8 Electric Analysis

This chapter presents the results of the electric analysis.

Contents

1. ANALYSIS OVERVIEW

The electric analysis in the 2021 IRP followed the six-step process outlined below. Steps 1, 3, and 4 are described in detail in this chapter. Other steps are treated in more detail elsewhere in the IRP.

1. Establish Resource Need
Three types of resource need are identified: peak capacity need, energy need and renewable need.

- Chapter 7 presents the resource adequacy analysis.

2. Determine Planning Assumptions and Identify Resource Alternatives

- Chapter 5 discusses the scenarios and sensitivities developed for this analysis.
- Chapter 6 presents the 2021 IRP demand forecasts.
- Appendix D describes existing electric resources and alternatives in detail.

3. Analyze Alternatives and Portfolios Using Deterministic and Stochastic Risk Analysis
Deterministic analysis identifies the least-cost mix of demand-side and supply-side resources that will meet need, given the set of static assumptions defined in the scenario or sensitivity.

- All scenarios and sensitivities were analyzed using deterministic optimization analysis.

Stochastic risk analysis deliberately varies the static inputs to the deterministic analysis to test how the different portfolios developed in the deterministic analysis perform with regard to cost and risk across a wide range of potential future power prices, gas prices, hydro generation, wind generation, loads and plant forced outages.

- Four portfolios were analyzed using stochastic risk analysis.

4. Analyze Results
Results of the quantitative analysis – both deterministic and stochastic – are studied to understand the key findings that lead to decisions for the preferred portfolio.

- Results of the analysis are presented in this chapter and in Appendix H.

5. Develop Resource Plan

Chapter 3 describes the reasoning behind the strategy chosen for this preferred portfolio.

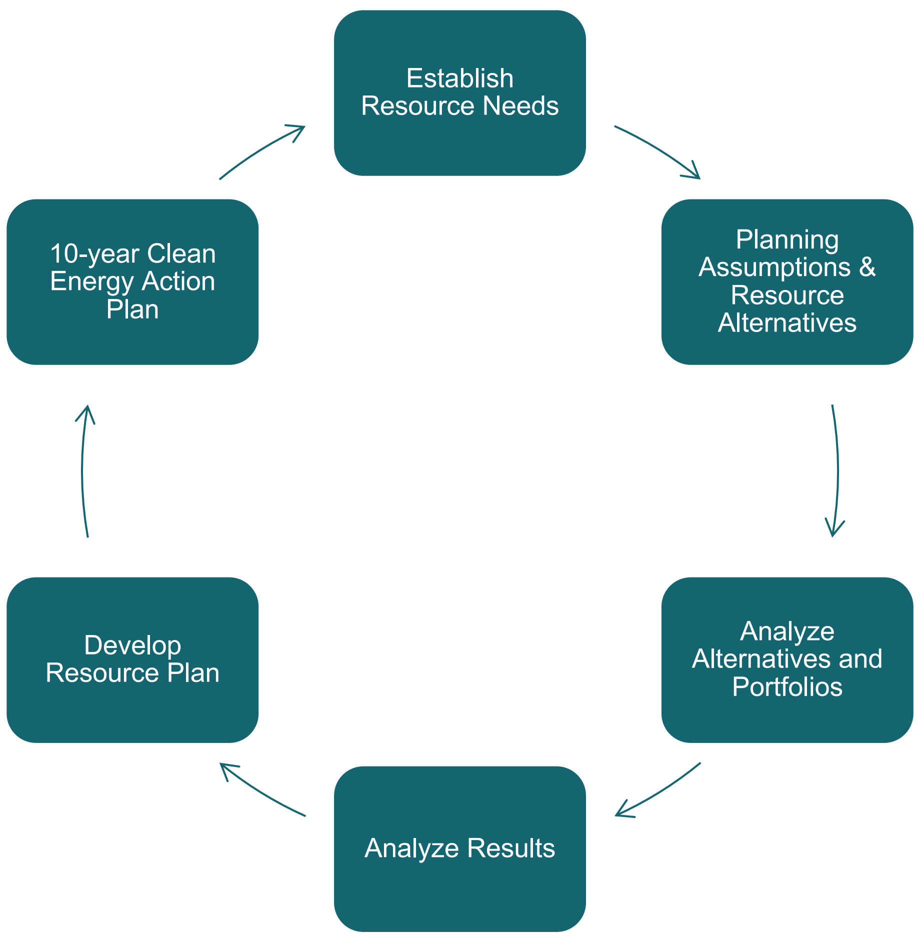
6. Create the 10-year Clean Energy Action Plan

Resource decisions are not made in the IRP. What we learn from the IRP forecasting exercise determines the IRP Action Plan and the 10-year Clean Energy Action Plan.

- The Action Plan is presented in the Executive Summary, Chapter 1.
- The 10-year Clean Energy Action Plan is presented in Chapter 2.

Figure 8-1 illustrates this process.

Figure 8-1: 2021 IRP Process



2. SUMMARY OF SUBSTANTIVE CHANGES

The 2021 IRP marks a major departure from past IRPs due in large part to the passage of the Clean Energy Transformation Act. Changes in technology, updates to datasets and other advances have also contributed to differences in the 2021 IRP. This section provides a summary of the substantive changes from the 2017 IRP to the 2021 IRP.

ELECTRIC POWER PRICES. Several updates were made to the development of the electric price model. AURORA, the power system software used for electric price simulations, was updated to version 13.4 in the 2021 IRP from version 12.3 in the 2017 IRP. In addition, the AURORA Zonal database was updated to the “2018 version 1” release in the 2021 IRP from the “2016 version 3” release used in the 2017 IRP. A detailed account of all updates to the electric price model is provided throughout Chapter 5 and Appendix G.

GENERIC RESOURCE COSTS. In the 2021 IRP, PSE developed a new process for obtaining generic resource costs. In past IRPs, PSE has relied on consultants to estimate generic resource costs. In the 2021 IRP, PSE aggregated publically available generic resource costs from a variety of sources. These data were presented to stakeholders during a public meeting and stakeholder input was used to refine generic resource cost assumptions. This framework mirrors the generic resource cost development process used by the Northwest Power and Conservation Council’s Generic Resource Advisory Group.

LEGISLATION. In 2019, the Clean Energy Transformation Act (CETA) passed into law. CETA set forth aggressive targets for clean and non-emitting resources. Investor-owned utilities are required to obtain 80 percent of energy sales from non-emitting resources by 2030 and 100 percent of energy sales from non-emitting resources by 2045. This dramatically increases the 15 percent renewable portfolio standard established by RCW 19.285. Furthermore, CETA introduced the need to incorporate the social cost of greenhouse gases and the equitable distribution of customer benefits in the resource planning process.

RESOURCE ADEQUACY MODEL. Between the 2017 IRP and the 2021 IRP, PSE completely overhauled its resource adequacy model. This included moving from a SAS based model to a Python based model that incorporates inputs from regional resource adequacy metrics. A full description of the new resource adequacy model is available in Chapter 7.

ELECTRIC PORTFOLIO MODEL. During the three years since the last IRP was filed, PSE has made significant improvements to the portfolio modeling process. For the 2017 IRP, PSE used an Excel-based model called the Portfolio Screening Model (PSM). This annual model relied on AURORA to dispatch the resources, then the data was pulled into PSM where a solver was added to Excel for the linear programming optimization model. By moving the LP optimization model directly into AURORA, PSE is able to evaluate the economic retirement of resources, increase the selection of new generic resources, model energy storage and hybrid resources, and a utilize a more robust solver engine.

STOCHASTIC MODEL. Since the 2017 IRP, PSE has moved stochastic modeling from a simple SAS model to a full dispatch and forecasting model in AURORA. The SAS model used in 2017 looked at historical trends to forecast out a range of monthly electric prices. By moving the electric price model into AURORA, PSE is able to achieve a more forward looking forecast based on the new legislation and changing mix of resources in the region. In the new stochastic model, no historical data is used, only forward looking changes in the region. AURORA then runs a complete dispatch of resources by hour for each draw and produces a forecast of hourly electric prices instead of monthly prices.

CONSERVATION POTENTIAL ASSESSMENT. In the 2017 IRP, the conservation potential assessment (CPA) was conducted by third-party Navigant Consulting. In the 2021 IRP, PSE retained a different consultant, CADMUS, to conduct the CPA. A full description of the CPA is available in Appendix E.

DEMAND FORECAST. The 2017 IRP base demand forecast was based on 2016 macroeconomic conditions such as population growth and employment; the forecast for the 2021 IRP is based on 2020 macroeconomic conditions. The updates to inputs and equations are documented in Chapter 6.

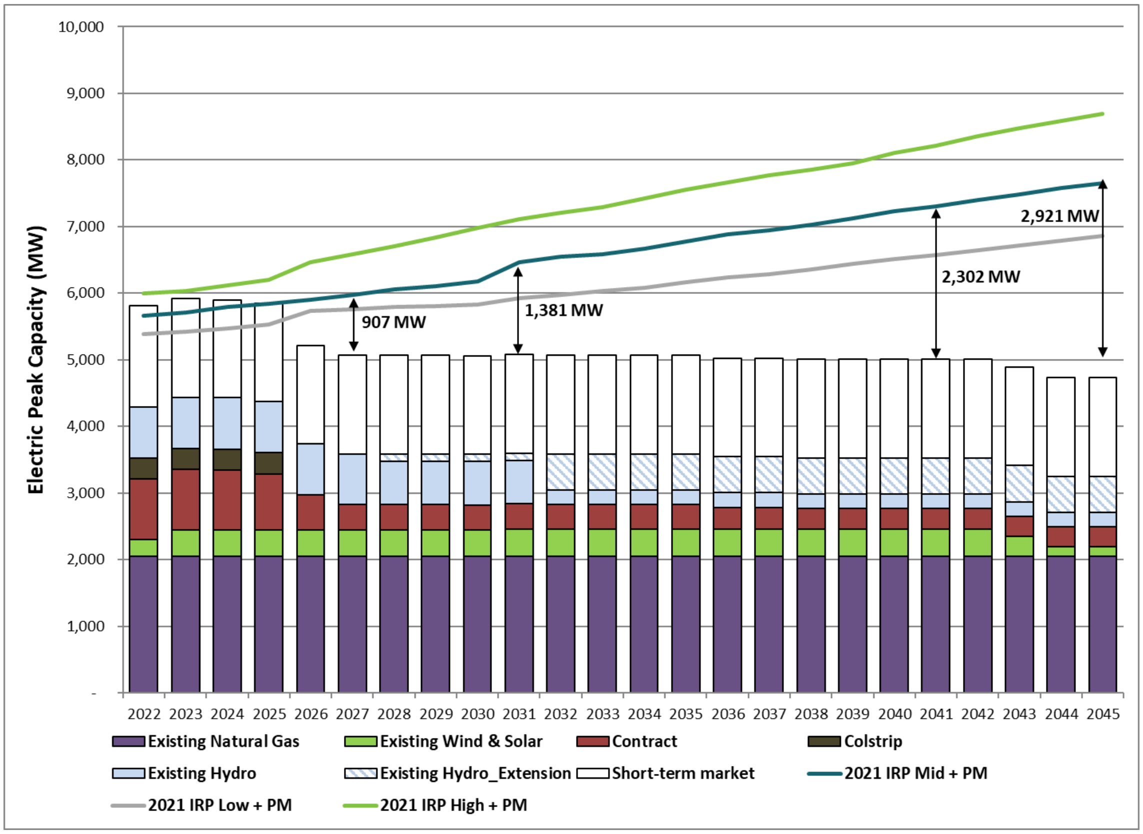
3. RESOURCE NEED

PSE's energy supply portfolio must meet the electric needs of our customers reliably. For resource planning purposes, those physical needs are simplified and expressed in three measurements: 1) peak hour capacity for resource adequacy, i.e., does PSE have the amount of capacity available in each hour to meet customer's electricity needs; 2) hourly energy, i.e., does PSE have enough energy available in every hour to meet customer's electricity needs; and 3) renewable energy, i.e., does PSE have enough renewable and non-emitting resources to meet the clean energy transformation targets.

Peak Capacity Need

Figure 8-2 shows the peak capacity need for the mid demand forecast modeled in this IRP (mid demand refers to the 2021 IRP Base Demand Forecast described in Chapter 6). Using the loss of load probability (LOLP) methodology, it was determined that 907 MW of capacity is needed by 2027 and 1,381 MW of capacity by 2031 before any new conservation. A full discussion of the peak capacity need is presented in Chapter 7, Resource Adequacy Analysis. The physical characteristics of the electric grid are very complex, so for planning purposes PSE simplifies physical resource need into a peak hour capacity metric using PSE's Resource Adequacy Model (RAM).

Figure 8-2: Electric Peak Capacity Need
(physical reliability need, peak hour need compared with existing resources)



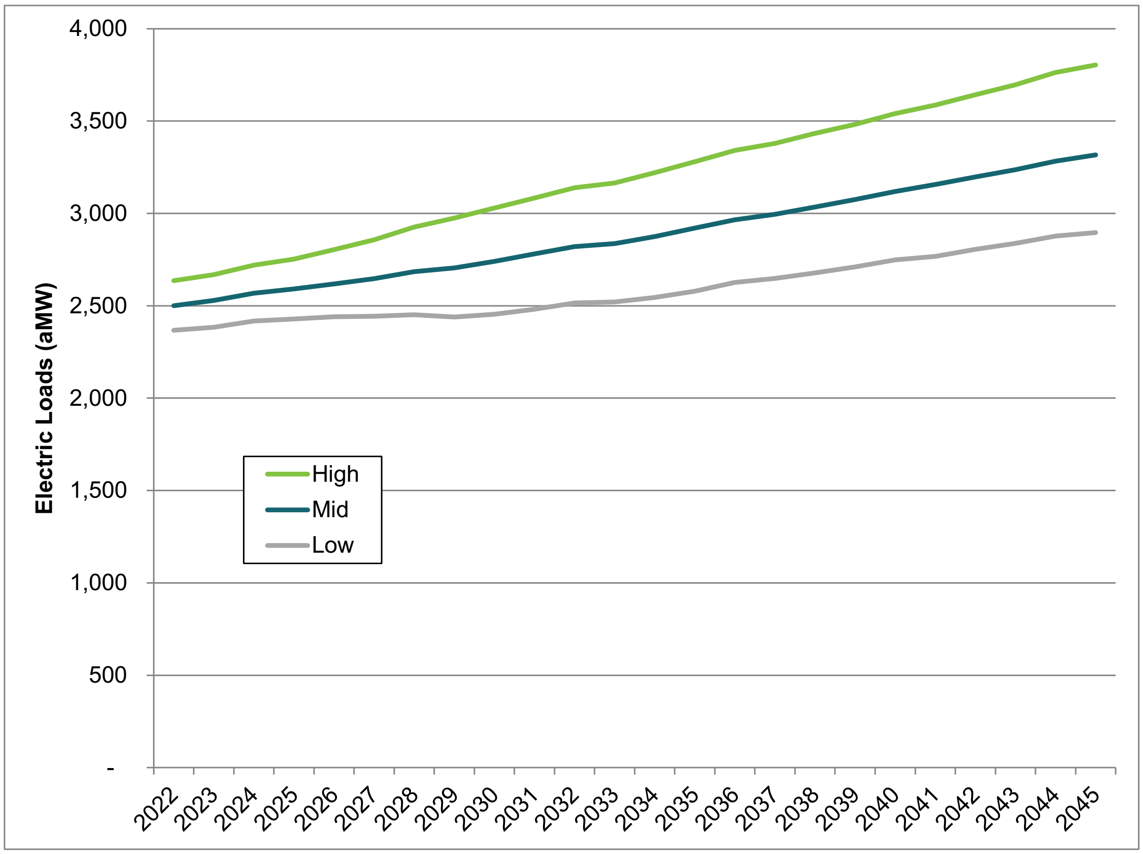
Energy Need

Compared to the physical planning constraints that define peak resource need, meeting customers' "energy need" for PSE is more of a financial concept that involves minimizing costs. Portfolios are required to cover the amount of energy needed in every hour to meet physical loads, but our models also examine how to do this most economically.

Unlike utilities in the region that are heavily dependent on hydro, PSE has thermal resources that can be used to generate electricity if needed. In fact, PSE could generate significantly more energy than needed to meet our load on an average monthly or annual basis, but it is often more cost effective to purchase wholesale market energy than to run our high-variable cost thermal resources. We do not constrain (or force) the model to dispatch resources that are not economical; if it is less expensive to buy power than to dispatch a generator, the model will choose to buy power in the market. Similarly, if a zero (or negative) marginal cost resource like wind is available, PSE's models will displace higher-cost market purchases and use the wind to meet the energy need.

Figure 8-3 illustrates the company's energy demand forecast across the planning horizon, based on the energy demand forecast for the Mid, High and Low Scenarios. The Mid Demand Scenario starts at 2,500 aMW in 2022 and grows to 2,740 aMW by 2030 and 3,316 aMW by 2045.

Figure 8-3: Annual Demand Forecast



Renewable Need

Washington State has two renewable energy requirements. The first is a renewable portfolio standard (RPS) that requires PSE to meet specific percentages of our load with renewable resources or renewable energy credits (RECs) by specific dates. Under the Energy Independence Act (RCW 19.285), PSE must meet 15 percent of retail sales with renewable resources by 2020. PSE has sufficient qualifying renewable resources to meet RPS requirements until 2023, including the ability to bank RECs. Existing hydroelectric resources may not be counted towards RPS goals except under certain circumstances for new run of river plants and efficiency upgrades to existing hydro plants.

The second renewable energy requirement is Washington State's Clean Energy Transformation Act (CETA). CETA requires that at least 80 percent of electric sales (delivered load) in Washington state be met by non-emitting/renewable resources by 2030 and 100 percent by 2045. The difference between CETA and RCW 19.285 is that hydro resources are qualifying renewable resources for compliance with CETA, and other non-emitting resources can be used to meet the requirements.

Washington State's RPS and renewable energy requirements calculate the required amount of renewable resources as a percentage of megawatt hour (MWh) sales; therefore, when MWh sales decrease, so does the amount of renewables needed. Achieving demand-side resource targets has precisely this effect. Demand-side resources decrease sales volumes, which then decreases the amount of renewable resources needed.

Figure 8-4 below shows the calculation for the 80 percent renewable requirement in 2030 to meet CETA. The first line of the table provides the estimated demand forecast in the year 2030 before demand-side resources (conservation) are applied. From this value, energy savings from conservation, line losses to adjust the demand forecast to retail sales, load reducing customer programs and PURPA generation[1] are subtracted to yield the sales net of conservation and customer programs (20.4 million MWh). Eighty-percent of this value represents the raw renewable need for 2030 (16.3 million MWh). From this value, existing renewable generation is subtracted to obtain the need for new renewable and non-emitting resources (7.6 million MWh).

Demand-side resources are optimized within the portfolio model and will provide a further reduction to the need shown in the last line of the table. Under normal hydro conditions and without the addition of new renewable/non-emitting resources, PSE will meet 40 percent of sales with renewable resources in 2022.

1 / The Public Utility Regulatory Policies Act of 1978 (PURPA) created a new class of generating resources known as qualifying facilities. Energy from qualifying facilities is included in this line item.

Figure 8-4: Calculation of 2021 IRP Renewable Need for 2030

	MWh
2030 Estimated Demand Forecast before Conservation[1]	24,004,160
Conservation: Codes & Standards, Solar PV	(774,387)
Line Losses	(1,579,625)
Load Reducing Customer Programs & PURPA	(1,243,449)
Sales Net of Conservation and Customer Programs	20,406,699
80% of Estimated Net Sales	16,325,360
Existing Non-emitting Resources[2]	(8,691,268)
Need for New Renewable/Non-emitting Resources	7,634,092

NOTES
1. 2021 IRP base demand forecast with no new conservation starting in 2022
2. Assumes normal hydro conditions and P50 wind and solar

Figure 8-5 below illustrates the renewable energy need for both RCW 19.285 and CETA based on the mid demand forecast, before any additional demand-side resources are added.

Figure 8-5: Qualifying Energy Need to Meet RCW 19.285 and CETA Requirements (before demand-side resources)

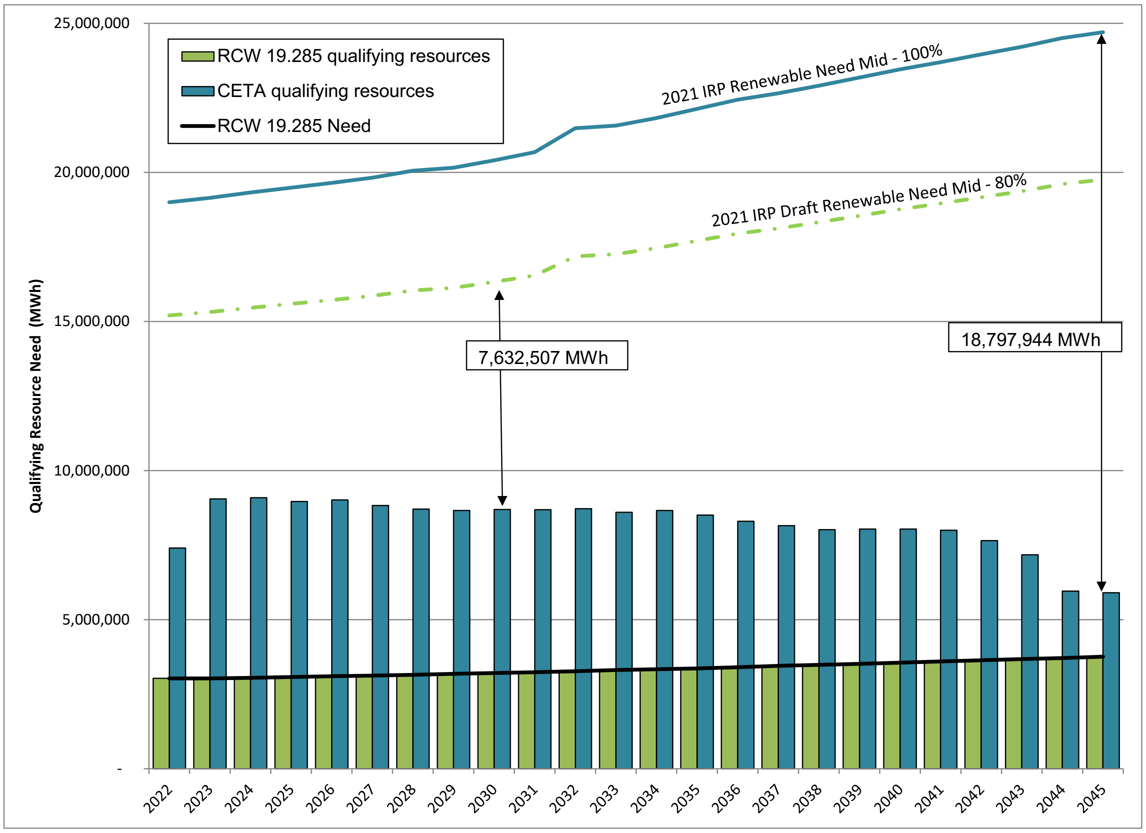
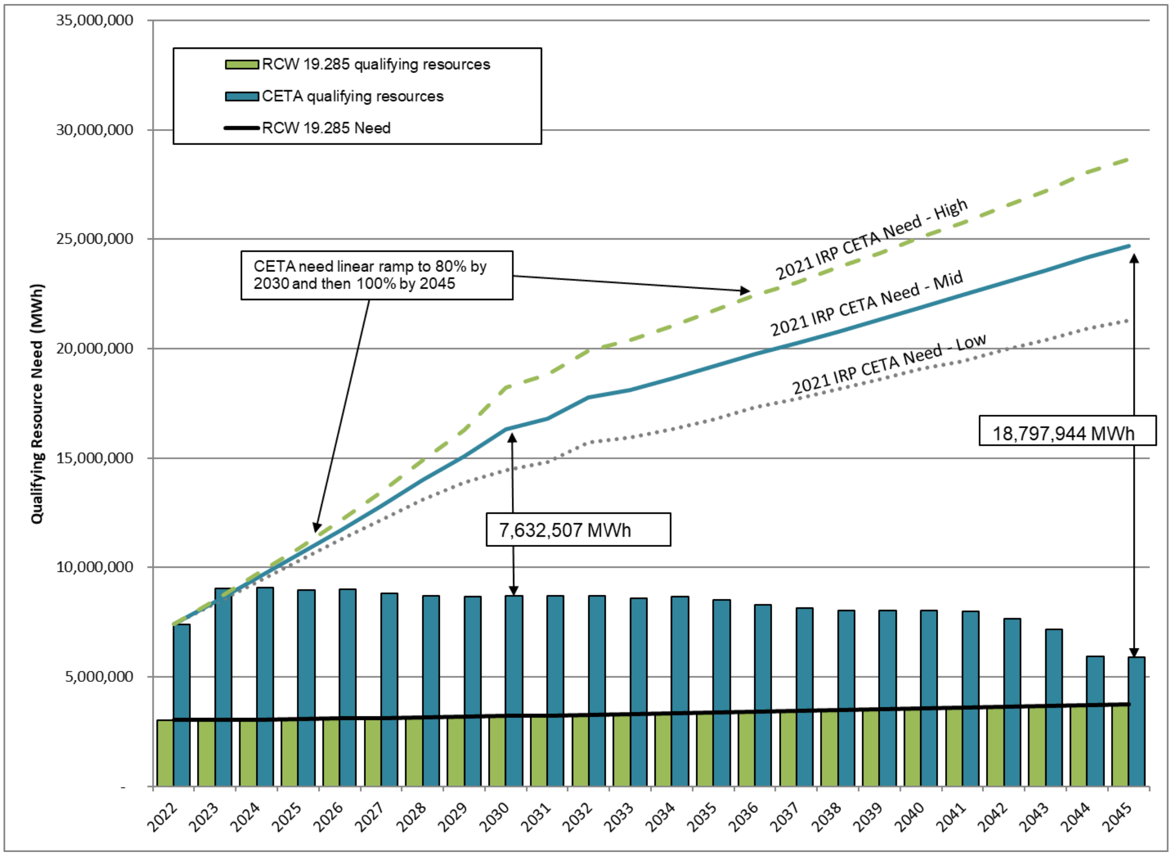


Figure 8-6 below assumes a linear ramp to reach the CETA 80 percent clean energy standard in 2030 and 100 percent clean energy standard in 2045. The linear ramp is needed to ensure that the portfolio model gradually adds resources to meet clean energy standards, rather than waiting until the final year before a goal must be achieved to add them. The linear ramp starts in 2022, as the IRP assumes all new resources are self-builds that will take at least two years before becoming operational. Since the IRP analysis starts in 2022, the earliest a resource can be built is 2024.

Figure 8-6: Renewable Need and Linear Ramp for CETA (before demand-side resources)



4. TYPES OF ANALYSIS

PSE uses deterministic optimization analysis to identify the lowest reasonable cost portfolio for each scenario. We then run a stochastic risk analysis to test different resource strategies.[2] The customer benefit analysis is used to inform the equitable distribution of burdens and benefits in the resource planning process to ensure that all customers are benefiting from the transition to clean energy.

Deterministic Portfolio Optimization Analysis

All scenarios and sensitivities are subjected to deterministic portfolio analysis in the first stage of the resource plan analysis. This identifies the least-cost integrated portfolio – that is, the lowest cost mix of demand-side and supply-side resources that will meet need under the given set of static assumptions defined in the scenario or sensitivity. This stage helps PSE to learn how specific input assumptions, or combinations of assumptions, can impact the least-cost mix of resources.

Deterministic analysis helps to answer the question: How will different resource alternatives dispatch to market given the assumptions that define each of the scenarios and sensitivities? All of PSE's existing resources are modeled, plus all of the generic resource alternatives.

Stochastic Risk Analysis

In this stage of the resource plan analysis, PSE examines how different resource strategies respond to the types of risk that go hand-in-hand with future uncertainty. Inputs that were static in the deterministic analysis are deliberately varied to create simulations called "draws" used to analyze the different portfolios. This allows PSE to learn how different strategies perform with regard to cost and risk across a wide range of power prices, gas prices, hydro generation, wind generation, loads and plant forced outages.

With stochastic risk analysis, PSE tests the robustness of different portfolios; in other words, determine how well the portfolio might perform under a range of different conditions. The goal is to understand the risks of different candidate portfolios in terms of costs and revenue requirements. This involves identifying and characterizing the likelihood of bad events and the likely adverse impacts they may have on a given portfolio.

2 / To screen some resources, we also use simpler, levelized cost analysis to determine if the resource is close enough in cost to justify spending the additional time and computing resources to include it in the two-step portfolio analysis.

For this purpose, PSE takes some of the portfolios (drawn from the deterministic analysis of scenario and sensitivity portfolios) and runs them through 310 draws[3] that model varying power prices, gas prices, hydro generation, wind and solar generation, load forecasts (energy and peak), and plant forced outages. This stochastic analysis enables PSE to evaluate the risk associated with the selected portfolios to inform the preferred portfolio.

Customer Benefits Analysis

The Clean Energy Transformation Act requires utility resource plans to ensure that all customers benefit from the transition to clean energy. The analysis of the equitable distribution of burdens and benefits into the resource planning process is new in the 2021 IRP. PSE is excited to incorporate these new ideas into the resource planning process, but acknowledges that stakeholder input and institutional learning must be allowed to evolve the process. Below is a brief overview of PSE's first attempt to incorporate customer benefits into the IRP process.

Incorporating the equitable distribution of burdens and benefits into the resource planning process requires a multifaceted approach. Therefore, PSE has developed several tools and methods; these include the Economic, Health and Environmental Benefits (EHEB) Assessment, the Equity Advisory Group (EAG) and the Customer Benefits Analysis.

The EHEB Assessment is an analysis outside of the IRP portfolio modeling process that seeks to determine how benefits and burdens are distributed among PSE customers. The EHEB Assessment provides a snapshot of current conditions across PSE's service area that shows where disparities exist and identifies key constituencies (vulnerable populations and highly impacted communities) which are at greater risk according to a range of customer benefit indicators. Customer benefit indicators are measures that speak to the degree to which specific groups are burdened or benefit from public health, environmental, economic and societal impacts. A full description of the methods and results of the EHEB Assessment are provided in Appendix K.

More directly related to the portfolio development process is the Customer Benefit Analysis. Historically, the IRP selected a preferred portfolio based on cost and reliability alone. CETA legislation has added the consideration of customer benefit indicators to these criteria. Since existing portfolio optimization software lacks the ability to incorporate customer benefit indicators, the Customer Benefit Analysis is performed outside of the portfolio and iterated into the overall portfolio development process. The Customer Benefit Analysis ranks portfolios based on a number of customer benefit indicators. Portfolios with high ranks help to inform key components

3 / Each of the 250 simulations is for the 24-year IRP forecasting period, 2022 through 2045.

that should be incorporated into the preferred portfolio. Preferred portfolio candidates are then incorporated into the ranking process to ensure they provide a suitable balance of customer benefit indicators. It is not enough to score well in one or two customer benefit indicator areas, a good portfolio must provide a range of benefits.

Portfolio outputs were mapped to customer benefit indicators using PSE's best judgement. The customer benefit indicators selected for the Customer Benefit Analysis do not necessarily align directly to the customer benefit indicators used in the EHEB Assessment. This is because of data availability constraints of each analysis. In future IRP cycles, PSE aims to better align customer benefit indicators across all analyses through customer input and insights from the Equity Advisory Group. Figure 8-7 provides an overview of the customer benefit indictors used in the Customer Benefit Analysis.

Figure 8-7: Customer Benefit Indicators for Portfolio Analysis

Area	Customer Benefit Indicator	Definition
Air Quality	Particulate Matter Emissions	Total emissions from thermal resources. Measured in tons.
	SO_2 Emissions	Total emissions from thermal resources. Measured in tons.
	NO_x Emissions	Total emissions from thermal resources. Measured in tons.
Environment	Renewable Generation	Energy generated from utility-scale renewable resources. Measured in MWh.
	Customer Programs	Energy generated from Green Direct, Green Power and Qualifying Resources. Measured in MWh.
	Energy Efficiency	Energy savings from energy efficiency, distribution efficiency and codes and standards. Measured in MWh.
	Distributed Generation	Energy generated from distributed solar (rooftop and ground-mounted), non-wires alternatives and net metering. Measured in MWh.
Economic	Portfolio Cost	Levelized cost of the portfolio. Measured in billions of dollars.
Energy Resiliency	Storage	Capacity of distributed storage added to the portfolio. Measured in MW.

Area	Customer Benefit Indicator	Definition
Climate Change	Social Cost of Greenhouse Gases	Levelized social cost of greenhouse gases. Measured in billions of dollars.
	Greenhouse Gas Emissions	CO_2 equivalent emissions. Measured in tons.
Market Position	Market Purchases	Energy purchased from market. Measured in MWh.
Resource Adequacy	Demand Response	Capacity of demand response programs in the portfolio. Measured in MW.

The customer benefit indicators are measured values from each portfolio analyzed. Measurements may be taken over various intervals along the planning horizon to gain an understanding of how customer benefit indicators evolve over time. For example, greenhouse gas emissions may be measured in the year 2031 to understand climate impacts at the 10-year Clean Energy Action Plan planning horizon as well as in the year 2045 to get a view of climate impacts for the entire IRP period.

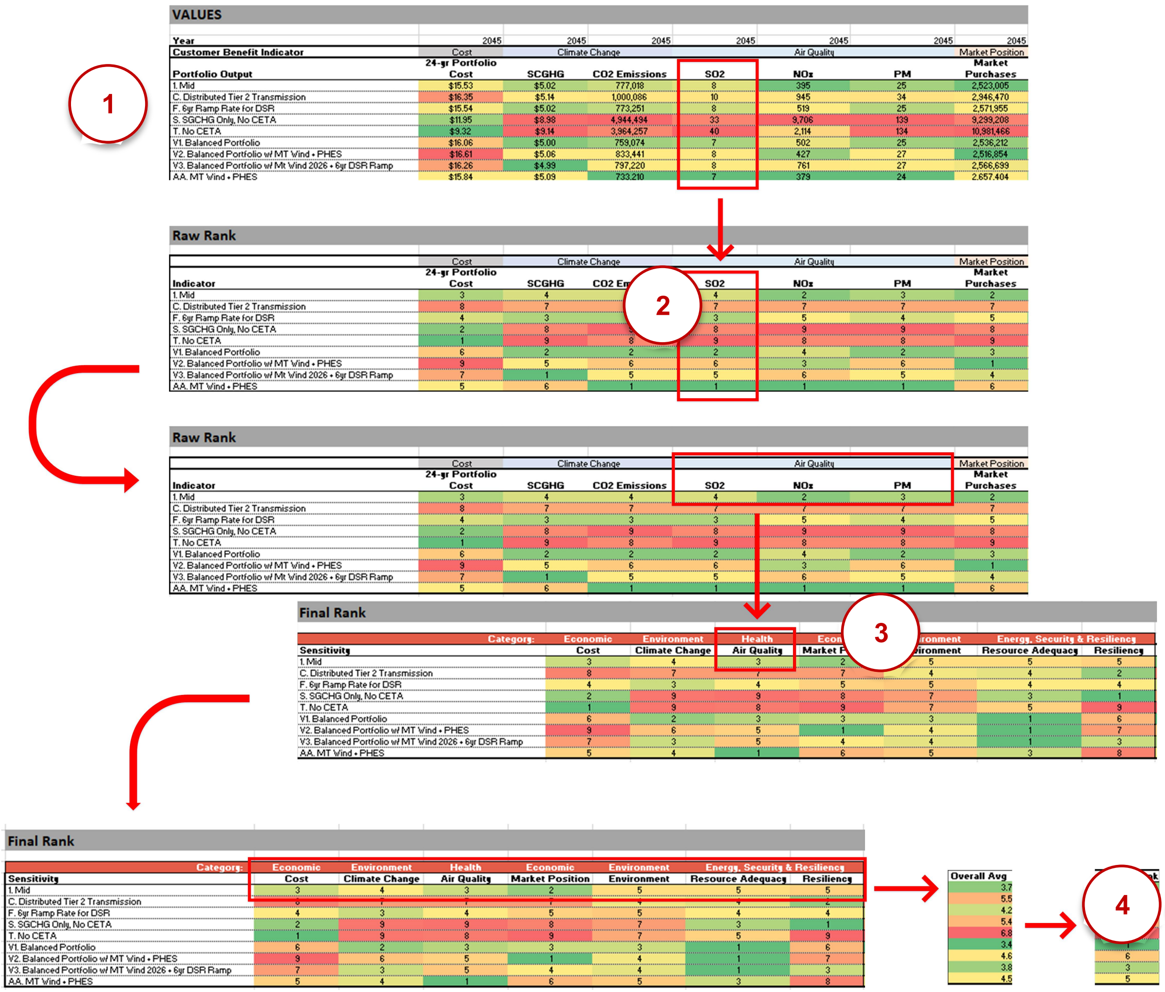
To make meaningful decisions about how different portfolios impact PSE's customers, the relative strengths and weaknesses of the portfolios are compared using the different customer benefit indicators.

The process to compare portfolio tradeoffs is depicted in Figure 8-8:

1. Values for each customer benefit indicator are extracted from the AURORA portfolio model for each portfolio being compared.
2. Values for each customer benefit indicator are ranked; where the most beneficial (or least burdensome) portfolio receives a rank of 1 and the least beneficial (or most burdensome) portfolio receives a rank of 'n', where there are n portfolios compared.
3. Individual customer benefit indicators are aggregated into customer benefit areas to more evenly distribute the benefit of each the various areas. For example, the ranks of SO_2, NO_x and PM are averaged together by portfolio to obtain an air quality rank.
4. Finally, for each portfolio, all the customer benefit indicator area ranks are averaged together to produce an overall average which is then converted to an overall rank.

The portfolio with the rank of 1 would provide the best balance of all customer benefit indicators. Furthermore, specific pieces of information may be used throughout the portfolio development process to help derive a more desirable portfolio. For example, the results for Sensitivity C: Distributed, Tier 2 Transmission Constraints, obtain favorable ranks in the Environment customer benefit indicator area, due to the large amount of energy efficiency and distributed resources in the portfolio. These elements may be incorporated into the preferred portfolio to improve its benefit to the environment.

Figure 8-8: Portfolio Ranking Process



VALUES

Year	2045	2045	2045	2045	2045	2045	2045
Customer Benefit Indicator	Cost	Climate Change		Air Quality			Market Position
Portfolio Output	24-yr Portfolio Cost	SCGHG	CO2 Emissions	SO2	NOx	PM	Market Purchases
1. Mid	$15.53	$5.02	777,018	8	395	25	2,523,005
C. Distributed Tier 2 Transmission	$16.35	$5.14	1,000,086	10	945	34	2,946,470
F. 6yr Ramp Rate for DSR	$15.54	$5.02	773,251	8	519	25	2,571,955
S. SGCHG Only, No CETA	$11.95	$8.98	4,944,494	33	9,706	139	9,299,208
T. No CETA	$9.32	$9.14	3,964,257	40	2,114	134	10,981,466
V1. Balanced Portfolio	$16.06	$5.00	759,074	7	502	25	2,536,212
V2. Balanced Portfolio w/ MT Wind + PHES	$16.61	$5.06	833,441	8	427	27	2,516,854
V3. Balanced Portfolio w/ Mt Wind 2026 + 6yr DSR Ramp	$16.26	$4.99	797,220	8	761	27	2,566,699
AA. MT Wind + PHES	$15.84	$5.09	733,210	7	379	24	2,657,404

Raw Rank

	Cost	Climate Change		Air Quality			Market Position
Indicator	24-yr Portfolio Cost	SCGHG	CO2 Emissions	SO2	NOx	PM	Market Purchases
1. Mid	3	4	4	4	2	3	2
C. Distributed Tier 2 Transmission	8	7	7	7	7	7	7
F. 6yr Ramp Rate for DSR	4	3	3	3	5	4	5
S. SGCHG Only, No CETA	2	8	9	8	9	9	8
T. No CETA	1	9	8	9	8	8	9
V1. Balanced Portfolio	6	2	2	2	4	2	3
V2. Balanced Portfolio w/ MT Wind + PHES	9	5	6	6	3	6	1
V3. Balanced Portfolio w/ Mt Wind 2026 + 6yr DSR Ramp	7	1	5	5	6	5	4
AA. MT Wind + PHES	5	6	1	1	1	1	6

Final Rank

Category:	Economic	Environment	Health	Economic	Environment	Energy, Security & Resiliency		
Sensitivity	Cost	Climate Change	Air Quality	Market Position	Environment	Resource Adequacy	Resiliency	Overall Avg
1. Mid	3	4	3	2	5	5	5	3.7
C. Distributed Tier 2 Transmission	8	7	7	7	4	4	2	5.5
F. 6yr Ramp Rate for DSR	4	3	4	5	5	4	4	4.2
S. SGCHG Only, No CETA	2	9	9	8	7	3	1	5.4
T. No CETA	1	9	8	9	7	5	9	6.8
V1. Balanced Portfolio	6	2	3	3	3	1	6	3.4
V2. Balanced Portfolio w/ MT Wind + PHES	9	6	5	1	4	1	7	4.6
V3. Balanced Portfolio w/ MT Wind 2026 + 6yr DSR Ramp	7	3	5	4	4	1	3	3.8
AA. MT Wind + PHES	5	4	1	6	5	3	8	4.5

NOTE: Data contained within this figure is draft and intended for demonstration purposes only. The results of the Customer Benefit Analysis is provided later in this chapter and a complete set of customer benefit indicator ranks is provided in Appendix H.

PSE recognizes the customer benefit indicators used in the Final IRP are preliminary and will evolve with time. Future IRPs will have the benefit of input from the Equity Advisory Group and the CEIP public participation process. In particular, two areas of consideration that require further stakeholder input have been identified so far:

- **Qualitative measures:** Although most customer benefit indicators are directly tied to quantitative metrics from the portfolio output, PSE recognizes that some customer benefit indicators may also be qualitative in nature. As qualitative measures are developed, this work may evolve the portfolio customer benefit indicator framework to incorporate indicators which are not directly related to specific portfolio model outputs.

- **Weighting factors:** Additionally, PSE understands some indicators may be more important than others to customers, especially for highly impacted communities and vulnerable populations, and thus require additional collaboration with stakeholders to determine the best weighting to apply across indicators and/or portfolios.

5. KEY FINDINGS

This section summarizes the assumptions for the economic scenarios, portfolio sensitivities and customer benefits indicators developed for this IRP; discusses the key findings from these analyses; and summarizes the optimal portfolio costs and builds produced by the scenario, sensitivity and customer benefits analyses. The following tables are included.

- Figure 8-9: 2021 IRP Electric Portfolio Scenarios and Sensitivities
- Figure 8-10: Relative Optimal Portfolio Costs by Sensitivity
- Figure 8-11: Relative Optimal Portfolio Builds by Sensitivity

> > > See Chapter 5, Key Assumptions, for a detailed description of the scenarios and sensitivities and the key assumptions used to create them: customer demand, natural gas prices, possible CO_2 prices, resource costs (demand-side and supply-side) and power prices.

> > > See Appendix D, Electric Resource Alternatives, for a detailed discussion of existing electric resources and resource alternatives.

> > > See Appendix K, Economic, Health and Environmental Benefits Assessment of Current Conditions, for a detailed discussion of the customer indicators developed for the customer benefits analysis.

Summary of Assumptions

Figure 8-9: 2021 IRP Electric Portfolio Sensitivities

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
ECONOMIC SCENARIOS		
1	Mid	Mid gas price, mid demand forecast[a.], mid electric price forecast
2	Low	Low gas price, low demand forecast, low electric price forecast
3	High	High gas price, high demand forecast, high electric price forecast
FUTURE MARKET AVAILABILITY		
A	Renewable Overgeneration Test	The portfolio model is not allowed to sell excess energy to the Mid-C market.
B	Reduced Firm Market Access at Peak	The portfolio model has a reduced access to the Mid-C market for both sales and purchases.
TRANSMISSION CONSTRAINTS AND BUILD LIMITATIONS		
C	"Distributed" Transmission/Build Constraints - Tier 2	The portfolio model is performed with Tier 2 transmission availability.
D	Transmission/Build Constraints – Time-delayed (Option 2)	The portfolio model is performed with gradually increasing transmission limits.
E	Firm Transmission as a Percentage of Resource Nameplate	New resources are acquired with firm transmission equal to a percentage of their nameplate capacity instead of their full nameplate capacity.
CONSERVATION ALTERNATIVES		
F	6-Year Conservation Ramp Rate	Energy efficiency measures ramp up over 6 years instead of 10.
G	Non-energy Impacts	Increased energy savings are assumed from energy efficiency not captured in the original dataset.
H	Social Discount Rate for DSR	The discount rate for demand-side resource measures is decreased from 6.8% to 2.5%.
SOCIAL COST OF GREENHOUSE GASES (SCGHG) AND CO_2 REGULATION		
I	SCGHG as an Externality Cost in the Portfolio Model	The SCGHG is used as an externality cost in the portfolio expansion model.
J	SCGHG as a Dispatch Cost in Electric Prices and Portfolio	The SCGHG is used as a dispatch cost (tax) in both the electric price forecast and portfolio model.
K	AR5 Upstream Emissions	The AR5 model is used to model upstream emissions instead of AR4.
L	SCGHG as a Fixed Cost Plus a Federal CO_2 Tax	Federal tax on CO_2 is included in addition to using the SCGHG as a fixed cost adder.

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
EMISSION REDUCTION		
M	Alternative Fuel for Peakers	Peaker plants use biodiesel as an alternative fuel.
N	100% Renewable by 2030	The CETA 2045 target of 100% renewables is moved up to 2030, with no new natural gas generation.
O	100% Renewable by 2045	All existing natural gas plants are retired in 2045.
P	No New Thermal Resources before 2030	1. This portfolio limits peaker builds before 2030 so that the model must meet peak capacity with alternative resources. 2. Build pumped hydro storage instead of battery energy storage to meet peak capacity before 2030. 3. Build 4-hour lithium-ion battery energy storage to meet peak capacity before 2030.
DEMAND FORECAST ADJUSTMENTS		
Q	Fuel Switching, Gas to Electric	Gas-to-electric conversion is accelerated in the PSE service territory.
R	Temperature Sensitivity	Temperature data used for economic forecasts is composed of more recent weather data as a way to represent changes in climate.
CETA COSTS		
S	SCGHG Included, No CETA	The SCGHG is included in the portfolio model without the CETA renewable requirement.
T	No CETA	The portfolio model does not have CETA renewable requirement or the SCGHG adder.
U	2% Cost Threshold	CETA is considered satisfied once the 2% cost threshold is reached.
BALANCED PORTFOLIO		
V	Balanced Portfolio	1. The portfolio model must take distributed energy resources ramped in over time and more customer programs. 2. The portfolio model must take distributed energy resources ramped in over time, more customer programs, and early addition of a MT wind + pumped hydro storage resource. 3. The portfolio model must take distributed energy resources ramped in over time, more customer programs, and conservation measures are ramped in over 6 years, instead of 10.
W	Balanced Portfolio with Alternative Fuel for Peakers	The portfolio model must take distributed energy resources ramped in over time and more customer programs, plus carbon-free combustion turbines using biodiesel as the fuel.

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
X	Balanced Portfolio with Reduced Firm Market Access at Peak	The portfolio model must take distributed energy resources ramped in over time and more customer programs, plus reduced access to the Mid-C market for both sales and purchases.
WX	Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak	The portfolio model implements the changes from portfolios W and X simultaneously.
Y	Maximum Customer Benefit	RCW 19.405.040 (8) In complying with this section, an electric utility must, consistent with the requirements of RCW 19.280.030 and 19.405.140, ensure that all customers are benefiting from the transition to clean energy: Through the equitable distribution of energy and nonenergy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits and reduction of costs and risks; and energy security and resiliency.
OTHER		
Z	No DSR	This portfolio includes no new demand-side resources. (energy efficiency, distribution efficiency and demand response)
AA	Montana Wind + Pumped Hydro Storage	This portfolio adds the hybrid resource of MT wind + pumped hydro storage instead of only the MT wind resource in 2026.

