and distribution deferrals resulting from the non-wires alternatives DER additions.

Table 5.12: Projected T&D Deferral by Project Type by 2040

Project Type	Energy Storage (MW)	Targeted EE/DR (MW)	PV Installation (MW)	Total DER (MW)
Planned Transmission System Projects[1]	7.1	6	0	13.1
Planned Substation Capacity Projects	17.6	12.4	3.9	33.9
Future Potential System Needs	59	42.6	16.4	118
Total	83.7	61	20.3	165

Note: [1]As identified in the PSE Plan for Attachment K

We modeled the energy storage and solar PV forecasts in the AURORA portfolio model as generating resource to represent the DSP non-wires alternatives. We included the targeted energy efficiency/demand response forecast as part of the cost-effective energy efficiency and demand response evaluation the model.

2.12. Transmission and Distribution Benefit

The transmission and distribution (T&D) benefit, also known as an avoided cost, is a benefit added to resources that reduce the need to develop new transmission and distribution lines. The T&D benefit is our forward-looking estimate of T&D system costs under a scenario where electrification requirements and electric vehicles drive substantial electric load growth. Studies of the electric delivery system identified capacity constraints on the transmission lines, substations, and distribution lines that serve PSE customers from increased load growth due to electrification and electric vehicle adoption. We used the estimated cost for the infrastructure upgrades required to mitigate these capacity constraints and the total capacity gained from these upgrades to calculate the benefit value. The 2023 Electric Progress Report included a T&D benefit of $74.70/kW-year for DER batteries. This estimated $74.70/kW-year is forecasted based on our additional transmission and delivery system needs under such a scenario. This increase is a significant change from the $12.93/kW-year we used in the 2021 IRP which used backward-looking metrics instead of the revised forward-looking scenario described.

2.13. Electric Generation Retirements

We modeled the economic retirement of existing thermal resources for this 2023 Electric Report. We assumed Colstrip would be removed from PSE's portfolio by December 31, 2025; based on economics, the model can retire Colstrip earlier. We assumed the other thermal plants would run through the planning horizon but could retire early based on economics.

When determining the retirement of a generating plant, the model looks at the economics of the power plant for meeting loads and peaks. The generating plants' valuation process considers emission and variable costs (fuel, operations, and maintenance), fixed costs (including ongoing capital for upkeep and maintenance), and decommissioning costs.