NOTE
a. Mid demand refers to the 2021 IRP Base Demand Forecast.

Key Findings: Economic Scenarios

The quantitative results produced by extensive analytical and statistical evaluation led to the key findings summarized in the following pages.

Economic Scenarios

Portfolio additions are very similar across all three economic scenarios. The amount of resources added increased or decreased based on high and low load forecasts, respectively. Direct emissions are lower with the retirement of Centralia and the removal of Colstrip 3 & 4 in 2025 as part of CETA compliance, and continue trending down throughout the planning horizon. The renewable requirement to meet CETA drives the renewable builds for each scenario.

Key Findings: Portfolio Sensitivities

Future Market Availability

Renewable overgeneration occurs when renewable resources generate more energy than there is demand. Limiting market access, either sales or purchases, increases the cost of CETA implementation by overbuilding battery storage to store the overgeneration of renewable resources instead of selling it to the market. Reducing the reliance on short-term market during peak increases the peak need for new capacity resources or firm resource adequacy qualifying contracts.

Transmission Constraints and Build Limitations

The majority of new renewable resources included in the 2021 IRP are sited outside of PSE's service area. These resources require transmission to deliver power from the generation site to PSE's customers. Transmission is a relatively scarce asset, and there is uncertainty about PSE's ability to procure transmission for the optimal renewable resource mix. Varying the amount of transmission available to regions around PSE's service area measures the impact of these uncertainties.

There is little impact on portfolio build decisions when transmission constraints are modeled to match transmission procurement expectations and timelines (Sensitivity D). This suggests that the generally unconstrained transmission identified for this IRP is a reasonable assumption for the comparative portfolio sensitivity analysis.

However, portfolio build decisions shift when transmission constraints limit resource build to under 3,070 MW outside of PSE's service area (Sensitivity C). More distributed solar resources located within PSE's service territory are selected and battery storage is increased to help balance generation and demand.

When contracting firm transmission less than the nameplate capacity of resources, site location and fixed transmission costs are important considerations. Project sites with low transmission costs tend to benefit less than sites with high transmission costs. Wind resources tend to benefit less than solar resources due to the significant portion of time that wind resources spend generating at or near nameplate capacity (i.e., rated power).

Conservation Alternatives

Across the conservation alternatives evaluated for this IRP, cost-effective demand-side resources, portfolio costs and build decisions remain relatively stable. Incremental energy savings by bundle vary depending on the conservation alternative driving the bundle selection. Changes in the assumptions for the conservation alternatives pushed more energy savings into lower bundles. In some results, decreased investment in conservation measures is supplemented by increased demand response measures. By changing the ramp rates and discount rate of the bundles, the portfolio moves into lower bundle levels than the Mid portfolio, but still adds a similar or lower amount of conservation as the Mid portfolio. Overall, the baseline assumptions around demand-side resources included in the mid portfolio optimize to the highest amount DSR added to the portfolio by 2045.

Demand response and conservation are important resource options in PSE's portfolio, and they are considered load-reducing resources in the calculation of the CETA renewable need. Absent these resources, the portfolio adds more renewable resources, resulting in increased portfolio costs.

Social Cost of Greenhouse Gases (SCGHG) and CO_2 Regulation

Different modeling approaches to incorporating the social cost of greenhouse gases do not have a material impact on the cost-effective amount of conservation, demand response and other resource additions or retirements.

Whether modeling SCGHG as a fixed cost planning adder, a dispatch cost in the resource selection or as a dispatch cost in both the resource selection and hourly portfolio run, CETA requirements for renewable resources are the key driver of portfolio resource additions and costs.

Using the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5) to calculate upstream emissions increased those emissions for natural gas, but did not change resource builds or retirements compared to utilizing the IPCC's Fourth Assessment Report (AR4).

Applying a Federal CO_2 tax in addition to SCGHG as a fixed-cost planning adder does appear to alter portfolio build decisions, resulting in the addition of fewer thermal resources. Dispatch from thermal plants also declines over time resulting in lower portfolio emissions.

Emissions Reduction

Reducing emissions and even achieving a 100 percent renewable portfolio may be possible with existing technologies, but the cost to do so is high. Large investments in storage to replace thermal resources results in high portfolio costs. Although direct emissions from generating resources are reduced, indirect emissions from market purchases increase because energy purchased from the market is needed to support the storage-heavy portfolios.

Demand Forecast Adjustments

Using alternative temperature data to forecast demand and use in the resource adequacy analysis lowers the demand forecast and the peak capacity need. The lower demand forecast lowers the CETA renewable need. The reduction in peak capacity need results in all future needs being met by new renewable resources and battery energy storage.

On the other hand, fuel switching from gas to electric results in a higher demand forecast and higher CETA renewable need. Resource builds of every resource type increased to support the higher loads.

CETA Costs

CETA requirements drive renewable resource build decisions. Absent CETA requirements, no renewable resources are added to the portfolio except a wind resource towards the end of the planning horizon, which is needed to maintain compliance with RCW 19.285, and more flexible capacity resources are added over time to meet increasing peak capacity need. The cost of the No CETA portfolio is significantly lower than the CETA-compliant portfolios. This is an initial attempt to evaluate the incremental cost of compliance. Portfolio costs stay within the 2 percent annual revenue requirement for the early part of the planning horizon, but increase over time and exceed the 2 percent cost threshold by 2030.

Balanced Portfolio

A forecast of distributed energy resources (DERs) and customer programs ramped in over time helps to spread the revenue requirement throughout the planning horizon. Although DERs have lower peak capacity contributions and increase portfolio costs, there are customer benefits to be gained related to air quality and environment. Significant emission reductions are achieved with the addition of non-emitting resources, the retirement of coal resources and lower dispatch of existing resources. The availability of biodiesel fuel for peaking capacity resources further reduces emissions.

Relative Optimal Portfolio Costs, Builds and Emissions

Figure 8-10: Relative Optimal Portfolio Costs by Sensitivity
(dollars in billions, NPV including end effects)

	24-Yr Levelized Costs ($ Billions)			
Portfolio	**Revenue Requirement**	**SCGHG Adder**	**Total**	**Change from Mid**
1 Mid	$15.53	$5.09	$20.62	$0.00
2 Low	$12.08	$4.53	$16.61	($4.01)
3 High	$21.37	$5.74	$27.11	$6.49
A Renewable Overgeneration	$17.11	$4.45	$21.55	$0.93
B Market Reliance	$16.57	$5.19	$21.76	$1.14
C Distributed Transmission	$16.35	$5.21	$21.56	$0.94
D Transmission/build constraints - time delayed (option 2)	$15.54	$5.11	$20.65	$0.03
F 6-Yr DSR Ramp	$15.54	$5.09	$20.62	$0.00
G NEI DSR	$15.24	$5.12	$20.36	($0.26)
H Social Discount DSR	$15.77	$5.16	$20.94	$0.32
I SCGHG Dispatch Cost - LTCE Model	$15.41	$5.10	$20.51	($0.11)
J SCGHG Dispatch Cost - LTCE and Hourly Models	$18.45	$4.81	$23.26	$2.64
K AR5 Upstream Emissions	$15.56	$5.14	$20.71	$0.09
L SCGHG Federal CO2 Tax as Fixed Cost	$17.77	$4.71	$22.47	$1.86
M Alternative Fuel for Peakers - Biodiesel	$15.53	$4.99	$20.52	($0.10)
N1 100% Renewable by 2030 Batteries	$32.03	$3.76	$35.79	$15.17
N2 100% Renewable by 2030 PSH	$66.64	$2.52	$69.16	$48.54
O1 100% Renewable by 2045 Batteries	$23.35	$4.81	$28.16	$7.54
O2 100% Renewable by 2045 PSH	$46.95	$3.98	$50.94	$30.32
P1 No Thermal Before 2030, 2Hr LiIon	$30.84	$6.38	$37.22	$16.60
P2 No Thermal Before 2030, PHES	$22.85	$4.77	$27.62	$7.00

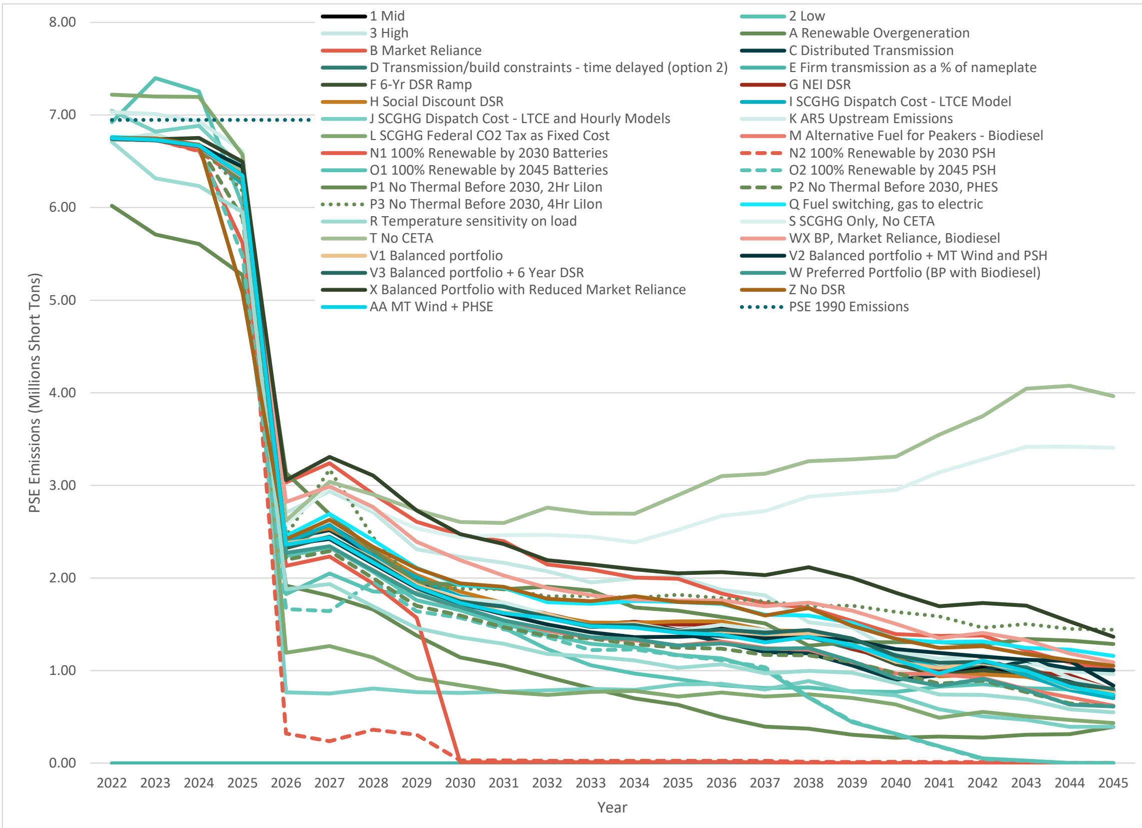
P3 No Thermal Before 2030, 4Hr LiIon	$39.01	$6.69	$45.70	$25.08
Q Fuel switching, gas to electric	$19.56	$5.60	$25.16	$4.54
R Temperature sensitivity on load	$13.53	$4.69	$18.22	($2.40)
S SCGHG Only, No CETA	$9.29	$8.86	$18.16	($2.46)
T No CETA	$9.32	$9.27	$18.59	($2.03)
V1 Balanced portfolio	$16.06	$5.07	$21.14	$0.52
V2 Balanced portfolio + MT Wind and PSH	$16.61	$5.12	$21.73	$1.11
V3 Balanced portfolio + 6 Year DSR	$16.26	$5.06	$21.32	$0.70
W Preferred Portfolio (BP with Biodiesel)	$16.10	$4.96	$21.06	$0.44
X Balanced Portfolio with Reduced Market Reliance	$17.21	$5.36	$22.57	$1.95
WX BP, Market Reliance, Biodiesel	$17.30	$5.06	$22.36	$1.74
Z No DSR	$17.54	$5.56	$23.10	$2.48
AA MT Wind + PHSE	$15.84	$5.16	$20.99	$0.37

Figure 8-11: Relative Optimal Portfolio Builds by Scenario and Sensitivity (cumulative nameplate capacity in MW for each resource addition by 2045)

	Resource Additions by 2045, Nameplate (MW)											
Portfolio	Demand-side Resources	Battery Energy Storage	Solar - Ground and Rooftop	Demand Response	DSP Non-Wire Alternatives	Biomass	Solar	Wind	Renewable + Storage Hybrid	Pump Hydro Storage	Peaking Capacity	Total
1 Mid	1,497	550	0	123	118	90	1,393	3,350	250	0	948	**8,319**
2 Low	1,537	275	0	181	118	30	1,096	2,450	250	0	237	**6,175**
3 High	1,733	900	0	128	118	150	2,292	3,850	0	0	1,659	**10,830**
A Renewable Overgeneration	1,537	1,525	0	192	118	150	2,388	2,250	725	0	474	**9,359**
B Market Reliance	1,497	650	50	173	118	135	995	3,350	375	0	1,732	**9,075**
C Distributed Transmission	1,537	1,050	2,700	178	118	150	500	2,615	125	0	1,003	**9,976**
D Transmission/ build constraints - time delayed (option 2)	1,537	650	0	180	118	135	1,295	3,300	250	0	948	**8,413**
F 6-Yr DSR Ramp	1,372	625	0	175	118	150	1,394	3,150	500	0	966	**8,449**
G NEI DSR	1,304	450	0	188	118	150	1,393	3,450	125	0	1,185	**8,363**
H Social Discount DSR	1,179	675	0	195	118	150	1,391	3,150	625	0	948	**8,431**
I SCGHG Dispatch Cost - LTCE Model	1,497	875	0	188	118	135	1,294	3,150	375	0	766	**8,398**
J SCGHG Dispatch Cost - LTCE and Hourly Models	1,497	850	0	205	118	60	996	3,550	375	0	747	**8,397**
K AR5 Upstream Emissions	1,497	625	0	140	118	150	1,393	3,150	250	0	948	**8,270**
L SCGHG Federal CO2 Tax as Fixed Cost	1,537	525	0	183	118	135	1,395	3,150	250	0	829	**8,122**
M Alternative Fuel for Peakers - Biodiesel	1,537	700	0	185	118	75	1,593	3,150	250	0	948	**8,557**
N1 100% Renewable by 2030 Batteries	1,304	26,200	0	59	118	0	1,994	3,850	0	0	0	**33,523**
N2 100% Renewable by 2030 PSH	1,169	0	0	59	118	75	3,268	3,600	622	21,300	0	**30,211**
O1 100% Renewable by 2045 Batteries	1,304	24,500	0	128	118	0	1,692	3,950	0	0	0	**31,692**

O2 100% Renewable by 2045 PSH	1,537	0	0	204	118	0	99	3,650	1,249	19,600	0	**26,458**
P1 No Thermal Before 2030, 2Hr LiIon	1,372	4,300	0	178	118	15	1,695	3,550	125	0	474	**11,827**
P2 No Thermal Before 2030, PHES	1,304	1,025	0	122	118	15	2,294	3,550	0	2,700	18	**11,146**
P3 No Thermal Before 2030, 4Hr LiIon	1,372	4,425	0	129	118	0	2,292	3,250	0	0	0	**11,586**
Q Fuel switching, gas to electric	1,537	2,000	0	108	118	135	4,880	3,850	825	0	2,961	**16,414**
R Temperature sensitivity on load	1,372	500	0	130	118	150	1,195	3,150	0	0	0	**6,614**
S SCGHG Only, No CETA	1,179	50	0	203	118	0	0	350	0	0	1,896	**3,795**
T No CETA	1,042	0	0	123	118	0	0	350	0	0	2,133	**3,766**
V1 Balanced portfolio	1,784	450	680	217	118	105	696	3,250	375	0	966	**8,641**
V2 Balanced portfolio + MT Wind and PSH	1,784	375	680	217	118	120	895	3,150	425	0	948	**8,711**
V3 Balanced portfolio + 6 Year DSR	1,658	675	680	217	118	120	895	3,450	125	0	1,003	**8,940**
W Preferred Portfolio (BP with Biodiesel)	1,784	450	680	217	118	105	696	3,250	375	0	966	**8,354**
X Balanced Portfolio with Reduced Market Reliance	1,824	775	680	217	118	120	596	3,350	250	0	1,677	**9,321**
WX BP, Market Reliance, Biodiesel	1,824	775	680	217	118	120	596	3,350	250	0	1,677	**9,607**
Z No DSR	690	1,250	0	0	118	150	2,688	3,450	500	0	1,422	**10,268**
AA MT Wind + PHSE	1,497	300	0	182	118	150	1,094	3,350	425	0	948	**8,064**

Figure 8-12: Relative Optimal Portfolio Emissions by Scenario and Sensitivity (annual direct portfolio emissions by year)



6. ECONOMIC SCENARIO ANALYSIS RESULTS

Portfolio Builds

The portfolio builds for all three economic scenarios look very much alike given the generic resource options. The mix of resources is similar and the amount of resources added varied depending on the load forecasts. In the Low economic scenario fewer resources are added due to lower demand, lower peak need and lower renewable need. In the High economic scenario, more resources are added due to higher demand, higher peak need and higher renewable need. Figure 8-13, shows the levelized cost by scenario while Figure 8-14 shows the optimal portfolio builds by scenario.

Figure 8-13: Relative Optimal Portfolio Costs by Scenario (dollars in billions, NPV including end effects)

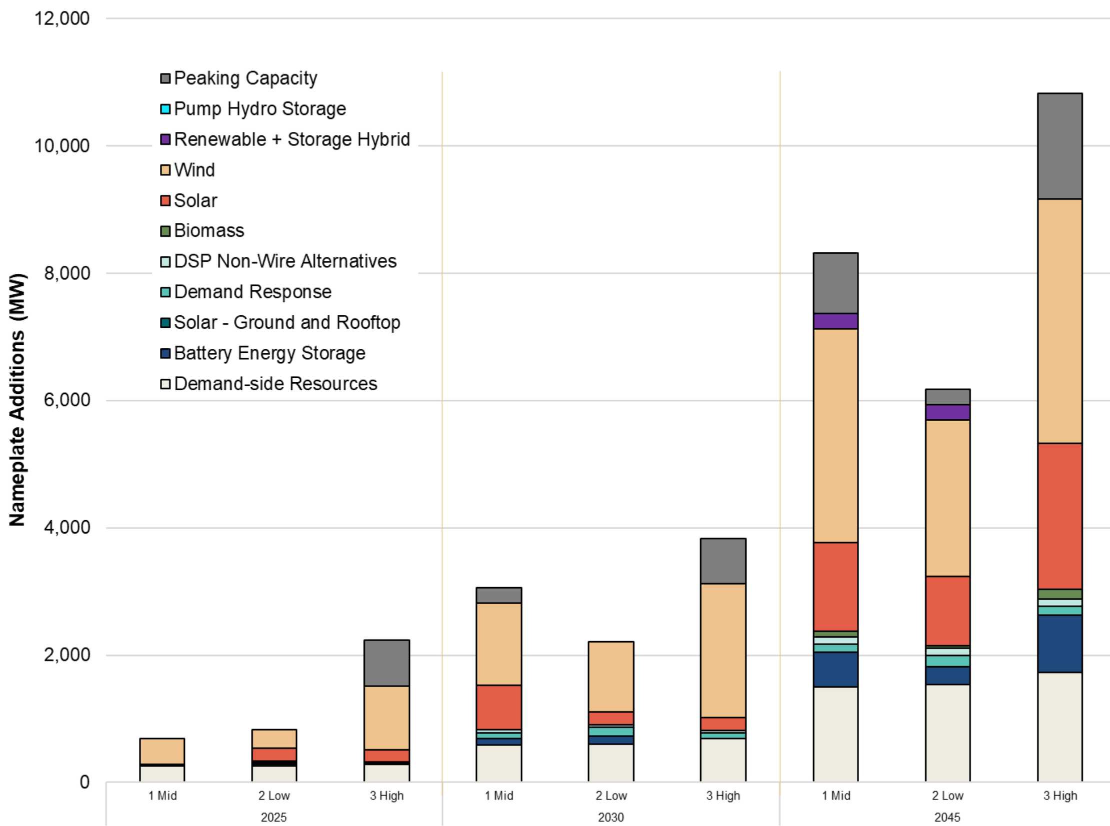
		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
2	Low Scenario	$12.08	$4.53	$16.61	($3.45)
3	High Scenario	$21.37	$5.74	$27.11	$5.84

Figure 8-14: Relative Optimal Portfolio Builds by Scenario
(cumulative nameplate capacity in MW for each resource addition by 2045)

Resource Additions by 2045	1 Mid	2 Low	3 High
Demand-side Resources	1,497 MW	1,537 MW	1,733 MW
Battery Energy Storage	550 MW	275 MW	900 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW
Demand Response	123 MW	181 MW	128 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	3,576 MW	6,292 MW
Biomass	90 MW	30 MW	150 MW
Solar	1,393 MW	1,096 MW	2,292 MW
Wind	3,350 MW	2,450 MW	3,850 MW
Renewable + Storage Hybrid	250 MW	250 MW	0 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW
Peaking Capacity	948 MW	237 MW	1,659 MW

Figure 8-15 below displays the megawatt additions for the deterministic analysis of optimal portfolios for all three scenarios in 2025, 2030 and 2045. No new resources are added until 2024. See Appendix H, Electric Analysis Inputs and Results, for more detailed information.

Figure 8-15: Resource Builds by Scenario, Cumulative Additions by Nameplate (MW)



Portfolio Emissions

Figure 8-16 shows CO_2 emissions for the Mid, Low and High Scenarios. The chart shows the direct emissions from portfolio resources for each scenario and does not account for alternative compliance mechanisms to achieve the carbon neutral standard from 2030 to 2045. Despite varying demand, natural gas price and electric price forecasts, the three scenarios all converge on a similar quantity of direct emissions by 2045, driven by CETA renewable energy targets.

Figure 8-16: CO_2 Emissions for the Mid, Low and High Scenarios (does not include alternative compliance to meet carbon neutral standard in 2030 and beyond)

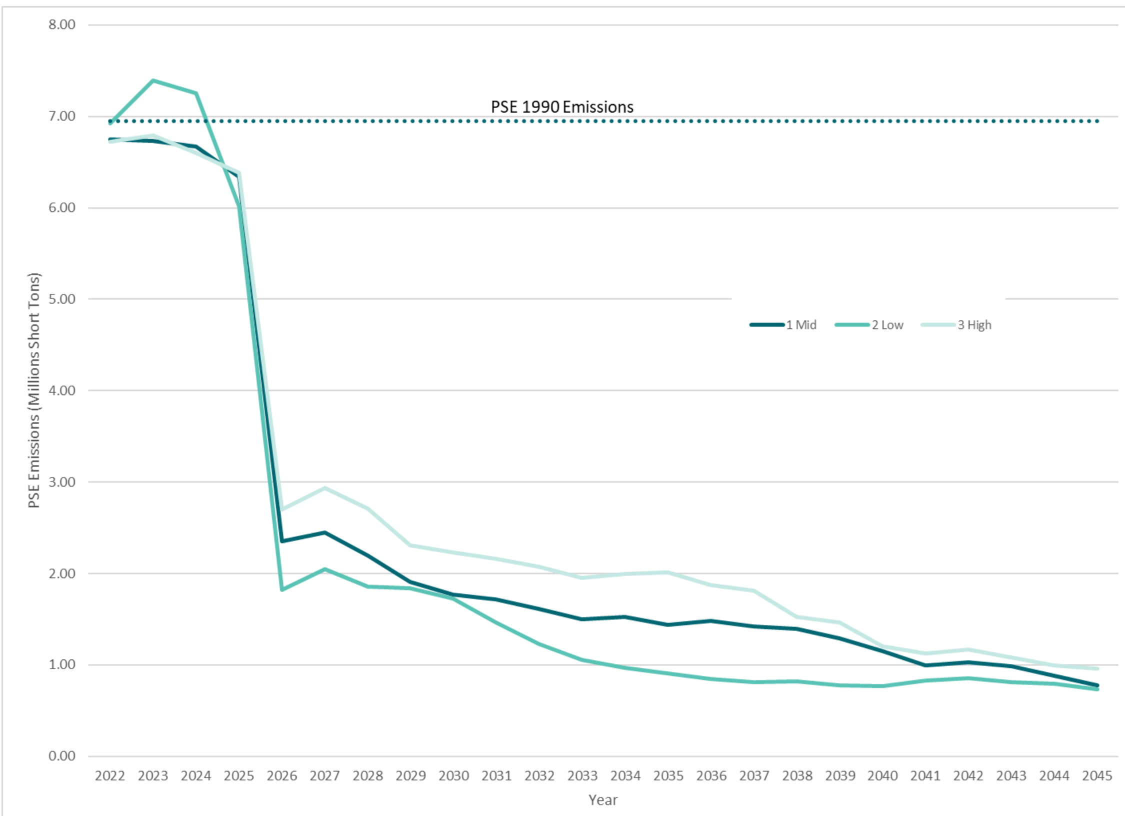
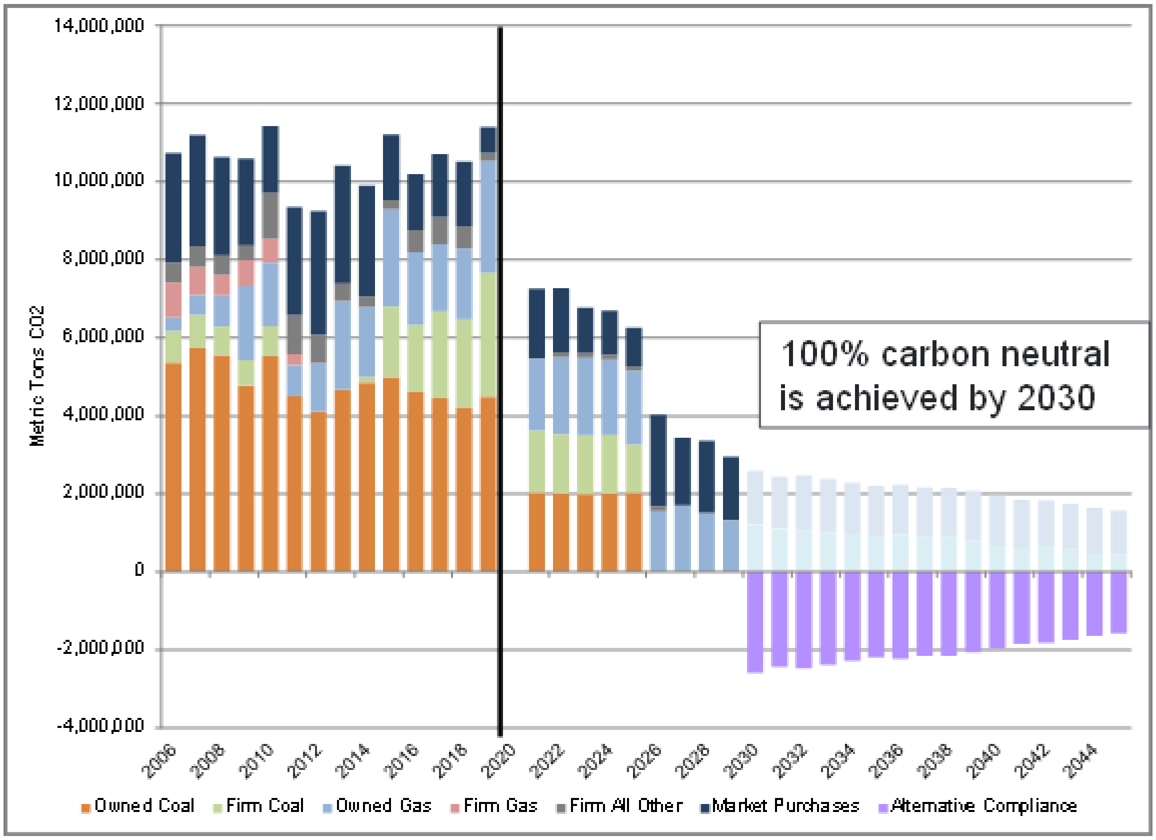


Figure 8-17, below, shows the Mid Scenario portfolio emissions by resource type. There is a direct relationship between emissions and the dispatch of thermal plants. Direct emissions decreased with the retirement of Colstrip 1 & 2 in 2019 and will decrease further with a lower projected economic dispatch of thermal resources as well the exit of Colstrip 3 & 4 and Centralia from the portfolio. With the resource retirements and forecasted drop in dispatch, total portfolio emissions decrease by over 70 percent from 2019 to 2029. Using alternative compliance mechanisms, the portfolio achieves carbon neutrality from 2030 through to 2045.

Figure 8-17: Historical and Projected Annual Total PSE Portfolio CO_2 Emissions for the Mid Scenario Portfolio



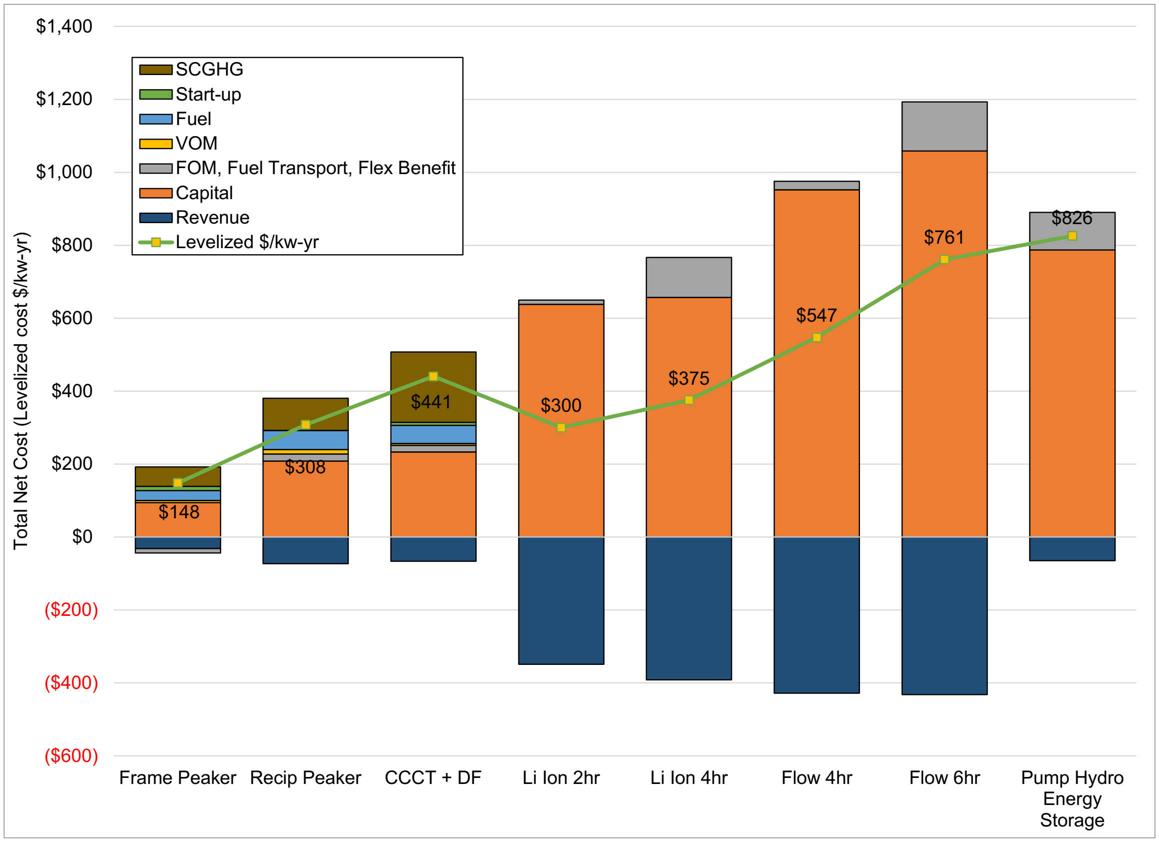
Levelized Cost of Capacity

The levelized costs for peakers, baseload natural gas plants and energy storage resources were evaluated using the Mid Scenario assumptions for electric price, natural gas price and demand to better understand how the resources compare during resource selection. The levelized cost of capacity is based on the peak capacity value of a resource. For example, the nameplate of a 2-hour lithium-ion battery is 25 MW, but it has an ELCC[4] of 12.4 percent, so the peak capacity value is 3.1 MW. (The total cost of the lithium-ion battery is divided by 3.1 MW instead of the 25 MW, which is why it has a high levelized cost of capacity.) When calculating the levelized cost of capacity for new peakers and baseload natural gas plants, the SCGHG is added to the total cost; this increased the levelized cost of capacity for frame peakers from \$95 to \$148. Figure 8-18

4 / The effective load carrying capacity (ELCC) of a resource represents the peak capacity credit assigned to that resource. More information on ELCC can be found in Chapter 7.

compares the net cost of capacity for peakers, baseload natural gas plants and energy storage resources.

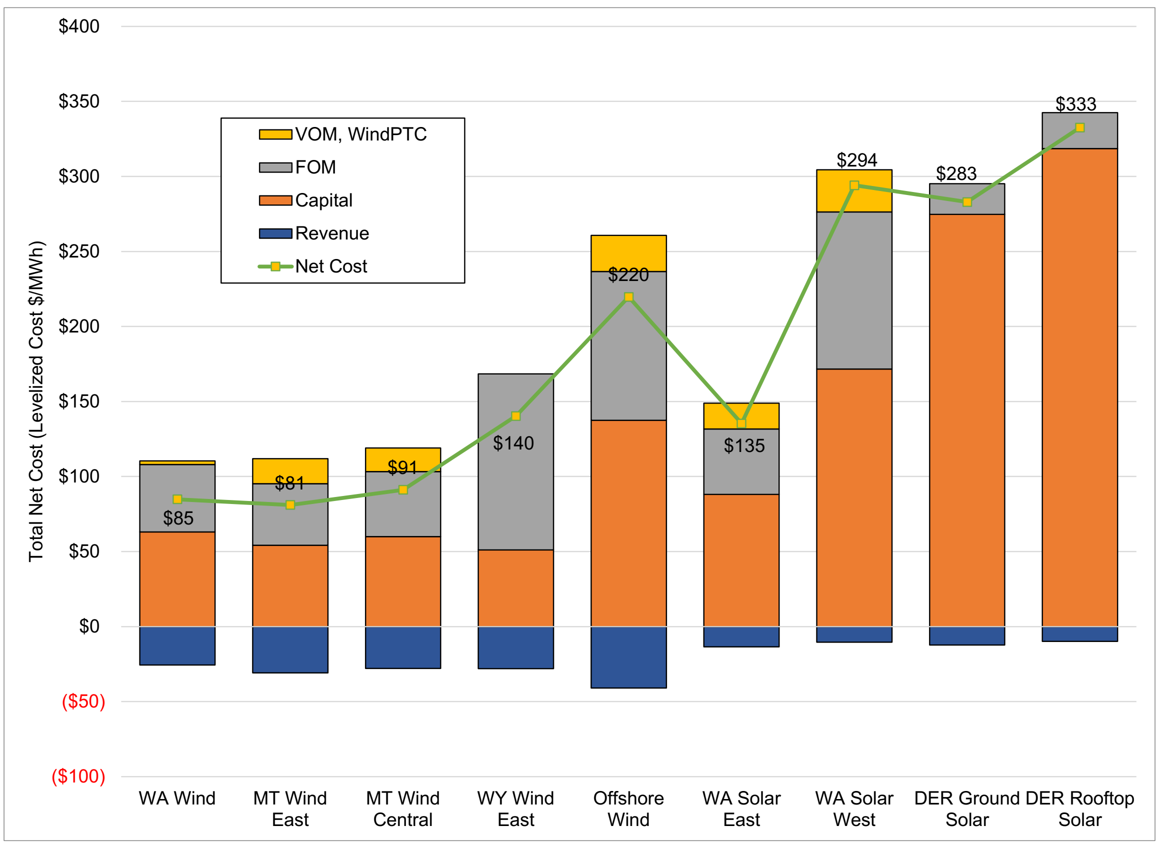
Figure 8-18: Net Cost of Capacity in the Mid Scenario Portfolio Model



Levelized Cost of Energy

The levelized costs of energy for wind and solar resources were also evaluated using the Mid Scenario assumptions to better understand how the resources compare during resource selection. The costs are calculated based on energy and do not account for any peak capacity contribution. Montana wind power is expected to be more cost effective than wind and solar from the Pacific Northwest. Even though Wyoming wind is higher cost because of transmission costs, it has a high peak capacity credit and provides other value to the portfolio. Given transmission constraints, resources outside of the Pacific Northwest region will be limited. After Montana and Wyoming wind, eastern Washington utility-scale solar is the next lowest cost resource. Figure 8-19 illustrates the levelized costs of renewable resource to meet CETA.

Figure 8-19: Wind and Solar Cost Components, Mid Scenario Portfolio



7. SENSITIVITY ANALYSIS RESULTS

Portfolio sensitivity analysis is an important form of risk analysis that helps PSE understand how specific assumptions can change the mix of resources in the portfolio and affect portfolio costs. This section provides the results and detailed analysis for each sensitivity. Additional results, including year-by-year resource timelines, cost breakdowns and emissions data are provided in Appendix H.

Future Market Availability

A. Renewable Overgeneration Test

In the Mid portfolio there were 0.23 percent of load (355 hours) of overgeneration in 2030 and 10 percent of load (4,000 hours) in 2045. This sensitivity tests the costs and portfolio changes to eliminate the overbuild of renewable generation observed in the Mid portfolio. By eliminating market sales of excess renewable energy in this sensitivity, PSE can quantify the importance of market sales to reduce cost of meeting CETA.

Baseline: PSE can sell 1,500 MW of energy to the Mid-C market at any given hour, subject only to transmission availability.
Sensitivity > PSE cannot sell any energy to the Mid-C market.

KEY FINDINGS. Prohibiting sales to the Mid-C market reduces renewable overgeneration by eliminating market sales and increasing battery energy storage so that the generation can be stored instead. Though renewable generation still occurs in Sensitivity A, it is reduced by 10 percent consistent with the 10 percent overbuild of generation in the Mid Scenario. Wind capacity is reduced, and the remaining renewable generation is from increased solar builds. This portfolio costs almost $1.6 billion more than the Mid portfolio by adding more battery energy storage, but only reduced the overgeneration by 3 percent by 2045. Figure 8-20 compares the amount of renewable overgeneration in the Mid Scenario and Sensitivity A portfolios. In the Mid Scenario portfolio, renewable overgeneration can provide value through sales. In Sensitivity A, without the ability to sell excess energy, the model can only curtail that production or use it to charge battery resources; once the battery resources are at capacity, there is no option left but to curtail the energy. The market is an effective way to reducing cost.

Figure 8-20: Renewable Overgeneration – Mid Scenario and Sensitivity A

	2030			2045		
Portfolio	Hours of Over-generation	MWh of Over-generation	% of total load with conservation	Hours of Over-generation	MWh of Over-generation	% of total load with conservation
Mid Scenario	355	53,946	0.23%	4,330	3,021,777	10.6%
Sensitivity A	29	1,495	0.01%	3,396	2,063,604	7.21%

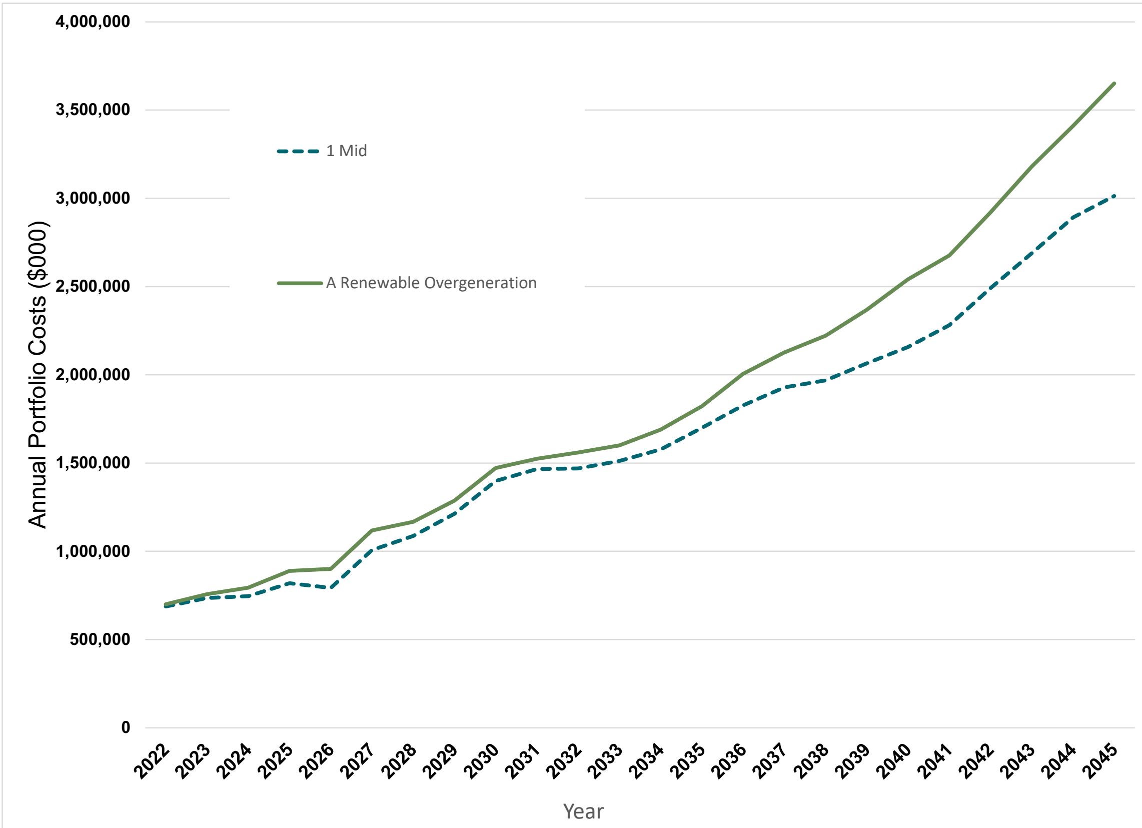
ASSUMPTIONS. This portfolio keeps all underlying assumptions from the Mid portfolio. The only difference between Sensitivity A and the Mid Scenario is PSE's ability to sell energy to the Mid-C market, which is removed in Sensitivity A.

ANNUAL PORTFOLIO COSTS. Figures 8-21 and 8-22 illustrate the breakdown of costs between the Mid Scenario and Sensitivity A portfolios. Sensitivity A is higher cost overall than the Mid portfolio, and costs begin to diverge at a greater pace as sensitivity A invests heavily in the energy storage necessary to store the renewable generation that cannot be sold to the market. .

Figure 8-21: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity A

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
A	Renewable Overgeneration test	$17.11	$4.45	$21.55	$0.93

Figure 8-22: Annual Portfolio Costs – Mid Scenario and Sensitivity A



RESOURCE ADDITIONS. Figure 8-23 compares the nameplate capacity additions of the Sensitivity A and Mid Scenario portfolios. Sensitivity A builds more nameplate capacity than the Mid Scenario, and the distribution of resources shifts some capacity from wind generation to solar and storage. No pumped hydro storage is built, but investment in hybrid resources and standalone battery resources increases. Conservation reaches Bundle 11 in this sensitivity. No PSE resources, new or existing, are retired in this sensitivity.

Figure 8-23: Portfolio Additions– Mid Scenario and Sensitivity A, Renewable Overgeneration

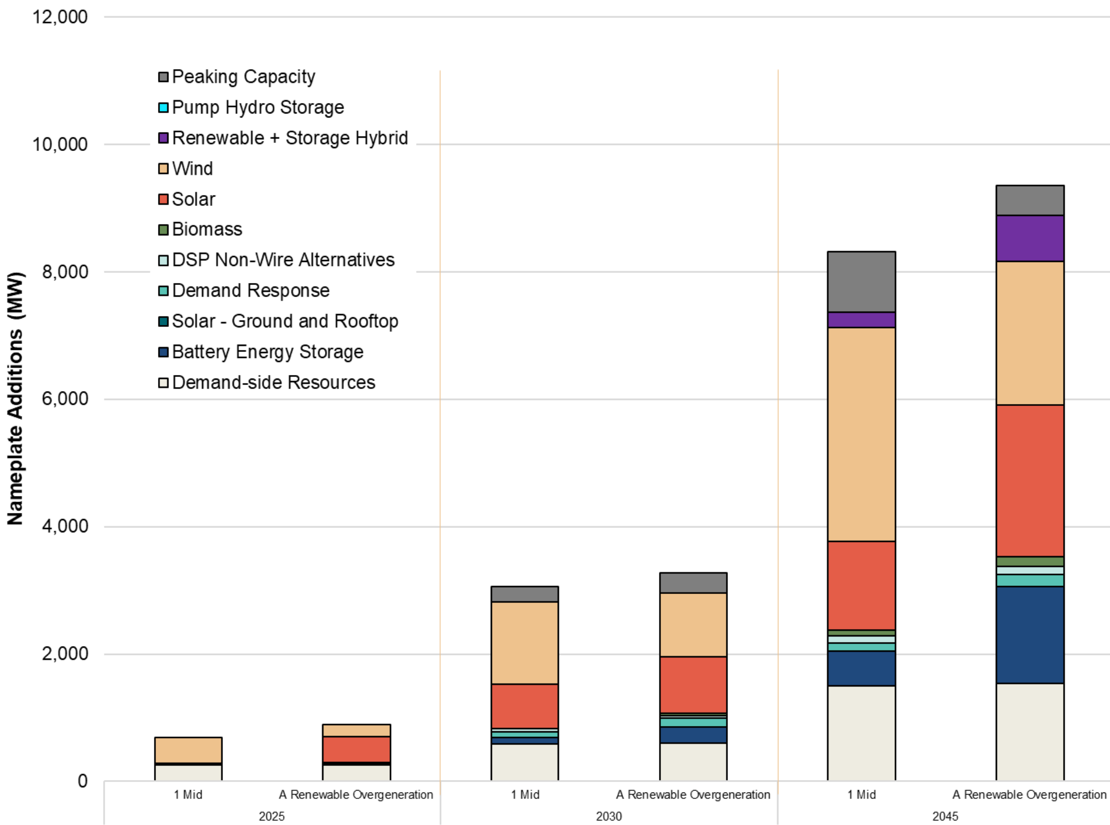


Figure 8-24: Portfolio Additions by 2045 – Mid Scenario and Sensitivity A, Renewable Overgeneration

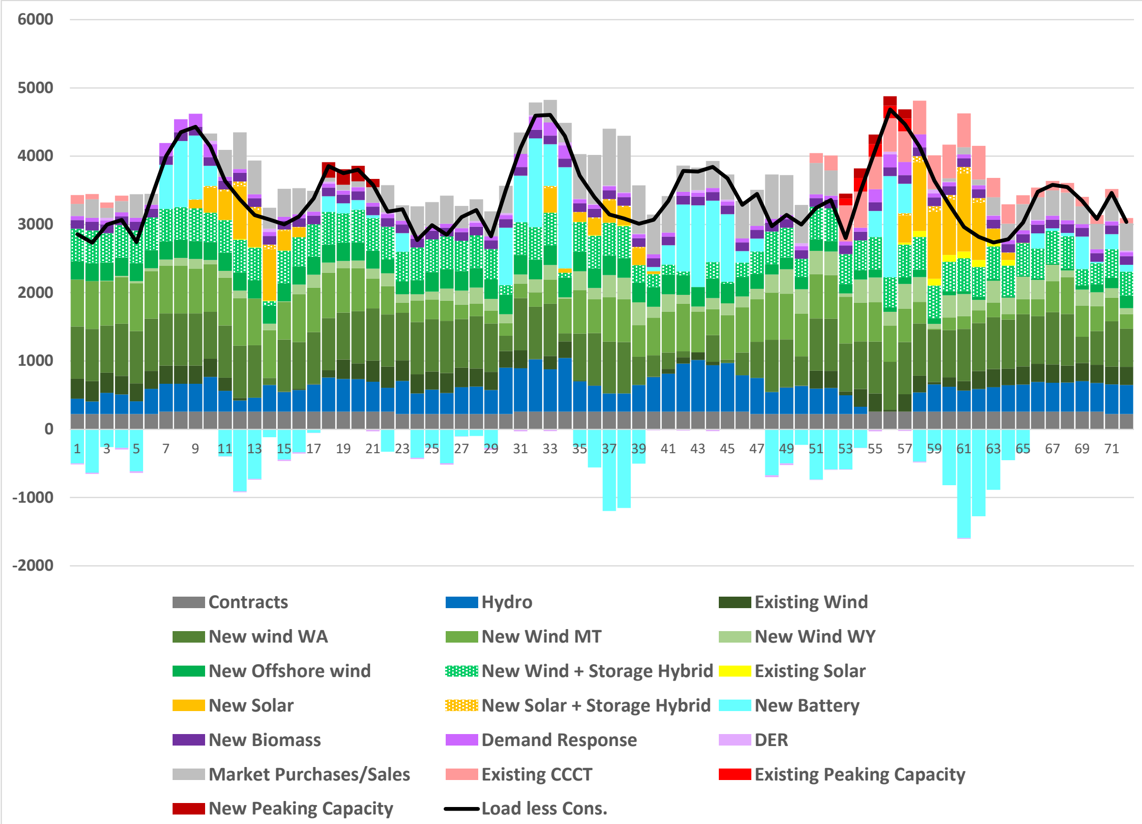
Resource Additions by 2045	1 Mid	A Renewable Overgeneration
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	1,525 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	192 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,788 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	2,388 MW
Wind	3,350 MW	2,250 MW
Renewable + Storage Hybrid	250 MW	725 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	474 MW[1]

NOTE
1. Includes 237 MW of recip peakers and 237 MW of frame peakers

PEAK NEED. In 2045, the peak capacity behavior of the new resources changes in this sensitivity. Figure 8-25 shows the hourly dispatch of resources in Sensitivity A during peak demand for 2045. Resources generating above the black line are producing power in excess of load from mostly market purchases (gray bars) and some new and existing natural gas generation (maroon and pink bars) mostly to charge batteries (blue bars below zero).