2.14. Achieving CETA Compliance: 100 Percent Greenhouse Gas Neutral by 2030

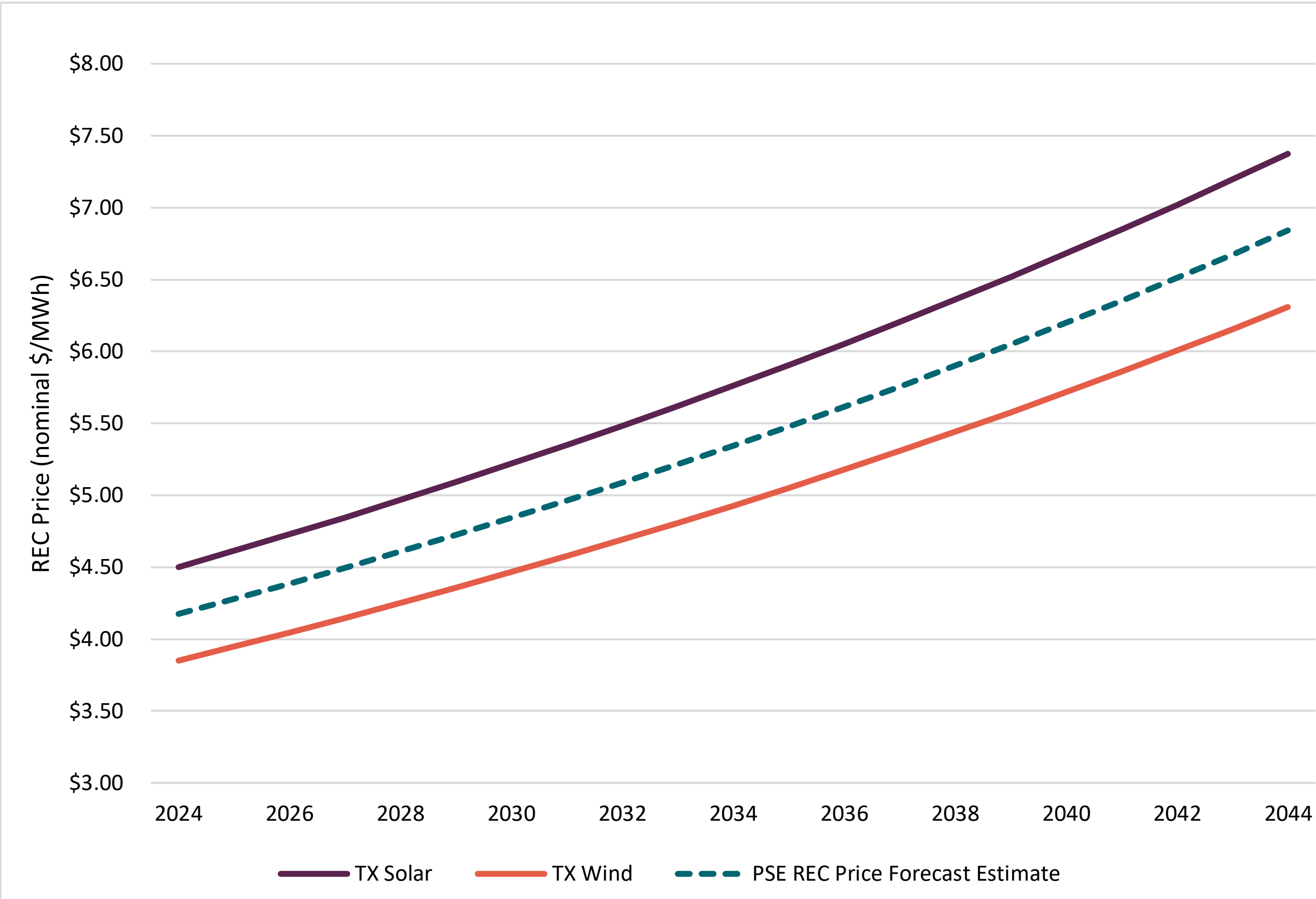
The CETA requires 100 percent greenhouse gas (GHG) neutrality by 2030, with a minimum of 80 percent of energy delivered met with renewable or non-emitting resources and the remaining energy delivered met by alternative options. Options for meeting the up to 20 percent remaining energy delivered include:

- Investing in energy transformation projects that meet criteria and quality standards developed by the Department of Ecology, in consultation with the Department of Commerce and the Commission
- Making an alternative compliance payment in an amount equal to the administrative penalty
- Purchasing carbon offsets
- Purchasing unbundled renewable energy credits

This 2023 Electric Report evaluated two methods to reach 100 percent GHG neutrality by 2030. For the first option, we assumed that we would purchase unbundled renewable energy credits (RECs) for up to 20 percent of the load not met by renewable generation starting in 2030 and decreasing to zero in 2045. The quantity of unbundled RECs purchased depends on the quantity of delivered energy not met by CETA-compliant resources. For example, if a given portfolio generated 85 percent of delivered energy with CETA-compliant resources in 2030, the remaining 15 percent would be compensated by purchasing unbundled RECs to achieve greenhouse gas-neutral compliance.

We reviewed REC markets nationwide to determine a suitable price forecast for unbundled RECs. The Texas wind and solar REC markets represent a stable, high-volume market with years of data available for review. Therefore, we selected an average of the Texas wind and solar REC price forecast as the REC price for achieving GHG neutrality compliance through the purchase of unbundled RECs. Figure 5.10 shows the Texas REC prices over the modeling horizon.

Figure 5.10: Forecasted Renewable Energy Credit Price Purchased to Achieve GHG Neutrality in Nominal $ per MWh



For the second option, we wanted to understand the impact of meeting 20 percent of the load with renewable resources to meet 100 percent of PSE's load with renewable resources by 2030. We modeled sensitivity 12 which retires all existing natural gas generation by 2030 and allows for addition of only renewable resources, thereby achieving 100 percent renewable energy by 2030.

➔ See Chapter Eight: Electric Analysis for the results of sensitivity 12 in detail.

We may meet actual compliance through other mechanisms that we are still developing. We will determine these mechanisms in the first CEIP that includes 2030, the year the greenhouse gas neutral standard takes effect. We will analyze these mechanisms as the Department of Ecology develops guidance on assigning greenhouse gas emission factors for electricity, establishes a process for determining what types of projects qualify as energy transformation projects, and includes other options such as transportation electrification.

3. Electric Portfolio Sensitivities

Sensitivity analysis is an essential component of the IRP process. After generating a reference portfolio, which is the optimized, least-cost set of resources to meet the base set of constraints, we model sensitivities that change a resource, environmental regulation, or condition to examine the effect of the change on the portfolio.

The portfolio modeling process is complex, with no shortage of potential sensitivities to investigate. In this 2023 Electric Report, we included key sensitivities necessary to develop a preferred portfolio in the analysis. We started with sensitivities that changed a single resource or assumption, such as adding more conservation programs or scheduled addition of pumped hydroelectric storage resources. These simple sensitivities provide context for how a given resource, which may not be part of the least-cost portfolio, may provide value, such as reduced greenhouse gas emissions or increased equity benefits. We then combined several of these simple changes to create diversified portfolios.

Diversified portfolios layer several minor changes to create a portfolio that provides even greater potential benefits. We modeled several diversified portfolios ranging from two to six small changes. These diversified portfolios become the candidate portfolios from which we will select a preferred portfolio based on its attributes related to cost, equity benefits, and feasibility.

The following sections provide an overview of the assumptions made for each sensitivity analyzed in this report. We provide their results and discussion in Chapter Eight: Electric Analysis. .

3.1. Reference Portfolio

The reference portfolio is a least-cost, CETA-compliant portfolio that allows the AURORA long-term capacity expansion model to optimize resource selection with as few constraints as possible. The reference portfolio is a basis against which to compare other portfolios. We used the assumptions described in the Electric Portfolio Analysis Assumptions section to develop the reference portfolio. We refer to the reference portfolio as sensitivity 1 throughout this report.

3.2. Conservation Alternatives

Adding higher conservation measures, we analyzed two sensitivities to assess portfolio builds and cost changes.

- Reference: 258 MW of new conservation will be added to the reference portfolio by 2045.
- Sensitivity 2: This sensitivity increases new conservation measures to 486 MW by 2045, an increase of 228 MW above the reference portfolio conservation.
- Sensitivity 3: This sensitivity increases new conservation measures to 382 MW by 2045, an increase of 123 MW above the reference portfolio conservation.

The reference, sensitivity 2 and sensitivity 3 portfolios all have codes and standards included for 437 MW by 2045. New energy efficiency up to bundle 3 was selected in reference portfolio for 258 MW by 2045. Although we did not select a distribution efficiency in the reference portfolio, we included a forecasted addition of distribution efficiency in sensitivity 2 and sensitivity 3 for a total of 11 MW by 2045. We included a forecasted addition of 475 MW by 2045 of energy efficiency in sensitivity 2 by having all measures through conservation bundle 10. We included a lower amount of the forecasted addition of 371 MW by 2045 of energy efficiency in sensitivity 3 by including all measures through conservation bundle 7. Table 5.13 shows the forecasted additions for demand-side resources for the portfolios.