During periods of peak demand, there is not enough generation to both meet customer demand and charge batteries. In order for the battery to meet energy need during peaks, the batteries must be charged. Without market for charging the batteries as in this sensitivity, the model uses natural gas generation to charge the batteries.

Figure 8-25: 2045 Peak Demand Period of Sensitivity A, December 28-30, 2045



The relationship between market purchases and battery activity can be seen by examining the times at which the market purchases are occurring. For Sensitivity A, Figure 8-26 shows the percentage of hours each month where market purchases are being made by PSE in the year 2045. Market purchases are made consistently throughout the winter to assist the generating resources. During off-peak hours, market purchases provide energy for the batteries to charge; during peak hours when the batteries are discharging, market purchases help to meet demand.

Figure 8-26: Percentage of Each Month Where Market Purchases are Being Made in Each Hour for Sensitivity A, 2045

All Purchase Hours

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0:00	81%	83%	87%	27%	0%	0%	13%	48%	83%	71%	67%	100%
1:00	81%	83%	84%	27%	0%	0%	13%	48%	90%	71%	67%	100%
2:00	81%	86%	84%	27%	0%	0%	13%	48%	83%	71%	67%	100%
3:00	81%	83%	81%	23%	0%	0%	13%	42%	83%	71%	67%	100%
4:00	81%	86%	77%	17%	0%	0%	10%	48%	83%	74%	63%	87%
5:00	84%	76%	77%	20%	0%	0%	6%	42%	87%	71%	63%	87%
6:00	84%	62%	61%	17%	0%	0%	3%	52%	83%	71%	67%	81%
7:00	81%	69%	65%	3%	0%	0%	10%	48%	73%	68%	60%	77%
8:00	84%	79%	58%	10%	0%	0%	6%	61%	70%	71%	60%	87%
9:00	84%	76%	68%	10%	0%	0%	6%	65%	70%	68%	57%	94%
10:00	81%	79%	71%	10%	0%	0%	13%	61%	67%	68%	57%	97%
11:00	77%	79%	68%	10%	0%	0%	19%	61%	70%	68%	60%	97%
12:00	77%	79%	65%	17%	0%	0%	19%	65%	70%	68%	60%	97%
13:00	77%	79%	71%	13%	3%	0%	23%	58%	70%	68%	60%	97%
14:00	81%	79%	71%	7%	3%	0%	10%	58%	70%	65%	63%	97%
15:00	81%	79%	71%	10%	3%	3%	13%	52%	70%	68%	67%	97%
16:00	84%	79%	61%	3%	0%	0%	0%	48%	70%	71%	73%	97%
17:00	84%	76%	68%	10%	3%	0%	3%	23%	63%	71%	70%	97%
18:00	84%	76%	68%	17%	3%	3%	19%	39%	60%	74%	73%	94%
19:00	84%	83%	68%	17%	6%	3%	26%	32%	63%	74%	70%	94%
20:00	87%	76%	71%	17%	6%	3%	23%	39%	73%	81%	67%	97%
21:00	84%	79%	77%	17%	6%	7%	26%	52%	90%	77%	73%	97%
22:00	81%	83%	77%	17%	6%	7%	19%	45%	93%	74%	73%	97%
23:00	81%	83%	77%	17%	6%	3%	19%	45%	90%	77%	73%	97%

B. Reduced Market Reliance

PSE has 1,500 MW of firm transmission capacity from the Mid-C market hub to access supply from the regional power market. To date, this transmission capacity has been assumed to provide PSE with access to reliable firm market purchases where physical energy can be sourced in the day-ahead or real-time bilateral power markets. PSE has effectively assumed this 1,500 MW of transmission capacity as equivalent to generation capacity available to meet demand. Historically, this assumption has reduced PSE's generation capacity need and the ensuing procurement costs. Given the market events of the past three years, PSE conducted a market risk assessment to evaluate this assumption in addition to the evaluation completed with the resource adequacy model. Sensitivity B provides insight into navigating a market with reduced availability of market purchases by examining how to optimize a portfolio that is limited by these conditions.

Baseline: PSE can make market purchases at the hourly power price, subject to the transmission limits to the Mid-C Market. PSE currently uses these purchases to meet demand at peak demand hours.

Sensitivity B > PSE's transmission access to the Mid-C Market is reduced to 1,300 MW in 2023, 1,100 MW in 2024, 900 MW in 2025, 700 MW in 2026, and 500 MW in 2027 and thereafter during November-February and June-August. Transmission access remains the same for the months March-May and September-October, as well as the year 2022.

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KEY FINDINGS. To compensate for reduced market purchases, sensitivity B overbuilds renewable resources to charge batteries and builds 1,495 of peaking capacity by 2031, nearly double the amount in the Mid Scenario. This sensitivity builds the same amount of Washington wind as the Mid Scenario, but on an accelerated timeline. By 2045, increased storage builds play a larger role in meeting peak demand. Peaking capacity and CCCT thermal generation continue to assist in meeting peak demand, but renewable overgeneration is the primary energy source for batteries.

ASSUMPTIONS. This portfolio keeps all underlying assumptions from the Mid Scenario portfolio, except for changes to Mid-C market access. The amount of Mid-C Market transmission access in Sensitivity B, which defines the amount of market purchases PSE can make, is seen in Figure 8-27.

Figure 8-27: Transmission Limits to the Mid-C Market in Sensitivity B in MW

MW	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2022	1544	1529	1516	1483	1442	1463	1472	1487	1569	1588	1558	1518
2023	1300	1300	1507	1466	1432	1300	1300	1300	1519	1519	1300	1300
2024	1100	1100	1536	1471	1418	1100	1100	1100	1546	1521	1100	1100
2025	900	900	1518	1455	1402	900	900	900	1529	1523	900	900
2026	700	700	1521	1457	1405	700	700	700	1530	1525	700	700
2027	500	500	1523	1460	1408	500	500	500	1532	1526	500	500
2028	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2029	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2030	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2031	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2032	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2033	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2034	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2035	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2036	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2037	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2038	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2039	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2040	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2041	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2042	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2043	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2044	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2045	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2046	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2047	500	500	1525	1462	1411	500	500	500	1533	1526	500	500

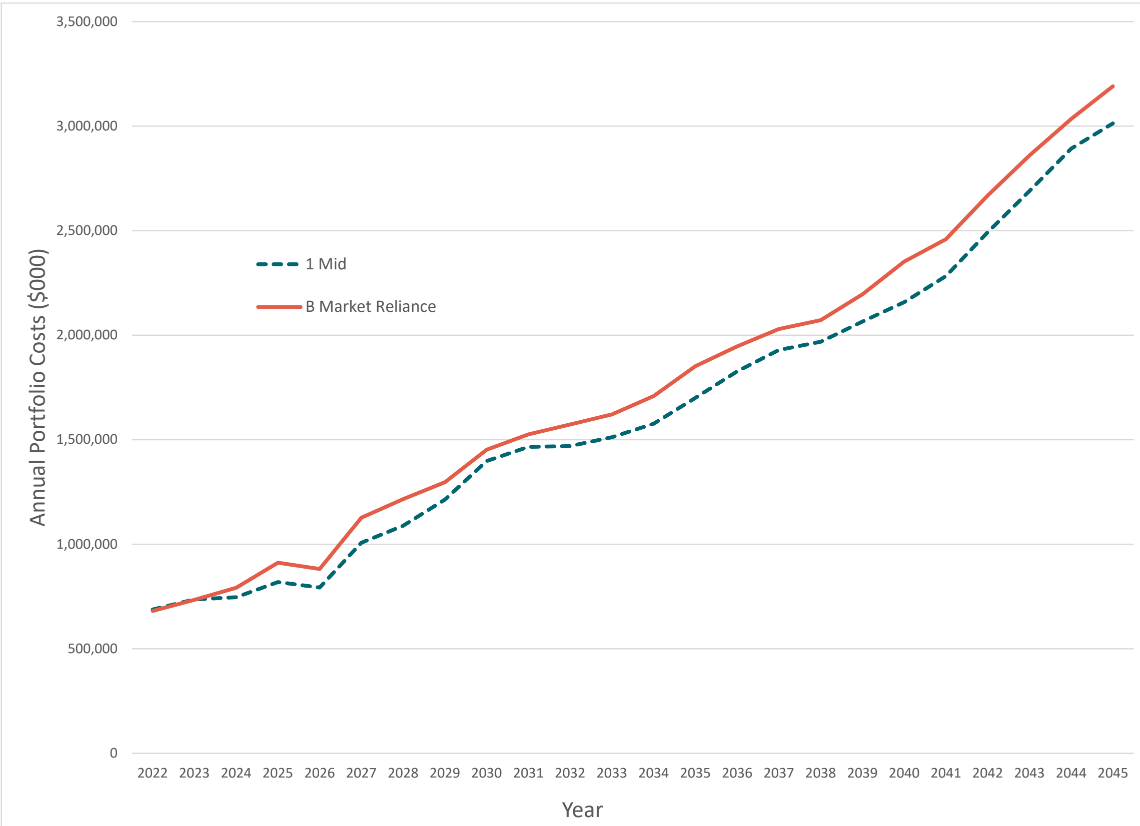
ANNUAL PORTFOLIO COSTS. Figures 8-28 and 8-29 illustrate the breakdown of costs between the Mid Scenario and Sensitivities B. As expected, increasing restrictions to market purchases increases portfolio costs. This sensitivity builds more resources in the early years of the simulation so the annual portfolio costs start diverging as early as 2023.

The final builds of the Sensitivity B and the Mid Scenario portfolios are similar, with more peaking capacity and an accelerated installation of Washington wind in Sensitivity B. As a result, the annual costs of Sensitivity B track with the costs of the Mid Scenario, with the earlier installation timeline and increased peaking capacity raising the overall price.

Figure 8-28: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity B

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
B	Reduced Market Reliance	$16.57	$5.19	$21.76	$1.35

Figure 8-29: Annual Portfolio Costs – Mid Scenario and Sensitivity B



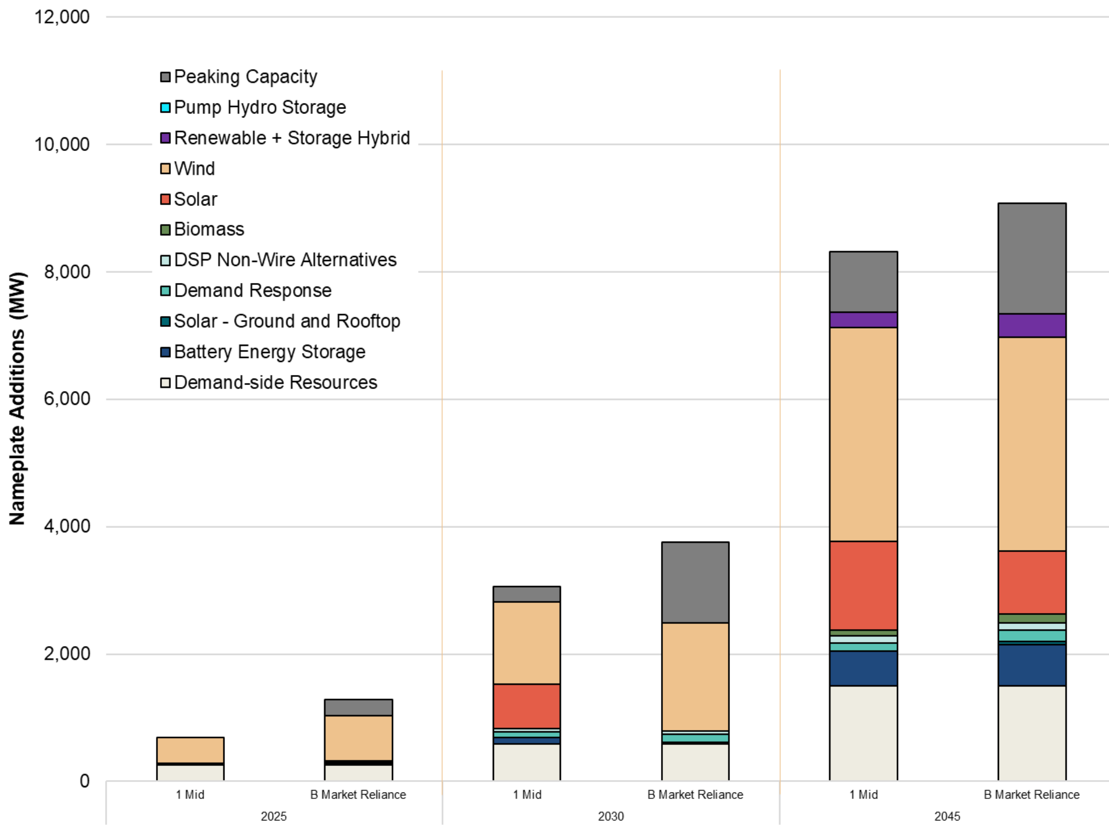
RESOURCE ADDITIONS. Figure 8-30 compares the nameplate capacity additions of the Mid Scenario and Sensitivity B.

Sensitivity B invests in the same amount of demand-side resources as the Mid Scenario (Bundle 10). With limited access to the market, this sensitivity invests heavily in peaking capacity and accelerates the construction of Washington wind resources compared to the Mid Scenario. In the later years of the simulation, storage resources are still needed, but they are delayed due to the high capacity of thermal resources being installed in the early years. Without market purchases to bridge the gap between renewable generation and demand, the portfolio leans heavily on increased peaking capacity builds. Increased peaking capacity is the most prominent difference between the Mid Scenario and Sensitivity B, indicating that the model selects thermal generation as the least cost resource to replace the market purchases. One of the modeling limitations in this IRP, is that new contracts are not modeled. Resources are modeled since they have a set procurement cost and build schedule, but future costs of contractual arrangements are more difficult to predict.

Figure 8-30: Portfolio Additions – Mid Scenario and Sensitivity B, Reduced Market Reliance

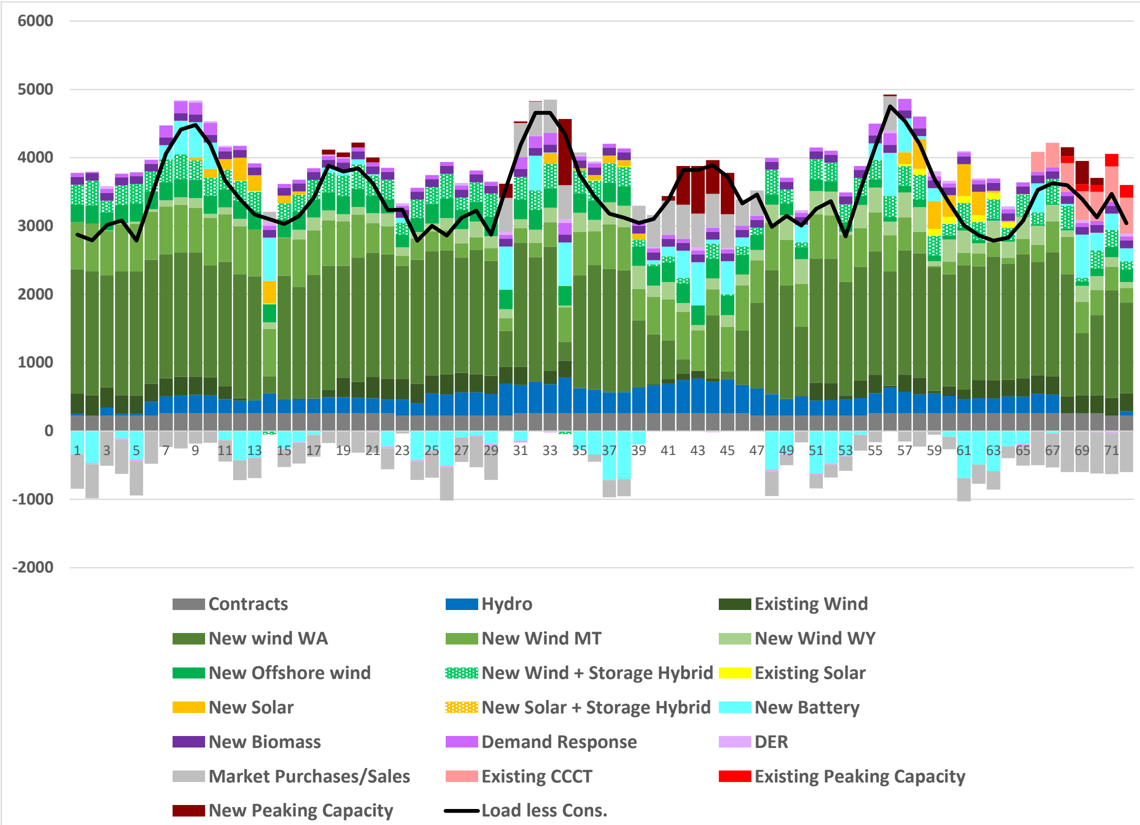
Resource Additions by 2045	1 Mid	B Reduced Market Reliance
Demand-side Resources	1,497 MW	1,497 MW
Battery Energy Storage	550 MW	650 MW
Solar – Ground and Rooftop	0 MW	50 MW
Demand Response	123 MW	173 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,480 MW
Biomass	90 MW	135 MW
Solar	1,393 MW	995 MW
Wind	3,350 MW	3,350 MW
Renewable + Storage Hybrid	250 MW	375 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	1,732 MW

Figure 8-31: Portfolio Additions by 2045 – Mid Scenario and Sensitivity B, Reduced Market Reliance



PEAK NEED AND EMISSIONS. The peak demand period of Sensitivity B is shown in Figure 8-32. Portfolio B uses renewable overbuilds as the main method of charging the batteries (blue bars). The excess energy, generation above the black lines, provides value through market sales (gray bars below zero) and the charging of batteries (blue bars below zero) during off-peak hours. Market purchases are still available in a limited capacity, and are still used to assist in meeting demand when renewable generation is not sufficient. Thermal generation also continues to play a role in meeting peak demand. In Figure 8-32, thermal generation is still needed when there is not enough energy from renewable resources, batteries, or demand response to meet demand as can be seen in the hours 30, 34, 40-45, and 68-72.

Figure 8-32: 2045 Peak Demand Period of Sensitivity B, December 28-30, 2045



EMISSIONS. Use of thermal generation to compensate for the reduction of market purchases increases the emissions of PSE resources in sensitivity B. Figure 8-33 compares the yearly emissions of PSE resources (without market purchases) to the Mid Scenario.

Figure 8-33: Annual Emissions of PSE Resources – Mid Scenario and Sensitivity B (market purchases are not included)

Transmission Constraints and Build Limitations

C. "Distributed" Transmission/Build Constraints - Tier 2

This sensitivity examines increased transmission constraints on PSE's resources. The PSE Energy Delivery team has defined "Tier 2" transmission availability as projects that are available by 2030, with a moderate degree of confidence in their feasibility. Available projects in this category total 3,070 MW of available transmission.

Baseline: The Mid Scenario assumes the transmission constraints described by Tier 0. PSE's system is subject to relatively few transmission constraints, including a maximum of 1,500 MW of Mid-C market access and build limitations for Montana, Idaho and Wyoming based resources.
Sensitivity > Sensitivity C assumes the more restrictive transmission constraints described by Tier 2, which includes those described in the baseline plus build limitations for eastern, southern and western Washington resources.

KEY FINDINGS. Tier 2 transmission constraints have relatively minimal impacts on portfolio build decisions for the first 15 years of the modeling horizon compared to the Mid Scenario portfolio. During this period, there is ample transmission to acquire solar and wind resources in eastern, southern and central Washington. However, once this transmission capacity is exhausted, Sensitivity C selects distributed solar resources located within PSE's service territory. Sensitivity C pairs the distributed solar resources with battery storage projects to better serve load when solar generation is not available. These more expensive resources drive up portfolio cost in the later years of the modeling horizon.

ASSUMPTIONS. Sensitivity C assumes transmission capacity outside of PSE's service territory will be limited to 3,070 MW. Figure 8-34 summarizes the Tier 2 transmission capacity assumptions for each resource group region. (A complete description of the four transmission tiers and resource group regions is provided in Chapter 5.)

Figure 8-34: Sensitivity C Transmission Constraints – Tier 2

Resource Group Region	Tier 2
PSE territory	unconstrained
Eastern Washington	675
Central Washington	625
Western Washington	100
Southern Washington/Gorge	705
Montana	565
Idaho / Wyoming	400
TOTAL	**3,070**

Several additional constraints were incorporated into the optimization to encourage realistic resource selections. The forecast of customer-owned, residential solar projects was adjusted to reflect increased adoption of residential solar and matches the Conservation Potential Assessment Low-cost, Business-as-Usual residential solar adoption rate, available in Appendix E. This assumption aligns with a portfolio focused on distributed energy resources.

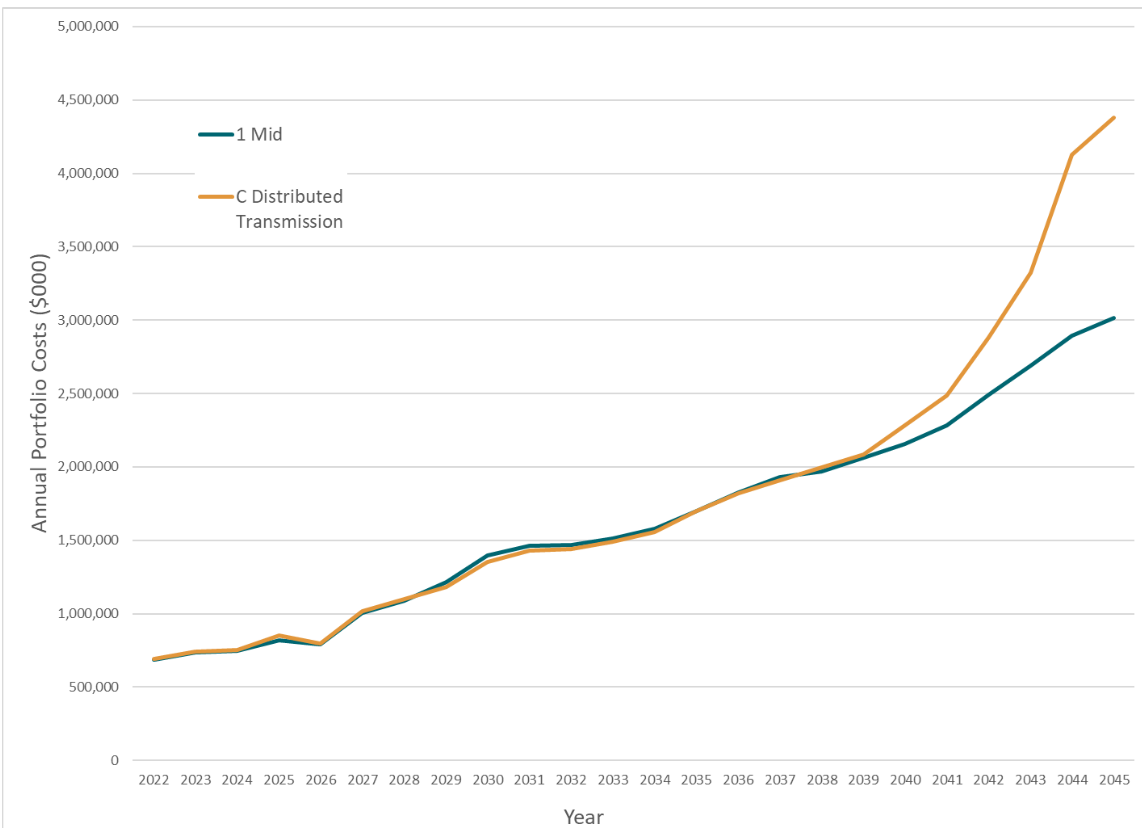
PORTFOLIO COSTS. Compared to the Mid Scenario portfolio, the Sensitivity C portfolio is more expensive over the modeling time horizon as shown in Figure 8-35. Distributed solar resources cost substantially more to install than utility-scale solar resources, resulting in increased generic resource revenue requirements. These increased generic resource revenue requirements are the major driver of the increased portfolio cost.

Figure 8-35: Portfolio Cost Comparison – Mid Scenario and Sensitivity C

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
C	Distributed – Transmission/Build Constraints Tier 2	$16.35	$5.21	$21.56	$0.94

Until year 2039, the Mid Scenario and Sensitivity C portfolios project similar annual revenue requirements as shown in Figure 8-36. After year 2039, Sensitivity C exhausts all available transmission outside of PSE's service territory and is forced to select more costly distributed solar resources, resulting in a sharp increase in annual revenue requirement in the later years.

Figure 8-36: Annual Portfolio Costs – Mid Scenario and Sensitivity C



RESOURCE ADDITIONS. Sensitivity C is marked by a transition from utility-scale wind and solar resources in central, eastern and southern Washington to distributed solar resources within the PSE service territory. Given that the effective load carrying capability of distributed solar resources is low, battery storage resources are added to the portfolio to meet load during peak hours. Biomass resources within the PSE service territory are also added to help accommodate base loads and meet CETA energy targets. New peaking capacity resource additions remain unchanged from the Mid Scenario.

Sensitivity C selects conservation Bundle 11 which is more conservation than selected in the Mid Scenario (Bundle 10). The increased conservation is due to the increased resource costs of distributed solar resources.

These resource build decisions are summarized in Figures 8-37 and 8-38.

Figure 8-37: Portfolio Additions – Mid Scenario and Sensitivity C, Distributed Transmission Tier 2

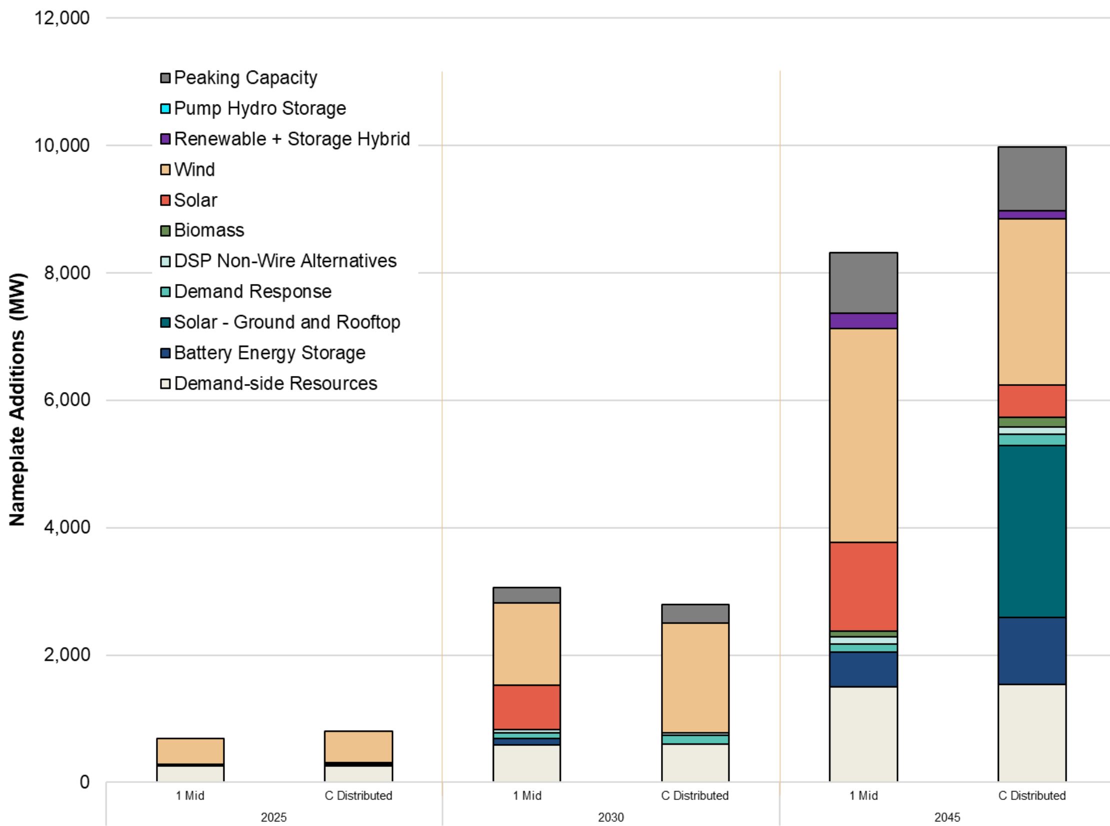


Figure 8-38: Portfolio Additions by 2045 – Mid Scenario and Sensitivity C, Distributed Transmission Tier 2

Resource Additions by 2045	1 Mid	C Distributed Transmission Tier 2
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	1,050 MW
Solar - Ground and Rooftop	0 MW	2,700 MW
Demand Response	123 MW	178 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	3,265 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	500 MW
Wind	3,350 MW	2,615 MW
Renewable + Storage Hybrid	250 MW	125 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	1,003 MW

OTHER FINDINGS. Distributed solar, ground mount and rooftop, is capable of meeting a significant portion of load. As shown in Figure 8-39, distributed solar contributes approximately 13 percent of total energy load in 2045. However, distributed solar is a poor resource for meeting peak capacity need, because it has an effective load carrying capability of less than 2 percent. This means that other resources are needed to provide capacity during peak need events. Sensitivity C selected peaking capacity resources to meet this need, so slightly more peaking resource capacity was added to Sensitivity C compared to the Mid Scenario portfolio. Furthermore, those peaking capacity resources were dispatched more often, resulting in increased emissions for Sensitivity C in the later years of the modeling horizon. In 2045, the Mid Scenario generated 0.78 million tons of greenhouse gases (GHGs), while Sensitivity C generated 1.00 million tons of GHGs. Figure 8-40 compares the emissions from the Mid Scenario and Sensitivity C portfolios in millions short tons.

Figure 8-39: Annual Energy Production by Resource Type (aggregated) – Sensitivity C

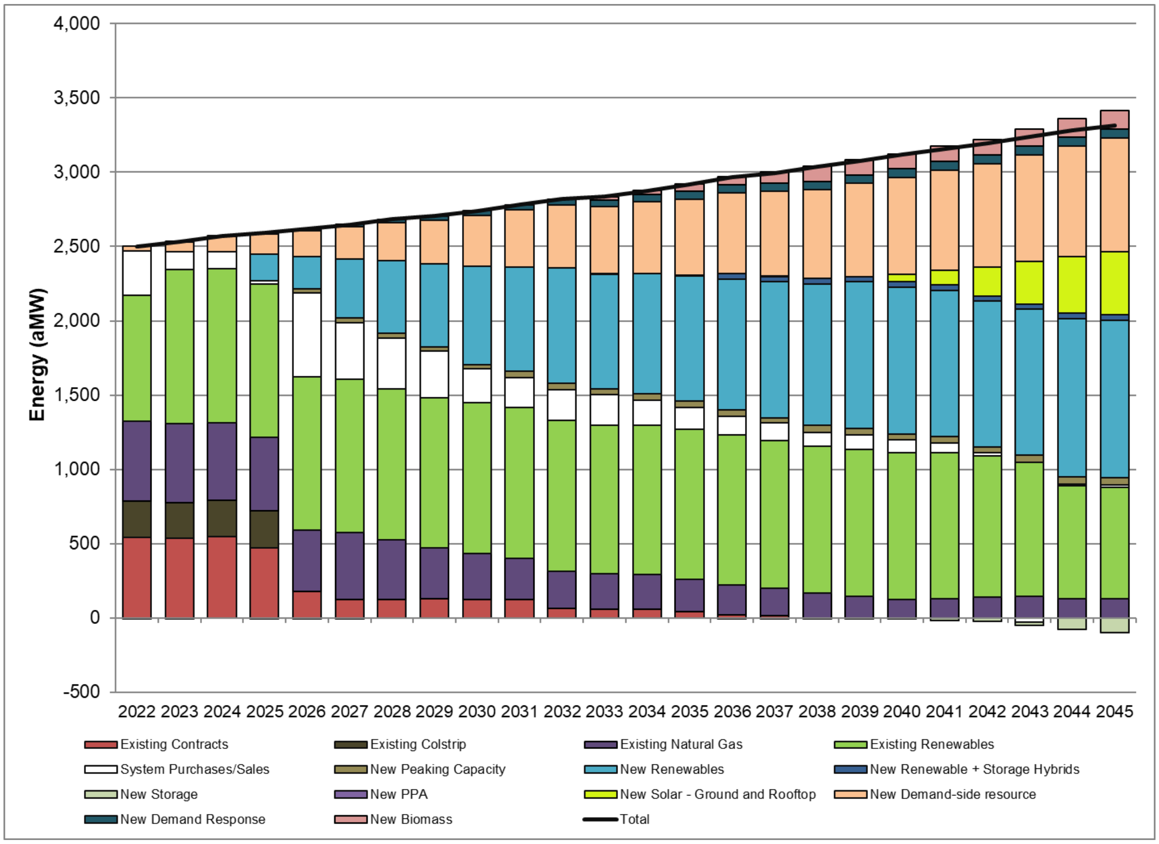
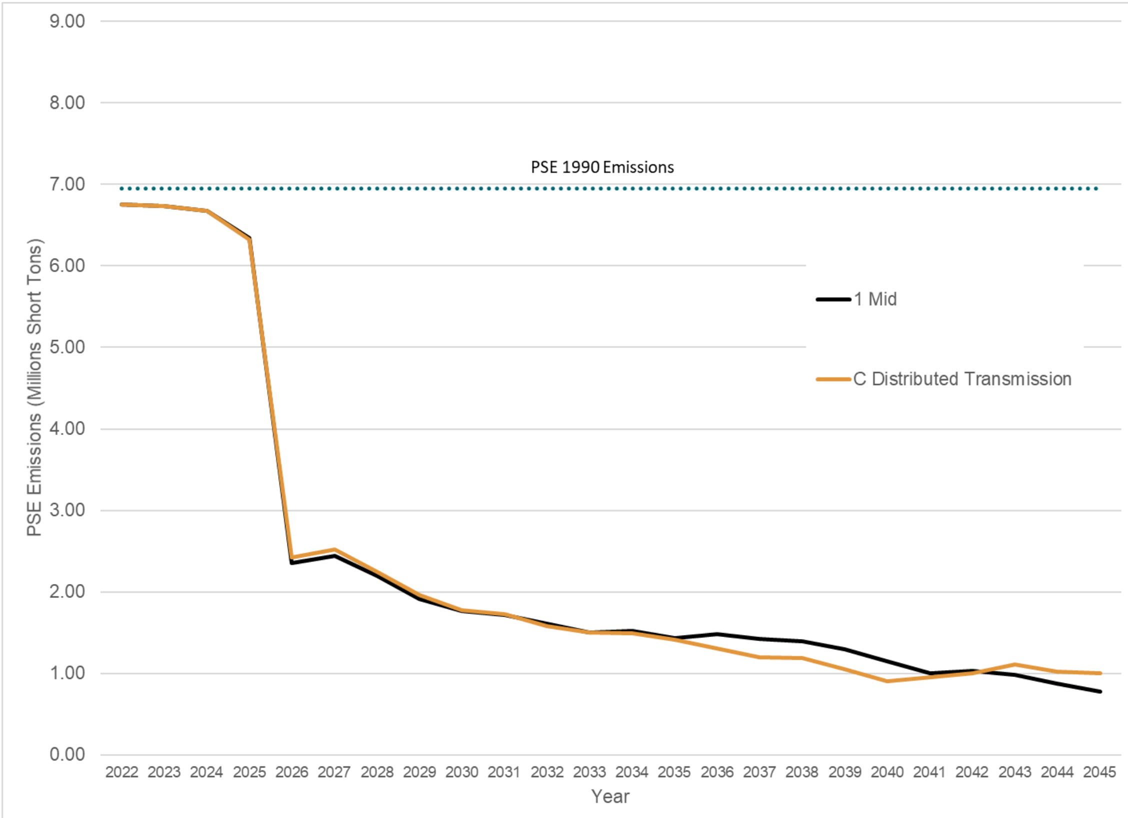


Figure 8-40: Direct Portfolio Emissions – Mid Scenario and Sensitivity C



D. Transmission/Build Constraints – Time-delayed (Option 2)

This sensitivity examines increased transmission constraints on PSE's resources. The PSE Energy Delivery team has defined four "Tiers" of transmission availability, which increase transmission capacity over time. This sensitivity ramps in transmission availability over the modeling horizon.

Baseline: The baseline assumes the transmission constraints described by Tier 0. PSE's system is subject to relatively few transmission constraints, including a limit of 1,500 MW of purchases from the Mid-C market and build limitations for Montana, Idaho and Wyoming based resources.
Sensitivity > Sensitivity D assumes that transmission constraints increase over time, modeling Tier 1 constraints through 2025, Tier 2 through 2030, Tier 3 through 2035 and Tier 0 (generally unconstrained) after 2035. PSE's system is subject to more restrictive transmission constraints, including those described in the baseline, plus build limitations for eastern, southern and western Washington resources.

KEY FINDINGS. The Tiered transmission constraints modeled in Sensitivity D had relatively little impact on the portfolio composition compared to the Mid Scenario. Early in the modeling horizon, Sensitivity D tends to select wind more often than solar compared to Mid Scenario. By the end of the modeling horizon, most resource builds are near those in the Mid Scenario. Costs and GHG emissions are also in line with those in the Mid Scenario. This suggests that transmission constraints (until the year 2035) have little influence on resource acquisition decisions. A similar result was observed in Sensitivity C.

ASSUMPTIONS. Sensitivity D assumes that transmission capacity availability outside of PSE's service territory ramps in over time. Figure 8-41 summarizes the transmission capacity assumptions for each Tier and associated timeframe. (See Chapter 5 for a complete description of the four transmission tiers and resource group regions.)

Figure 8-41: Sensitivity D Transmission Constraints

Resource Group Region	Added Transmission (MW)			
	Tier 0	Tier 1	Tier 2	Tier 3
PSE territory (a)	(b)	(b)	(b)	(b)
Eastern Washington	Unconstrained	300	675	1,330
Central Washington	Unconstrained	250	625	875
Western Washington	Unconstrained	0	100	635
Southern Washington/Gorge	Unconstrained	150	705	1,015
Montana	750	350	565	750
Idaho / Wyoming	600	0	400	600
TOTAL	**generally unconstrained**	**1,050**	**3,070**	**5,205**
Modeling Timeframe	**2035-2045**	**2022-2025**	**2025-2030**	**2030-2035**

NOTES
(a) Not including the PSE IP Line (cross Cascades) or Kittitas area transmission which is fully subscribed.
(b) Not constrained in resource model, assumes adequate PSE transmission capacity to serve future load.

PORTFOLIO COSTS. The Sensitivity D portfolio is slightly more expensive over the modeling time horizon compared to the Mid Scenario portfolio, as shown in Figure 8-42. However, the 24-year levelized cost difference is less than $30 million, which suggests that transmission limitations do not strongly constrain resource builds over the 2022 to 2035 time horizon.

Figure 8-42: Portfolio Cost Comparison – Mid Scenario and Sensitivity D

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
D	Transmission/Build Constraints – Time-delayed (Option 2)	$15.54	$5.11	$20.65	$0.03

RESOURCE ADDITIONS. Resource additions for Sensitivity D are very similar to the Mid Scenario. This similarity suggests that transmission constraints (until the year 2035) do not have a significant impact on resources build decisions. Sensitivity D shifts away from eastern Washington solar and toward Washington wind due to wind's higher capacity factor, which results in more energy production early in the planning horizon. Sensitivity D also builds slightly more and longer-duration storage than the Mid Scenario. However, the increased storage builds in Sensitivity D occur after 2035, once transmission constraints have been lifted, which suggests the storage decisions were a result of the early focus on wind instead of solar. By 2024, wind and solar builds in Sensitivity D are nearly equal the Mid Scenario.

Sensitivity D selects conservation Bundle 11, which is more conservation than selected in the Mid Scenario (Bundle 10).

These resource build decisions are summarized in Figures 8-43 and 8-44.

Figure 8-43: Portfolio Additions – Mid Scenario and Sensitivity D, Transmission Build Constraints – Time Delayed (Option 2)

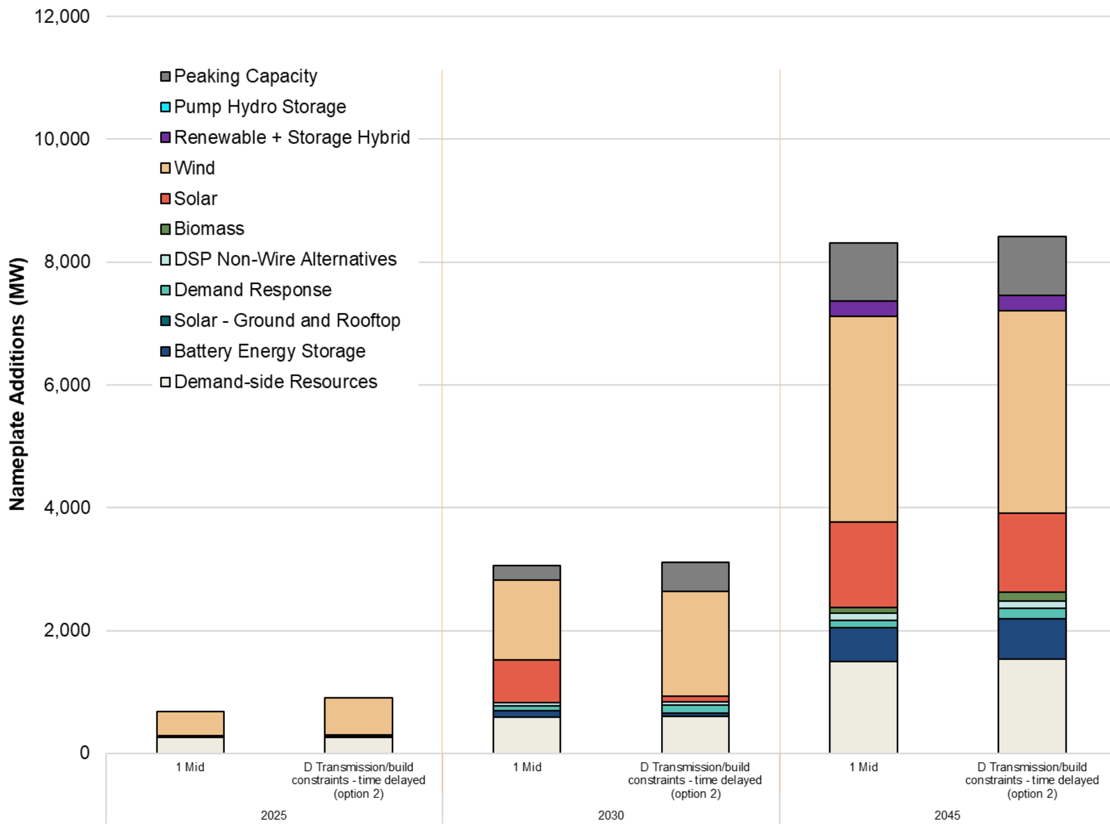


Figure 8-44: Portfolio Additions by 2045, Sensitivity D – Transmission Build Constraints – Time delayed (Option 2)

Resource Additions by 2045	1 Mid	D Transmission Build Constraints – Time delayed (Option 2)
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	650 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	180 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,730 MW
Biomass	90 MW	135 MW
Solar	1,393 MW	1,295 MW
Wind	3,350 MW	3,300 MW
Renewable + Storage Hybrid	250 MW	250 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	948 MW

E. Firm Transmission as a Percentage of Resource Nameplate

This sensitivity examines the impact on portfolio costs when the capacity of firm transmission purchased with new resources is less than the nameplate capacity of the generating resource.

Baseline: New resources are acquired with transmission capacity equal to their nameplate capacity.

Sensitivity > New resources are acquired with less transmission capacity than nameplate capacity.

KEY FINDINGS. The benefit from contracting firm transmission less than the nameplate capacity of a renewable resource is highly site specific. Project sites with low transmission costs tend to benefit less than sites with high transmission costs. Wind resources tend to benefit less than solar resources due the significant portion of time that wind resources spend at or near nameplate capacity (i.e., rated power).

ASSUMPTIONS. This sensitivity examines the trade-off between investing in the cost of firm transmission versus the cost of having to replace power lost to transmission curtailment because transmission less than nameplate capacity was acquired. This trade-off was calculated for the following generic resource alternatives: Washington wind, Montana wind east, Montana wind central, Wyoming wind east, Wyoming wind west, Idaho wind, utility-scale Washington solar east, utility-scale Wyoming solar east, utility-scale Wyoming solar west and utility-scale Idaho solar.

The annual transmission cost for each resource was calculated using the fixed transmission cost of the resource (provided in Figure 5-25 in Chapter 5) times the nameplate capacity of the resource. The transmission-curtailed energy was calculated as the sum of all hours where the resource production exceeded the transmission limit. For example, a 100 MW wind farm operating at rated power with 10 percent reduced transmission will curtail 10 MWh for a one-hour period (100 MW x 1 h – 100 MW x (1-0.10) x 1 h = 10 MWh).

The replacement cost of transmission-curtailed energy was assumed to be equal to the levelized cost of power for the given resource. PSE acknowledges that these assumptions present a “worst-case scenario” analysis, where it is assumed that all power produced can be used (i.e., production equals demand) and that no short-term transmission may be purchased to supplement long-term firm transmission. While not a comprehensive analysis, this assessment provides a reasonable estimate of potential costs and benefits attributable to reduced transmission sensitivities.

WIND RESULTS. Figure 8-45 shows the trade-off for 200 MW of generic wind resources modeled in the 2021 IRP at various degrees of transmission under-build. Points greater than zero on this plot indicate reduced transmission scenarios that provide a benefit to the project, while negative values indicate a cost. All transmission reduction scenarios are presented relative to firm transmission capacity equal to resource nameplate capacity (100 percent), therefore at 100 percent, there is no benefit or cost.

The results show that resources with high transmission costs (Wyoming and Idaho wind resources) return the greatest savings. All wind resources indicate at least some benefit in the range of transmission capacity reductions from around 99 percent to 96 percent of nameplate capacity. This is because wind farms typically produce 0 to 3 percent less power than nameplate due to internal electrical line losses. After this point, the trade-off quickly drops below zero for resources with low fixed transmission costs because wind resources often produce close to their rated power. Figure 8-46 shows a typical histogram for a generic wind resource, where the plurality of the generation time is at or above 95 percent net capacity factor. Most often, therefore, when the wind farm is generating power, it is likely to be using all available transmission.