Table 5.13: Demand-side Resources (MW for Reference, Sensitivity 2 Bundle 10, and Sensitivity 3 Bundle 7)

MW by 2045	1 Reference	2 Bundle 10	3 Bundle 7
Codes and Standards	437	437	437
New Distribution Efficiency	0	11	11
New Energy Efficiency	258	475	371
Total	695	923	818

3.3. Distributed Energy Resources Alternatives

We analyzed two sensitivities to assess changes in portfolio builds and costs with additional distributed energy resources (DERs).

- Reference: 1,494 MW of distributed solar and 117 MW of distributed storage will be added to the reference portfolio by 2045.
- Sensitivity 4: This sensitivity adds 600 MW of additional distributed solar by 2045, resulting in 2,094 MW of distributed solar by 2045.
- Sensitivity 5: This sensitivity adds 150 MW of additional distributed storage by 2045, resulting in 267 MW of distributed storage by 2045.

The reference portfolio, sensitivity 4 and sensitivity 5, all include DER forecasts for customer-sited solar, non-wires alternatives, and new programs identified in the CEIP. Based on the results of the reference portfolio, we did not find it economical to add any additional DERs due to the higher cost relative to utility-scale resources. Sensitivity 4 explores the impact of adding distributed solar above the established forecasts by adding 30 MW of distributed rooftop solar each year from 2026 to 2045. Sensitivity 5 examines the impact of adding distributed storage above the established forecast by adding 25 MW of distributed battery storage each year from 2026 to 2031.

3.4. Pumped Hydroelectric Storage Alternatives

We analyzed three sensitivities to assess changes in portfolio builds and cost by adding pumped hydroelectric storage (PHES) resources.

- Reference: PHES is selected on an economic basis, resulting in zero MW of PHES added to the reference portfolio.

- Sensitivity 6: This sensitivity adds 200 MW of Montana PHES and 400 MW of eastern Montana wind in 2026.
- Sensitivity 7: This sensitivity adds 200 MW of Montana PHES, 200 MW of central Montana wind, and 200 MW of eastern Montana wind in 2026.
- Sensitivity 8: This sensitivity adds 200 MW Pacific Northwest PHES in 2026.

Energy storage is a critical component of a CETA-compliant portfolio. The reference portfolio selected battery storage as a cost-effective storage resource. We explored diversifying the portfolio by adding PHES and battery energy storage in sensitivities 6, 7, and 8.

In sensitivities 6 and 7, we added 200 MW of Montana PHES in 2026. Energy from Montana resources currently gets to PSE via the Colstrip transmission line. The Colstrip transmission line has an available capacity of 750 MW for PSE to use. Given this restriction, we decided to overbuild Montana resources to provide surplus energy to charge the PHES resource and simultaneously maximize the throughput of energy over the Colstrip line to PSE. In sensitivity 6, we added 400 MW of eastern Montana wind to the existing 350 MW of Clearwater wind. In sensitivity 7, we added 200 MW of eastern Montana wind and 200 MW of central Montana wind in addition to the existing 350 MW of Clearwater wind. The Montana PHES and wind resources have a combined maximum output of 750 MW (the Colstrip transmission capacity limit), and excess energy is stored in the PHES resource.

In sensitivity 8, we added 200 MW of Pacific Northwest PHES in 2026. Since transmission capacity is less constrained in Washington and Oregon, we did not model any resource overbuild in sensitivity 8.

3.5. Advanced Nuclear Small Modular Reactors

We analyzed a sensitivity that added advanced nuclear SMR to the portfolio to assess changes in builds and cost.

- Reference: Advanced nuclear SMR is selected on an economic basis, resulting in zero MW of advanced nuclear SMR added to the reference portfolio.
- Sensitivity 9: This sensitivity adds 250 MW of advanced nuclear SMR in 2032.