Fixed transmission costs for Idaho and Wyoming resources are more than four times higher than for eastern Washington wind resources. These premium fixed transmission costs are why Idaho and Wyoming wind resources have such a large potential benefit compared to other wind resources.

Figure 8-45: Trade-off as a Function of Transmission Under-build Degree for 200 MW Wind Resources

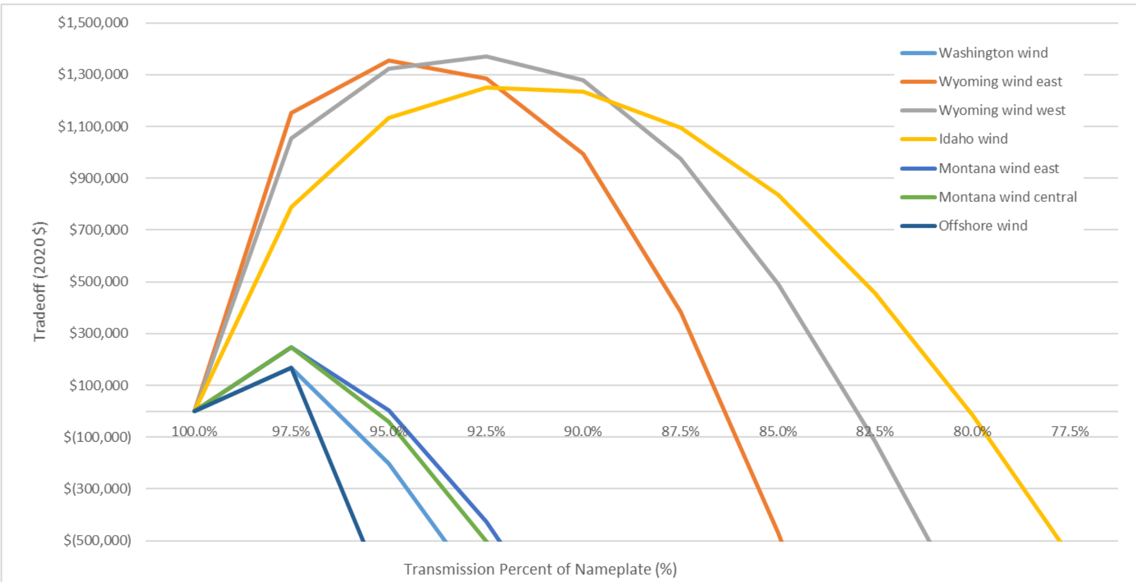
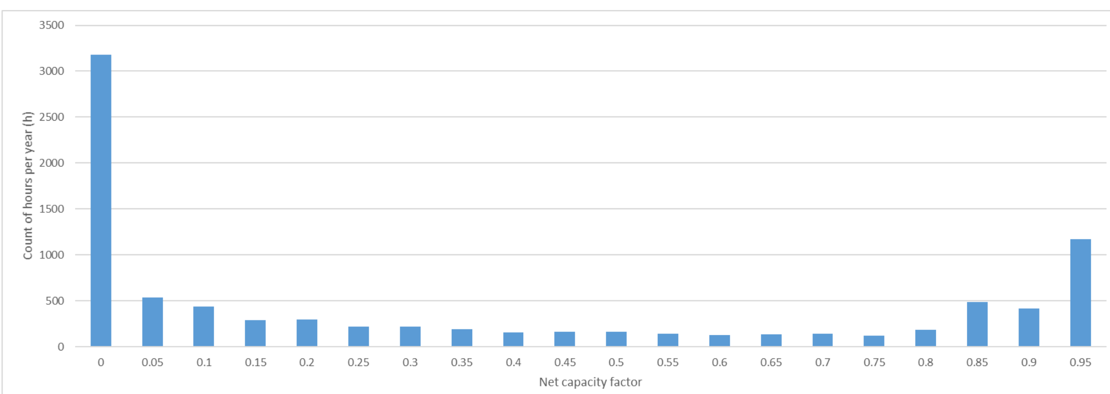


Figure 8-46: Net Capacity Factor Distribution of a Typical Wind Resource



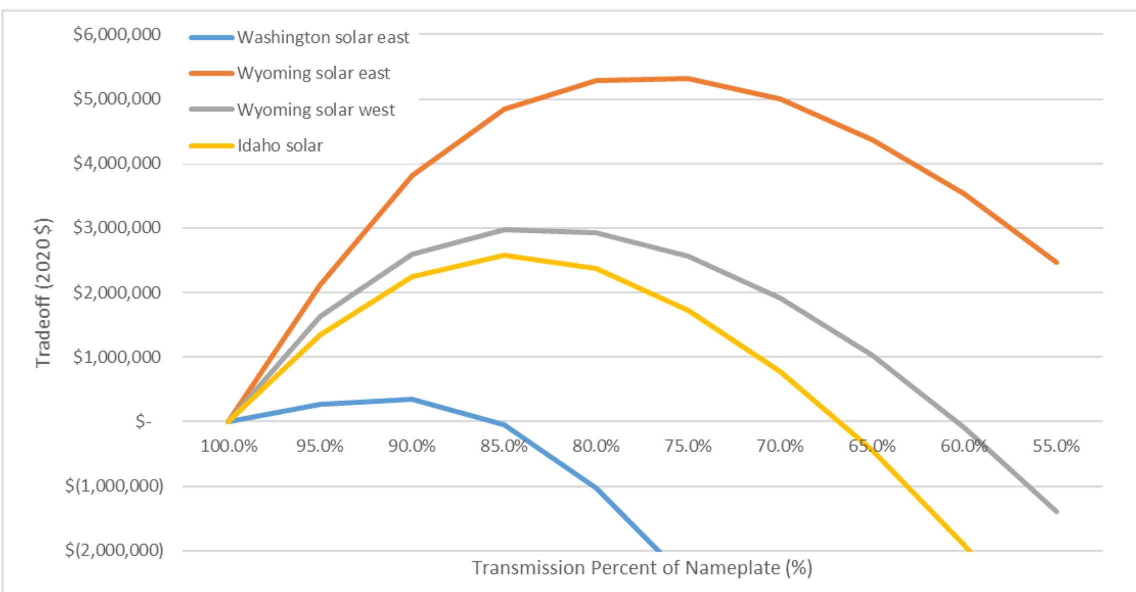
The results of this investigation came as a surprise to PSE. Initial investigations in the 2021 Draft IRP showed very little benefit for all wind resources. However, re-evaluation of the transmission costs for Idaho and Wyoming resources resulted in a very different conclusion. The new results show that firm transmission less than nameplate capacity can be an effective means to reduce portfolio cost; however, the results are highly site specific.

PSE will continue to investigate the potential benefits and risks of contracting less firm transmission than the nameplate capacity of resources. There are numerous modeling obstacles to overcome, such as assessing impacts on the effective load carrying capability of resources, long-term capacity expansion frameworks, and others. PSE looks forward to learning more about the benefits of reducing firm transmission contracts in future IRP cycles.

SOLAR RESULTS. Figure 8-47 shows the trade-off for 200 MW of generic solar resources modeled in the 2021 IRP at various degrees of transmission reduction. Points greater than zero on this plot indicate transmission reduction scenarios which provide a benefit to the project, while negative values indicate a cost. All transmission reduction scenarios are presented relative to firm transmission capacity that equals resource nameplate capacity (100 percent), therefore at 100 percent there is no benefit or cost.

Similar to the wind resources discussed above, the benefit of under-built transmission capacity is highly site specific and strongly correlated to fixed transmission cost. Regions with high fixed transmission costs (Idaho and Wyoming) have significantly more benefit than regions with low fixed transmission costs (eastern Washington).

Figure 8-47: Trade-off as a Function of Transmission Under-build Degree for 200 MW Solar Resources



Similar to the wind results above, the results of the solar investigation came as a surprise to PSE. Initial investigations for the 2021 draft IRP showed very little benefit for all solar resources. However, re-evaluation of the transmission costs for Idaho and Wyoming resources resulted in a very different conclusion. The new results show that firm transmission less than nameplate capacity can be an effective means to reduce portfolio cost; however, the circumstances are highly site specific.

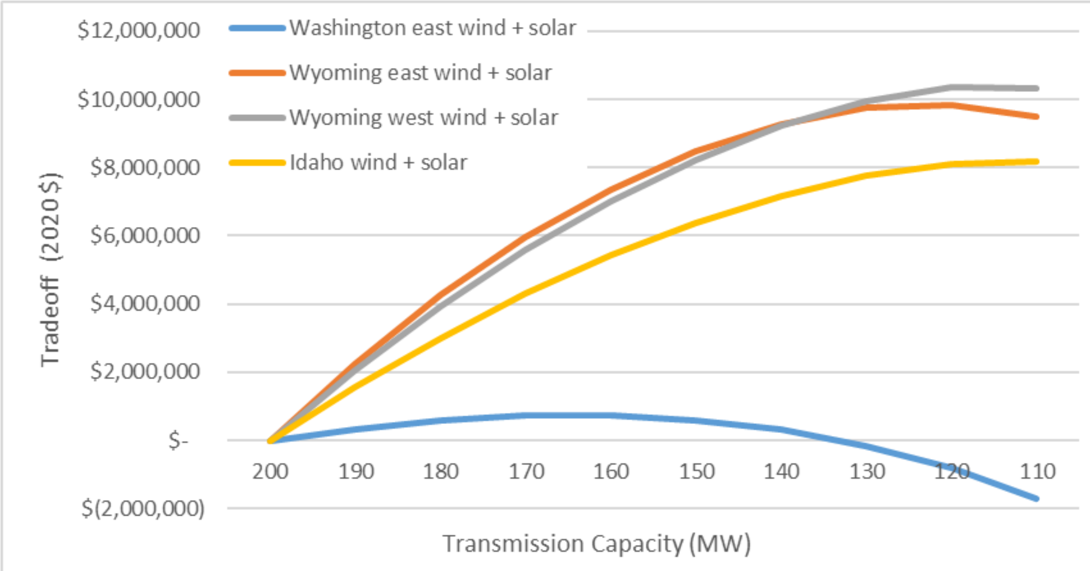
PSE will continue to investigate potential benefits and risks of contracting less firm transmission than the nameplate capacity of resources. There are numerous modeling obstacles to overcome, such as assessing impacts on the effective load carrying capability, long-term capacity expansion frameworks, and others. PSE looks forward to learning more about the benefits of reducing firm transmission contracts in future IRP cycles.

NEXT STEPS. In addition to the transmission sensitivities described above, PSE also looked at co-locating a wind and solar resource with shared, limited transmission capacity. A complementary relationship appears to exist between the resource pairs assessed. First, wind resources with higher winter production may benefit from co-location with solar resources that have higher summer production. Second, wind resources with higher overnight production may benefit from co-location with solar resources that, by nature, only produce power during the day. Optimizing the amount of transmission to better match the average seasonal and diurnal production of the co-located resources may realize cost savings, as opposed to securing firm transmission for both resources individually.

Figure 8-48 shows the possible benefits of co-locating a 100 MW wind farm with a 100 MW solar farm at various locations. Cost benefits from reducing firm transmission contracts are strongly correlated to fixed transmission cost, as seen in the analysis of individual wind and solar resources. Interestingly, on a dollar-per-megawatt nameplate capacity basis, the benefit of the co-location is even greater than for individual wind or solar resources, which shows a synergistic relationship between co-located wind and solar resources that share transmission capacity.

PSE looks forward to continuing to learn more about benefits of co-located resources in future IRP cycles.

Figure 8-48: Trade-off as a Function of Transmission Capacity for Co-located 100 MW Wind and 100 MW Solar Resources



Conservation Alternatives

F. 6-year Ramp Rate for Conservation
G. Non-energy Impacts
H. Social Discount Rate

These sensitivities were performed to assess changes in the implementation rate, financial structure, and overall effectiveness of conservation measures.

Baseline: Conservation resources are implemented over 10 years using PSE's baseline assumptions on costs and energy savings.
Sensitivity F > Conservation measures are implemented over 6 years instead of 10 years, and associated costs and energy savings are updated.
Sensitivity G > Conservation measures include additional non-energy impacts. Assuming there are additional benefits not captured in the original dataset, this increases the amount of energy savings from conservation and demand response.
Sensitivity H > The discount rate of DSR projects is changed from 6.8 percent to 2.5 percent. When the discount rate is decreased, the present value of future DSR savings is increased.

KEY FINDINGS. Costs and resource builds remain relatively stable across changes to the conservation inputs. Sensitivity F (6-year Ramp) selected Bundle 9, Sensitivity G (Non-energy

Impacts) selected bundle 8 and Sensitivity G (Social Discount Rate) selected bundle 6, compared to bundle 10 in the Mid Scenario. Though lower conservation bundles were selected, additional demand response measures were added. Changes to the conservation assumptions push more energy savings measures into lower bundles so the portfolio selects similar or lower amounts of conservation for lower costs. Overall, the baseline assumptions around demand-side resources included in the mid portfolio optimize to the highest amount DSR added to the portfolio by 2045, compared to making adjustments around ramp rates and discount rates.

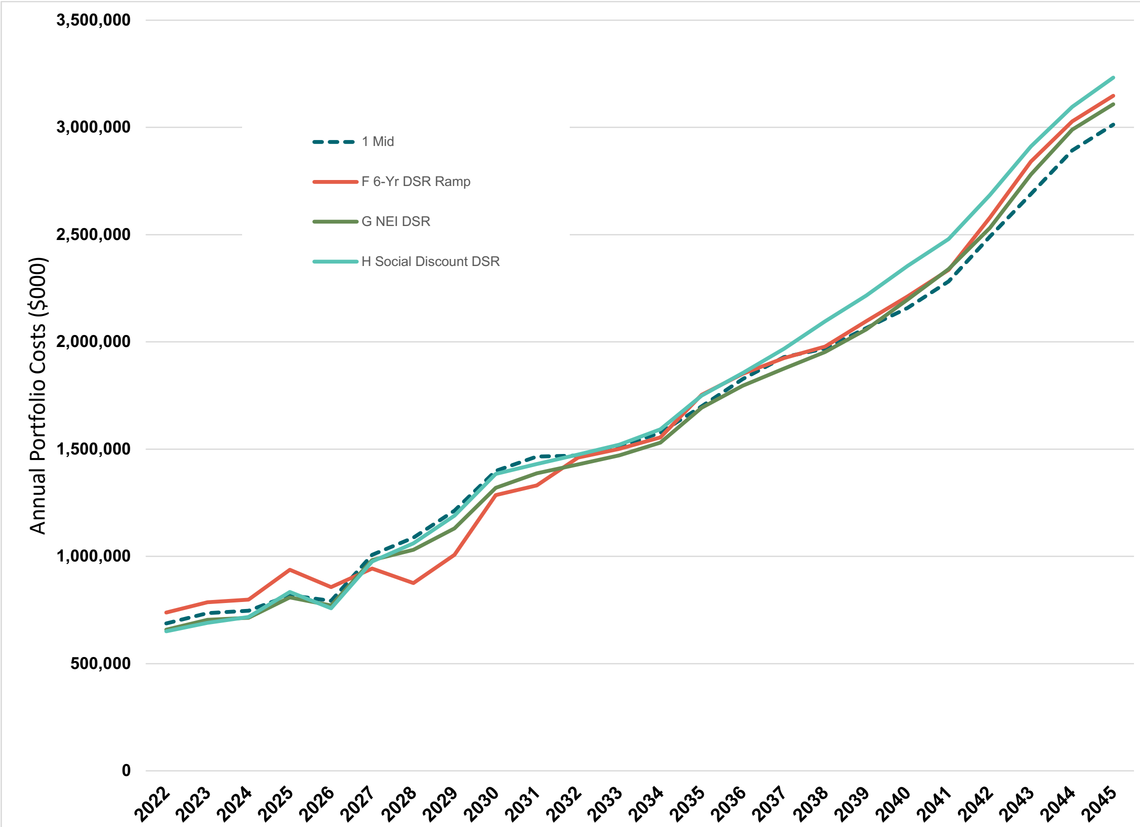
ASSUMPTIONS. These portfolios keep all underlying assumptions from the Mid Scenario portfolio, then change the costs and energy savings of the conservation measures available as resources. All DSR inputs in the Mid Scenario and Sensitivities F, G and H, can be found in Appendix H.

ANNUAL PORTFOLIO COSTS. Across all three sensitivities, changes to the overall costs of the portfolio are minor. In Sensitivity F, there is virtually no difference in overall portfolio cost compared to the Mid Scenario, although different timelines for the additions of Washington wind, Wyoming wind and Washington east solar lead to differences in annual costs in the earlier years of the simulation. Sensitivity G shows a small decrease in costs, achieving the same energy savings benefits as Sensitivity F at a lower cost conservation bundle. Sensitivity G also adds a frame peaker by 2045 compared to the Mid Scenario and Portfolio F, resulting in fewer battery builds. Frame peaker builds are a less expensive way to increase capacity and peak capacity, but the overall changes to the portfolio costs are small. Sensitivity H shows a minor increase in costs as a result of increased battery and renewable hybrid builds in the later years of the simulation. Otherwise, the portfolio costs of Sensitivity H follow the annual cost trends of the Mid Scenario.

Figure 8-49: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivities F, G and H

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
F	6-Year Conservation Ramp Rate	$15.54	$5.09	$20.63	$0.01
G	Non-energy Impacts for DSR	$15.24	$5.12	$20.36	($0.26)
H	Social Discount Rate for DSR	$15.77	$5.16	$20.94	$0.32

Figure 8-50: Annual Portfolio Costs – Mid Scenario and Sensitivities F, G and H



RESOURCE ADDITIONS. Figures 8-51 and 8-52 compare the nameplate capacity additions of the Mid Scenario to Sensitivities F, G and H. Resource builds do not change significantly across the portfolios. Minor differences are seen in the timing of renewable resource construction and total nameplate capacity built. Any reductions in standalone renewable capacity are offset by increased hybrid resources or battery storage resources. Sensitivity H shows the largest increase in overall capacity, adding 100 MW of wind, 250 MW of hybrid resources and 100 MW of battery storage by 2045. Sensitivity F builds an additional 250 MW of hybrid resources and 75 MW of battery resources, but reduces standalone wind resources by 200 MW. Sensitivity G increases battery storage and standalone wind resources by 200 MW each, but reduces hybrid resource builds by 250 MW by 2045. These differences from the Mid Scenario are minor and affect the later years of the simulation.

Figure 8-51: Portfolio Additions – Mid Scenario and Sensitivities F, G and H

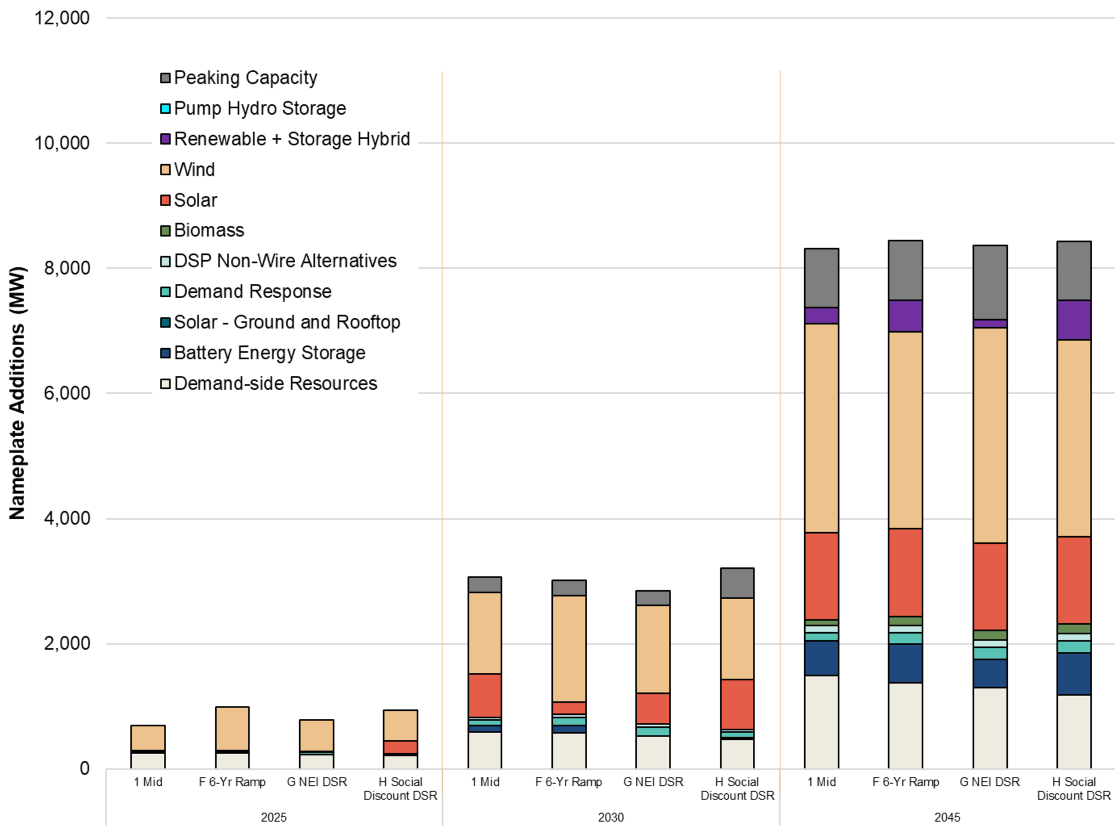


Figure 8-52: Portfolio Additions – Mid Scenario and Sensitivities F, G and H

Resource Additions by 2045	1. Mid	F. 6-Yr DSR Ramp	G. NEI DSR	H. Social Discount DSR
Demand-side Resources	1,497 MW	1,372 MW	1,304 MW	1,179 MW
Battery Energy Storage	550 MW	625 MW	450 MW	675 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW	0 MW
Demand Response	123 MW	175 MW	188 MW	195 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	4,694 MW	4,993 MW	4,691 MW
Biomass	90 MW	150 MW	150 MW	150 MW
Solar	1,393 MW	1,394 MW	1,393 MW	1,391 MW
Wind	3,350 MW	3,150 MW	3,450 MW	3,150 MW
Renewable + Storage Hybrid	250 MW	500 MW	125 MW	625 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW	0 MW
Peaking Capacity	948 MW	966 MW	1,185 MW	948 MW

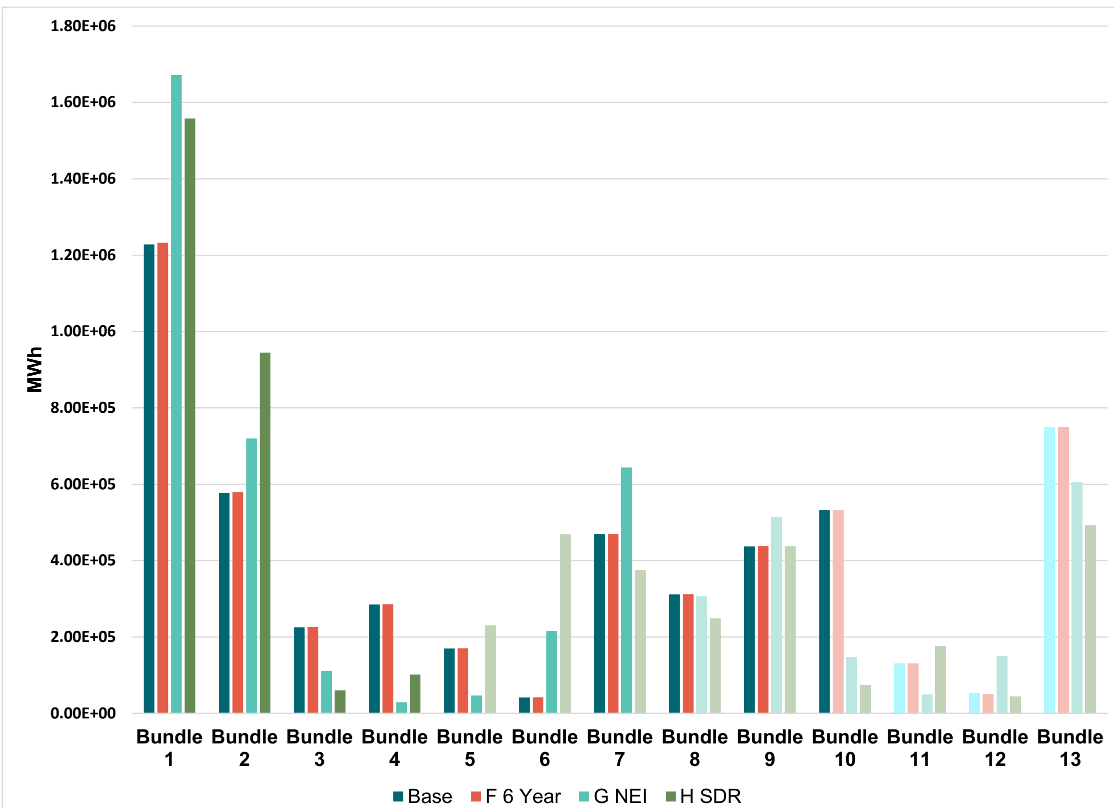
CHANGES IN CONSERVATION AND DEMAND RESPONSE. The primary focus of these sensitivities was to assess the implementation of changes to the available conservation measures. Figure 8-53 shows the final conservation selections in each sensitivity.

Figure 8-53: Conservation Measures Selected – Mid Scenario and Sensitivities F, G and H

Sensitivity	Conservation Bundle	Average Annual Energy Savings from Conservation	Number of Demand Response Measures	Capacity of Demand Response Measures Added
Mid Scenario	Bundle 10	718 aMW	3	123 MW
F - 6-Year Ramp	Bundle 9	659 aMW	5	175 MW
G - Non-Energy Impacts	Bundle 7	624 aMW	8	188 MW
H - Social Discount Rate	Bundle 4	538 aMW	9	195 MW

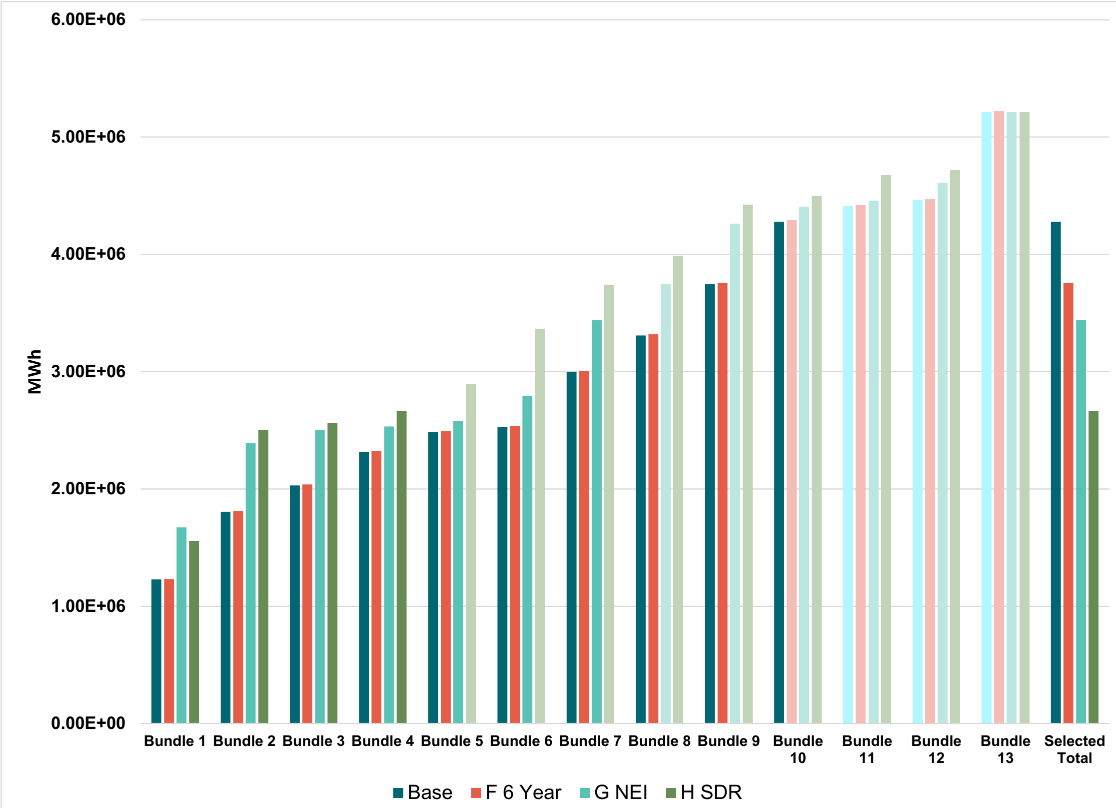
Updates to the DSR inputs changed the energy and cost values associated with each conservation measure. Since each conservation bundle is a collection of individual conservation programs within a price range, the assessment of individual measures within a bundle is not possible. However, the aggregate attributes of each bundle can be seen. Figure 8-39 shows the incremental energy savings provided by each bundle by 2045. In order to add a bundle in the AURORA model, the previous bundle must also be added (excluding Bundle 1), each bundle is dependent on adding the previous bundle. Figure 8-54 shows the cumulative energy savings provided by a selected bundle and all preceding bundles.

Figure 8-54: Incremental Energy Savings Provided by Each Bundle by the Year 2045 (darkened bars indicate that the bundle was selected in the portfolio)



Across the DSR sensitivities, adjustments to the underlying DSR attributes push more energy savings into lower bundles. In the long-term capacity expansion model, AURORA responds to these changes by adding less conservation while increasing investment in demand response measures. This trend is shown in Figure 8-55 where the cumulative energy savings within each bundle is greater for Sensitivities F, G and H than the Mid Scenario (Base).

Figure 8-55: Cumulative savings Achieved by Each Incremental Bundle by the Year 2045 (darkened bars indicate that the bundle was selected in the portfolio)



Social Cost of Greenhouse Gases and CO_2 Regulation

I. SCGHG as an Externality Cost in the Portfolio Model Only
J. SCGHG as an Externality Cost in the Portfolio Model and Dispatch Model

The goal of these sensitivities is to compare methodologies for applying the social cost of greenhouse gases to portfolios.

Baseline: The SCGHG is included as a planning adder to emitting resources in the long-term capacity expansion (LTCE) model. The planning adder is a fixed cost.
Sensitivity I > The SCGHG is included as an externality cost to emitting resources in the LTCE model. This externality cost is a variable cost of dispatch, in contrast to the fixed cost of the planning adder.

Sensitivity J > As in Sensitivity I, the SCGHG is included as an externality cost to emitting resources in the LTCE model. In addition, the SCGHG is included as a dispatch cost in the hourly dispatch model as a carbon tax.

KEY FINDINGS. Including the SCGHG in the LTCE and hourly dispatch models produces portfolios similar to the Mid Scenario. This is expected, as the CETA renewable requirement is the main driver of reduced emissions and thermal resources. In Portfolio I, costs and emissions are nearly identical to the Mid Scenario. In Portfolio J, which also includes the SCGHG as a carbon tax, the overall revenue requirement increases over the course of the planning horizon, but the largest increase occurs while Colstrip is operating from 2022 to 2025. Portfolio J also increases the use of market purchases to meet demand and shows a small decrease in overall emissions compared to the Mid Scenario.

ASSUMPTIONS. In both Sensitivity I and J, the SCGHG defined by CETA is simply applied as a variable cost on the dispatch of emitting resources. Figure 8-56 shows the value of the SCGHG as defined by CETA and the conversion used in AURORA.

In Sensitivity J, the SCGHG is also applied as a carbon tax in the hourly dispatch model. This requires an updated power price dataset since a carbon tax would impact the operations of all utilities in Washington.

Figure 8-56: CETA Definition of SCGHG and the Converted Values Used in AURORA

Year	2019$ / metric ton CO2	AURORA Input 2012$ / short ton CO2
2022	77.73	59.33
2023	78.95	60.25
2024	80.16	61.18
2025	82.59	63.03
2026	83.81	63.96
2027	85.02	64.89
2028	86.24	65.81
2029	87.45	66.74
2030	88.67	67.67
2031	89.88	68.60
2032	91.09	69.52
2033	92.31	70.45
2034	93.52	71.38
2035	94.74	72.30
2036	95.95	73.23
2037	98.38	75.08
2038	99.60	76.01
2039	100.81	76.94
2040	102.03	77.86
2041	103.24	78.79
2042	104.46	79.72
2043	105.67	80.65
2044	106.88	81.57
2045	108.10	82.50

ANNUAL PORTFOLIO COSTS. Figures 8-57 and 8-58 illustrate the breakdown of costs between the Mid Scenario and Sensitivities I and J.

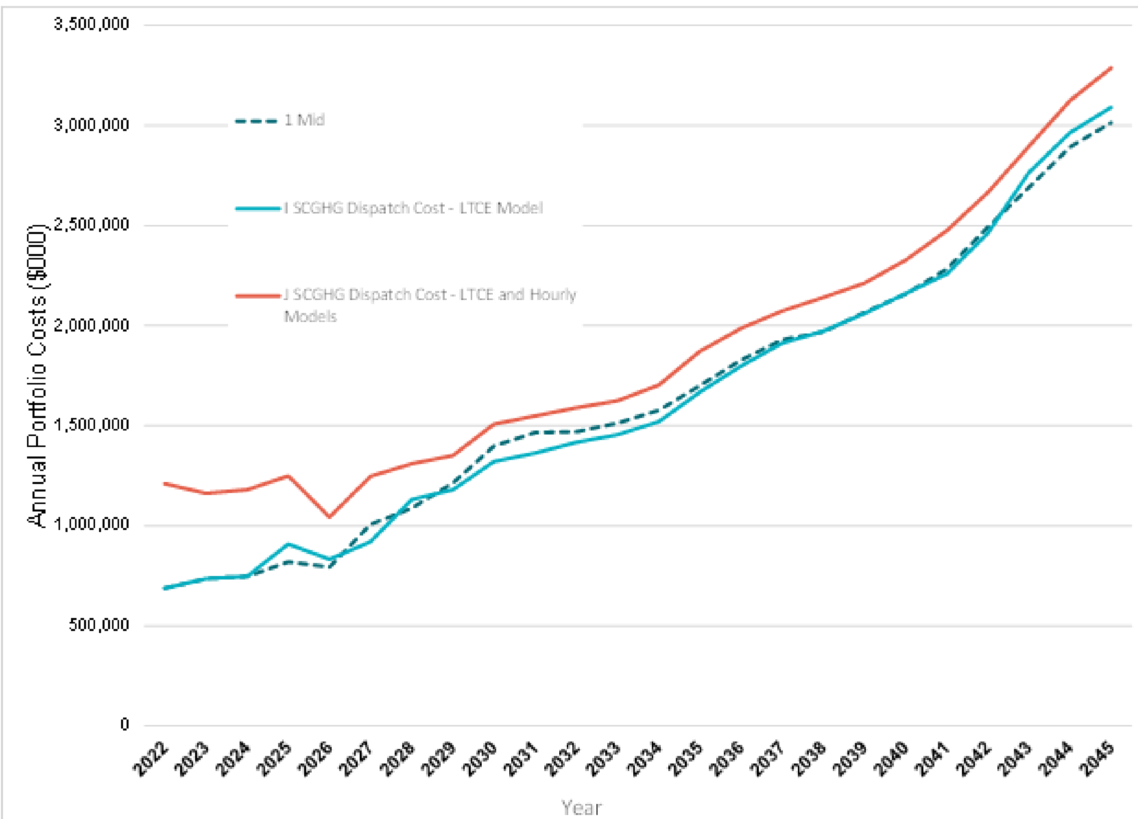
The final builds of the portfolios are similar, though Portfolio J greatly increases the emission costs of the portfolio in earlier years since the emissions of Colstrip and other thermal resources are now also taxed in the hourly dispatch model. After the retirement of Colstrip, as the carbon tax delays the construction of more flexible capacity resources, Portfolio J emissions do decrease compared to the portfolios in the Mid Scenario and Sensitivity I. Despite these differences, the cost trends of the portfolios remain the same after 2036. Sensitivity J has a higher overall cost since the SCGHG is now included as a dispatch cost and in the electric price forecast. This makes it difficult to divide out the revenue requirement from SCGHG. Even though sensitivity J has a lower SCGHG cost, it only reflects the cost of generating resources; the cost of market is in the revenue requirement, so it is hard to compare this portfolio against the Mid scenarios.

Figure 8-57: 24-year Levelized Portfolio Costs – Mid Scenario, Sensitivities I and J

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
I	SCGHG Externality Cost – LTCE Model Only	$15.41	$5.10	$20.51	($0.11)
J	SCGHG Externality Cost – LTCE Model and Hourly Dispatch*	$18.45	$4.81	$23.26	$2.64

** Sensitivity J uses a different electric price forecast than the Mid Scenario.*

Figure 8-58: Annual Portfolio Costs – Mid Scenario, Sensitivity I and Sensitivity J



RESOURCE ADDITIONS. Figures 8-59 and 8-60 compare the nameplate capacity additions of the Mid Scenario to Sensitivities I and J. Both sensitivities select Bundle 10 for conservation and reach 2045 with a similar builds of batteries and renewables. Timing of resources builds is different for each sensitivity, but both result in similar portfolios to the Mid Scenario.

Sensitivity I builds one less frame peaker than the Mid Scenario, but adds 55 MW of reciprocating peakers. It also builds 200 MW less of Washington wind and 100 MW less of Washington solar than the Mid Scenario, but adds 125 MW of hybrid resources to the portfolio. Overall, Sensitivity I adds 325 MW more battery resources than the Mid Scenario. There is also a shift in the type of battery resources selected with 575 MW of 4-hour lithium-ion batteries built compared to the Mid Scenario's 50 MW.

Sensitivity J builds two fewer frame peakers than the Mid Scenario, but adds 273 MW of reciprocating peakers. Washington wind capacity increases by 200 MW by 2045, and Washington solar capacity decreases by 400 MW, netting the same overall intermittent renewable nameplate capacity as Portfolio I. Portfolio J also adds 125 MW of hybrid resources. Overall, Sensitivity J adds an additional 300 MW more of battery resources than the Mid Scenario. There is also a shift in the type of battery resources selected with 400 MW of 6-hour flow batteries built compared to no 6-hour flow batteries the Mid Scenario.

Figure 8-59: Portfolio Additions – Mid Scenario and Sensitivities I and J

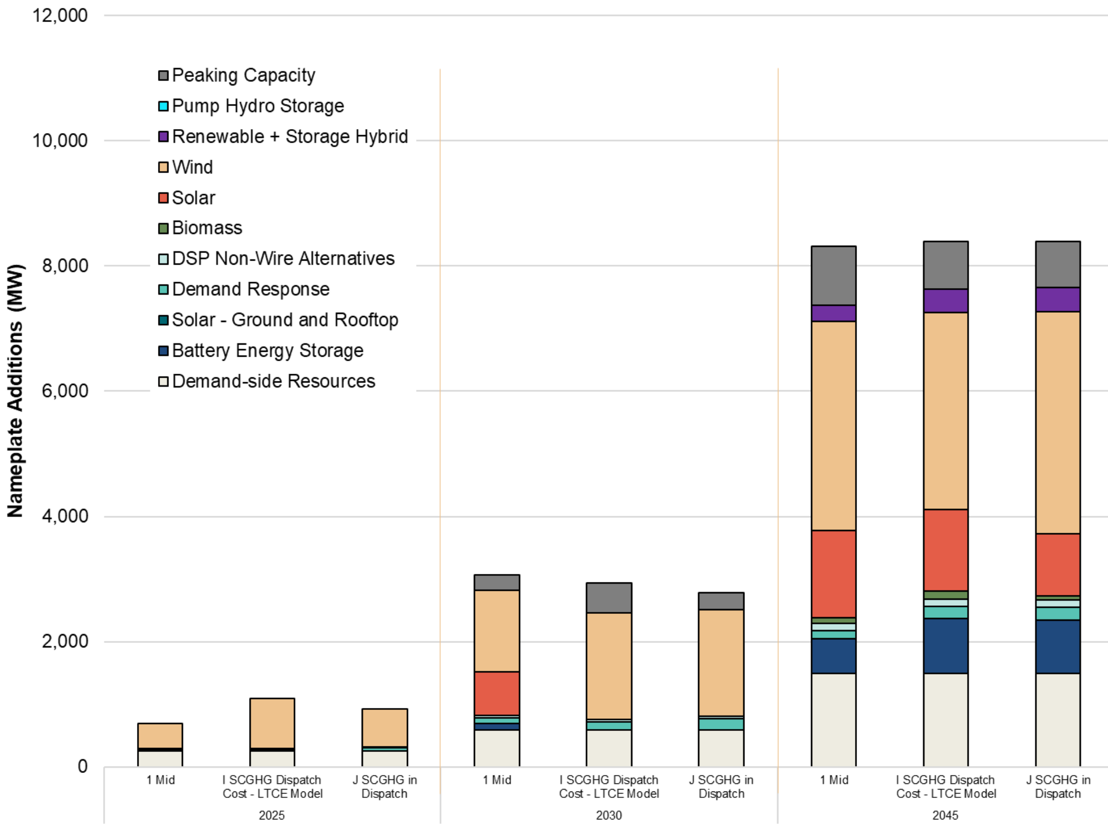


Figure 8-69: Portfolio Additions – Mid Scenario and Sensitivities I and J

Resource Additions by 2045	1 Mid	I SCGHG Dispatch Cost - LTCE Model	J SCGHG Dispatch Cost - LTCE and Hourly Models
Demand-side Resources	1,497 MW	1,497 MW	1,497 MW
Battery Energy Storage	550 MW	875 MW	850 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW
Demand Response	123 MW	188 MW	205 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	4,579 MW	4,606 MW
Biomass	90 MW	135 MW	60 MW
Solar	1,393 MW	1,294 MW	996 MW
Wind	3,350 MW	3,150 MW	3,550 MW
Renewable + Storage Hybrid	250 MW	375 MW	375 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW
Peaking Capacity	948 MW	766 MW	747 MW

EMISSIONS. Emissions are the largest difference between Sensitivity I and J. Figure 8-61 compares the direct emissions of the Mid Scenario, Sensitivity I and Sensitivity J. Portfolio J builds a similar amount of peaking capacity as Portfolio I, but relies much more heavily on market purchases to meet demand. Including the market purchase emission rate assumed in CETA brings Portfolio J in line with Sensitivity I, showing a modest decrease in emissions as shown in Figure 8-62. This is expected, as the CETA renewable requirement is the main driver of emissions reductions, not the SCGHG.

Figure 8-61: Direct Portfolio Emissions – Mid Scenario and Sensitivities I and J (market purchases not included)

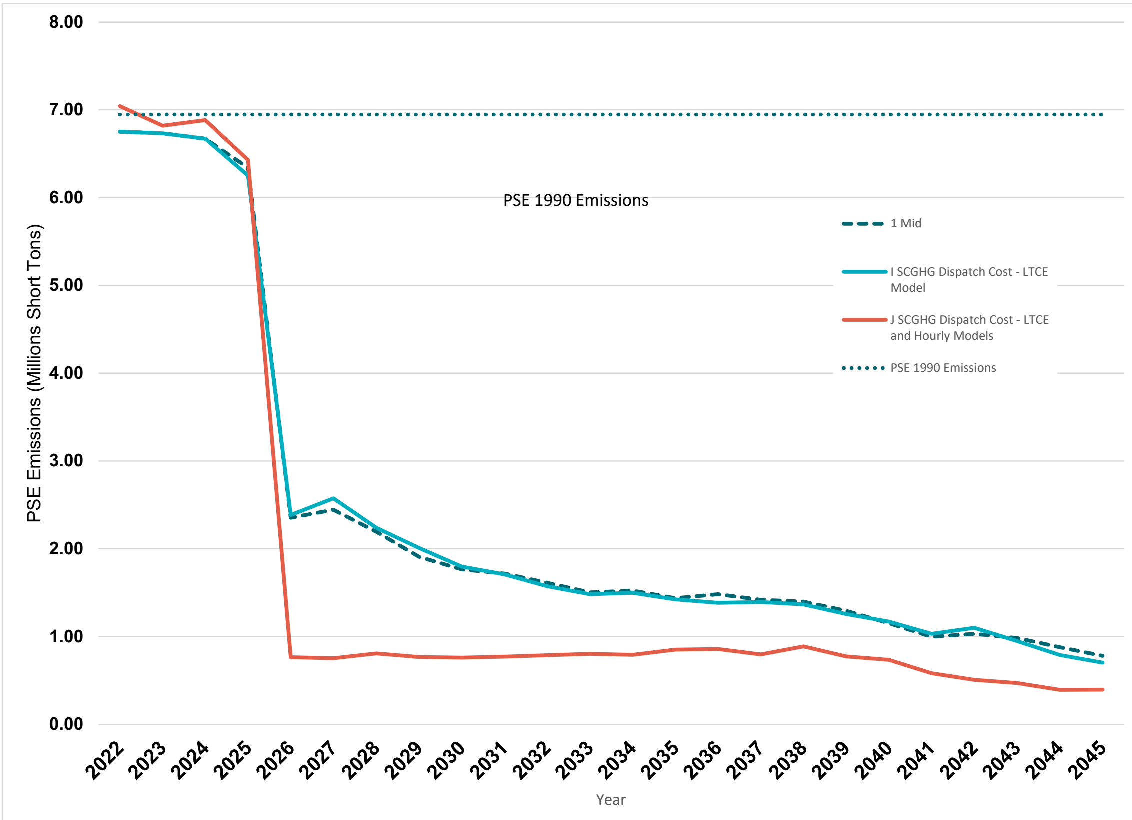
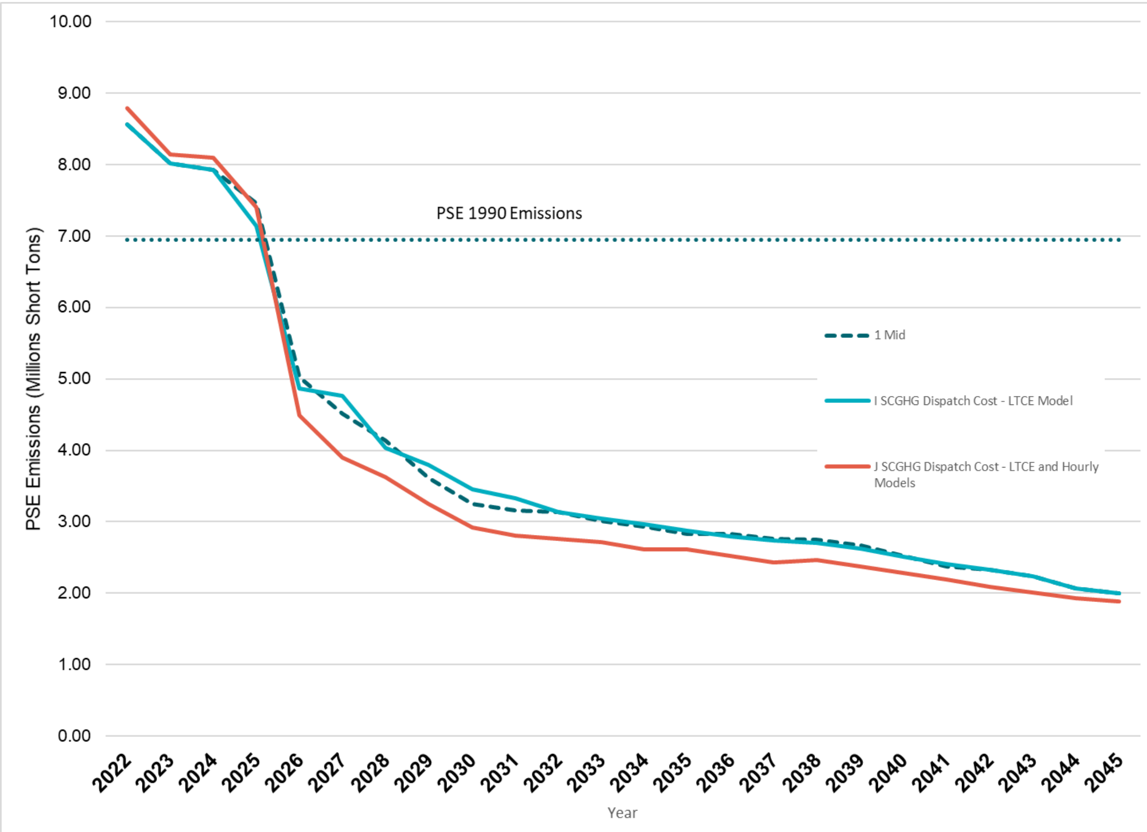


Figure 8-62: Indirect Portfolio Emissions – Mid Scenario and Sensitivities I and J (market purchases included)



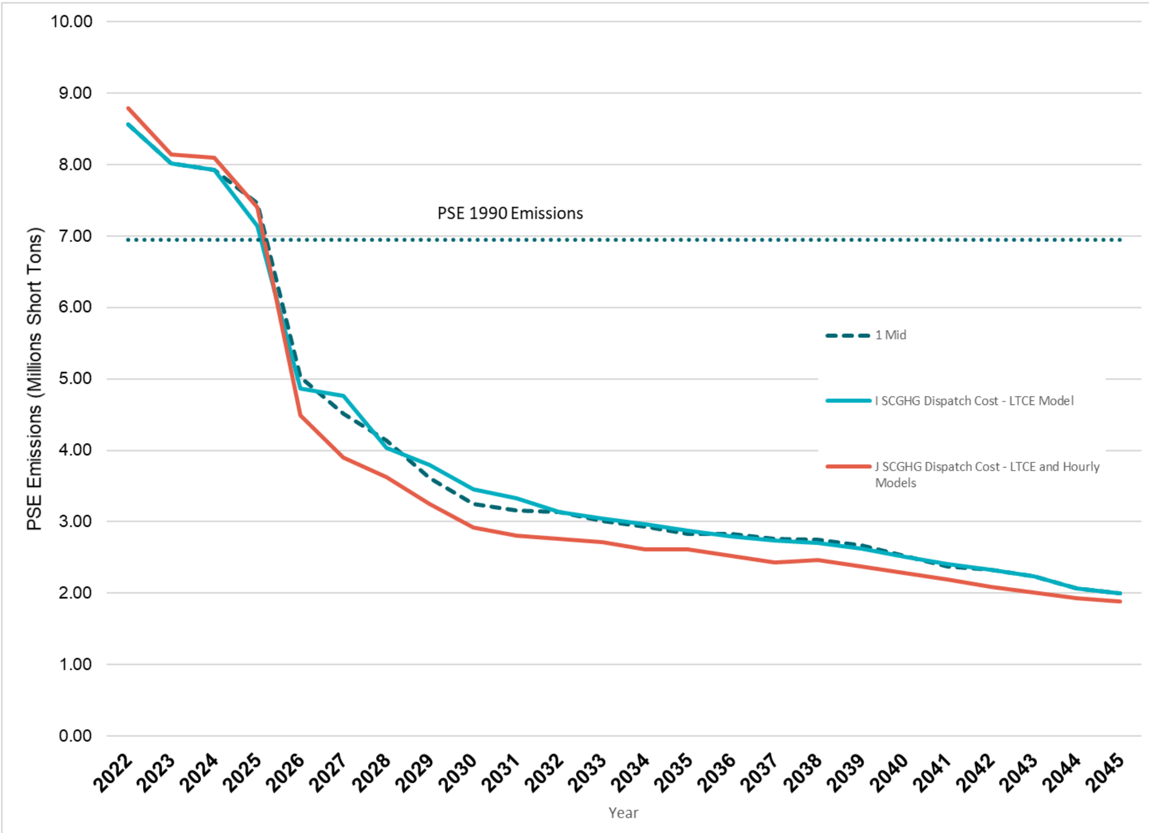
K. AR5 Upstream Emissions

This sensitivity examines how using different methodologies to calculate upstream emissions affects portfolios.