The reference portfolio is updated to include a forecast in 2032 of 5 units of 50 MW advanced nuclear SMR resources for 250 MW. This advanced nuclear SMR provides a combination of dispatchability, reliability, and emission-free production benefits, making it an attractive alternative to traditional peaking resources as we move toward a zero-emissions portfolio.

3.6. No New Thermal Resources Before 2030

We analyzed a sensitivity where new thermal resources were unavailable before 2030 to assess changes in builds and cost.

- Reference: Thermal resources include natural gas peakers, blended natural gas and hydrogen peakers, and biodiesel peakers available for economical addition throughout the modeling horizon.
- Sensitivity 10: This sensitivity limited the availability of thermal resources before the year 2030. After 2030, we permitted natural gas, blended natural gas and hydrogen and biodiesel peakers in the portfolio.

This sensitivity aims to reduce the amount of thermal, or combustion, resources added to portfolio. No combustion resources are permitted to be added to the portfolio before the year 2030.

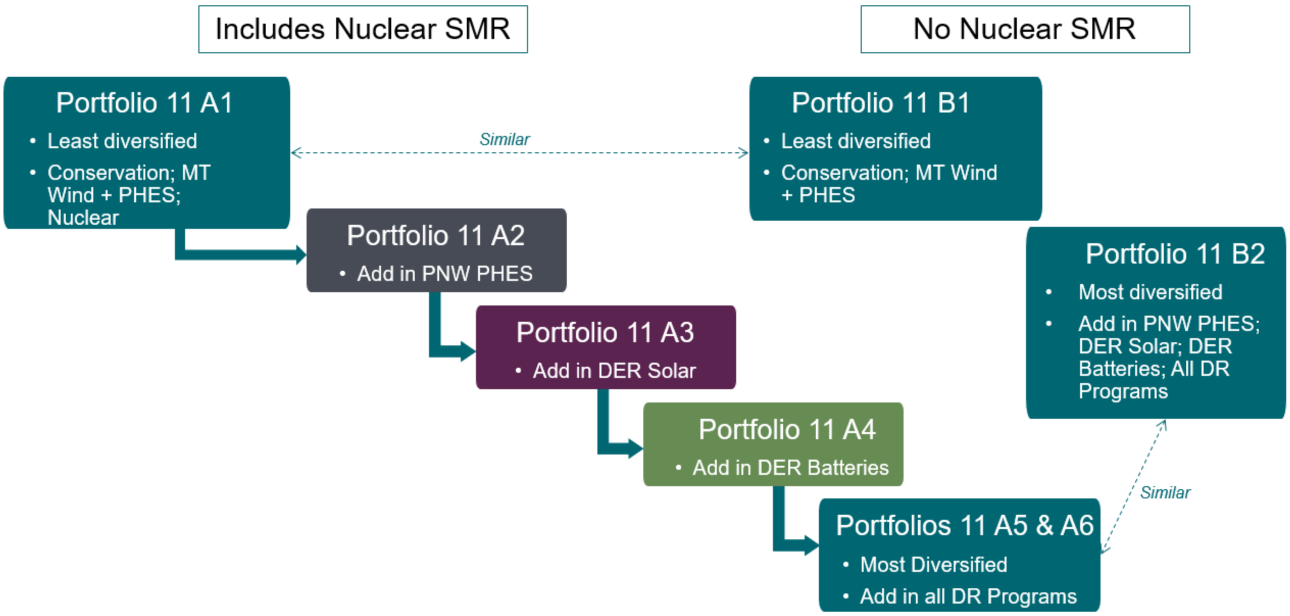
3.7. Diversified Portfolios

In comparison to the least-cost reference portfolio, the diversified portfolios broaden the resource additions, lower the technology and feasibility risks, and seek to maximize equity-related benefits. All diversified portfolios are based on the least-cost reference portfolio. Portfolios 11 A1 through 11 A5 explore layering in combinations of sensitivities 3 through 9. At the request of interested parties, portfolios 11 B1 and 11 B2 replicate the least and most diversified portfolios, 11 A1 and 11 A5, respectively, but without adding advanced nuclear SMR technology to the portfolio.

- Reference: New resources are acquired when cost-effective and needed.
- Sensitivity 11 A1: This sensitivity is the least diversified portfolio we developed in this report and therefore serves as the baseline diversified portfolio. Built on the least-cost reference portfolio, this portfolio increases conservation to 371 aMW by 2045 (Sensitivity 3), adds 400 MW of eastern Montana wind and 200 MW of Montana PHES in 2026 (Sensitivity 6), and adds 250 MW of advanced nuclear SMR in 2032 (Sensitivity 9).
- Sensitivity 11 A2: Same as 11 A1 but adds 200 MW of Pacific Northwest PHES in 2026 (Sensitivity 8).
- Sensitivity 11 A3: Same as 11 A2 but adds 30 MW of distributed solar resources annually from 2026 through 2045 (Sensitivity 4).
- Sensitivity 11 A4: Same as 11 A3 but adds 25 MW of distributed battery resources annually from 2026 through 2031 (Sensitivity 5).
- Sensitivity 11 A5: Same as 11 A4 but adds all demand response programs.
- Sensitivity 11 B1: Same as 11 A1 but without advanced nuclear SMR.
- Sensitivity 11 B2: Same as 11 A5 but without advanced nuclear SMR.

Figure 5.11 illustrates the relationships between the diversified portfolios we explored in this report.

Figure 5.11: Diversified Portfolio Schema



3.8. 100 Percent Renewable and Non-emitting by 2030

This sensitivity examines the impacts of retiring all existing thermal resources by 2030 and removing the ability to build any new thermal regardless of fuel type.

- Reference: The baseline assumes we will transition existing thermal to a 30 percent hydrogen blend starting in 2030 and ramp up to 100 percent hydrogen by 2045. New thermal fueled by natural gas, biodiesel, and hydrogen are all available as new resource options.
- Sensitivity 12: All existing thermal is retired on a ramped schedule from the late 2020s to 2030. All thermal resource options, including alternative fuels, are excluded from the modeling scenario producing a portfolio that is effectively 100 percent non-emitting by 2030.

We initially assumed we would retire existing thermal options for this sensitivity and remove new thermal options. However, we needed to adjust other assumptions to facilitate the long-term capacity expansion model. Those adjustments included removing all transmission capacity constraints, expanding available quantities of each resource type, and allowing the model to build advanced nuclear SMR in 2025. We made these changes to increase access to additional resources over the reference portfolio to help meet the large capacity deficit early in the modeling horizon.

With these changes implemented, the model solved in the preliminary stages when sampling settings were relatively coarse. But when we increased the sampling resolution for the final sensitivity run, the model could not converge on a solution.

3.9. High Carbon Price

We analyzed this sensitivity to explore the impact of a higher-than-expected greenhouse gas allowance price in the market established by the Climate Commitment Act.

- Reference: We modeled an ensemble allowance price as a direct cost on greenhouse gas emissions using the Washington Department of Ecology Linkage to California from 2024 to 2029, transitioning to the mid allowance price forecast created by the California Energy Commission in 2030.
- Sensitivity 13: We used the Washington Department of Ecology price ceiling as the allowance price as a direct cost of greenhouse gas emissions.

Figure 5.4 illustrates the relationship between the PSE ensemble price and the Department of Ecology ceiling price as described in Section 2.4 of this Chapter.

3.10. No Hydrogen Fuel Available

This sensitivity examines a future where green hydrogen fuel is unavailable for the electric sector.

- Reference: Hydrogen fuel blending at a rate of 30 percent in 2030 and increasing to 100% by 2045 is available for new blended fuel peakers and existing natural gas plants.
- Sensitivity 14: Hydrogen is unavailable, so existing natural gas plants burn only natural gas, and blended fuel peakers are not available for economic addition to the portfolio.