Baseline: The IPCC's Fourth Assessment Report (AR4) is used to calculate the rate of upstream emissions for PSE thermal generating plants.
Sensitivity K > The IPCC's Fifth Assessment Report (AR5) is used to calculate the rate of upstream emissions for PSE thermal generating plants.

KEY FINDINGS. Updating the upstream emission rate from AR4 to AR5 methodology does not produce broad changes to the Mid Scenario portfolio. When thermal resources are assumed to have a higher rate of emissions, emissions and costs increase slightly.

Figure 8-62: Indirect Portfolio Emissions – Mid Scenario and Sensitivities I and J (market purchases included)



K. AR5 Upstream Emissions

This sensitivity examines how using different methodologies to calculate upstream emissions affects portfolios.

Baseline: The IPCC's Fourth Assessment Report (AR4) is used to calculate the rate of upstream emissions for PSE thermal generating plants.
Sensitivity K > The IPCC's Fifth Assessment Report (AR5) is used to calculate the rate of upstream emissions for PSE thermal generating plants.

KEY FINDINGS. Updating the upstream emission rate from AR4 to AR5 methodology does not produce broad changes to the Mid Scenario portfolio. When thermal resources are assumed to have a higher rate of emissions, emissions and costs increase slightly.

ASSUMPTIONS. The sensitivity is updated to include the AR5 methodology of calculating upstream emissions. Figure 8-63 compares the emission rates of resources in the Mid Scenario and Sensitivity K. All other underlying assumptions from the Mid Scenario portfolio are kept the same.

Figure 8-63: Upstream Emission Rates – Mid Scenario (AR4) and Sensitivity K (AR5)

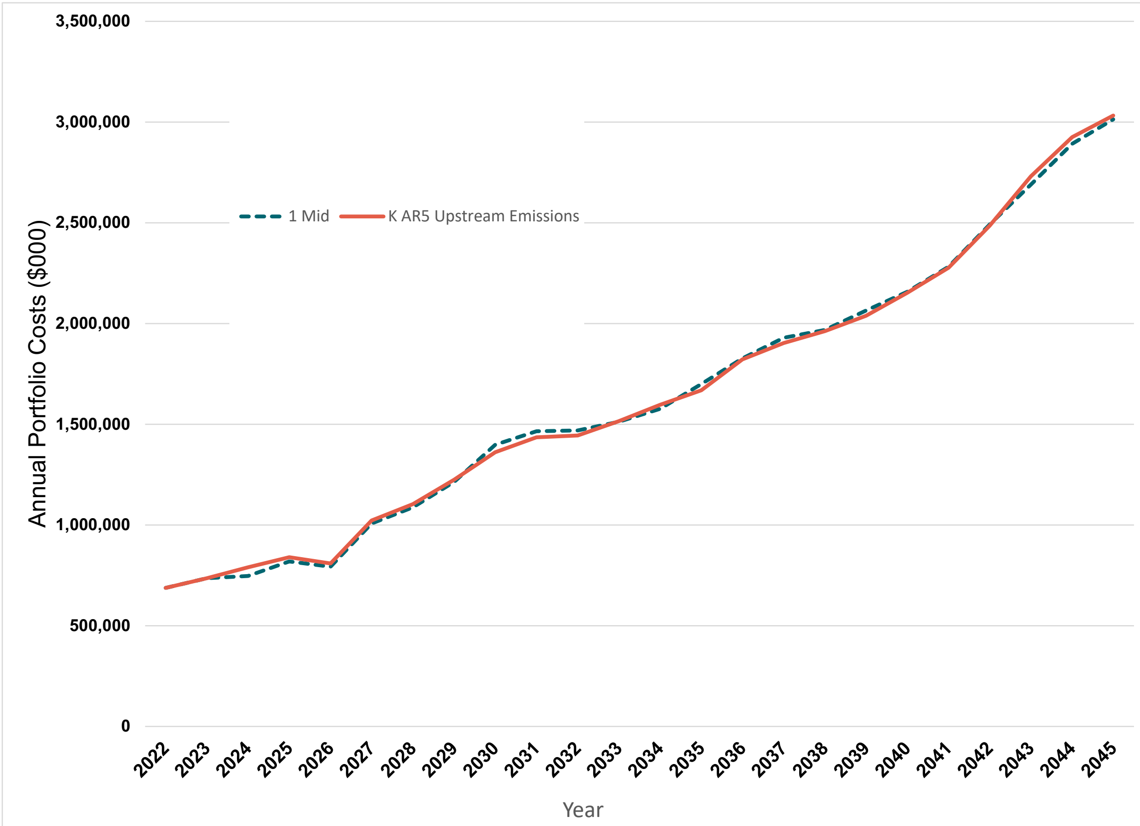
Resource	Mid Scenario AR4 Upstream Emission Rates (lb/mmBtu)	Sensitivity K AR5 Upstream Emission Rates (lb/mmBtu)
New Frame Peaker	23	24
New Recip Peaker	23	24

ANNUAL PORTFOLIO COSTS. The costs of the Sensitivity K and Mid Scenario portfolios are nearly identical. There are no significant changes in portfolio builds that would lead to changes in costs. The increased emissions costs are expected, as thermal plants are associated with slightly higher emissions.

Figure 8-64: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity K

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	**Mid Scenario**	$15.53	$5.09	$20.62	--
K	**AR5 Emissions**	$15.56	$5.14	$20.71	$0.09

Figure 8-65: Annual Portfolio Costs – Mid Scenario and Sensitivity K



RESOURCE ADDITIONS. Figures 8-66 and 8-67 compare the nameplate capacity additions in the portfolios of the Mid Scenario and Sensitivity K. Both select Bundle 10 for conservation, and Sensitivity K selects four additional demand response resources for a total of seven. Minor differences are seen in the timing of wind and solar resources. Nearly the same amount of peaking capacity, solar and hybrid capacity is built by 2045 in both portfolios. However, 200 MW less of wind and an additional 75 MW of battery storage are built by 2045 in the Sensitivity K portfolio.

Figure 8-66: Portfolio Additions – Mid Scenario and Sensitivity K

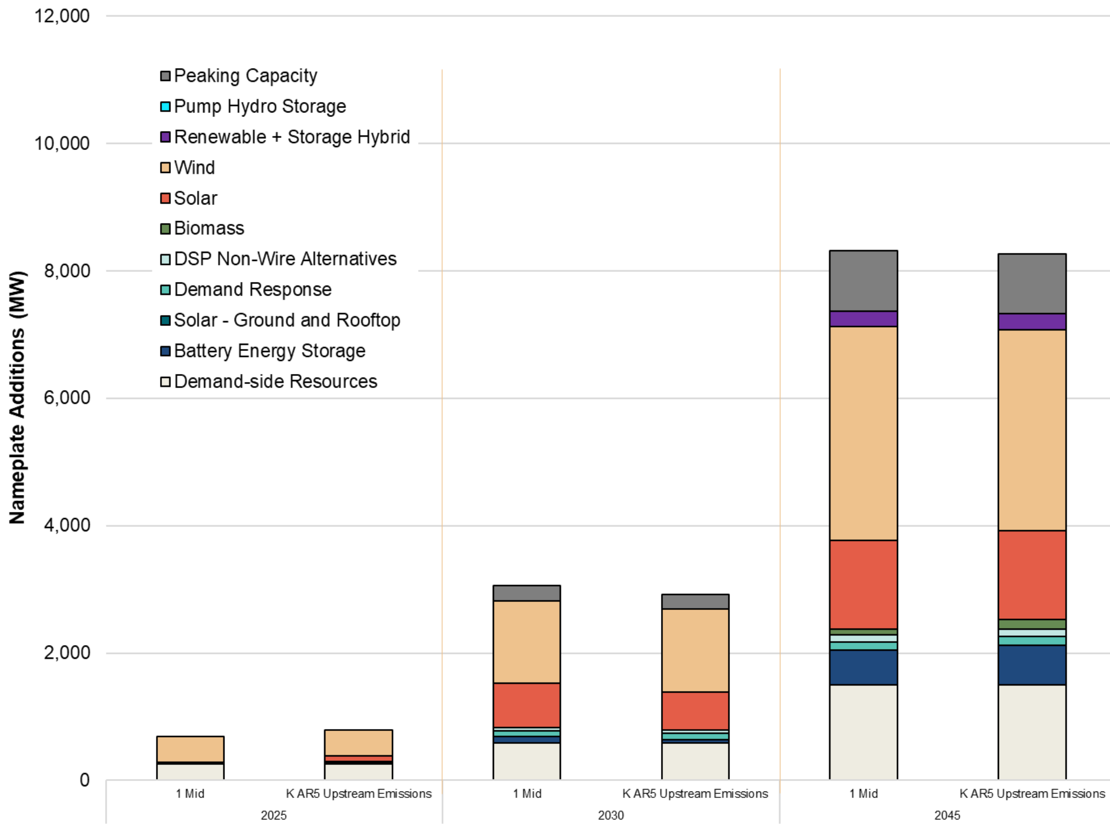
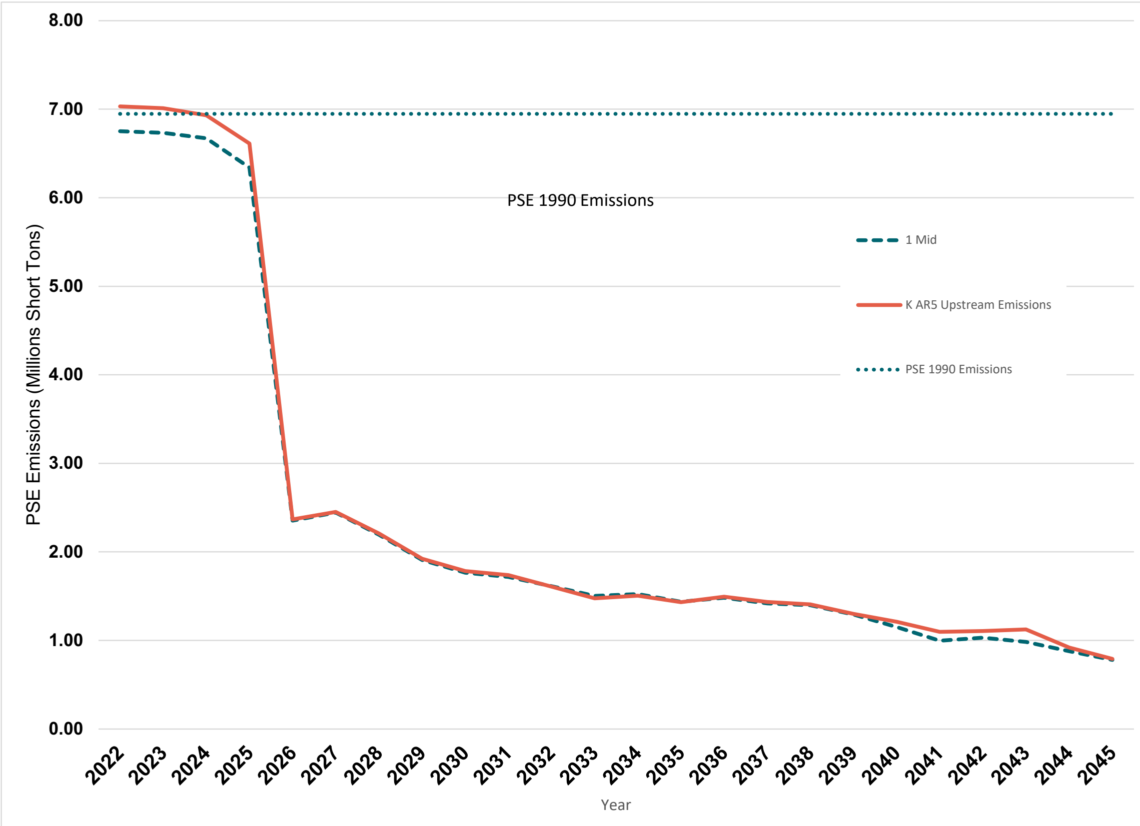


Figure 8-67: Portfolio Additions – Mid Scenario and Sensitivity K

Resource Additions by 2045	1 Mid	K AR5 Upstream Emissions
Demand-side Resources	1,497 MW	1,497 MW
Battery Energy Storage	550 MW	625 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	140 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,693 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	1,393 MW
Wind	3,350 MW	3,150 MW
Renewable + Storage Hybrid	250 MW	250 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	948 MW

EMISSIONS. Changing to the AR5 methodology does not significantly change the emissions of Portfolio K. Figure 8-68 compares the emissions of the Mid Scenario and Portfolio K. The change to the AR5 methodology makes the most difference in the earlier years when dispatch of the natural gas resources are higher. Over time, the dispatch of the natural gas resources drops significantly enough that there is negligible change in emissions between the two portfolios.

Figure 8-68: Annual Emissions – Mid Scenario and Portfolio K



L. SCGHG as a Fixed Cost Plus a Federal CO_2 Tax

This sensitivity examines the impact of adding a Federal CO_2 tax in addition to SCGHG as a fixed cost adder for thermal plants during the resource selection process.

Baseline: The SCGHG is included as a planning adder (fixed cost) to thermal resources during the LTCE modeling process.

Sensitivity L > In addition to SCGHG as a planning adder (fixed cost) to thermal resources during the LTCE modeling process, a Federal CO_2 tax is applied to emissions from thermal resources during both the LTCE modeling process and the hourly dispatch model. This Federal CO_2 tax is applied to the power prices of the portfolio as well, which affects all WECC resources.

KEY FINDINGS. There is relatively little change to the renewable resource additions in Sensitivity L since the CETA requirement drives renewable portfolio additions rather than the SCGHG or a Federal CO_2 tax. However, adding a Federal CO_2 alters the dispatch of thermal resources. The capacity factor of all thermal plants declines overtime as the Federal CO_2 tax increases during the planning horizon.

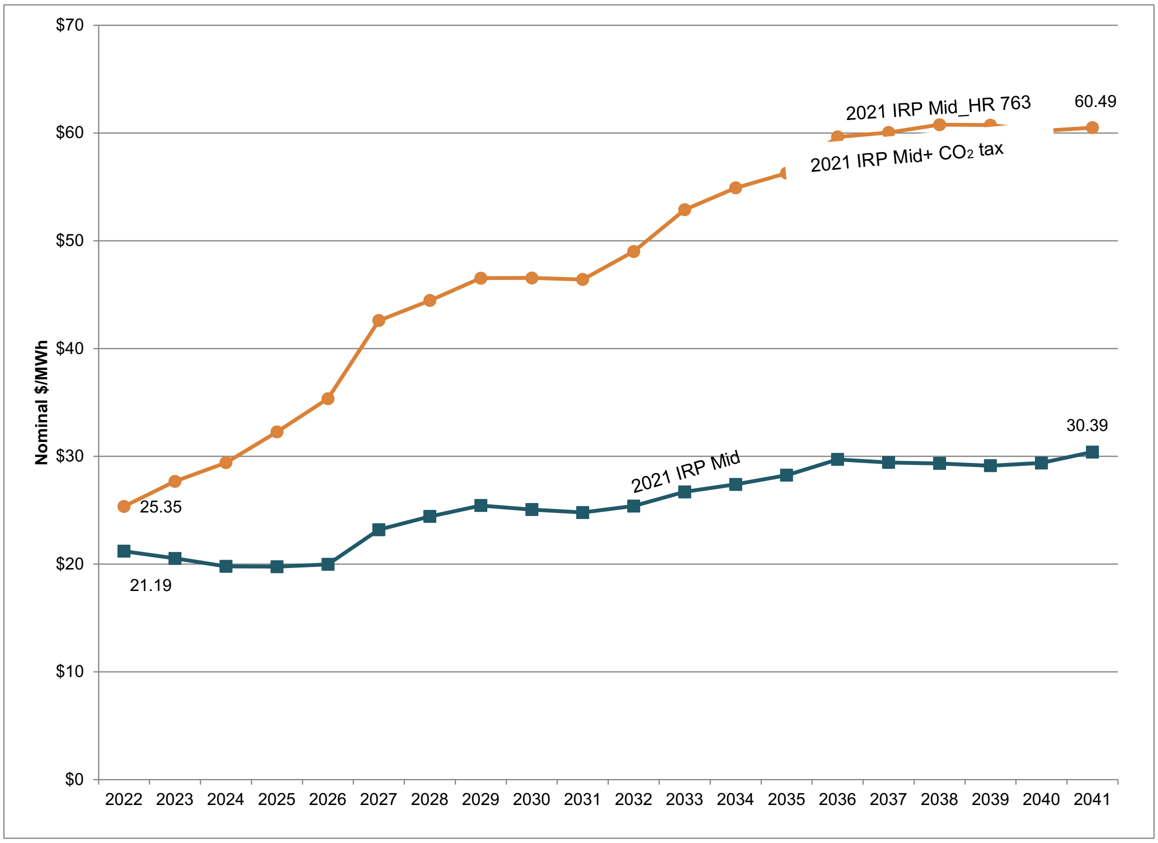
ASSUMPTIONS. For this sensitivity, PSE modeled the Energy Innovation and Carbon Dividend Act of 2019 (H.R. 763) that was introduced in Congress on January 2019, as the assumed federal CO_2 tax. The bill imposes a fee on the carbon content of fuels, including crude oil, natural gas, coal or any other product derived from those fuels. The fee is imposed on the producers or importers of the fuels and is equal to the greenhouse gas content of the fuel multiplied by the carbon fee rate. The rate begins at $15 in 2019, increases by $10 each year, and is subject to further adjustments based on progress in meeting specified emissions reduction targets. Figure 8-69 shows the value of the Federal CO_2 tax included in AURORA and the SCGHG used for this sensitivity.

Figure 8-69: SCGHG under CETA and the Federal CO_2 Tax under H.R. 763 (in 2012 dollars per short ton)

Year	SCGHG 2012$ / short ton CO_2	Federal CO_2 Tax 2012$ / short ton CO_2
2022	59.33	12.33
2023	60.25	20.35
2024	61.18	28.37
2025	63.03	36.20
2026	63.96	43.83
2027	64.89	51.28
2028	65.81	58.55
2029	66.74	65.64
2030	67.67	72.56
2031	68.60	79.31
2032	69.52	85.90
2033	70.45	92.32
2034	71.38	98.59
2035	72.30	104.70
2036	73.23	110.67
2037	75.08	116.49
2038	76.01	122.17
2039	76.94	127.71
2040	77.86	133.11
2041	78.79	138.38
2042	79.72	143.53
2043	80.65	148.55
2044	81.57	153.44
2045	82.50	158.22

Using the Federal CO_2 tax requires an updated power price forecast since the Federal tax would impact the operations of all thermal plants in the WECC. Figure 8-70 compares the addition of a Federal CO_2 tax to Mid-C power prices with the Mid Scenario power price forecast. The 20-year levelized Mid-C power price is $43.11 per MWh, an increase of almost $19 per MWh over the Mid Scenario power prices.

Figure 8-70: Mid-C Power Prices – Mid Scenario and Sensitivity L
(in 2012 dollars per short ton)

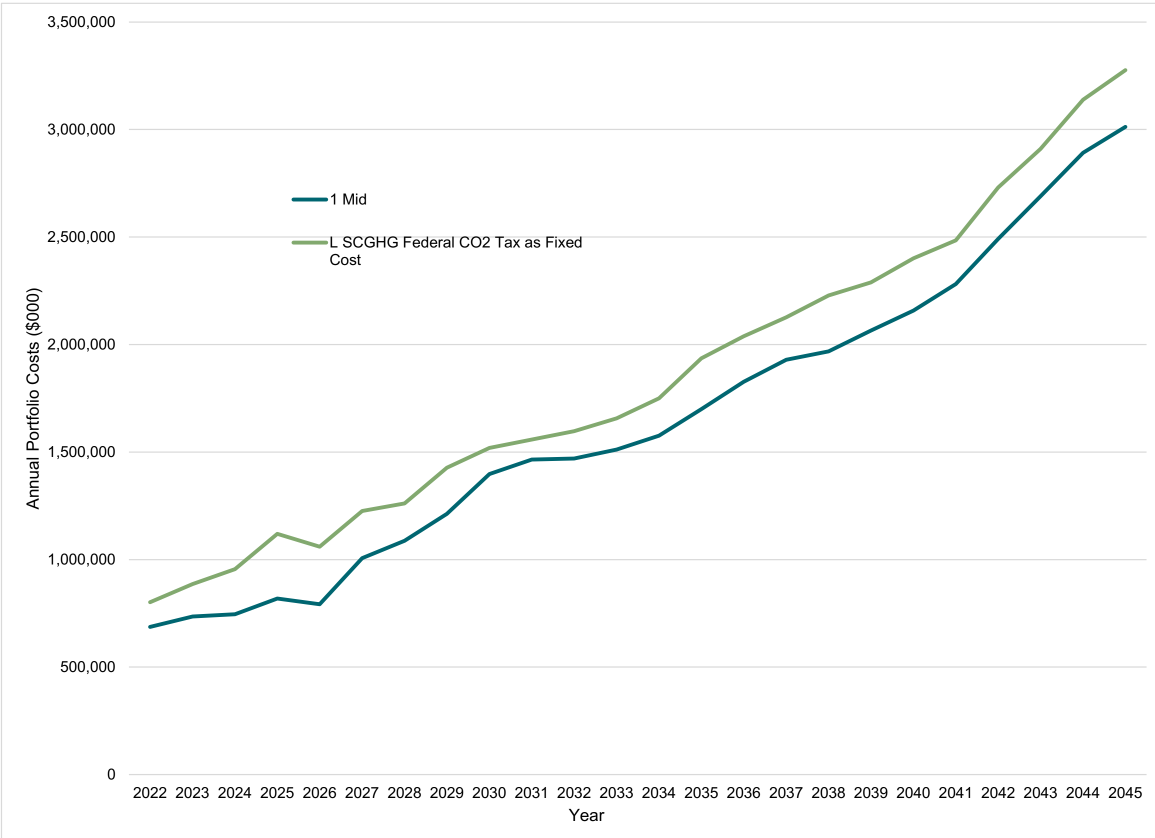


ANNUAL PORTFOLIO COSTS. The Sensitivity L portfolio costs are $2.24 billion higher than Mid Scenario costs. The higher costs can be attributed to the increase in market purchases and the selection of conservation Bundle 11 in Sensitivity L instead of conservation Bundle 10 in the Mid Scenario portfolio. Emissions costs in Sensitivity L are lower since thermal plants are dispatching less and generating lower emissions.

Figure 8-71: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity L

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
L	SCGHG as a Fixed Cost Plus a Federal CO_2 Tax	$17.77	$4.71	$22.47	$2.24

Figure 8-72: Annual Portfolio Costs – Mid Scenario and Sensitivity L



RESOURCE ADDITIONS. Figure 8-73 compares the nameplate capacity additions in the Mid Scenario and Sensitivity L portfolios. Adding the Federal CO_2 tax not only reduced the amount of flexible capacity resources added, but it also changed the mix of those flexible capacity resources. Sensitivity L adds a combined-cycle turbine in 2026, while the Mid Scenario adds a frame peaker in 2026. Sensitivity L also selects a higher conservation bundle (Bundle 11 compared to Bundle 10 in the Mid Scenario) and two additional demand response resources for a total of five. Minor differences are seen in the portfolio builds for solar, wind and hybrid capacity built by 2045.

Figure 8-73: Portfolio Additions – Sensitivity L and Mid Scenario

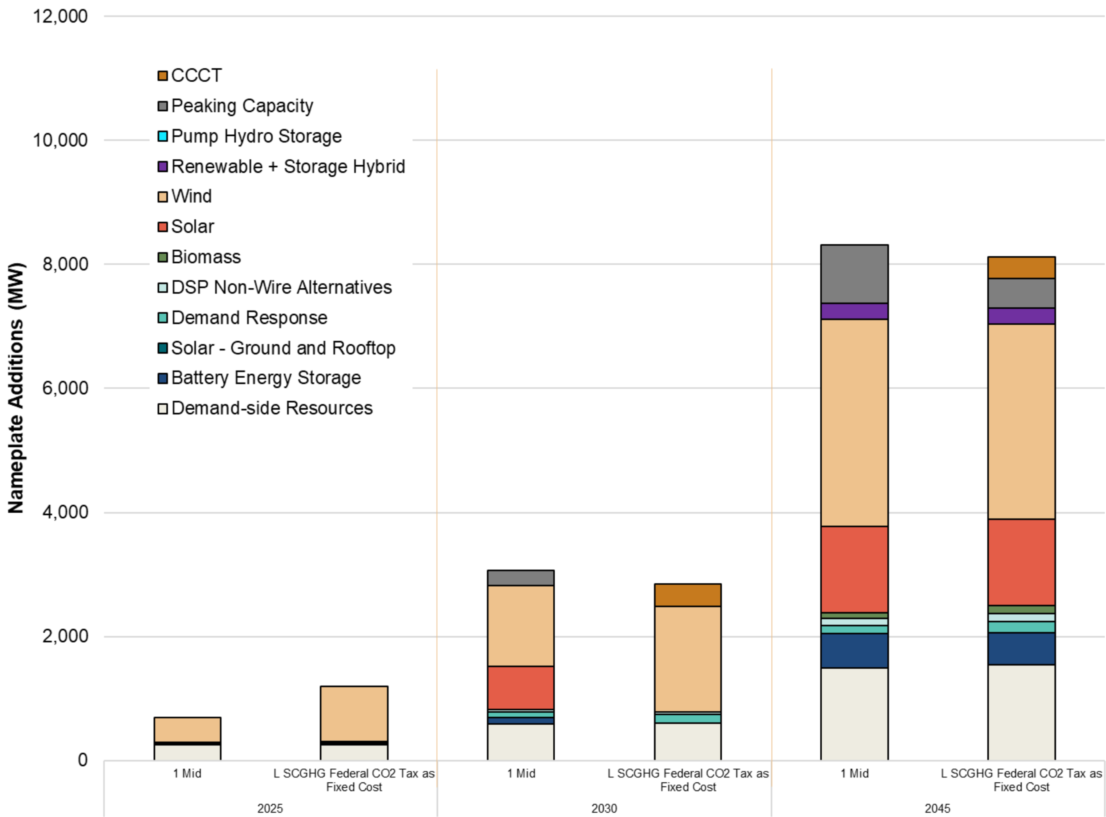


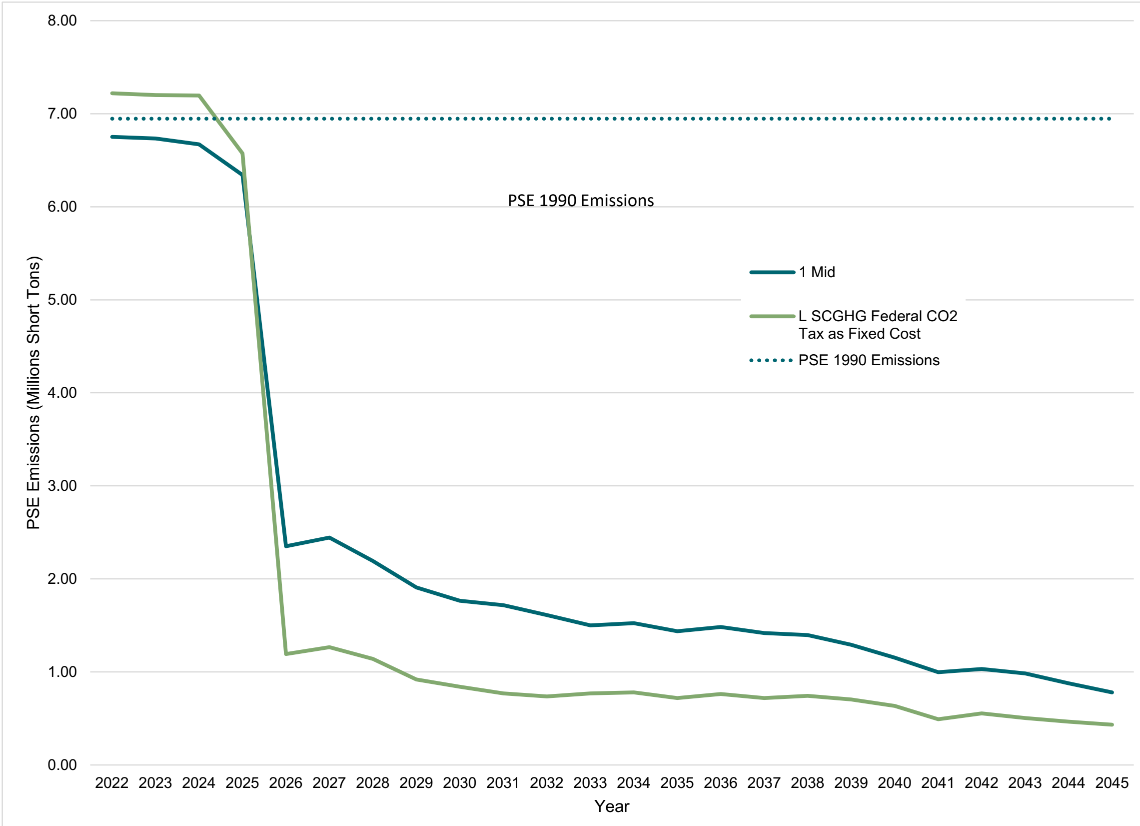
Figure 8-74 compares the nameplate capacity additions of the Mid Scenario and Sensitivity L portfolios by 2045.

Figure 8-74: Portfolio Additions – Mid Scenario and Sensitivity L

Resource Additions by 2045	1 Mid	L Federal CO_2 Tax SCGHG as Fixed Cost
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	525 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	183 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,680 MW
Biomass	90 MW	135 MW
Solar	1,393 MW	1,395 MW
Wind	3,350 MW	3,150 MW
Renewable + Storage Hybrid	250 MW	250 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	474 MW
CCCT	0 MW	355 MW

EMISSIONS. Inclusion of a Federal CO_2 tax changed the emissions of Portfolio L significantly. In Portfolio L, after a large decline in emissions following the retirement of Centralia and Colstrip in 2026, existing and new thermal plants dispatch less and generate lower emissions due to the cost hurdle imposed by the Federal CO_2 tax. As a result, market purchases increased in Sensitivity L to make up for the decline in energy from thermal plants. Figure 8-75 compares the emissions of the Mid Scenario and Sensitivity L portfolios.

Figure 8-75: Annual Emissions – Mid Scenario and Portfolio L



Emissions Reduction

M. Alternative Fuel for Peakers

This sensitivity examines the effects of replacing the fuel supply for new frame peaker resources with a renewable fuel source, specifically biodiesel.

Baseline: New frame peaker resources are supplied with natural gas as their primary fuel source.
Sensitivity > New frame peaker resources are supplied with biodiesel as their primary fuel source.

KEY FINDINGS. In Sensitivity M, substituting biodiesel for natural gas in new frame peakers has only subtle impacts on the resulting portfolio. The 24-year levelized portfolio costs remain relatively unchanged, and resource additions are very similar to the Mid Scenario. GHG emissions are reduced slightly over the course of the modeling horizon. Biodiesel may be a feasible, cost-effective option for fueling peaking capacity resources while attaining CETA's zero emission goals and maintaining grid reliability.

ASSUMPTIONS. In Sensitivity M, new frame peaker resources are supplied with biodiesel as their primary fuel source. It is assumed that there are negligible differences between natural gas and biodiesel-fueled frame peakers in plant capital costs and fixed and variable operations and maintenance costs. Biodiesel is only available to frame peakers; new reciprocating peakers, new combined-cycle plants. Existing thermal resources are fueled with natural gas.

The market price for biodiesel was estimated from PSE experience and informed by the U.S. Department of Energy Clean Cities Alternative Fuel Price Report, October 2020. PSE has assumed a fixed biodiesel price of $37.20 per million British Thermal Units (MM BTU) (2020 dollars, adjusted for inflation annually) over the entire study period.

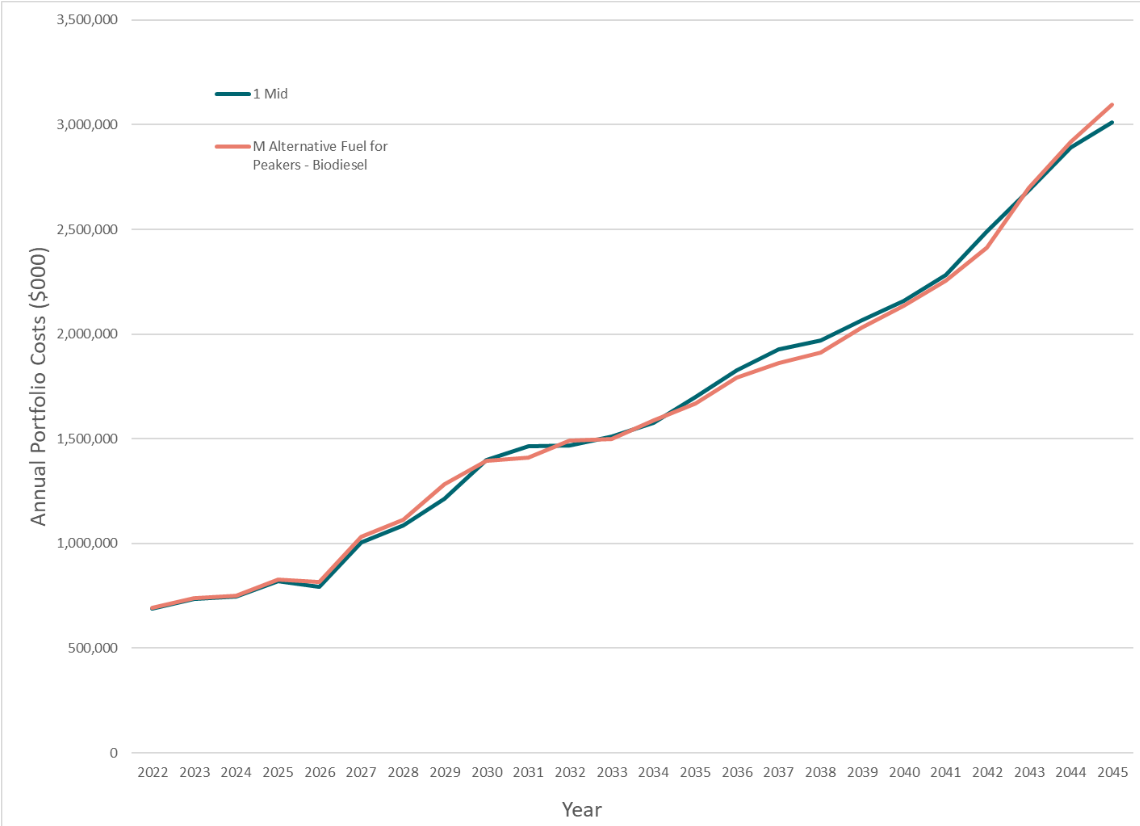
Given the anticipated constraints on biodiesel fuel supply, the flexibility benefit of frame peakers was removed ($0/kW-yr) in Sensitivity M as compared to the flexibility benefit of $23.45/kW-yr for frame peakers in the Mid Scenario.

PORTFOLIO COSTS. Figures 8-76 and 8-77 compare the breakdown of costs between the Mid Scenario and Sensitivity M portfolios. The 24-year levelized cost of Sensitivity M is nearly equal to the cost of Mid Scenario. However, the social cost of greenhouse gases is $100 million less in Sensitivity M compared to the Mid Scenario due to the use of a carbon neutral fuel for new frame peakers.

Figure 8-76: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity M

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
M	Alternative Fuel for Peakers	$15.53	$4.99	$20.52	($0.10)

Figure 8-77: Annual Portfolio Costs – Mid Scenario and Sensitivity M



RESOURCE ADDITIONS. Figures 8-78 and 8-79 compare the nameplate capacity additions of the Sensitivity M and Mid Scenario portfolios. Resource additions for Sensitivity M are very similar to those in the Mid Scenario. Both add the same quantity of peaking capacity, hybrid resources and similar quantities of renewable resources. Sensitivity M builds slightly more solar and slightly less wind than the Mid Scenario, and Sensitivity M selects conservation Bundle 11, whereas the Mid Scenario selects Bundle 10.

Figure 8-78: Portfolio Additions – Sensitivity M and the Mid Scenario

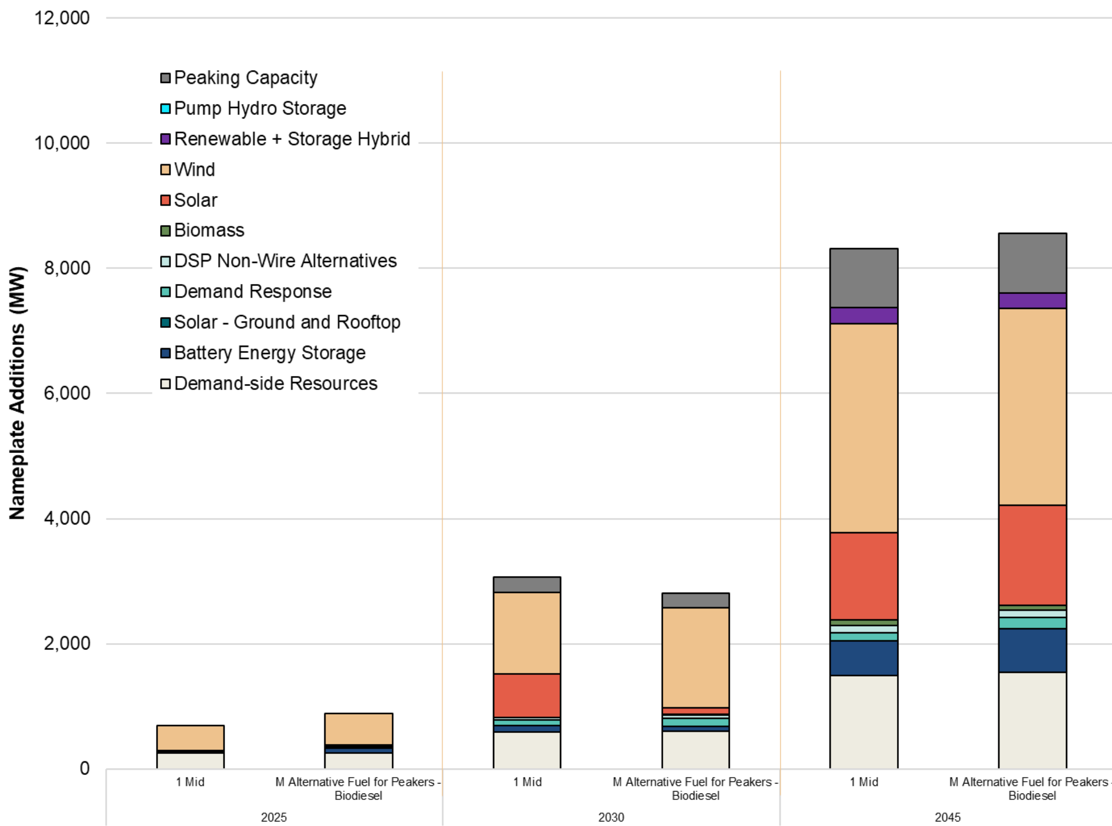
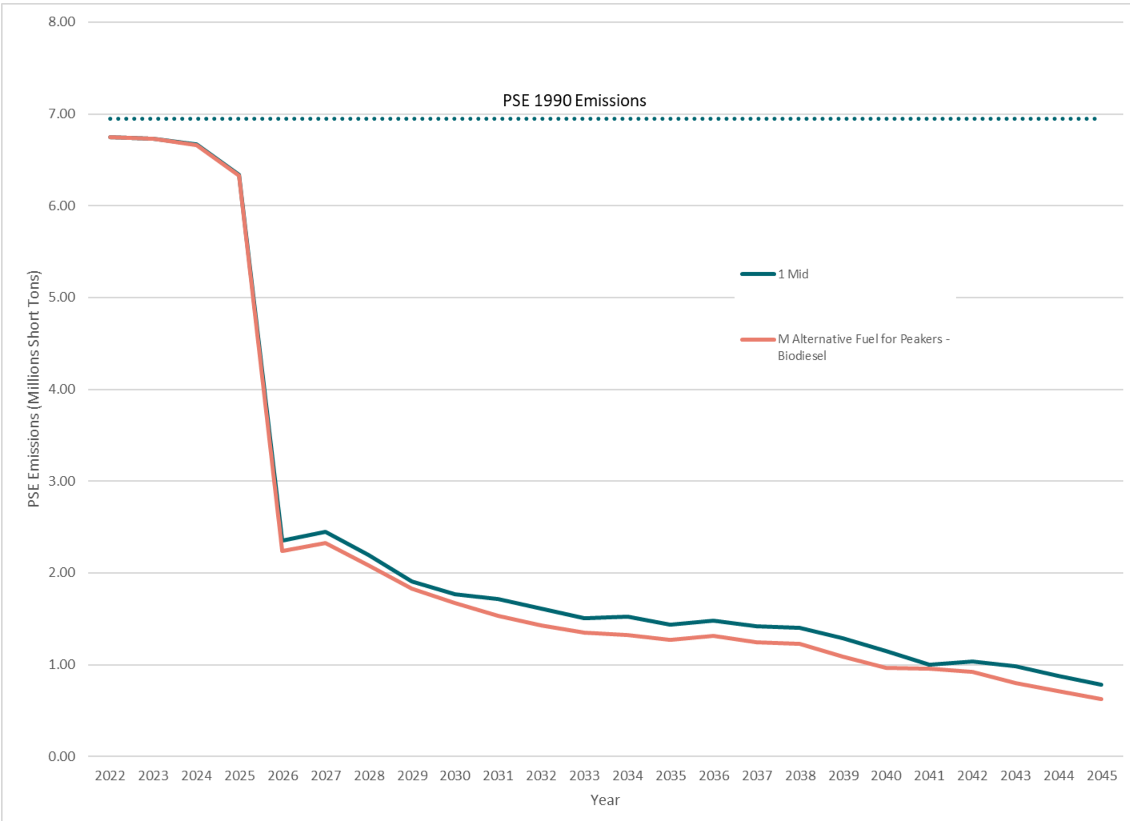


Figure 8-79: Portfolio Additions by 2045 – Mid Scenario and Sensitivity M, Alternative Fuel for Peakers

Resource Additions by 2045	1. Mid	M. Alternative Fuel for Peakers
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	700 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	185 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,818 MW
Biomass	90 MW	75 MW
Solar	1,393 MW	1,593 MW
Wind	3,350 MW	3,150 MW
Renewable + Storage Hybrid	250 MW	250 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	948 MW

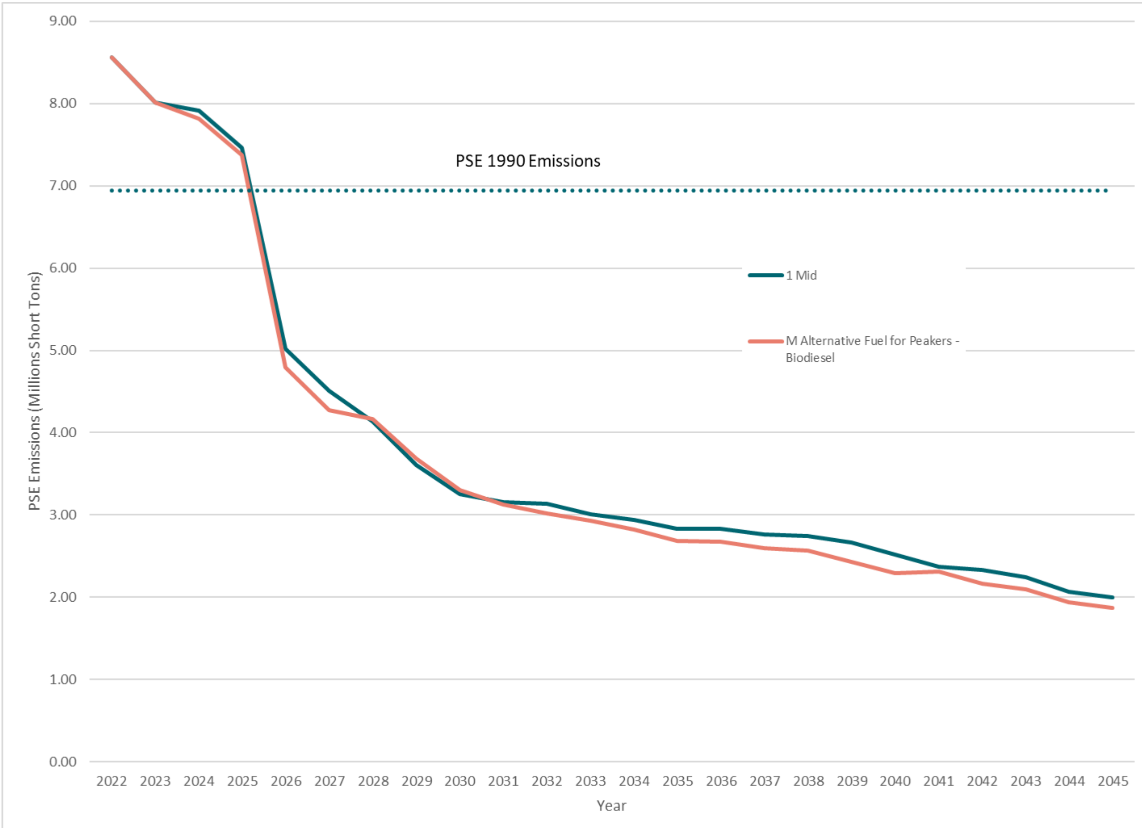
EMISSIONS. Sensitivity M resulted in fewer direct GHG emissions compared to the Mid Scenario due to the use of a carbon neutral fuel for peaking capacity needs. Figure 8-80 compares the GHG emissions from the Mid Scenario and Sensitivity M portfolios. Following acquisition of the first peaking capacity resource in 2026, Sensitivity M has consistently lower GHG emissions over the course of the modeling horizon.