Interest and commercialization of large-scale green hydrogen production are at an all-time high, largely thanks to production and investment tax credits established by the Inflation Reduction Act. However, green hydrogen production is not guaranteed to materialize in the volumes needed to support the electric power sector. This sensitivity assumes a future with no green hydrogen for combustion in existing or new peaking resources modeled in this report.

3.11. Social Cost of Greenhouse Gases in Dispatch

This sensitivity compares different methodologies to apply the SCGHG as externality or dispatch costs and their effect on portfolios.

- Reference: We modeled the SCGHG as an externality cost in the long-term capacity expansion (LTCE) model. We omitted the SCGHG in the dispatch decision for emitting resources in the LTCE run.
- Sensitivity 15: We modeled the SCGHG as dispatch cost in the long-term capacity expansion model. We included the SCGHG in the dispatch decision for emitting resources in the LTCE run.

We omitted the SCGHG in the dispatch decision for emitting resources in the hourly dispatch run for the Baseline and Sensitivity 15. Figure 5.3 provides the social cost of greenhouse gases.

4. Purchasing Versus Owning Electric Resources

The 2023 Electric Report determines the supply-side capacity, renewable energy, and energy need, which sets the supply-side targets for future detailed planning in the Clean Energy Implementation Plan and the acquisition process. The Request for Proposal (RFP) processes for demand-side and supply-side resources are just one source of information for making acquisition decisions. We also considered market opportunities outside the RFP and resource-build decisions when making prudent resource acquisition decisions. The 2023 Electric Report assumes ownership of supply-side resources since the cost of power purchase agreements (PPA) is confidential.

In build-versus-buy, build refers to resource acquisitions involving asset ownership. Ownership could occur anywhere along the development cycle of a project. The company could develop or purchase the project anytime during the development cycle. Buy refers to purchasing the output of the plant through a PPA.

In general, quantitative and qualitative evaluations for build-and-buy proposals are conducted similarly in the Request for Proposal process to meet the company's needs, consistent with WAC 480-107,[16] solving for the lowest reasonable cost for customers. We evaluate qualitative project risks in the same way for both acquisitions. Quantitative evaluations for build options include ownership costs such as operating expenses, depreciation, and return on invested capital. Developers embed similar costs in the total price of PPAs, but we have no visibility on the breakdown of those costs.

The supplier of the PPA makes the financial investment for the utility. Rating agencies view PPAs as a financial obligation to the utility, representing a debt-financed capital investment in generation capacity. Rating agencies add/impute debt to the balance sheet to reflect the financial obligations to account for the company's credit exposure. The request for proposal (RFP) process includes an adjustment for imputed debt for PPAs to account for the impact on credit ratings. The cost of imputed debt is a consideration in the evaluation process but is not recoverable in rates.

The CETA provides a provision allowing for a return on expenses incurred from the PPA of no less than the authorized cost of debt and no greater than the rate of return. We did not include the PPA return in the evaluation process. The statutorily authorized PPA return has yet to be requested or approved in a General Rate Case proceeding.

Several factors could influence pricing differences between the buy and build scenarios. Independent power producers (IPP) have tax advantages over utilities since the tax rules differ. A carve-out in the tax code allows IPPs to depreciate the cost of investments upfront, whereas utilities depreciate the cost over time. This situation provides a tax shield on the front end to IPPs. Independent power producers are also more able to maximize the benefits of investment tax credits. The tax code limits the utilities' ability to fully utilize ITC for the customer benefit on ITCs on solar. Developers have more flexibility in how they finance projects with their capital structure. In the build scenario, our equipment selection and design specifications must meet PSE standards for ownership, whereas a supplier might be more inclined to be driven by cost. We can better control how the plant operates and be good community stewards when we own it.

[16] WAC 480-107