Figure 8-80: Direct GHG Emissions – Mid Scenario and Sensitivity M, Alternative Fuel for Peakers



A similar trend is observed in Figure 8-81 which compares GHG emissions from the Sensitivity M with the Mid Scenario emissions, including both direct and indirect (i.e. market) emissions. Sensitivity M maintains lower emissions, however, the difference in emission reductions between the two portfolios is smaller.

Figure 8-81: Direct and Indirect GHG Emissions– Mid Scenario and Sensitivity M



To put emission reductions into perspective, it is useful to look at them as a function of portfolio cost (or, the cost of emissions reduction). To calculate this metric, divide the difference in the 24-year levelized cost between the sensitivity and the Mid Scenario by the difference in 24-year levelized emissions between the Mid Scenario and the sensitivity:

$$\frac{Sensitivity\ 24yr\ Levelized\ Cost\ - Mid\ Sc\ 24\ yr\ Levelized\ Cost}{Mid\ 24yr\ Levelized\ Emissions - \ Sensitivity\ 24yr\ Levelized\ Emissions}$$

Figure 8-82 shows the results of this calculation for Sensitivity M and provides the preferred portfolio (Sensitivity W) as a comparison. The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent. Sensitivity M is very efficient a reducing portfolio emissions; this is why biodiesel was added a fuel to the preferred portfolio.

Figure 8-82: Cost of Emissions Reduction – Mid Scenario, Sensitivity M and Sensitivity W (the Preferred Portfolio)

Portfolio	Direct and Indirect GHG Emissions (millions tons CO_2eq, 24-year levelized)	Portfolio Cost (Billion $, 24-year levelized)	Cost of Emissions Reduction (millions tons CO_2eq / $ billion)
1 Mid	53.87	$15.53	--
M Alternative Fuel for Peakers	52.84	$15.53	<0.01
W Preferred Portfolio (BP with Biodiesel)	52.77	$16.10	0.52

CAPACITY FACTOR. Despite the much higher cost of biodiesel ($30.53/MMBtu) as compared to natural gas ($3.56/MMBtu), the overall revenue requirement of Sensitivity M and the Mid Scenario are roughly equal. This is because the high cost of biodiesel drives down the dispatch frequency of the new frame peaking resources. New frame peakers in the Mid Scenario had an annual capacity factor of about 3 percent in the year 2045. In Sensitivity M, the annual capacity factor of new frame peakers dropped to less than 0.1 percent. This suggests that the frame peakers were only dispatched in periods of peak demand to fill a specific role in providing peak capacity to the portfolio.

BIODIESEL AVAILABILITY. When modeling a portfolio like Sensitivity M that relies on a limited commodity such as biodiesel, it is important to consider the availability of that resource. Washington state produced around 114 million gallons of biodiesel in 2019 from two facilities.[5] In Sensitivity M, biodiesel fueled frame peakers supplied, at most, 7,233 MWh of energy over the modeling horizon. This equates to an annual need of approximately 600,000 gallons of biodiesel or about 0.5 percent of Washington State's annual production. This relationship suggests that the Washington biodiesel market could plausibly support the use of biodiesel for peak need electricity generation. PSE also evaluated the fuel needed to maintain resource adequacy which is included in Chapter 7.

5 / https://www.eia.gov/biofuels/biodiesel/production/

N. 100% Renewable by 2030

This sensitivity examines the cost difference between the Mid Scenario portfolio and a portfolio that advances the CETA target of 100 percent renewable energy to 2030.

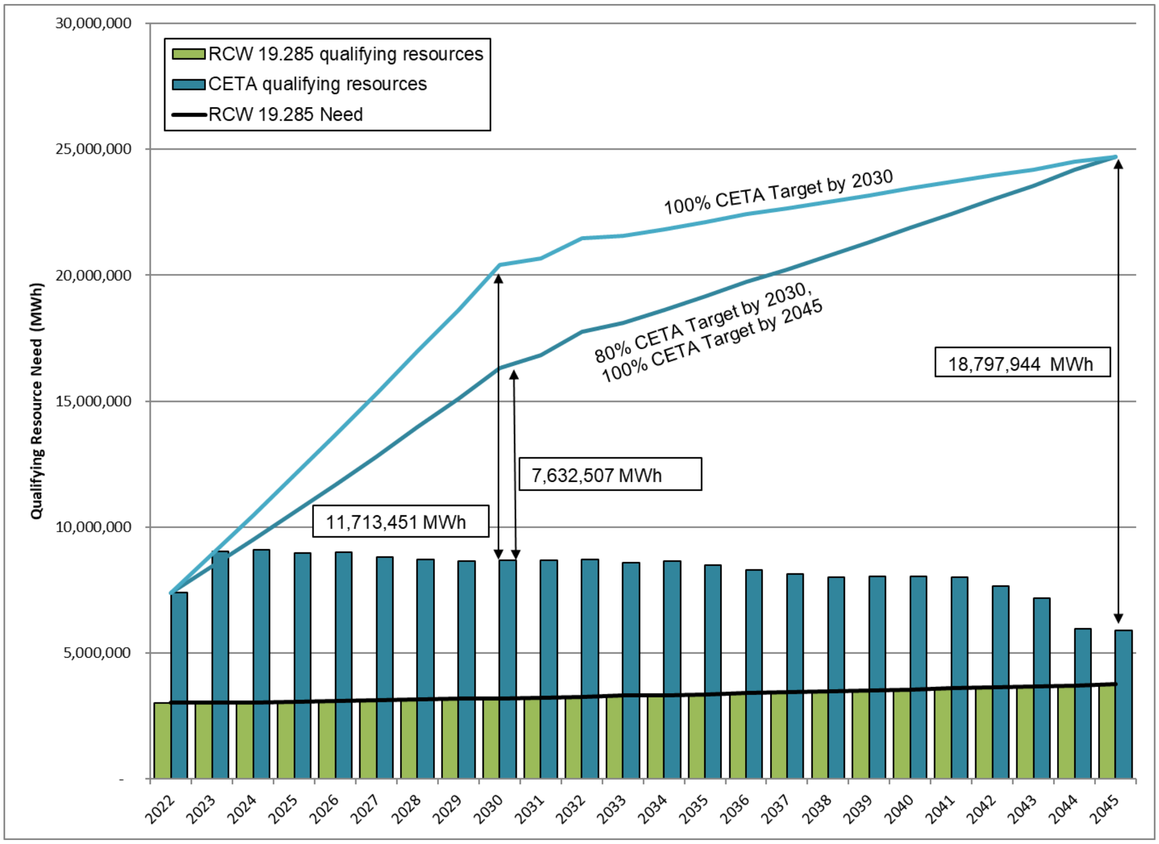
Baseline: 80 percent of sales must be met by non-emitting/renewable resources by 2030; the remaining 20 percent is met through alternative compliance.
Sensitivity > 100 percent of sales must be met by non-emitting/renewable resources by 2030.

KEY FINDINGS. Sensitivity N demonstrates that achieving a 100 percent renewable portfolio is possible with existing technologies, but the cost to do so is unrealistically high. The 24-year levelized portfolio cost of Sensitivity N is $15.17 and $33.37 billion more than the Mid Scenario for variations N1 and N2 respectively. The resource additions responsible for these higher portfolio costs do provide a benefit to overall portfolio emissions, but the efficiency of these emissions reductions per dollar spent are extremely low.

ASSUMPTIONS. In the Mid Scenario portfolio, 80 percent of sales are met by non-emitting/renewable resources by 2030, ramping up to 100 percent by 2045. Existing thermal plants continue to be in operation unless economically retired by the model. New peaking capacity resources remain an option for new resource selection. In order for the Mid Scenario portfolio to be 100 percent greenhouse gas neutral by 2030, an estimate for alternative compliance costs is calculated starting in 2030 through 2044. In Sensitivity N, all existing thermal plants are retired by 2030 regardless of economic viability. New peaking capacity resources are also removed for new resource selection. The CETA target is adjusted to 100 percent renewable by 2030. This means the renewable energy target increases by 4.1 million MWhs, rising from 7.6 million MWhs in 2030 to 11.7 million MWhs as shown in Figure 8-70.

Sensitivity N modeled two slightly different sets of assumptions. The first iteration, Sensitivity N1, used the model constraints provided above. Sensitivity N1 allowed the portfolio model to optimize to the 100 percent CETA target by 2030 by whatever means necessary. The second iteration, Sensitivity N2, removed lithium-ion and flow batteries from the available resources. Sensitivity N2 forced the model to solve using pumped hydro storage as the primary storage technology.

Figure 8-83: Renewable Targets – Mid Scenario and Sensitivity N1 and N2 Portfolios

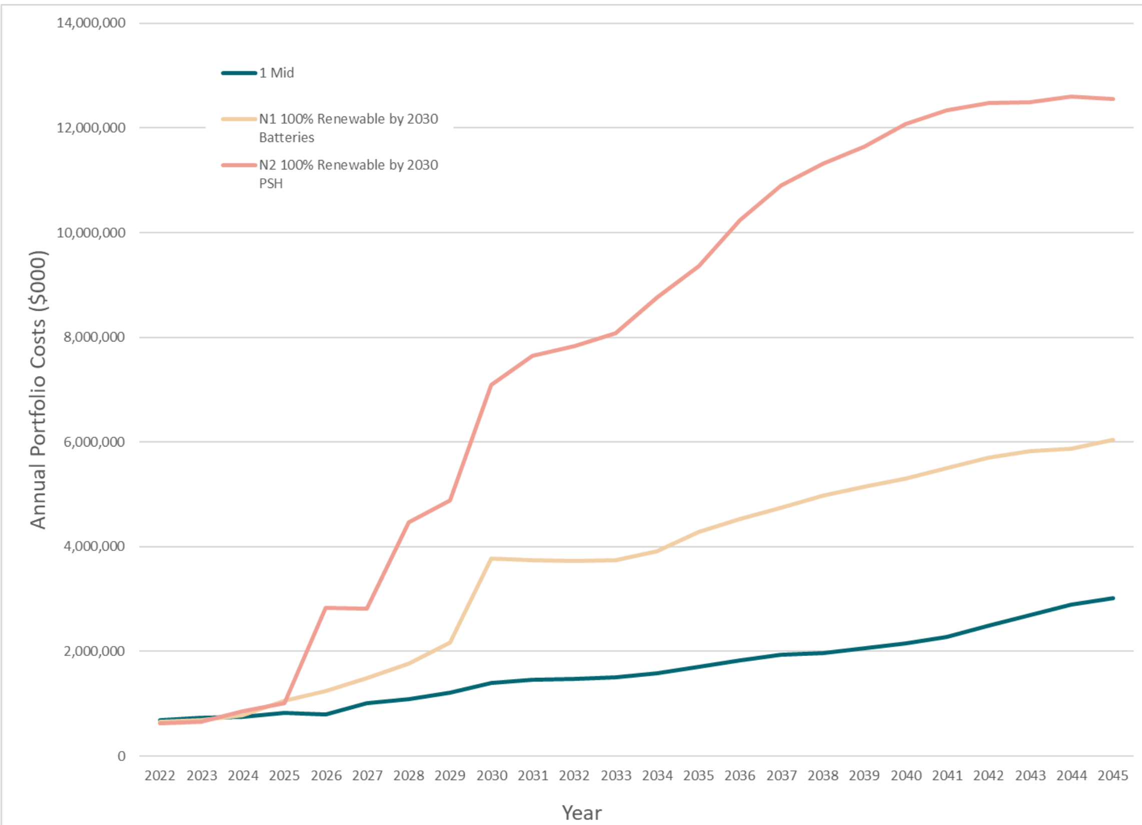


PORTFOLIO COSTS. Sensitivity N demonstrates that aggressively meeting CETA targets ahead of schedule may be possible with existing technologies, but that the cost to do so is high. The increase in costs for Sensitivity N is due to the increase in overall resource builds, particularly for storage resources. Both variations of Sensitivity N have lower SCGHG compared to the Mid Scenario; however, both variations also are among the most expensive portfolios modeled as part in the 2021 IRP. Figures 8-84 and 8-85 compare the breakdown of costs between the Mid Scenario and Sensitivity N portfolios.

Figure 8-84: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity N1 and N2

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
N1	100% Renewable by 2030 (Batteries)	$32.03	$3.76	$35.79	$15.17
N2	100% Renewable by 2030 (PHES)	$66.64	$2.52	$69.16	$33.37

Figure 8-85: Annual Portfolio Costs – Mid Scenario and Sensitivity N1 and N2



RESOURCE ADDITIONS. Figures 8-86 and 8-87 compare the nameplate capacity additions of the Sensitivity N and Mid Scenario portfolios. By 2025, Sensitivity N1 has built a large amount of wind and Sensitivity N2 has built a large amount of solar (both standalone and hybrid) to replace the energy from retirements of Colstrip and Centralia, as well as to meet the high CETA renewable need. Through 2030, Sensitivity N1 selects a portfolio composed largely of 2-hour lithium-ion batteries and wind, whereas Sensitivity N2 selects a more diversified set of resources, adding pumped hydro as a storage resource and a mix of solar and wind projects. At the end of planning period, storage resources compose 78 percent and 71 percent of the resource capacity for Sensitivities N1 and N2 respectively. These massive investments in storage dwarf the resource additions selected in the Mid Scenario, resulting in exorbitant portfolio costs.

Figure 8-86: Portfolio Additions – Mid Scenario and Sensitivity N, 100% Renewable by 2030

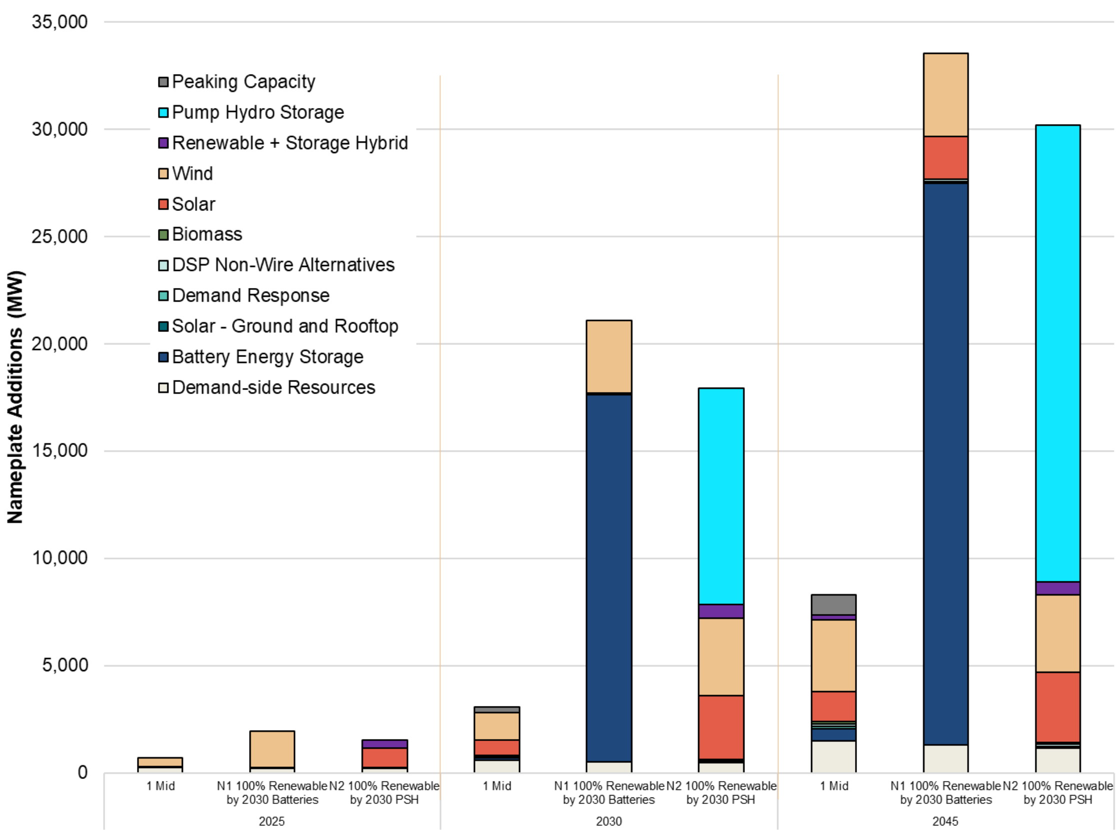


Figure 8-87: Portfolio Additions by 2045 – Sensitivity N, 100% Renewable by 2030

Resource Additions by 2045	1 Mid	N1 100% Renewable by 2030 - Batteries	N12100% Renewable by 2030 - PHES
Demand-side Resources	1,497 MW	1,304 MW	1,169 MW
Battery Energy Storage	550 MW	26,200 MW	0 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW
Demand Response	123 MW	59 MW	59 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	5,844 MW	6,943 MW
Biomass	90 MW	0 MW	75 MW
Solar	1,393 MW	1,994 MW	3,268 MW
Wind	3,350 MW	3,850 MW	3,600 MW
Renewable + Storage Hybrid	250 MW	0 MW	622 MW
Pumped Hydro Storage	0 MW	0 MW	21,300 MW
Peaking Capacity	948 MW	0 MW	0 MW

EMISSIONS. Figure 8-88 compares the direct GHG emissions from the Sensitivity N variations with the Mid Scenario. Direct emissions are defined as emissions linked directly to PSE-owned generating equipment. Since all emitting resources have been retired by 2030, the emissions for Sensitivity N drop to zero at 2030. However, this tells only part of the story. PSE is an active participant in the Mid-C wholesale power market. Storage resources are able to charge from market purchases, and under CETA rules, these market purchases are associated with a specific GHG emission rate.

Figure 8-88: Direct GHG Emissions – Mid Scenario and Sensitivity N, 100% Renewable by 2030

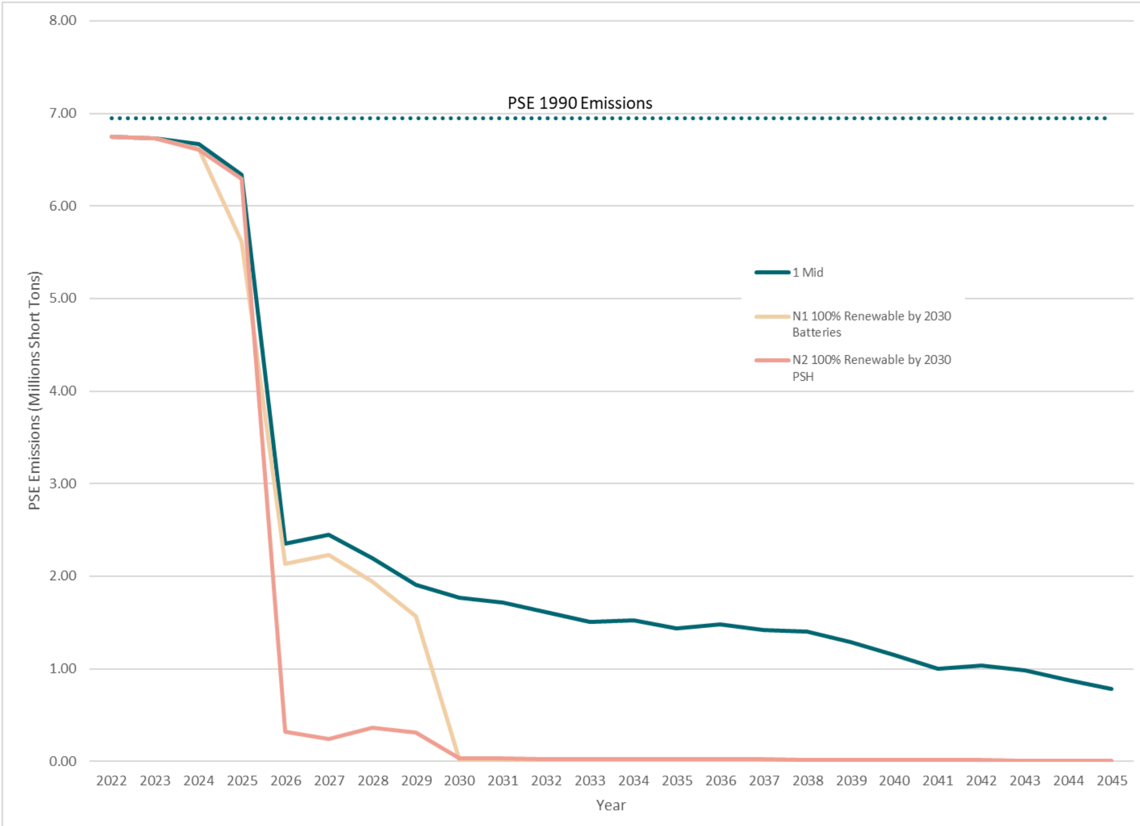
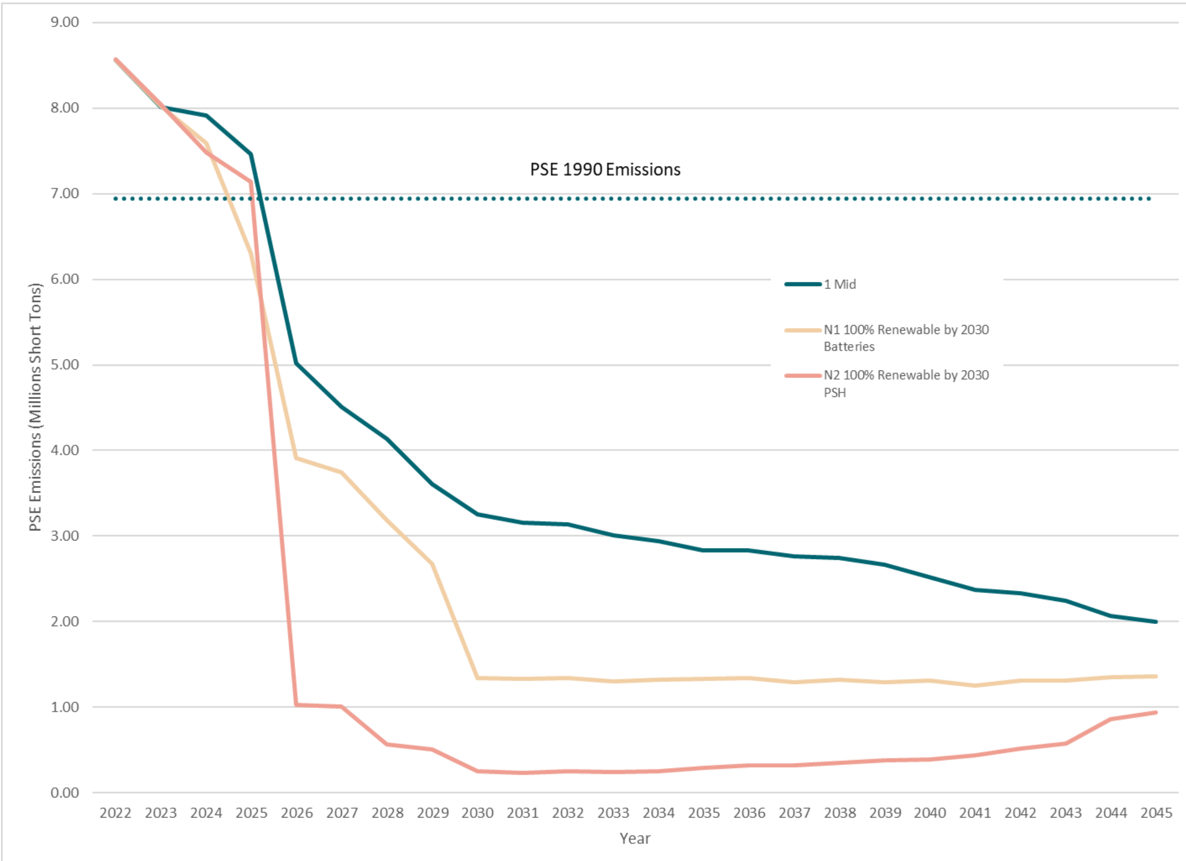


Figure 8-89 compares GHG emissions from the Sensitivity N1 and N2 variations with the Mid Scenario, for both direct and indirect (i.e., market) emissions. Sensitivity N emissions are lower than Mid Scenario emissions throughout the planning horizon, but it is interesting to note that emissions start to increase again for both Sensitivities N1 and N2 in the later years of the planning period due to the increase in energy purchased from market to fill the growing demand from storage resources.

Figure 8-89: Direct and Indirect GHG Emissions – Mid Scenario and Sensitivity N, 100% Renewable by 2030



To put emission reductions in perspective, it is useful to look at them as a function of portfolio cost (or, the cost of emissions reduction). To calculate this metric, divide the difference in the 24-year levelized cost between the sensitivity and the Mid Scenario by the difference in 24-year levelized emissions between the Mid Scenario and the sensitivity:

$$\frac{Sensitivity\ 24yr\ Levelized\ Cost\ - Mid\ Sc\ 24\ yr\ Levelized\ Cost}{Mid\ 24yr\ Levelized\ Emissions -\ Sensitivity\ 24yr\ Levelized\ Emissions}$$

Figure 8-90 shows the results of this calculation for the Sensitivity N variations and provides the preferred portfolio (Sensitivity W) as a comparison. The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent. The Sensitivity N variations are an order of magnitude higher than the preferred portfolio, which suggests that forcing 100 percent renewable energy by 2030 is not an efficient means to reduce emissions.

Figure 8-90: Cost of Emissions Reduction – Mid Scenario, Sensitivity N and Preferred Portfolio

Portfolio	Direct and Indirect GHG Emissions (millions tons CO_2eq, 24-year levelized)	Portfolio Cost (Billion $, 24-year levelized)	Cost of Emissions Reduction (millions tons CO_2eq / $ billion)
1 Mid	53.87	$15.53	--
N1 100% Renewable by 2030 - Batteries	42.16	$32.03	1.41
N2 100% Renewable by 2030 - PHES	30.65	$66.64	2.20
W Preferred Portfolio (BP with Biodiesel)	52.77	$16.10	0.52

O. 100% Renewable by 2045

This sensitivity examines the cost difference between the Mid Scenario portfolio and a portfolio that has no natural gas-fired generation resources by 2045.

Baseline: No planned retirements of existing gas fired generation resources; however, the model allows for economic retirement.
Sensitivity > All existing natural gas-fired resources, including new peaking capacity resources, must be retired by 2045.

KEY FINDINGS. Sensitivity O shows that it is possible to phase out natural gas generation by the year 2045. However, the capital cost to do so it very high. On the basis of tons of GHG emissions reduced per dollar, there are more efficient ways to achieve comparable emissions reductions. Sensitivity O also shows the importance of market purchases to supporting a storage-heavy portfolio in a cost-effective manner.

ASSUMPTIONS. In the Mid Scenario portfolio, existing natural gas-fired generation resources remain in operation unless economically retired by the model. Generic peaking capacity resources are available as a new resource, but they retire by 2045. In Sensitivity O, all existing natural gas-fired generation resources are retired by 2045, regardless of economic viability. Existing thermal plant retirements are ramped in over time at a rate of approximately 200 MW per year between 2030 and 2045 to create a smoother transition to renewable generation.

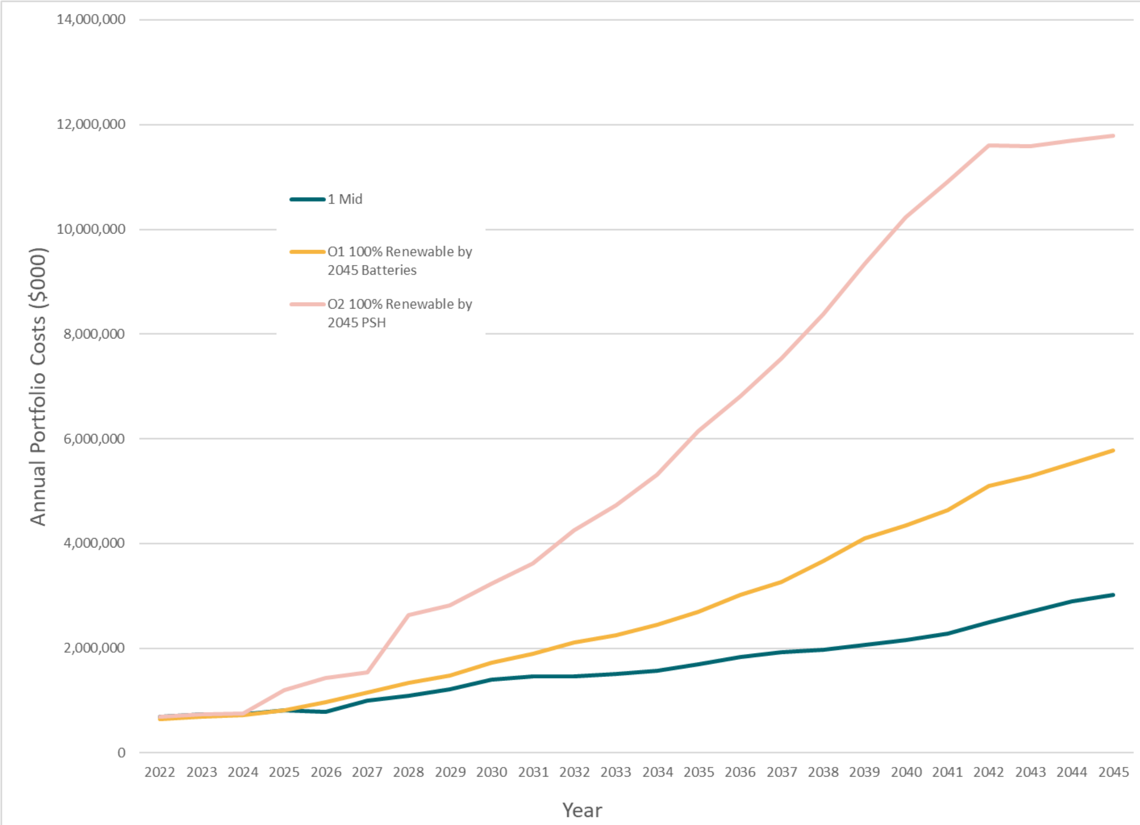
Sensitivity O modeled three slightly different sets of assumptions. The first iteration, Sensitivity O1, used the model constraints provided above and allowed the model to optimize removing natural gas fueled resource by 2045. The second iteration, Sensitivity O2, removed lithium-ion and flow batteries from the list of available resources and forced the model to solve using pumped hydroelectric storage as the primary storage technology.

PORTFOLIO COSTS. Figures 8-91 and 8-92 illustrate the breakdown of costs between the Mid Scenario and Sensitivity O portfolios. The increase in costs for Sensitivity O is attributed to the increase in the overall resource builds.

Figure 8-91: 24-year Levelized Portfolio Costs – Mid Scenario, Sensitivity O1 and Sensitivity O2

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
O1	100% Renewable by 2045 – Batteries	$23.35	$4.81	$28.16	$7.54
O2	100% Renewable by 2045 – PHES	$46.95	$3.98	$50.94	$30.32

Figure 8-92: Annual Portfolio Costs – Mid Scenario and Sensitivity O



RESOURCE ADDITIONS. Figures 8-93 and 8-94 compare the nameplate capacity additions of Sensitivity O and the Mid Scenario portfolios. Neither variation of Sensitivity O selects any flexible capacity resources over the course of the planning period. Both variations focus on building storage resources early and often to keep up with growing capacity need. Sensitivity O1 builds solely standalone 2-hour lithium-ion batteries, whereas Sensitivity O2 builds a mix of pumped hydroelectric storage and hybrid resources. Both variations rely heavily on market purchases to charge storage resources throughout the planning period.

Figure 8-93: Portfolio Additions – Mid Scenario and Sensitivity O

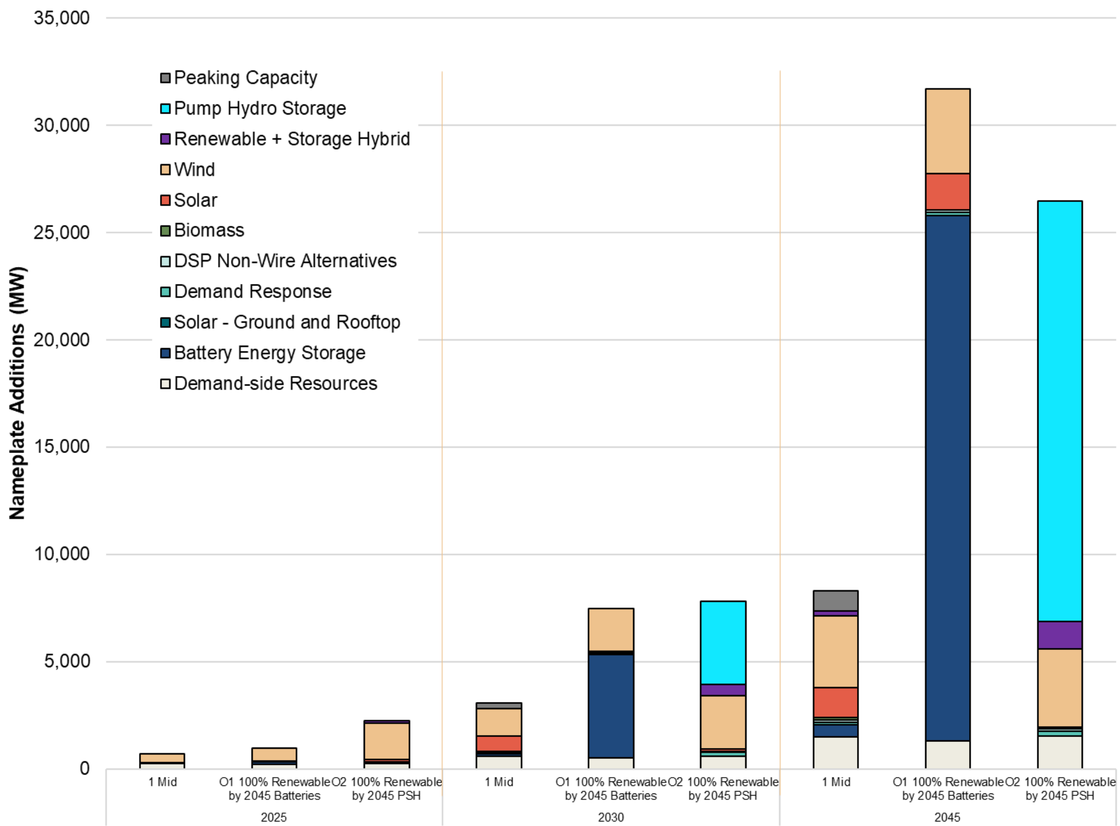


Figure 8-94: Portfolio Additions by 2045 – Mid Scenario and Sensitivity O, – 100% Renewable by 2045

Resource Additions by 2045	1 Mid	O1 100% Renewable by 2045 - Batteries	O2 100% Renewable by 2045 - PHES
Demand-side Resources	1,497 MW	1,304 MW	1,537 MW
Battery Energy Storage	550 MW	24,500 MW	0 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW
Demand Response	123 MW	128 MW	204 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	5,642 MW	3,749 MW
Biomass	90 MW	0 MW	0 MW
Solar	1,393 MW	1,692 MW	99 MW
Wind	3,350 MW	3,950 MW	3,650 MW
Renewable + Storage Hybrid	250 MW	0 MW	1,249 MW
Pumped Hydro Storage	0 MW	0 MW	19,600 MW
Peaking Capacity	948 MW	0 MW	0 MW

PEAK CAPACITY. The results of Sensitivity O are somewhat conflicted. On one hand, Sensitivity O1 just barely exceeds the peak capacity need in the year 2045 as shown in Figure 8-95. On the other hand, Sensitivity O2 was significantly over-built, exceeding peak need by over 5,000 MW in 2045 as shown in Figure 8-83. These two extremes make the results difficult to interpret with confidence. It seems unlikely that many small 2-hour storage resources are the most effective resources to meet peak need without the aid of thermal resources. However, Sensitivity O1 was far less costly than Sensitivity O2, which included seemingly more flexible 8-hr storage resources. Sensitivity O placed extreme demands on the simulation to dispatch over 10,000 MW of storage capacity and to replace over 2,000 MW of existing thermal resources in a single year. More work is required to refine storage logic within the portfolio model.

Figure 8-95: Peak Capacity Contribution – Mid Scenario and Sensitivity O1, 100% Renewable by 2045 – Batteries

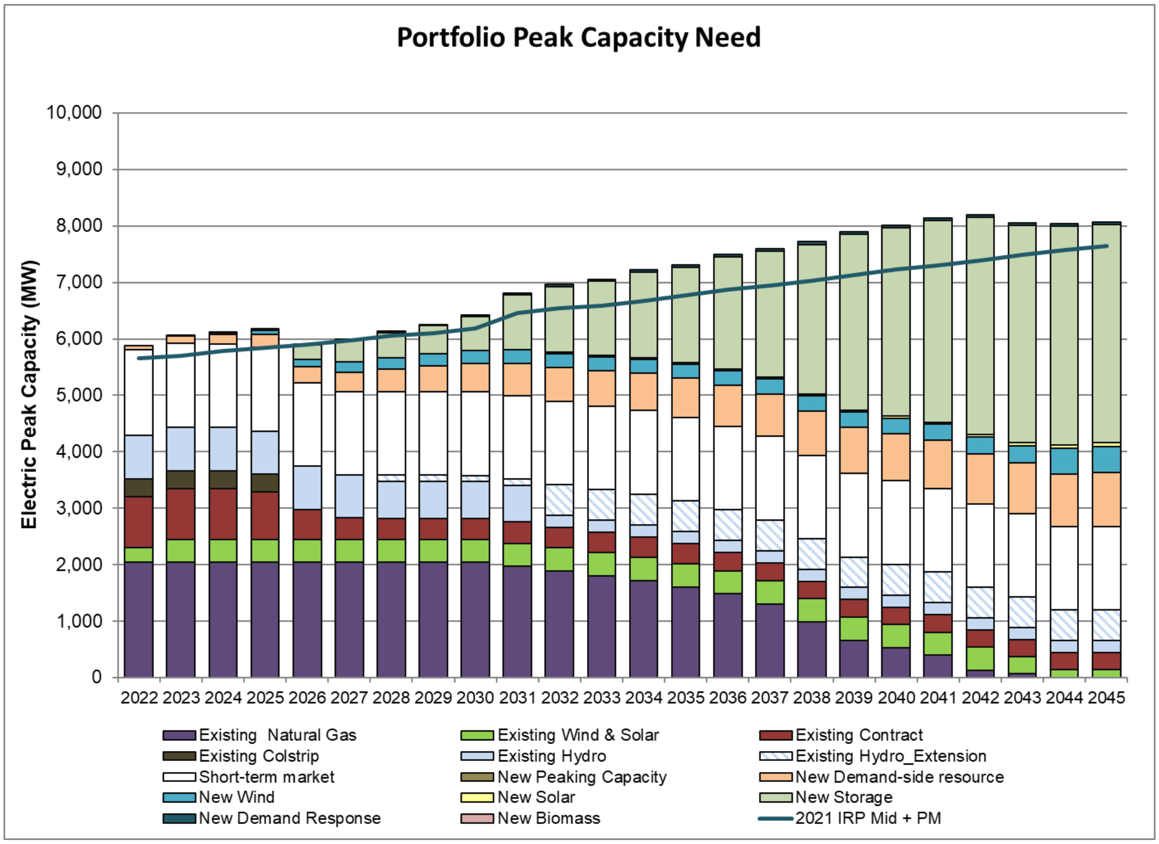
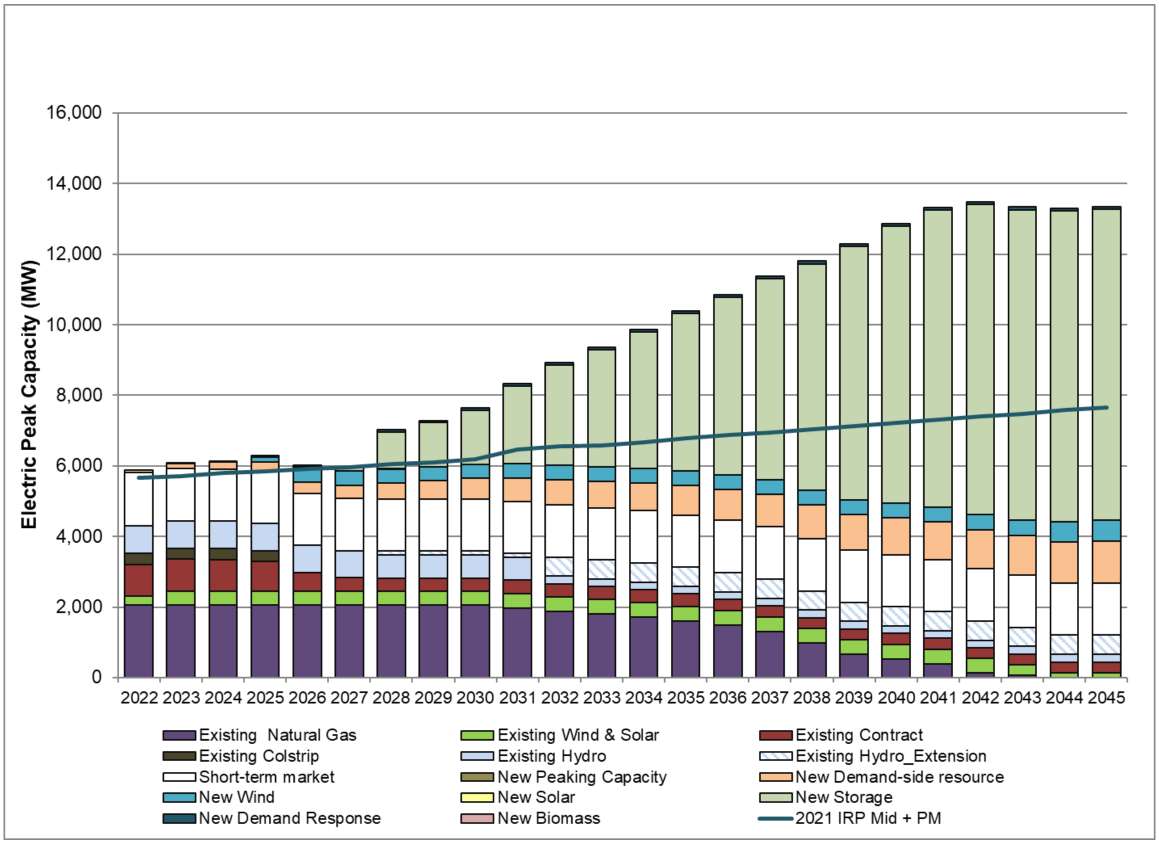


Figure 8-96: Peak Capacity Contribution – Mid Scenario and Sensitivity O2 – 100% Renewable by 2045 – Pumped Hydro Storage



EMISSIONS. Figure 8-97 compares the direct GHG emissions from the Sensitivity O variations with the Mid Scenario. Direct emissions are defined as emissions linked directly to PSE-owned generating equipment. Since all emitting resources have been retired by 2045, the emissions for Sensitivity O drop to zero by 2045. However, this tells only part of the story. PSE is an active participant in the Mid-C wholesale power market. Storage resources are able charge from market purchases, and under CETA rules, these market purchases are associated with a specific GHG emission rate.

Figure 8-97: Direct GHG Emissions – Mid Scenario and Sensitivity O, 100% Renewable by 2045

Figure 8-98 provides a view of GHG emissions from the Sensitivity O variations compared to the Mid Scenario, for both direct and indirect (i.e., market) emissions. Sensitivity O emissions are still lower than Mid Scenario emissions throughout the planning horizon.

Figure 8-98: Direct and Indirect GHG Emissions – Mid Scenario and Sensitivity O, 100% Renewable by 2045

To put emission reductions into perspective, it is useful to look at them as a function of portfolio cost (or, the cost of emissions reduction). To calculate this metric, divide the difference in the 24-year levelized cost between the sensitivity and the Mid Scenario by the difference in 24-year levelized emissions between the Mid Scenario and the sensitivity:

$$\frac{Sensitivity\ 24yr\ Levelized\ Cost\ - Mid\ Sc\ 24\ yr\ Levelized\ Cost}{Mid\ 24yr\ Levelized\ Emissions - \ Sensitivity\ 24yr\ Levelized\ Emissions}$$

Figure 8-99 shows the results of this calculation for Sensitivity O and provides the preferred portfolio (Sensitivity W) as a comparison. The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent. The Sensitivity O variations are an order of magnitude larger than the preferred portfolio, suggesting that forcing out natural gas generation is not an efficient means to reduce emissions.

Figure 8-99: Cost of Emissions Reduction – Mid Scenario, Sensitivity O and Preferred Portfolio

Portfolio	Direct and Indirect GHG Emissions (millions tons CO_2eq, 24-year levelized)	Portfolio Cost (Billion $, 24-year levelized)	Cost of Emissions Reduction (millions tons CO_2eq / $ billion)
1 Mid	53.87	$15.53	--
O1 100% Renewable by 2045 - Batteries	51.83	$23.35	3.83
O2 100% Renewable by 2045 - PHES	43.54	$46.95	3.04
W Preferred Portfolio (BP with Biodiesel)	52.77	$16.10	0.52

P. No New Thermal Resources Before 2030

This sensitivity provides insight into how energy storage provides value to a system that has traditionally been provided by natural gas plants.

Baseline: Thermal peaking capacity resources may be added to the portfolio as early as 2025**.**
Sensitivity P > No thermal peaking capacity may be added to the portfolio until 2030, thereby requiring the model to optimize new energy storage, renewable resources and demand-side resources to meet near-term capacity need.

KEY FINDINGS. In Sensitivity P, delaying the availability of peaking capacity resources resulted in much earlier addition of storage resources and the addition of fewer peaking capacity resources. However, these changes increased portfolio costs by $7 to $25 billion depending on the type of storage resource selected. Furthermore, Sensitivities P1 and P3 showed no reduction in GHG emissions compared to the Mid Scenario. Sensitivity P2 did show a small reduction in GHG emissions, but the emission reduction efficiency was quite low compared to other portfolios such as the preferred portfolio.

ASSUMPTIONS. In the Mid Scenario portfolio, peaking capacity resources are available as early as 2025. In Sensitivity P, peaking capacity resources are available much later, in 2030. This forces the model to optimize its resource selection of energy storage, renewable resources and demand-side resources to keep the portfolio balanced until peaking capacity resources are available.

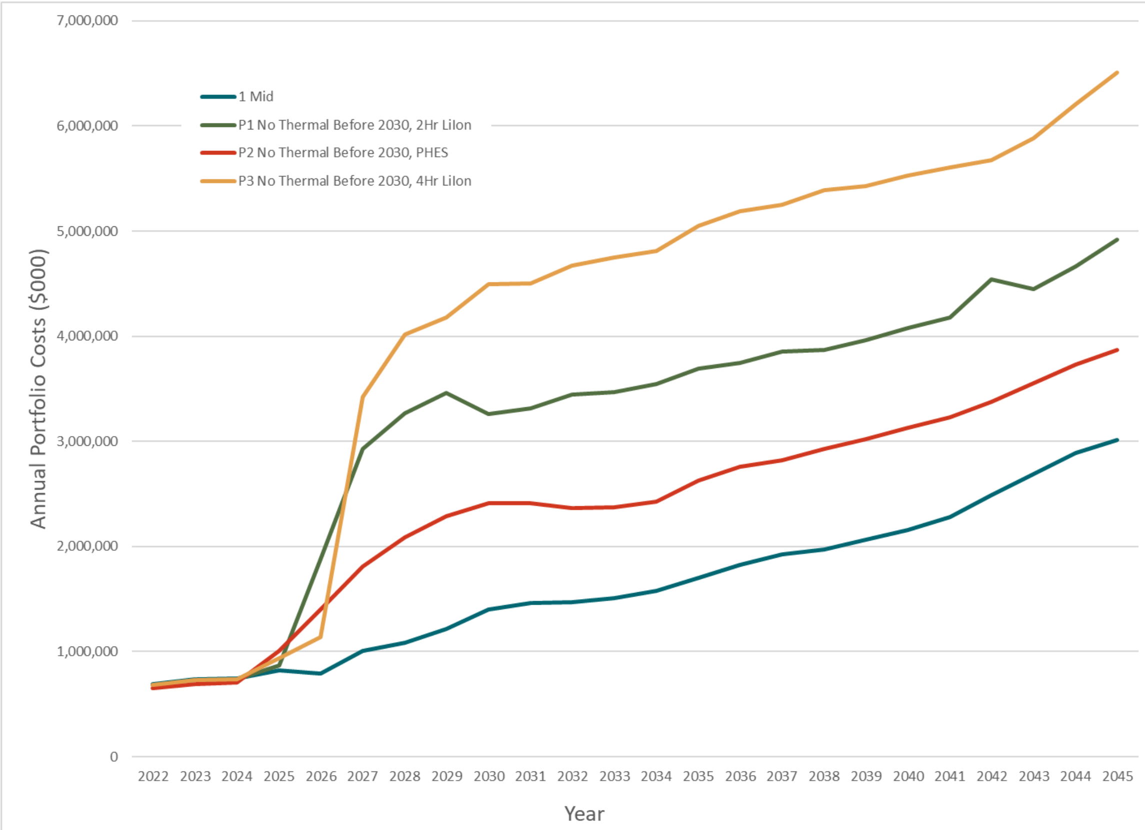
To gain an understanding of how the model reacts to different storage resources, three variations on Sensitivity P were run. Sensitivity P1 used the model constraints described above and allowed the model to select the most cost-effective storage resource in the period 2022 to 2030; the model selected 2-hour lithium-ion batteries. Sensitivity P2 removed lithium-ion and flow batteries from the list of available resources before 2030 and forced the model to solve using pumped hydroelectric storage as the primary storage technology. Sensitivity P3 removed 2-hour lithium-ion batteries from the available resources before 2030, and forced the model to select the next most cost-effective storage resource to meet capacity need before 2030; then the model selected 4-hour lithium-ion batteries.

PORTFOLIO COSTS. Figures 8-100 and 8-101 illustrate the breakdown of costs between the Mid Scenario and Sensitivities P1, P2 and P3. Annual portfolio costs are significantly higher for all variations of Sensitivity P compared to the Mid Scenario. Storage resources and demand response programs are more expensive options than peaking capacity resources. All variations of Sensitivity P added over 2,500 MW more nameplate capacity of new resources compared to the Mid Scenario, resulting in higher portfolio costs. A significant amount of batteries and pumped hydro energy storage was added to both portfolios between 2025 and 2030 causing the spike in annual portfolio costs.

Figure 8-100: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity P

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
P1	No New Thermal Resources – 2-hr Li-Ion	$30.84	$6.38	$37.22	$16.60
P2	No New Thermal Resources – PHES	$22.85	$4.77	$27.62	$7.00
P3	No New Thermal Resources – 4-hr Li-Ion	$39.01	$6.69	$45.70	$25.08

Figure 8-101: Annual Portfolio Costs – Mid Scenario and Sensitivity P



RESOURCE ADDITIONS. Figures 8-102 and 8-103 compare the nameplate capacity additions of the portfolios in Sensitivities P1, P2 and P3 and the Mid Scenario. The Mid Scenario portfolio added 237 MW of peaking capacity resources in 2026 as Colstrip and Centralia were removed. It would take about 3,800 MW nameplate capacity of batteries to equal those new peaking capacity resources since 2-hour lithium-ion batteries have only a 12.4 percent ELCC. Sensitivity P1 selected 3,775 MW of 2-hour lithium-ion batteries to make up for the absence of new peaking capacity resources. Similar resources are added in the other variations of Sensitivity P, the only difference being the addition of alternative storage resources (pumped hydroelectric storage and 4-hour lithium-ion batteries).

All three Sensitivity P portfolios added a significant amount of 2-hour lithium-ion battery resources. Sensitivity P1 selected 2-hour lithium-ion batteries as the most cost-effective resource and built nearly exclusively 2-hour lithium ion batteries, except for 25 MW of 4-hour lithium-ion batteries in the year 2045. Sensitivity P2 was forced to select pumped hydro storage as the initial storage technology; after 2030, no new pumped hydro storage was added, but 1,025 MW of 2-hour lithium-ion batteries were added. Similarly, Sensitivity P3 was forced to select 4-hour lithium-ion batteries as the initial storage technology; after 2030 no new 4-hour batteries were added, but 875 MW of 2-hour lithium-ion batteries were added to the portfolio.

By the end of the planning period, Sensitivity P1 had built 474 MW of peaking capacity, about half of the peaking capacity selected in the Mid Scenario. The large capacity storage resources (PHES and 4-hour lithium-ion batteries) built far less peaking capacity, with Sensitivity P2 building only 18 MW of peaking capacity and Sensitivity P3 building none at all.

Figure 8-102: Portfolio Additions – Mid Scenario and Sensitivity P

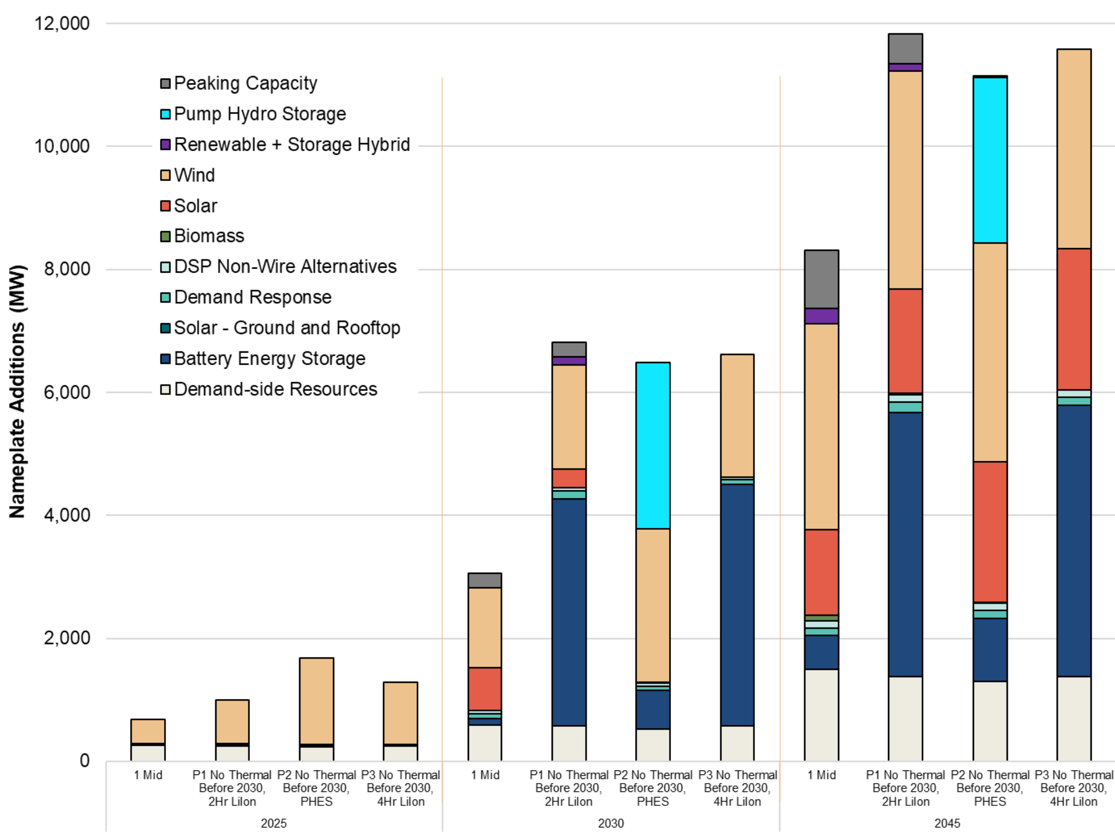
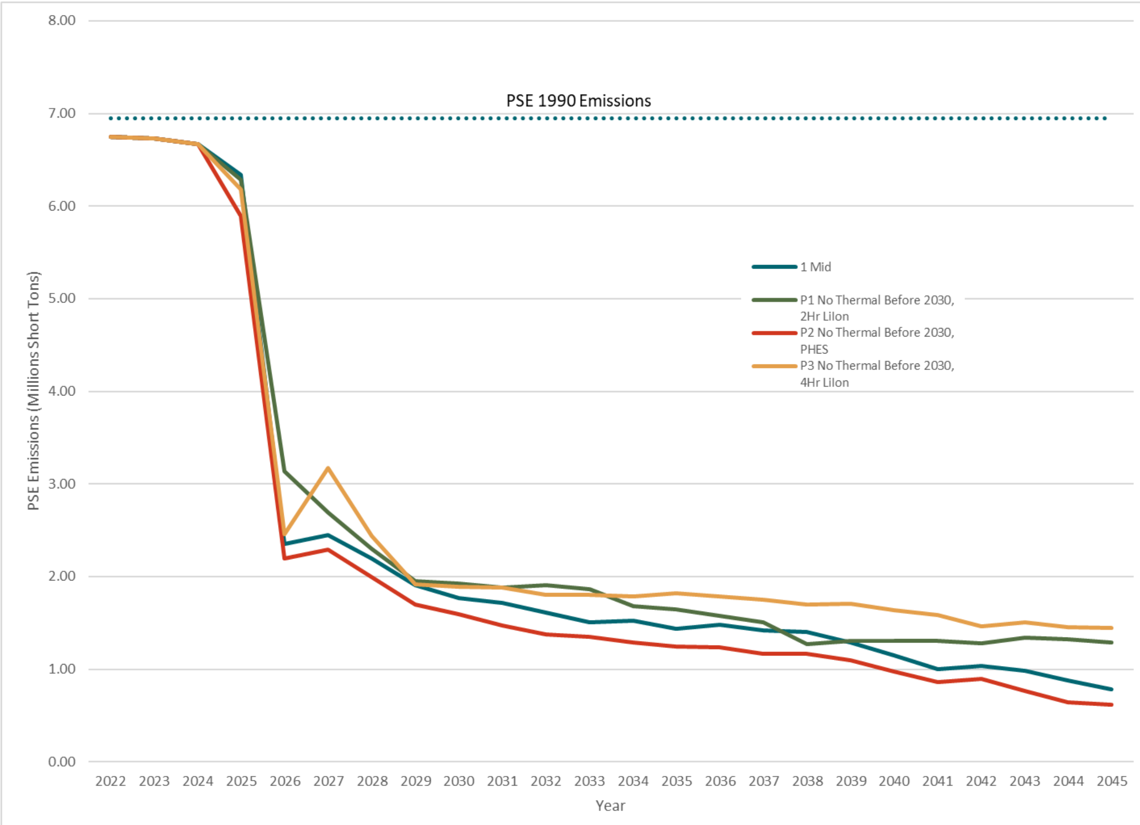


Figure 8-103: Portfolio Additions by 2045 – Mid Scenario and Sensitivity P, No New Thermal Before 2030

Resource Additions by 2045	1 Mid	P1 No New Thermal – 2hr Li-Ion	P2 No New Thermal – PHES	P3 No New Thermal – 4hr Li-Ion
Demand-side Resources	1,497 MW	1,372 MW	1,304 MW	1,372 MW
Battery Energy Storage	550 MW	4,300 MW	1,025 MW	4,425 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW	0 MW
Demand Response	123 MW	178 MW	122 MW	129 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	5,260 MW	5,859 MW	5,542 MW
Biomass	90 MW	15 MW	15 MW	0 MW
Solar	1,393 MW	1,695 MW	2,294 MW	2,292 MW
Wind	3,350 MW	3,550 MW	3,550 MW	3,250 MW
Renewable + Storage Hybrid	250 MW	125 MW	0 MW	0 MW
Pumped Hydro Storage	0 MW	0 MW	2,700 MW	0 MW
Peaking Capacity	948 MW	474 MW	18 MW	0 MW

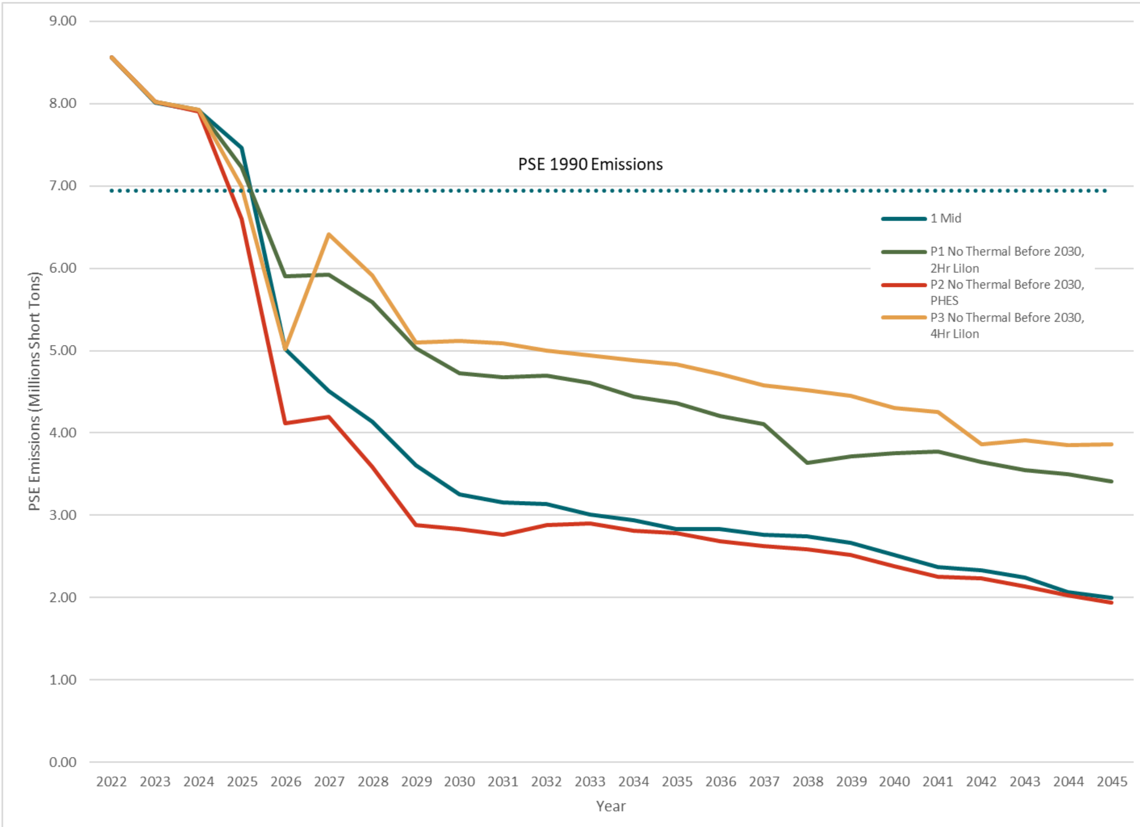
OTHER FINDINGS. Figure 8-104 compares the direct GHG emissions from the Sensitivity P variations with to the Mid Scenario. Direct emissions are defined as emissions linked directly to PSE-owned generating equipment. Despite fewer peaking capacity resources built over the planning period, Sensitivities P1 and P3 have higher direct GHG emissions compared to the Mid Scenario due increased dispatch of existing thermal resources over the planning period. Existing thermal resources are not as efficient as new peaking resources and therefore generate greater emissions.

Figure 8-104: Direct GHG Emissions – Mid Scenario and Sensitivity P, No New Thermal Before 2030



When storage is a major component of a resource portfolio, indirect emissions from market purchases increase. Storage resources may charge from market purchases and these unspecified market purchases are tagged with a GHG emission rate per CETA rules. Figure 8-105 provides a view of GHG emissions from the Sensitivity P variations as compared to the Mid Scenario, for both direct and indirect (i.e., market) emissions. Sensitivities P1 and P3 are now significantly higher emitters than the Mid Scenario, and Sensitivity P3 has nearly the same emission rate as the Mid Scenario. The increase in emissions from portfolios P1 and P3 comes from an increase in dispatch from the existing natural gas resources.

Figure 8-105: Direct and Indirect GHG Emissions – Mid Scenario and Sensitivity P, No New Thermal Before 2030



To put emission reductions into perspective, it is useful to look at the reduction in emissions as a function of portfolio cost (or, the cost of emissions reduction). To calculate this metric, divide the difference in the 24-year levelized cost between the sensitivity and the Mid Scenario by the difference in 24-year levelized emissions between the Mid Scenario and the sensitivity:

$$\frac{Sensitivity\ 24yr\ Levelized\ Cost\ - Mid\ Sc\ 24\ yr\ Levelized\ Cost}{Mid\ 24yr\ Levelized\ Emissions - \ Sensitivity\ 24yr\ Levelized\ Emissions}$$

Figure 8-106 shows the results of this calculation for Sensitivity P and provides the preferred portfolio (Sensitivity W) as a comparison. The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent. For Sensitivities P1 and P3, both the cost of the portfolio and the levelized quantity emissions were greater than the Mid Scenario, which by definition means they are not feasible plans for reducing emissions. Sensitivity P2 did result in a small reduction in emissions, but the cost of emissions reduction is much higher than in the preferred portfolio, suggesting that replacing the new peaker with storage is not an effective means to reduce emissions.

Figure 8-106: Cost of Emissions Reduction – Mid Scenario, Sensitivity P and Preferred Portfolio

Portfolio	Direct and Indirect GHG Emissions (millions tons CO_2eq, 24-year levelized)	Portfolio Cost (Billion $, 24-year levelized)	Cost of Emissions Reduction (millions tons CO_2eq / $ billion)
1 Mid	53.87	$15.53	--
P1 No New Thermal Before 2030 – 2hr Li-Ion	64.73	$30.84	higher cost & higher emissions
P1 No New Thermal Before 2030 – PHES	50.60	$22.85	2.24
P1 No New Thermal Before 2030 – 4hr Li-Ion	67.00	$39.01	higher cost & higher emissions
W Preferred Portfolio (BP with Biodiesel)	52.77	$16.10	0.52

Demand Forecast Adjustments

Q. Fuel Switching, Gas to Electric

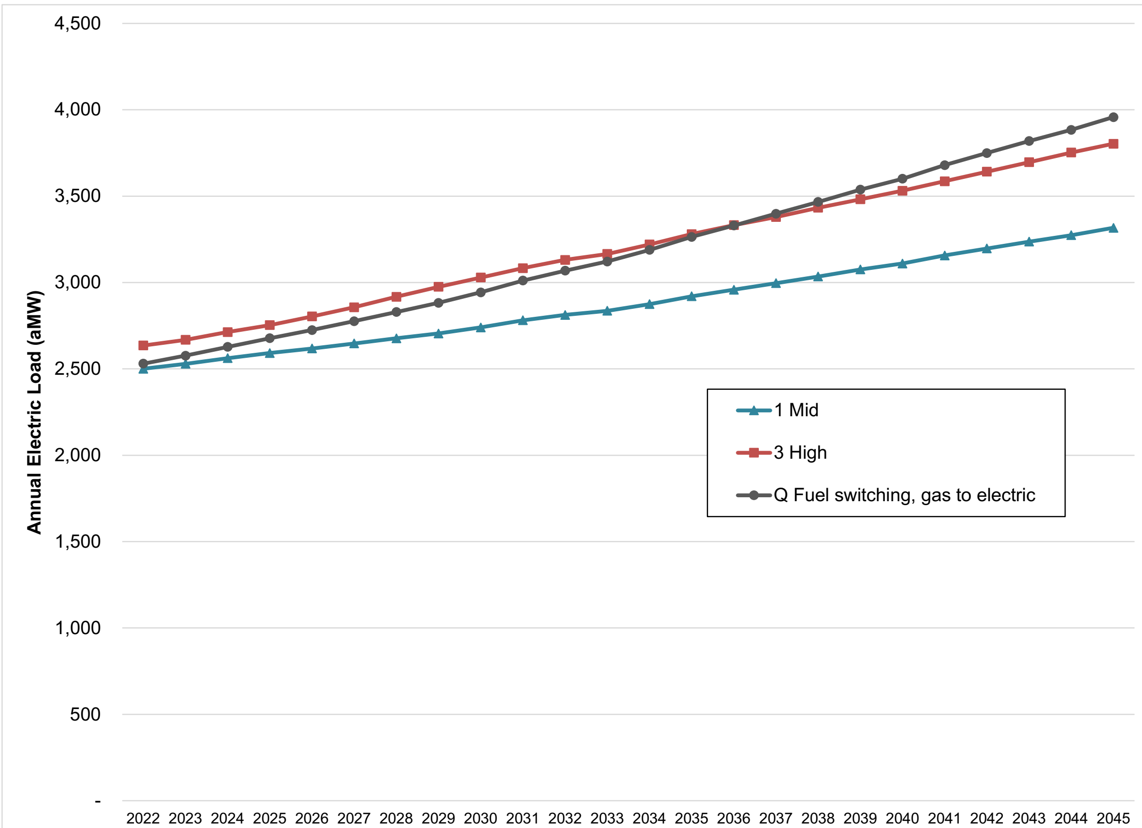
Natural gas is often used for space heating, water heating, cooking, industrial process heat and feedstocks and other uses in residential, commercial and industrial settings. Recent trends in local legislation limit the use of natural gas for these purposes in new construction. Sensitivity Q explores how the energy environment may change if electricity was used as an energy supply in place of the current uses of natural gas.

Baseline: The Mid Scenario assumes the IRP Base Demand Forecast.
Sensitivity R > Sensitivity Q modifies the demand forecast to simulate substitution of electricity for current uses of natural gas in PSE's service area.

KEY FINDINGS. Incorporating a higher penetration of electrification changed the key modeling assumptions for the portfolio and produced a higher electric demand forecast, higher CETA renewable need and a higher peak capacity need compared to the IRP Base Demand Forecast used in the Mid Scenario. As a result, Sensitivity Q selected higher resource builds and had higher portfolio costs compared to the Mid Scenario. More capacity was added in nearly every resource category to meet the increased demand forecast.

ASSUMPTIONS. The demand forecast is adjusted to add a transition from natural gas to electricity for end uses in the PSE service territory resulting in a higher electric demand forecast. PSE hired Cadmus to develop the adjusted electric load which assumes an increase in energy of 203 aMW in 2030 to 641 aMW by 2045 from the Mid Scenario. Figure 8-107 shows the annual electric load (aMW) used for Sensitivity Q compared to the Mid and High Scenarios. In comparison to the electric load in the High Scenario, the electric load for Sensitivity Q is lower through 2036, then higher by 154 aMW by 2045. More information on the load conversion assumptions can be found in Appendix E, Conservation Potential Assessment.

Figure 8-107: Electric Energy Demand Forecast for the Mid and High Scenario Compared to Sensitivity Q (Electrification) Demand Forecast (aMW)

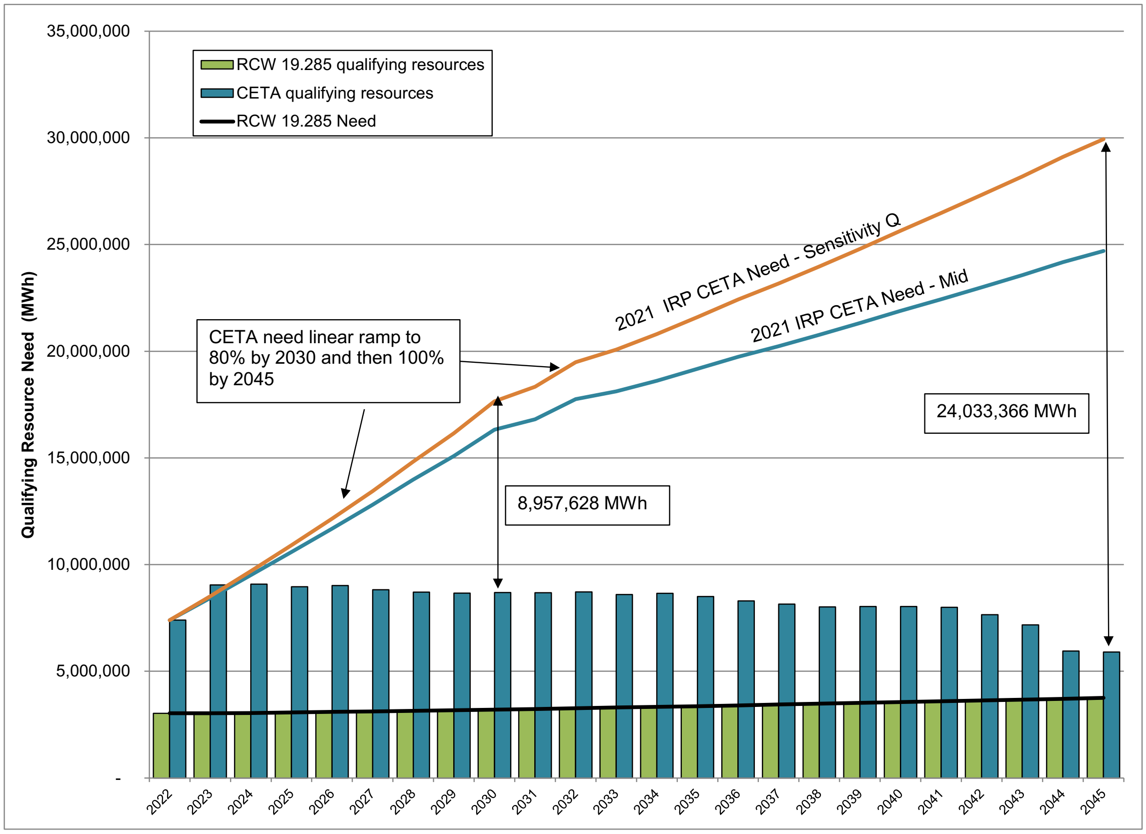


The increased electric demand requires additional CETA-compliant electricity above the Mid Scenario. To reflect this increased electric demand, the CETA renewable need is updated to reflect the change in the electric demand forecast. Figures 8-108 and 8-109 show the CETA renewable need for Sensitivity Q compared to the Mid Scenario. In Sensitivity Q, the CETA renewable need in 2045 is 24 million MWhs, an increase of 5.2 million MWhs from the Mid Scenario.

Figure 8-108: CETA Renewable Need – Mid Scenario and Sensitivity Q by 2030 and 2045

		CETA Renewable Need (MWh)	
	Portfolio	**2030**	**2045**
1	**Mid Scenario**	7,632,507	18,797,944
Q	**Fuel Switching, Gas to Electric**	8,957,628	24,033,366

Figure 8-109: CETA Renewable Need – Mid Scenario and Sensitivity Q

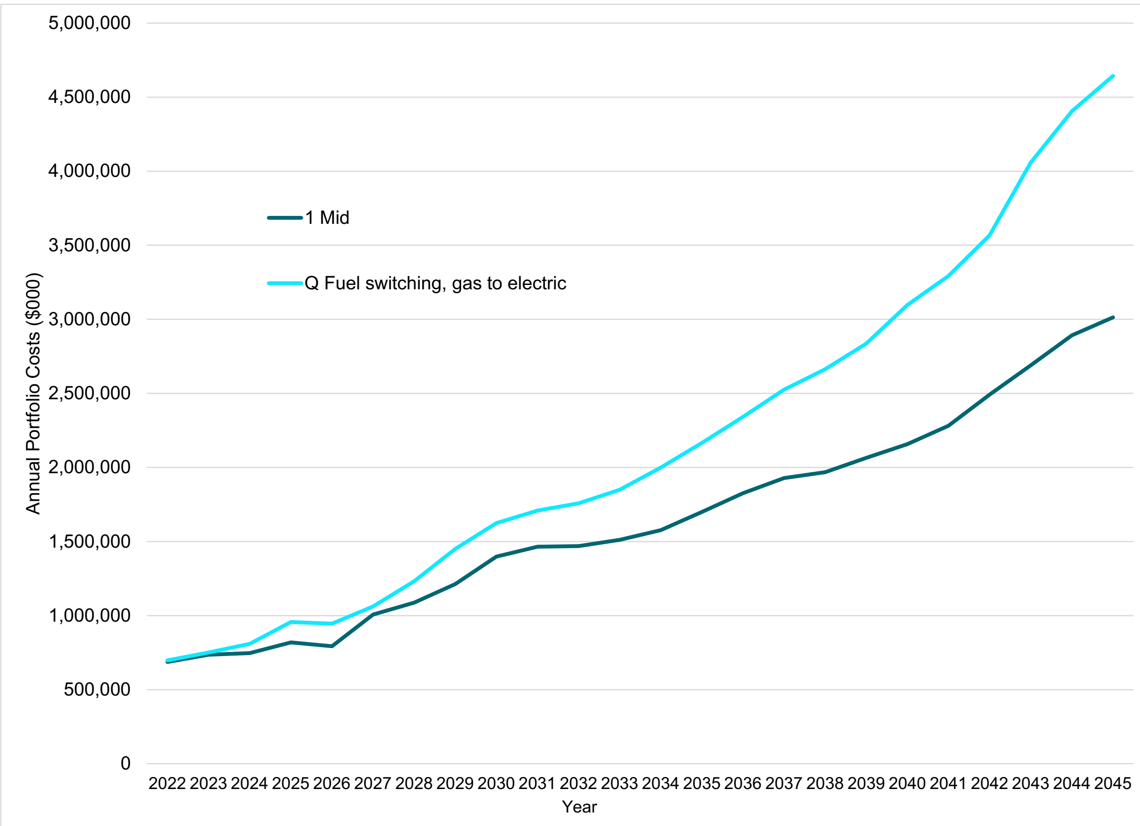


ANNUAL PORTFOLIO COSTS. Figures 8-110 and 8-111 illustrate the breakdown of portfolio costs between the Mid Scenario and Sensitivity Q. Due to the significant increase in electric demand and renewable need, costs for Sensitivity Q are much higher than the Mid Scenario. Additional costs associated with fuel switching (such as appliance or process replacement), changes to the electric and natural gas distribution systems and any incremental transmission needs, are not included in this analysis.

Figure 8-110: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity Q

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
Q	Fuel Switching, Gas to Electric	$19.56	$5.60	$25.16	$4.54

Figure 8-111: Annual Portfolio Costs – Mid Scenario and Sensitivity Q



RESOURCE ADDITIONS. Figures 8-112 and 8-113 compare the nameplate capacity additions of Sensitivity Q and the Mid Scenario portfolios. Sensitivity Q added more capacity in nearly every resource category to meet the increased demand forecast, except for wind which shifted to an increase in Wind + Battery hybrid resource. Sensitivity Q selected conservation Bundle 11, whereas the Mid Scenario selected Bundle 10.

Figure 8-112: Portfolio Additions – Mid Scenario and Sensitivity Q

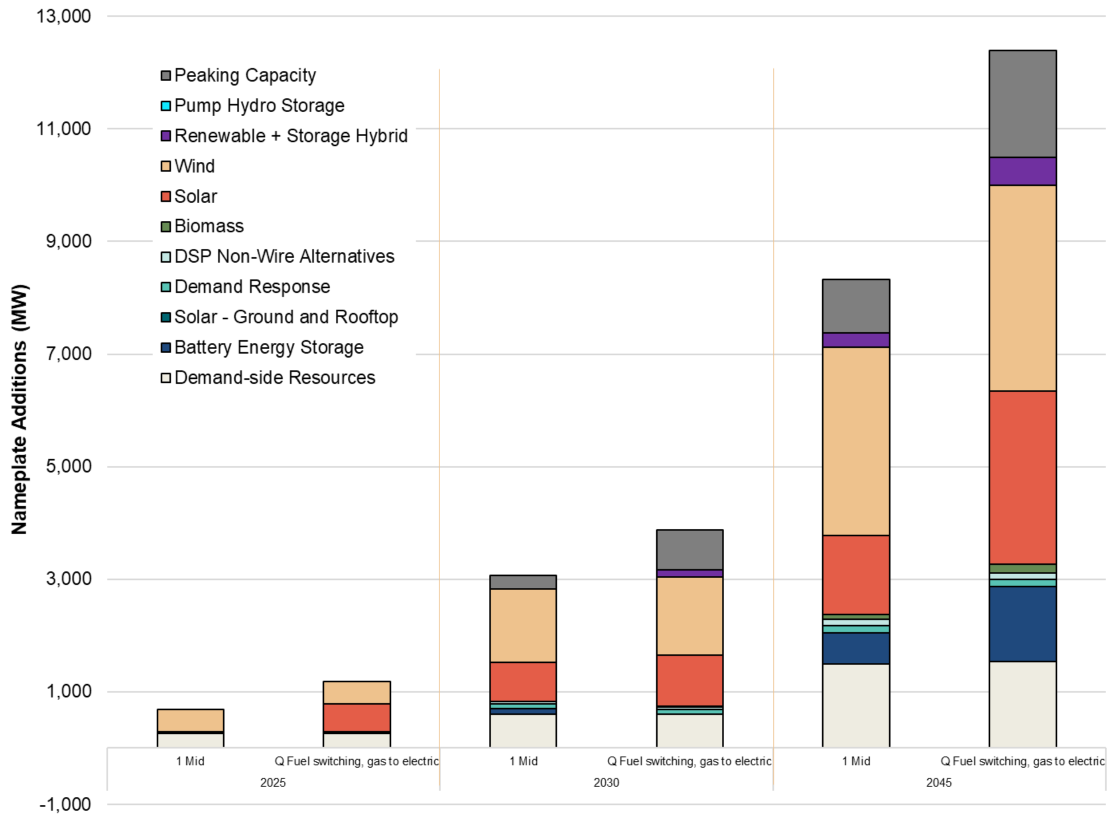
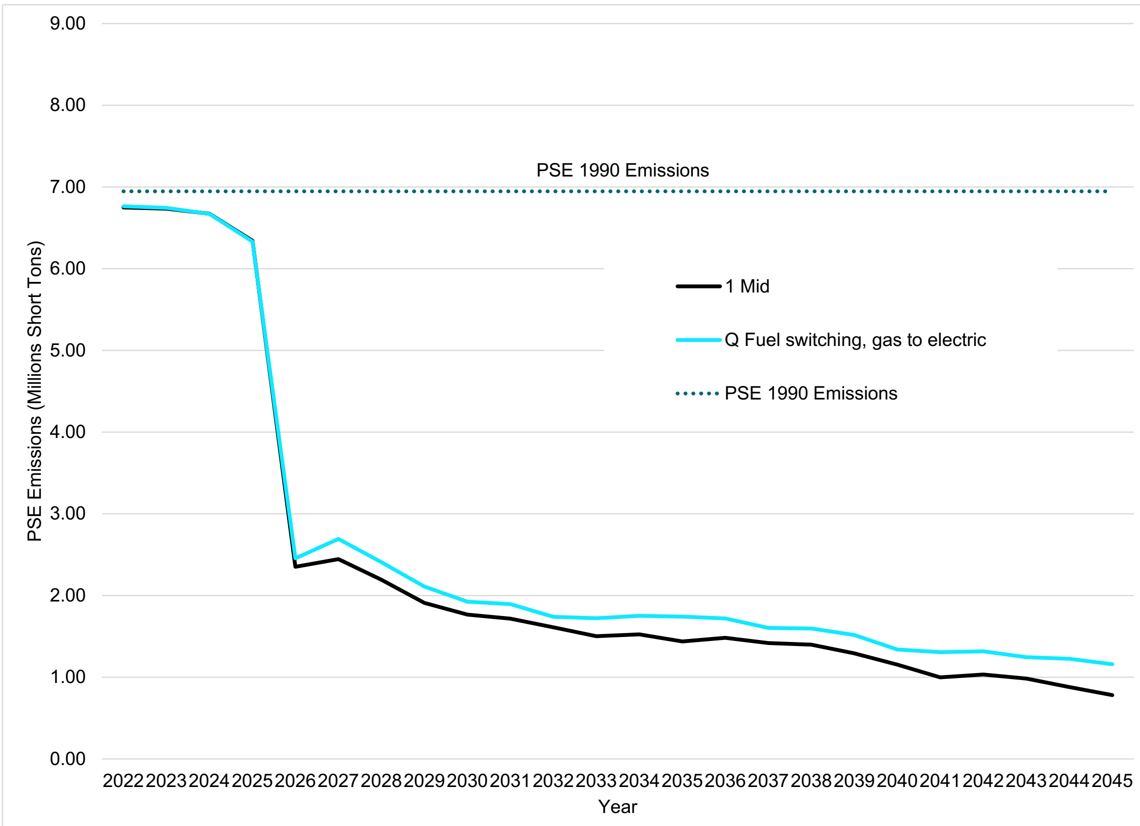


Figure 8-113: Portfolio Additions – Mid Scenario and Sensitivity Q

Resource Additions by 2045	1 Mid	Q Fuel Switching, Gas to Electric
Demand-side Resources	1,497 MW	1,537 MW
Battery Energy Storage	550 MW	1,325 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	129 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	6,888 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	3,088 MW
Wind	3,350 MW	3,650 MW
Renewable + Storage Hybrid	250 MW	500 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	1,896 MW

EMISSIONS. The amount of peaking capacity resources doubled from 948 MW in the Mid Scenario to 1,896 MW in Sensitivity Q as result of the higher energy and peak need, despite increases in demand response and batteries. The higher dispatch from these flexible capacity resources produce a slightly higher overall emissions compared to the Mid Scenario. Figure 8-114 compares the emissions of the Mid Scenario and Sensitivity Q.

Figure 8-114: Direct GHG Emissions – Mid Scenario and Sensitivity Q



R. Temperature Sensitivity

This sensitivity models a change in temperature trends, adjusting the underlying temperature data of the demand forecast to emphasize the influence of more recent years. This change attempts to show the effect of rising temperature trends in the Pacific Northwest. Results from this sensitivity illustrate potential changes in PSE's load profile.

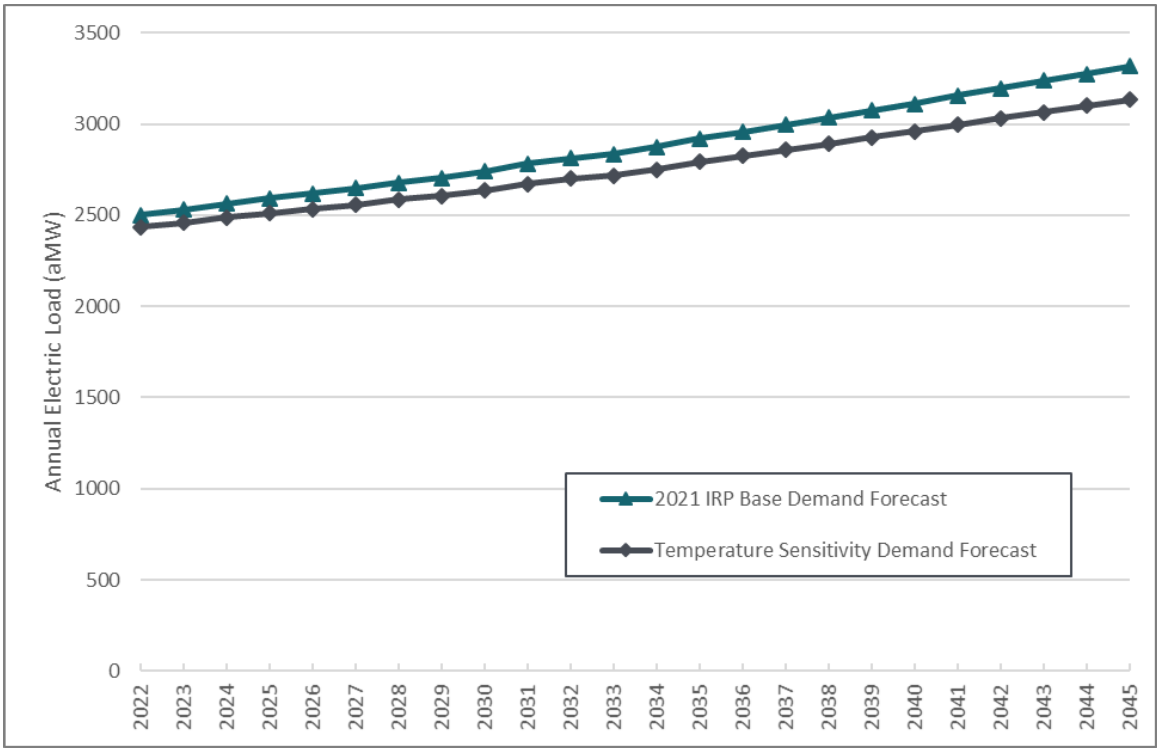
Baseline: The IRP Base Demand Forecast used in the Mid Scenario is based on “normal” weather, defined as the average monthly weather recorded at NOAA’s Sea-Tac Airport station over the past 30 years ending in 2019.

Sensitivity R > PSE used forecast temperature data from the Northwest Power and Conservation Council (the "Council") to model a new demand forecast. The Council is using global climate models that are scaled down to forecast temperatures for many locations within the Pacific Northwest. The Council weighs temperatures by population from metropolitan regions throughout the Northwest. However, PSE also received data from the Council that is representative of Sea-Tac airport. This data is consistent with how PSE plans for its service area and is not mixed with temperatures from Idaho, Oregon or eastern Washington. The climate model data provided by the Council is hourly data from 2020 through 2049. This data resembles a weather pattern in which temperatures fluctuate over time, but generally trend upward. For the load forecast portion of the temperature sensitivity, PSE smoothed out the fluctuations in temperature and increased the heating degree days (HDDs) and cooling degree days (CDDs) over time at 0.9 degrees per decade, the rate of temperature increase found in the Council's climate model. PSE also updated the peak capacity need using the resource adequacy analysis. A full description of the temperature sensitivity can be found in Chapter 7.

KEY FINDINGS. Using alternative temperature data for forecasting demand and peak changed the key modeling assumptions for the portfolio and produced a lower demand forecast, lower CETA renewable need and a lower peak capacity need compared to the IRP Base Demand Forecast used in the Mid Scenario. As a result, Sensitivity R selected lower resource builds and had lower portfolio costs compared to the Mid Scenario. Resource additions were driven by the CETA renewable need, and a total of 4,495 MW nameplate capacity of renewable resources was added by 2045 to meet CETA.

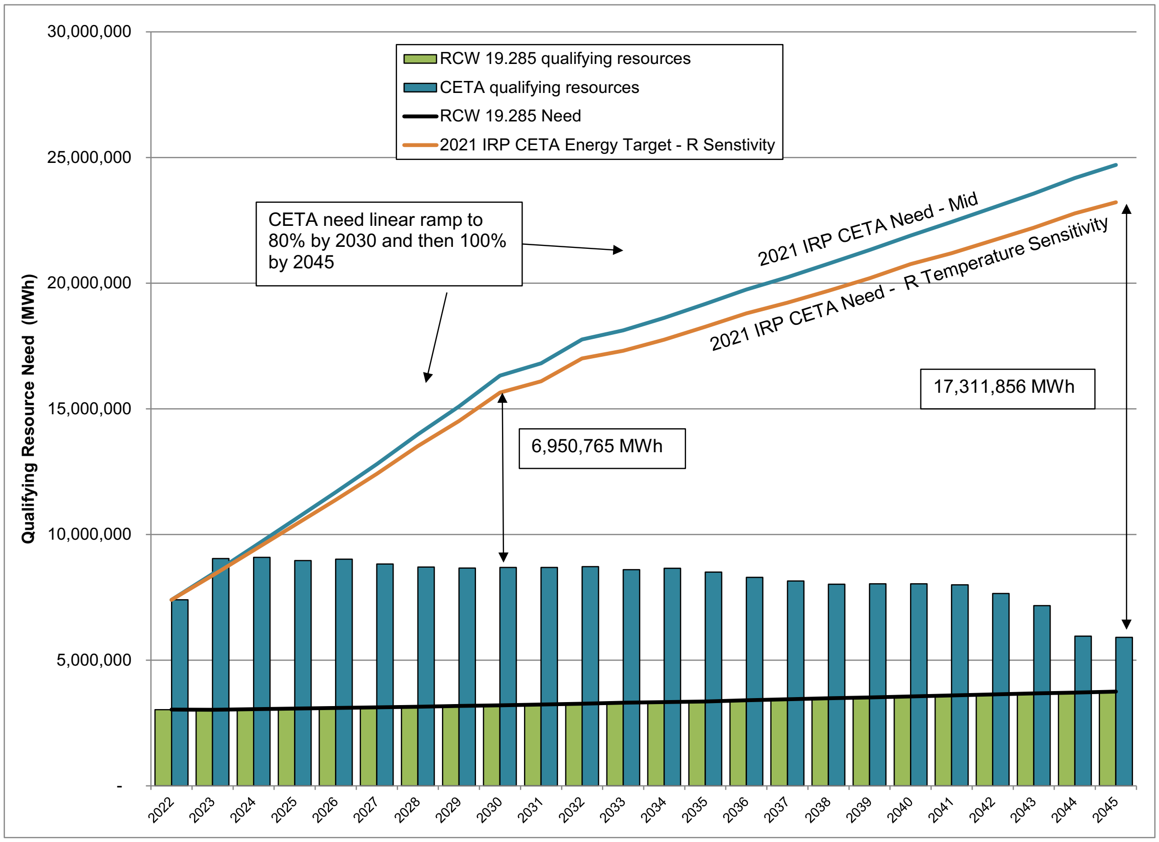
ASSUMPTIONS. In this sensitivity, the demand forecast reflects temperatures warming over time based on the trend of one model that the Council is using in its climate analyses. The related demand forecast is discussed in Chapter 6, Demand Forecasts. Figure 8-115 shows the annual electric load (aMW) used for Sensitivity R compared to the Mid Scenario.

Figure 8-115: Electric Energy Demand Forecast – Mid Scenario Compared to Temperature Sensitivity Demand Forecast (aMW)



The CETA renewable need is updated to reflect the change in the electric demand forecast. Figure 8-116 shows the CETA renewable need for Sensitivity R compared to the Mid Scenario. In Sensitivity R, the CETA renewable need in 2045 is 17.3 million MWhs, a decrease of 1.5 million MWhs from the Mid Scenario.

Figure 8-116: CETA Renewable Need – Mid Scenario and Sensitivity R



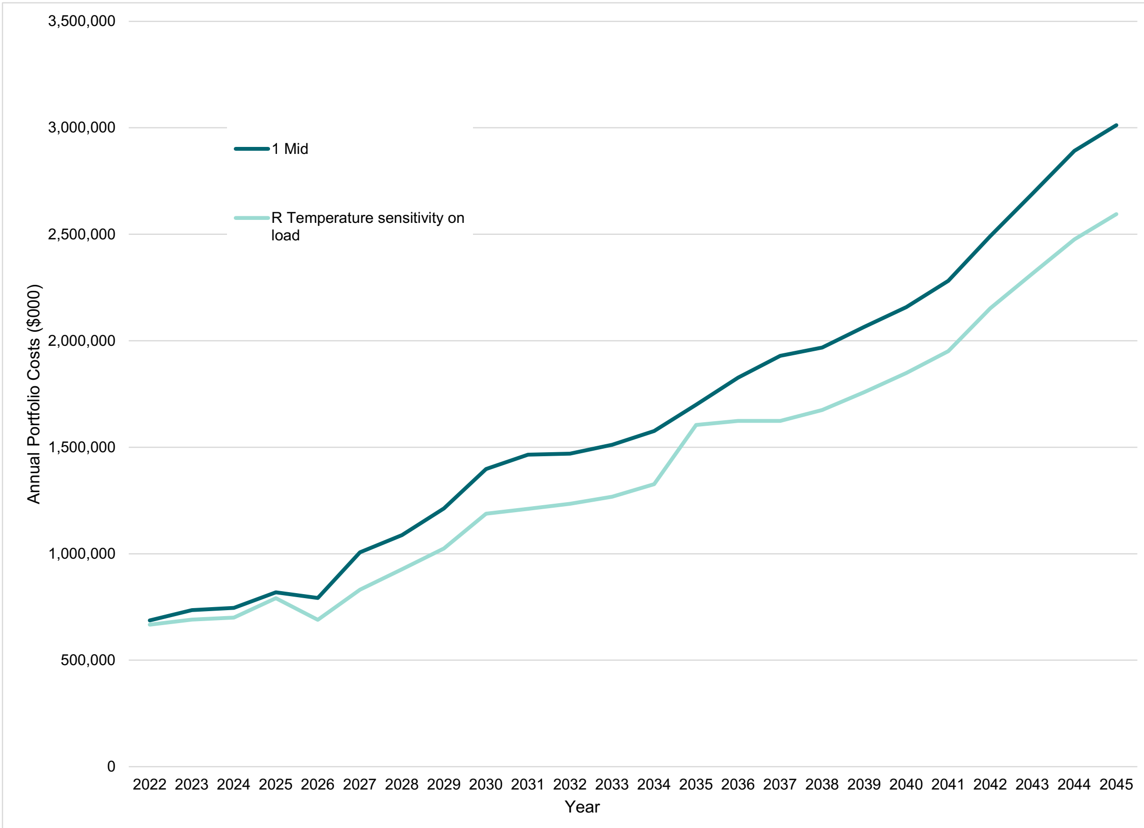
In addition to the change in the electric demand forecast and CETA renewable need, the Resource Adequacy Model was run for this temperature sensitivity reflecting a decrease in peak capacity need from 907 MW to 328 MW in 2027, and from 1,381 MW to 1,019 MW in 2031. More information on this sensitivity can be found in Chapter 7, Resource Adequacy Analysis.

ANNUAL PORTFOLIO COSTS. Figures 8-117 and 8-118 illustrate the breakdown of costs between the Mid Scenario and Sensitivity R. The reduction in costs for Sensitivity R is due to the decrease in the overall resource builds.

Figure 8-117: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity R

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
R	Temperature Sensitivity	$13.53	$4.69	$18.22	($2.40)

Figure 8-118: Annual Portfolio Costs – Mid Scenario and Sensitivity R



RESOURCE ADDITIONS. Figures 8-119 and 8-120 compare the nameplate capacity additions of the Sensitivity R and Mid Scenario portfolios. Peaking capacity resources are not added in Sensitivity R. All other resource options have lower additions except for 2-hour lithium-ion batteries and biomass, both of which showed a minor increase. Sensitivity R selected conservation Bundle 9, which includes 1,372 MW of capacity, whereas the Mid Scenario selected Bundle 10.

Figure 8-119: Portfolio Additions – Mid Scenario and Sensitivity R

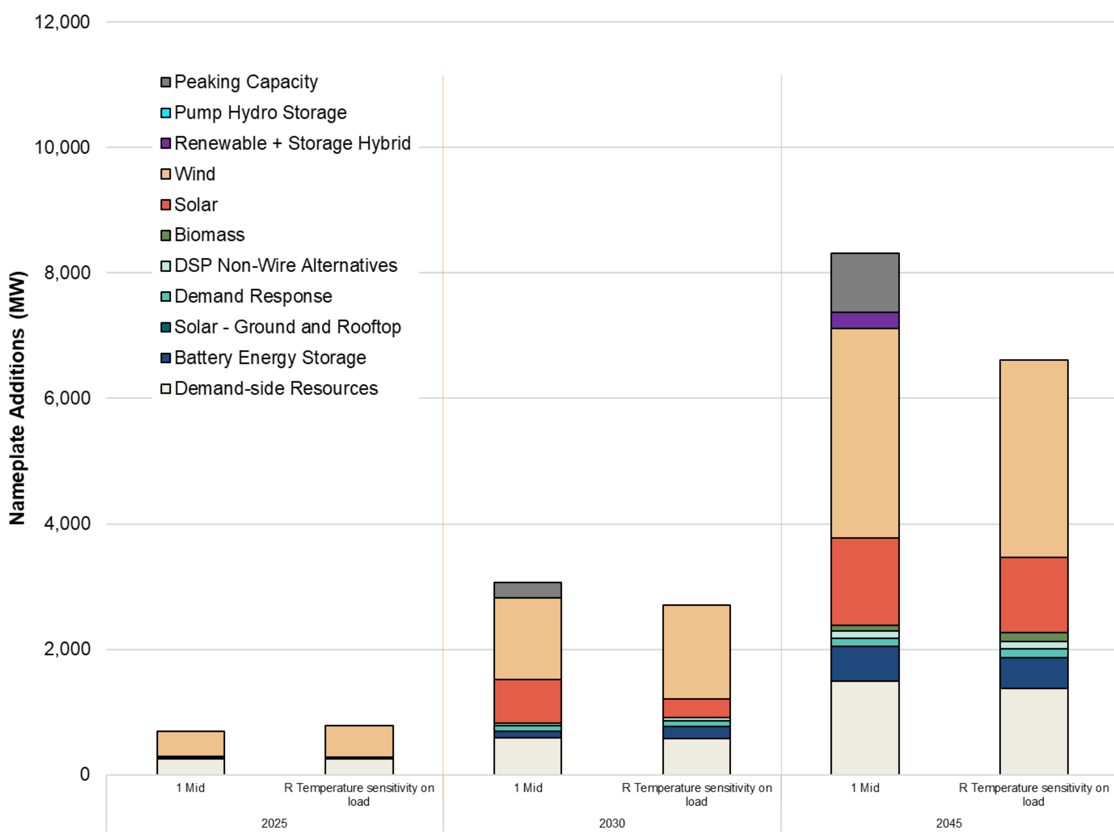
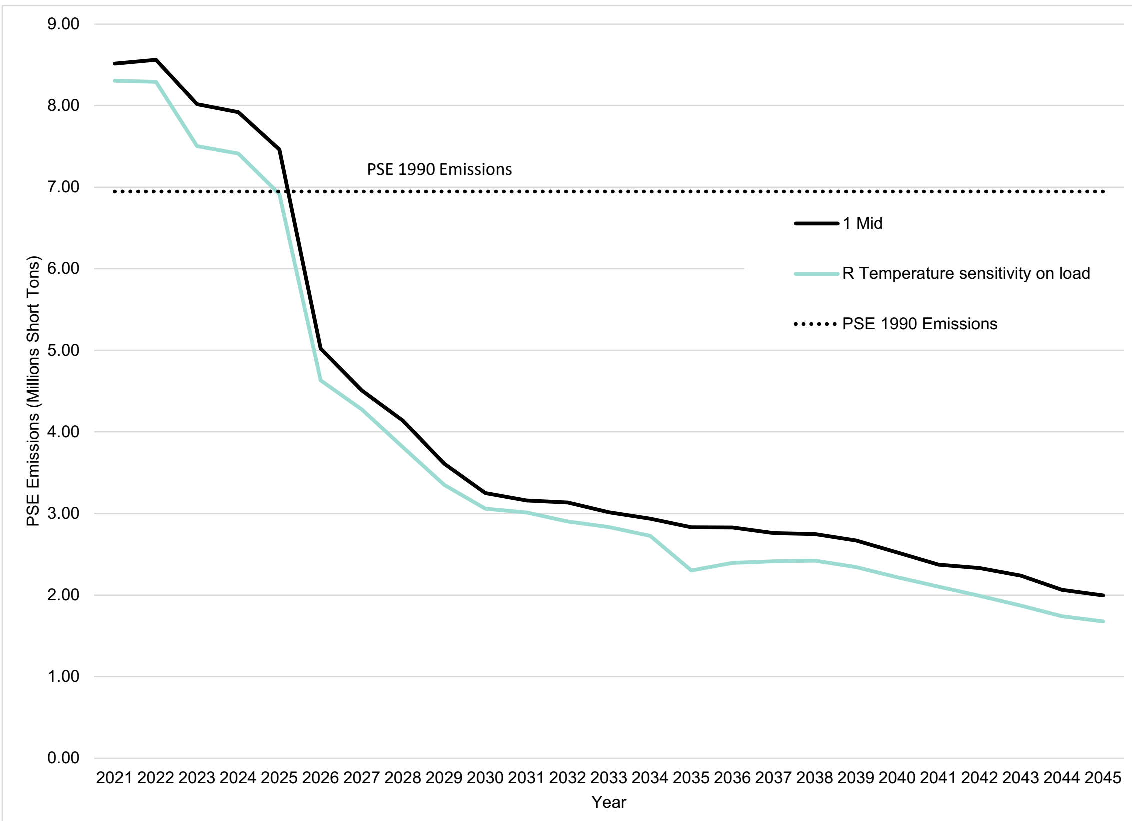


Figure 8-120: Portfolio Additions – Mid Scenario and Sensitivity R

Resource Additions by 2045	1 Mid	R Temperature sensitivity on load
Demand-side Resources	1,497 MW	1,372 MW
Battery Energy Storage	550 MW	500 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	130 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,495 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	1,195 MW
Wind	3,350 MW	3,150 MW
Renewable + Storage Hybrid	250 MW	0 MW
Pumped Hydro Storage	0 MW	0 MW
Peaking Capacity	948 MW	0 MW

EMISSIONS AND ECONOMIC RETIREMENTS. Sensitivity R resulted in fewer GHG emissions compared to the Mid Scenario. This is due to the lower dispatch of existing thermal resources and the lack of peaking capacity resource additions. The lower energy demand and peak capacity need also contributed to the economic retirement of existing thermal plants. Two of the natural gas resources were retired by 2023 and replaced by 2-hour lithium-ion batteries. Figure 8-121 compares the GHG emissions from Sensitivity R with the Mid Scenario.

Figure 8-121: Annual Emissions – Mid Scenario and Portfolio R



CETA Costs

S. SCGHG Cost Included, No CETA
T. No CETA

The purpose of this sensitivity is to evaluate the cost of CETA compliance. To assess the effect of CETA and the SCGHG, a baseline must be established. Sensitivity S models PSE without the CETA renewable generation requirement. Sensitivity T models PSE without the CETA renewable requirement or the SCGHG. By analyzing the PSE portfolios without CETA requirements, the impact of CETA can be quantified.

Baseline: The Mid Scenario includes SCGHG for thermal resources as a fixed cost adder and CETA requirements.
Sensitivity S > The model includes SCGHG as a fixed cost adder, but there is no CETA renewable requirement.
Sensitivity T > The model includes no SCGHG and no CETA renewable requirement.

KEY FINDINGS. Without the CETA renewable requirement and SCGHG as a fixed cost adder, the 24-year levelized revenue requirement for Sensitivity T is $9.05 billion dollars, $6.48 billion dollars less than the Mid Scenario portfolio. Compared to Sensitivity S, the 24-year levelized revenue requirement for Sensitivity T is higher by $0.02 billion dollars. The price differences between Sensitivity S and T are negligible, indicating that some conservation and demand response additions can be a revenue requirement-neutral way of cutting emissions. Even so, less conservation is selected in both sensitivities compared to the Mid Scenario.

ASSUMPTIONS. In the Mid Scenario portfolio, 80 percent of sales must be met by non-emitting/renewable resources by 2030; the remaining 20 percent is met through alternative compliance.

In Sensitivity S, the SCGHG is included as a fixed cost adder for thermal resources during resource selection. The CETA renewable generation requirement is not included, but the 15 percent of sales RPS requirement under RCW 19.285 is applied.

In Sensitivity T, there is no CETA renewable requirement and the SCGHG is not included, but the 15 percent of sales RPS requirement under RCW 19.285 is applied.

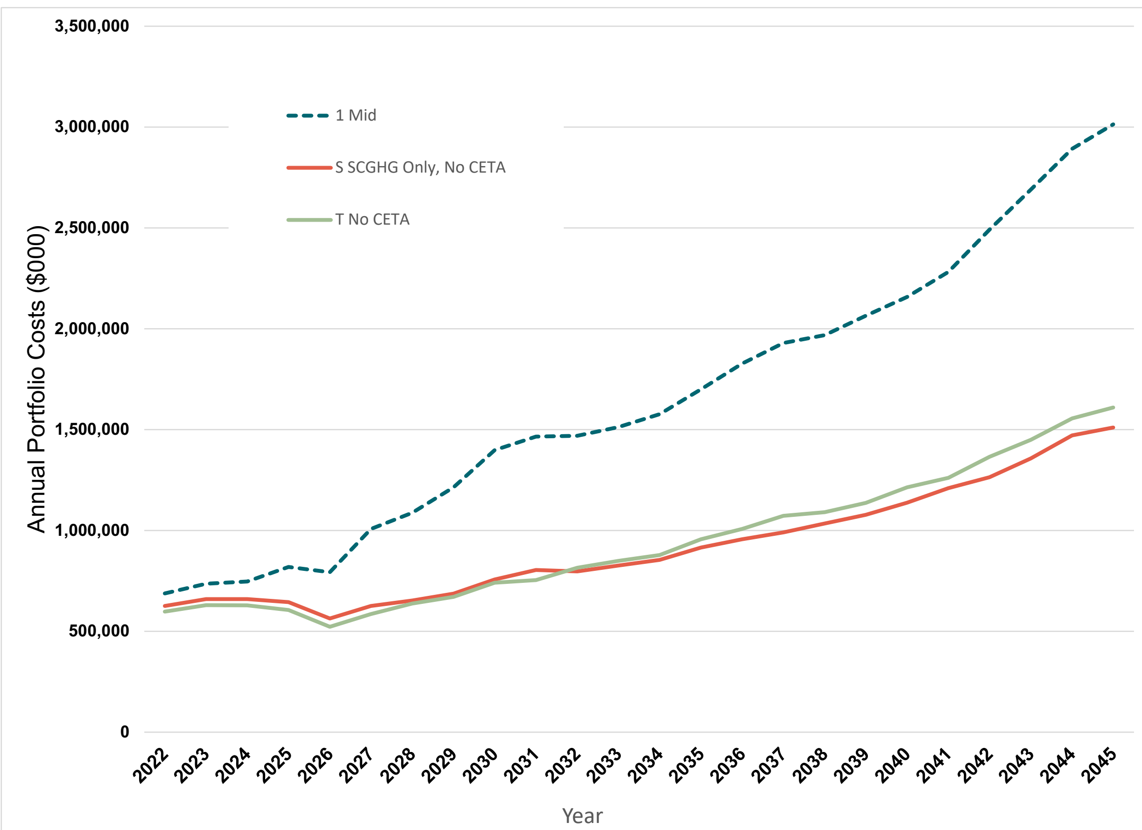
ANNUAL PORTFOLIO COSTS. Figures 8-122 and 8-123 illustrate the breakdown of costs between the Mid Scenario, Sensitivity S and Sensitivity T portfolios. The conservation resources selected in Sensitivity S drive the revenue requirements of the portfolio even lower compared to

Sensitivity T, as they slow the pace of peaker construction and prevent an additional frame peaker from being built by 2045. Since the SCGHG is not included in Sensitivity T, the costs of emissions are not included.

Figure 8-122: 24-year Levelized Portfolio Costs – Mid Scenario, Sensitivity S and Sensitivity T

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
S	SCGHG Only, No CETA	$9.03	$8.86	$17.89	($2.73)
T	No CETA, No SCGHG	$9.05	--	$9.05	($11.57)

Figure 8-123: Annual Portfolio Costs – Mid Scenario, Sensitivities S and Sensitivity T



RESOURCE ADDITIONS. Figure 8-124 compares the nameplate capacity additions of the Mid Scenario to Sensitivities S and T. The build patterns of Sensitivities S and T are similar and simple; both portfolios build frame peakers to keep up with increasing demand. Aside from the Montana wind addition in 2044 to maintain compliance with the RPS requirement, no new renewable resources are built in either portfolio. In Sensitivity T, conservation Bundle 2 is selected, along with 3 demand response measures. In Sensitivity S, conservation Bundle 6 is selected, along with 11 demand response measures. Sensitivity S also builds 50 MW of 2-hour lithium-ion batteries in 2025. The additional demand response, conservation, and storage added in Sensitivity S results in one less frame peaker resource being built by 2045 compared to Sensitivity T.

Figure 8-124: Portfolio Additions – Mid Scenario, Sensitivity S and Sensitivity T

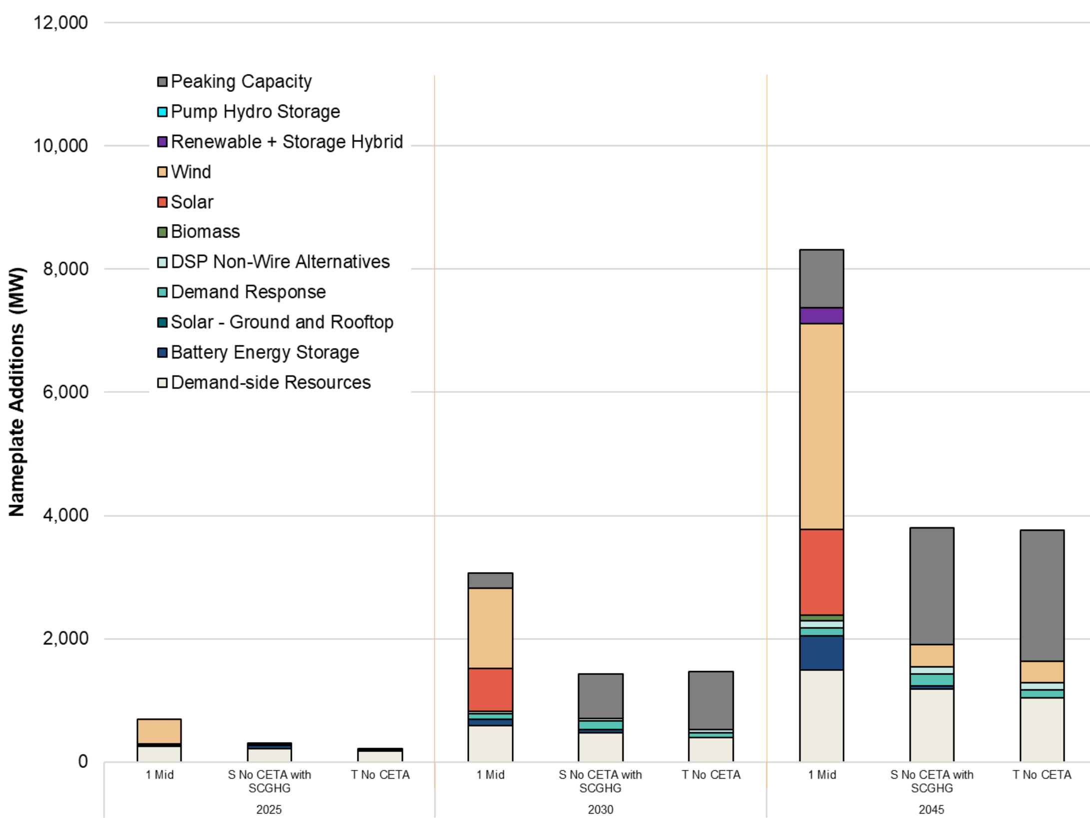
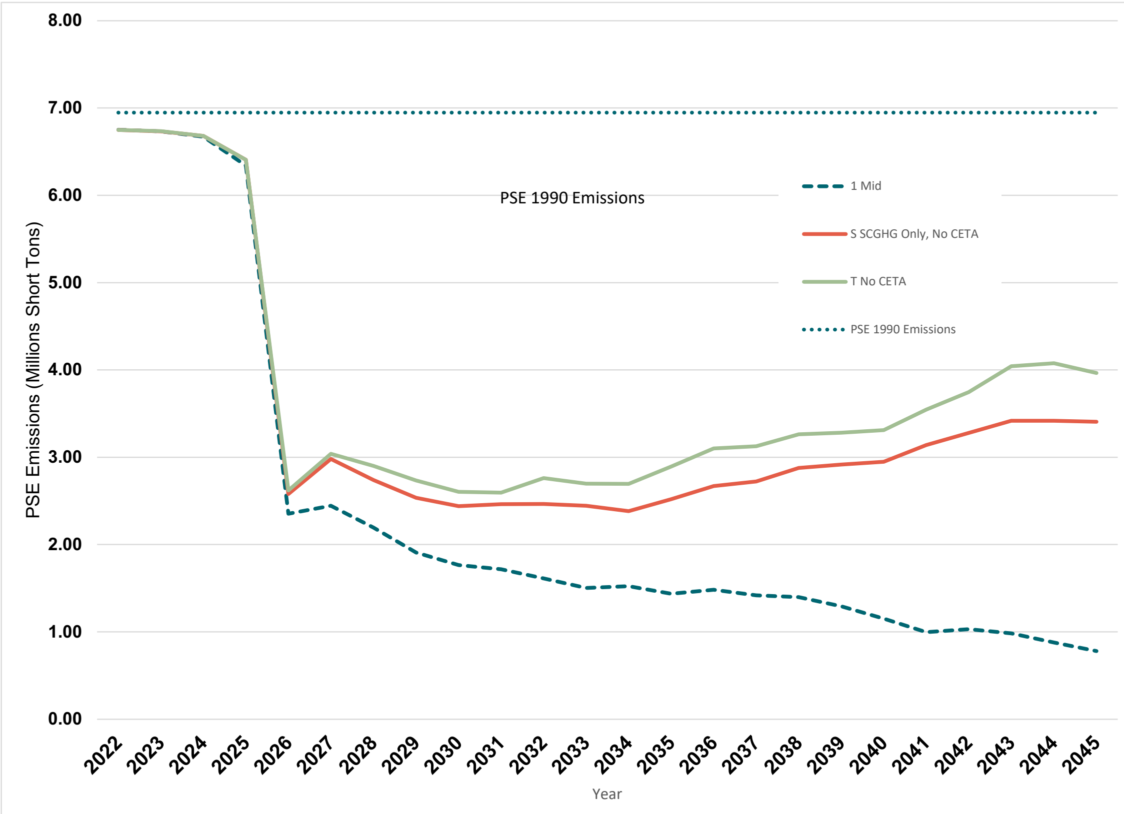


Figure 8-125: Portfolio Additions by 2045 – Mid Scenario, Sensitivity S and Sensitivity T

Resource Additions by 2045	1 Mid	S SCGHG Only, No CETA	T No CETA
Demand-side Resources	1,497 MW	1,179 MW	1,042 MW
Battery Energy Storage	550 MW	50 MW	0 MW
Solar - Ground and Rooftop	0 MW	0 MW	0 MW
Demand Response	123 MW	203 MW	123 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	350 MW	350 MW
Biomass	90 MW	0 MW	0 MW
Solar	1,393 MW	0 MW	0 MW
Wind	3,350 MW	350 MW	350 MW
Renewable + Storage Hybrid	250 MW	0 MW	0 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW
Peaking Capacity	948 MW	1,896 MW	2,133 MW

EMISSIONS. As expected, the S and T portfolios have a significantly higher rate of emissions than the Mid Scenario. The ultimate goal of CETA is to reduce GHG emissions, and the S and T portfolios demonstrate the need for CETA in curbing emissions from PSE's portfolio. Figure 8-126 shows the annual emissions of the PSE portfolio in Sensitivities S and T.

Figure 8-126: Portfolio Emissions – Mid Scenario, Sensitivity S and Sensitivity T (market purchases are not included)



U. 2% Cost Cap Threshold

The incremental cost of compliance section of CETA states:

> An investor-owned utility must be considered to be in compliance with the standards under RCW 19.405.040(1) and 19.405.050(1) if, over the four-year compliance period, the average annual incremental cost of meeting the standards or the interim targets established under subsection (1) of this section equals a two percent increase of the investor-owned utility's weather-adjusted sales revenue to customers for electric operations above the previous year, as reported by the investor-owned utility in its most recent commission basis report.[6]

6 / RCW 19.405.060 3(a)

PSE calculated the incremental cost as the difference between Portfolio T, No CETA with SCGHG adder, and the preferred portfolio, Portfolio W. The calculation is as follows:

$$Incremental\ Cost = Preferred\ Portfolio\ Annual\ Cost - No\ CETA\ with\ SCGHG\ adder\ annual\ Cost$$

The 2 percent cost threshold is calculated based upon the expected annual revenue requirement. Figure 8-127 illustrates how the 2 percent cost threshold is calculated. First, the current revenue requirement is established using PSE's 2019 General Rate Case (GRC) revenue requirement. The GRC revenue requirement is adjusted for inflation at 2.5 percent per year to obtain the estimated 2021 revenue requirement (shown in the top half of the figure). The 2 percent cost threshold for the year 2022 is simply 2 percent of the inflation-adjusted GRC revenue requirement in 2021, approximately $44 million. For subsequent years, 2 percent of the inflation-adjusted GRC revenue requirement is added to the previous 2 percent cost threshold (also adjusted for inflation). This creates the compounding 2 percent cost threshold (shown in the bottom half of the figure).

Figure 8-127: Calculation of the 2 Percent Cost Threshold

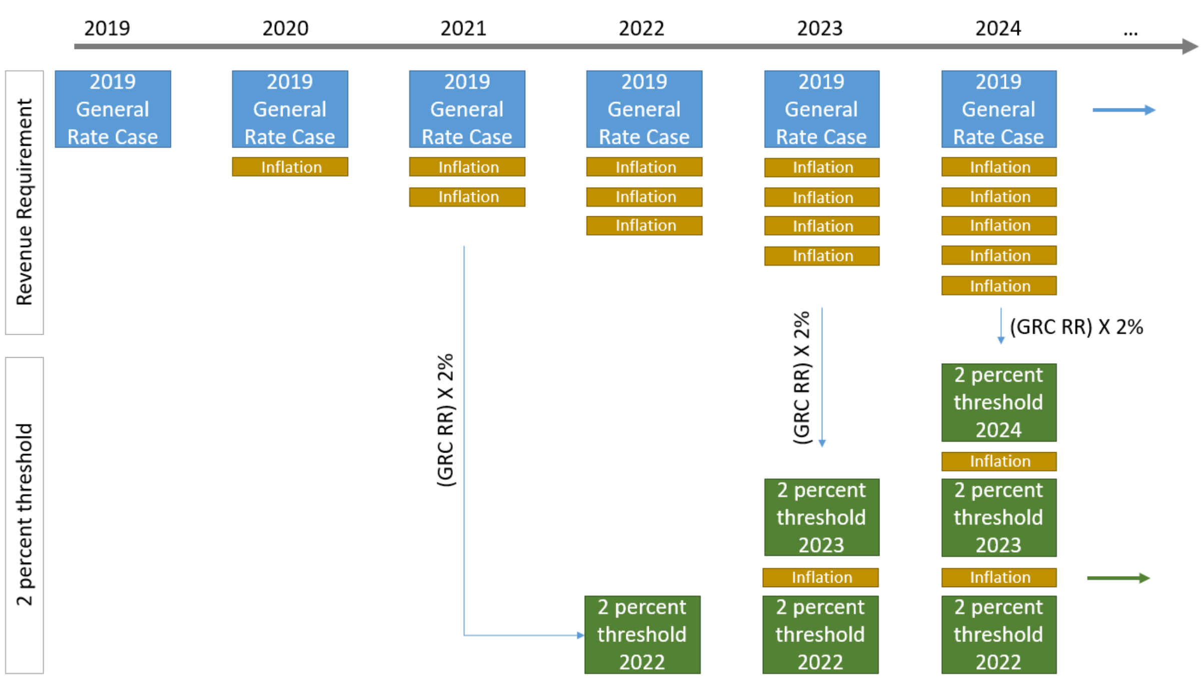
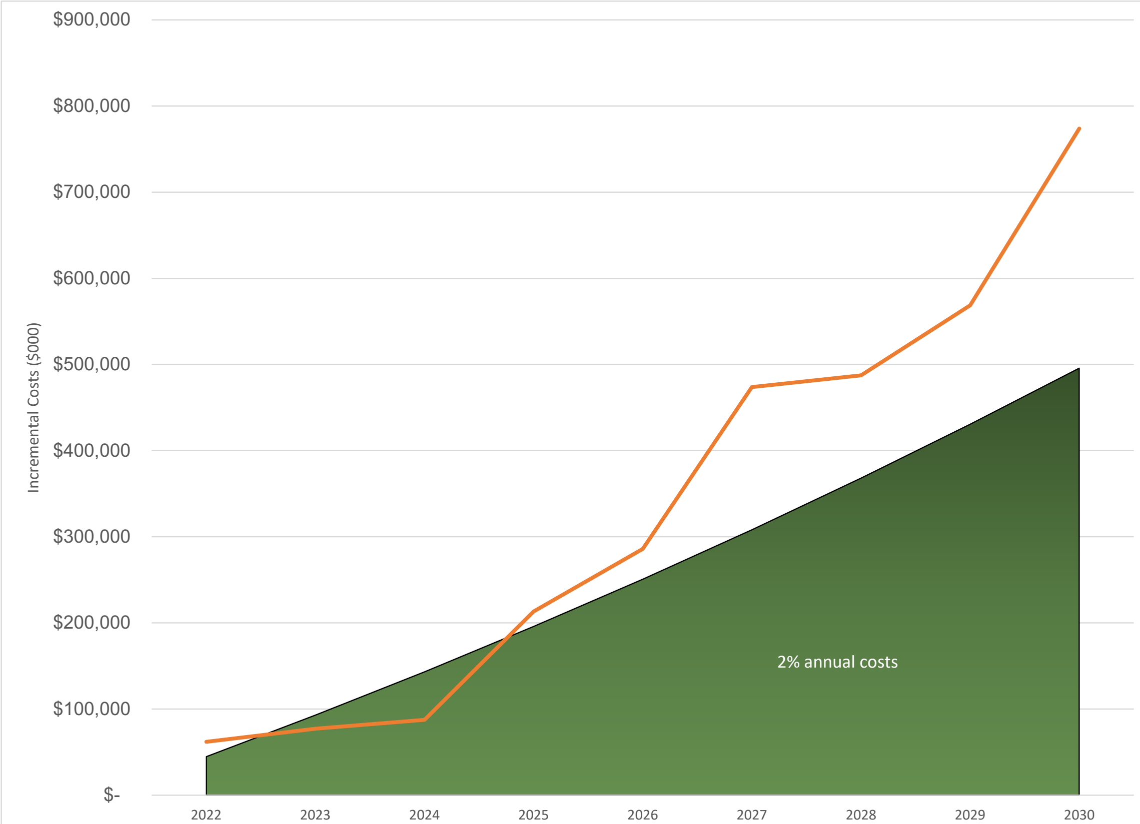


Figure 8-128 compares the 2 percent cost threshold (the green area) with the incremental cost of the preferred portfolio (the orange line). By 2025, the cost of CETA compliance increases to more than the 2 percent cost threshold.

Figure 8-128: Incremental Cost of CETA Compliance



There is some uncertainty associated with this comparison. The annual portfolio costs only include the costs associated with generating resources modeled in the IRP. There may be other costs that are not captured as part of the IRP analysis. Better clarity into this comparison will be obtained through the CEIP. All costs associated with the CETA implementation will be available and included in CEIP. In this IRP, PSE has included the cost of compliance calculation and a comparison with the preferred portfolio for information only.

Balanced Portfolios

V. Balanced Portfolio

Sensitivity V applies insights gained from the analysis of other sensitivities to compare with the results to the Mid Scenario portfolio. Sensitivity V gives increased consideration to distributed energy resources, ramping those and other customer programs in over time starting in 2025. In contrast, the Mid Scenario capacity expansion model is set to optimize total portfolio cost and builds new resources toward the end of the planning period because the cost curve of all resources declines over time. In Sensitivity C, for example, the model waits until the end of the planning period to add a significant amount of distributed resources. However, waiting until the end is not always realistic.

Baseline: New resources are acquired when cost effective and needed, and conservation and demand response measures are acquired when cost-effective.
Sensitivity V1 > Increased distributed energy resources and customer programs are ramped in over time. These include rooftop and ground-mounted solar, demand response programs, battery energy storage, customer-owned rooftop solar and an expanded Green Direct program.
Sensitivity V2 > Same as Sensitivity V1, with the substitution of a Montana wind + pumped hydro storage resource for the first eastern Montana resource constructed in 2028, similar to Sensitivity AA described below.
Sensitivity V3 > Same as Sensitivity V1, except conservation measures ramp in over 6 years instead of 10 years, similar to Sensitivity F described above.

KEY FINDINGS. Ramping in resource additions versus economic resource selection resulted in higher portfolio costs in Sensitivity V variations compared to the Mid Scenario. Distributed solar resources are higher cost than Washington wind and Washington solar east resources, which were found to be the optimal renewable resources after the addition of Montana and Wyoming wind resources in the Mid Scenario portfolio. In Sensitivity V1, the 24-year levelized revenue requirement is $16.06 billion, an increase of $0.47 billion or 3 percent over the Mid Scenario portfolio. Adding MT wind plus pumped hydro storage (V2) or a 6-year DSR ramp increases these costs further.

ASSUMPTIONS. Sensitivity V1 assumes greater investment in distributed energy resources and load-reducing resources like the Green Direct program and conservation measures to create a portfolio with greater balance between large, central power plants and small, distributed resources. Investments in these resources are modeled as must-take resource additions. These must-take resource additions include:

- Addition of 50 MW of distributed, ground-mounted solar in the year 2025.
- Annual addition of 30 MW of distributed, rooftop solar from the year 2025 to 2045 for a total of 630 MW of nameplate capacity.
- Addition of all demand response programs with a cost less than $300/kw-yr.
- Annual addition of 25 MW of 2-hour lithium-ion battery storage from the year 2025 to 2031 for a total of 175 MW of nameplate capacity.
- An adjusted forecast of customer-owned solar projects to reflect increased residential solar adoption. The forecast matches the CPA Low-cost, Business-as-Usual residential solar adoption rate, available in Appendix E.
- Addition of three new Green Direct programs consisting of 100 MW of Washington wind in 2025, 100 MW of eastern Washington solar in 2027 and 100 MW of Washington wind in 2030.

PSE has ramped in resource additions in this sensitivity to spread out the acquisition of new resources. All generic resource options are still available for economic selection by the optimization model.

Sensitivity V2 makes the same assumptions as Sensitivity V1 except a Montana wind + pumped hydro storage resource is forced into the portfolio in the year 2028.

Sensitivity V3 makes the same assumptions as Sensitivity V1 except conservation measures are implemented over 6 years instead of 10 years and associated costs and energy savings are updated.

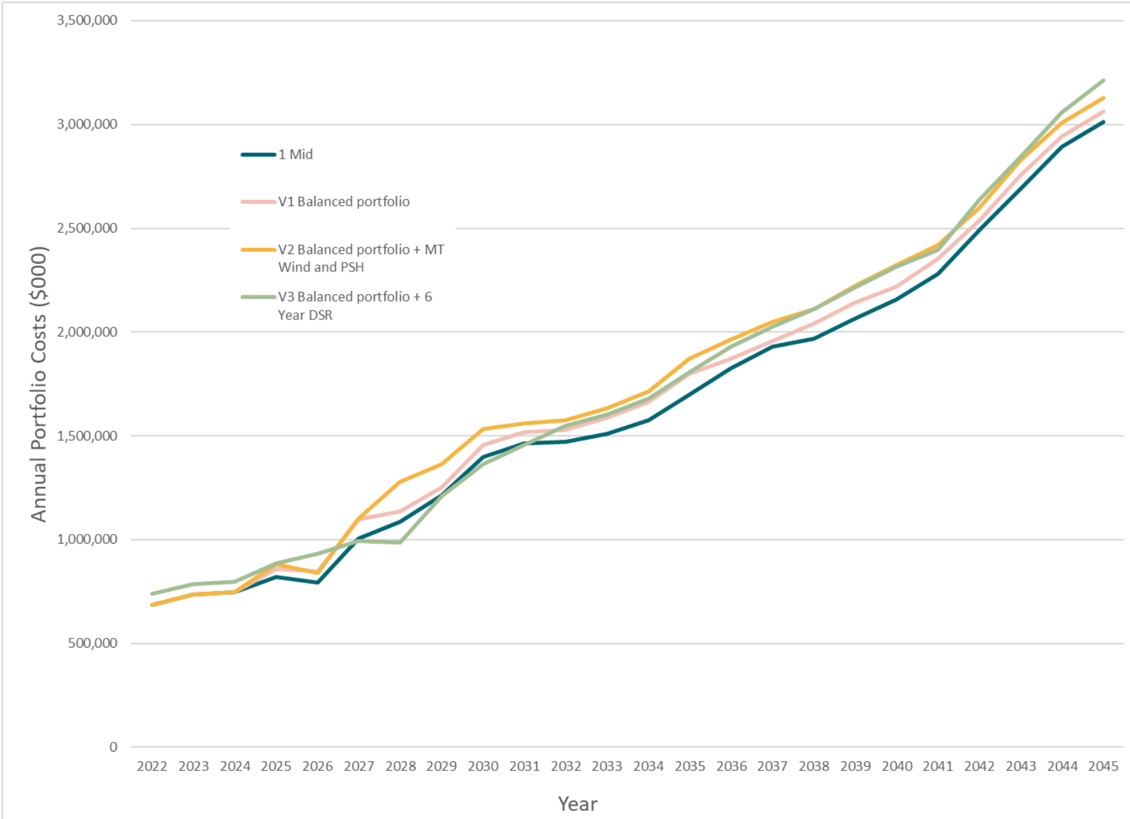
PORTFOLIO COSTS. Figures 8-129 and 8-130 compare the portfolio costs and annual revenue requirements, respectively, of the Sensitivity V variations and the Mid Scenario. Early investments in high-cost resources such as distributed solar and storage result in overall higher portfolio costs for the Sensitivity V variations compared to the Mid Scenario. Sensitivity V1 has a slightly higher revenue requirement from 2024 to the end of the planning period compared to the Mid Scenario. Sensitivity V2 has a significant increase the annual revenue requirement in 2028 from the addition of the expensive Montana wind plus pumped hydro storage resource and never recovers those costs compared to the Mid Scenario. Sensitivity V3 starts as the most expensive portfolio due to the accelerated ramp of conservation measures, and then sees some cost savings in the years 2027 to 2032 compared to the Mid Scenario. However, in 2032 the Mid Scenario conservation measures complete their 10-year ramp-in, equalizing the energy savings between the two portfolios. After 2032, Sensitivity V3 costs increase above the Mid Scenario due to resource acquisitions in the later portion of the planning period.

The SCGHG for the Sensitivity V variations is similar the SCGHG for the Mid Scenario. Sensitivities V1 and V2 achieve slightly lower SCGHG than the Mid Scenario, while Sensitivity V2 has a slightly higher SCGHG overall.

Figure 8-129: Portfolio Cost Comparison – Mid Scenario and Sensitivities V, W and X

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
V1	Balanced Portfolio	$16.06	$5.07	$21.14	$0.54
V2	Balanced Portfolio with MT wind + PHES	$16.61	$5.12	$21.73	$1.11
V3	Balanced Portfolio with 6-year DSR	$16.26	$5.06	$21.32	$0.70

Figure 8-130: Annual Portfolio Costs – Mid Scenario and Sensitivities V1, V2 and V3



RESOURCE ADDITIONS. Figures 8-131 and 8-132 compare the nameplate capacity additions of the Sensitivity V variations and the Mid Scenario portfolio. Resource additions for Sensitivity V1 and the Mid Scenario are similar, except for the quantity of ground-mounted and rooftop solar forced into the portfolio in the early years that displaces utility-scale solar. Resource additions for the Sensitivity V variations are all very similar. Sensitivity V3 delays acquisition of resources until the later years of the planning period, but concludes the planning period with a similar resource mix as Sensitivities V1 and V2.

Figure 8-131: Portfolio Additions – Mid Scenario and Sensitivities V1, V2 and V3

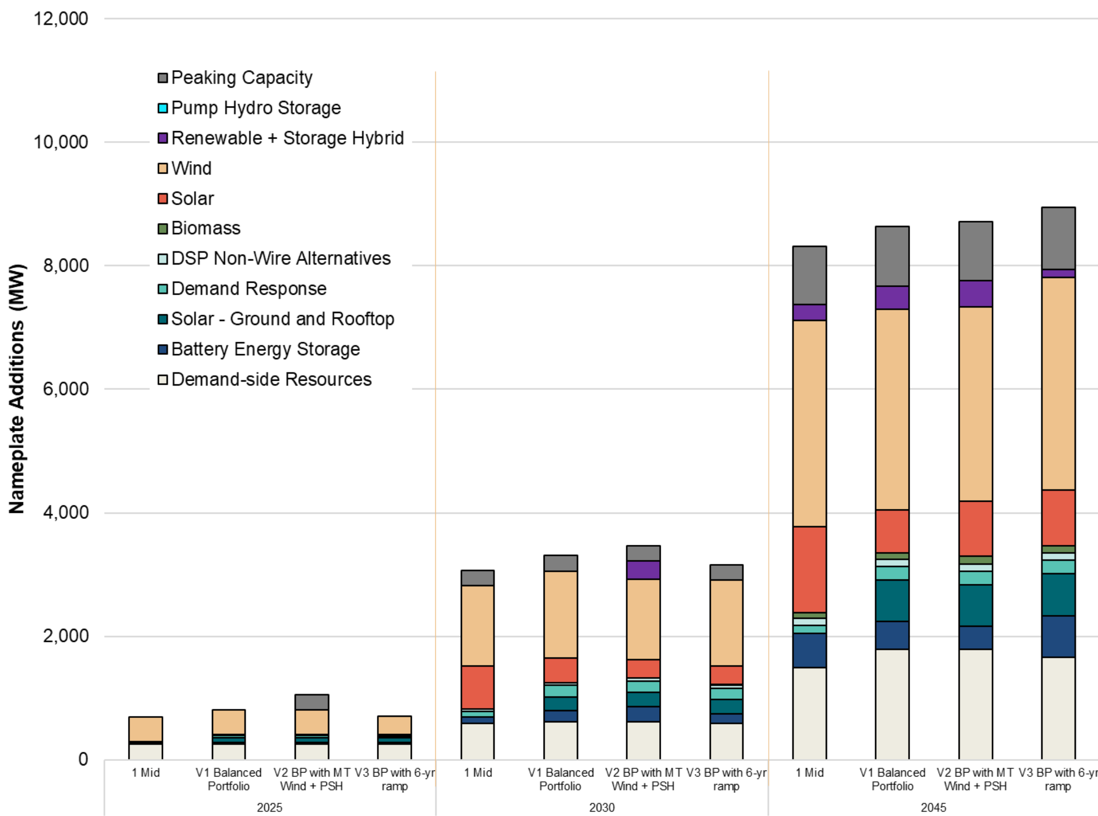
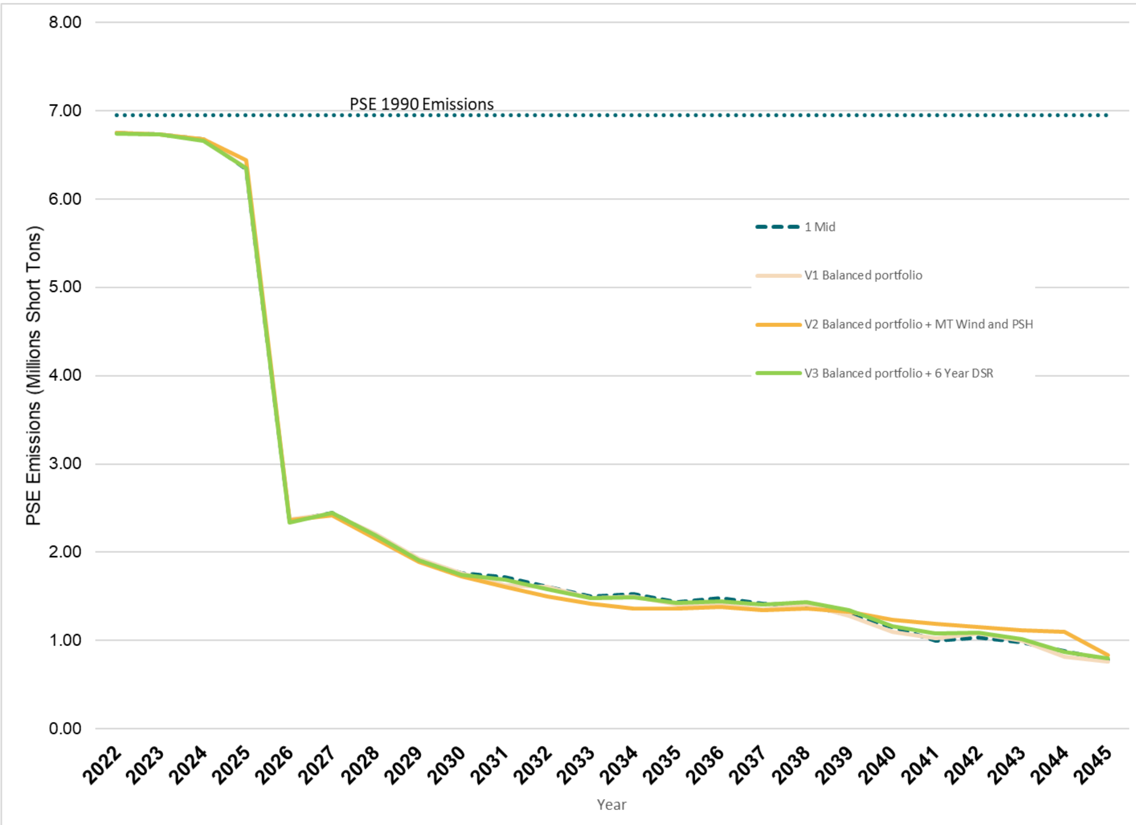


Figure 8-132: Portfolio Additions by 2045 – Sensitivities V1, V2 and V3

Resource Additions by 2045	Mid Scenario Portfolio	Sensitivity V1 - Balanced Portfolio	Balanced Portfolio with MT wind + PHES	Balanced Portfolio with 6-year DSR
Demand-side Resources	1,497 MW	1,784 MW	1,784 MW	1,658 MW
Battery Energy Storage	550 MW	450 MW	375 MW	675 MW
Solar - Ground and Rooftop	0 MW	680 MW	680 MW	680 MW
Demand Response	123 MW	217 MW	217 MW	217 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	4,051 MW	4,165 MW	4,465 MW
Biomass	90 MW	105 MW	120 MW	120 MW
Solar	1,393 MW	696 MW	895 MW	895 MW
Wind	3,350 MW	3,250 MW	3,150 MW	3,450 MW
Renewable + Storage Hybrid	250 MW	375 MW	425 MW	125 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW	0 MW
Peaking Capacity	948 MW	966 MW	948 MW	1,003 MW

OTHER FINDINGS: GHG Emissions. Figure 8-133 compares the direct GHG emissions from Sensitivities V1, V2 and V3 with the Mid Scenario. Significant emissions reductions are achieved with the addition of non-emitting resources, the retirement of coal resources and lower dispatch of existing resources. All three Sensitivity V variations show similar reductions in emissions by the year 2045.

Figure 8-133: Portfolio GHG Emissions – Sensitivities V1, V2 and V3

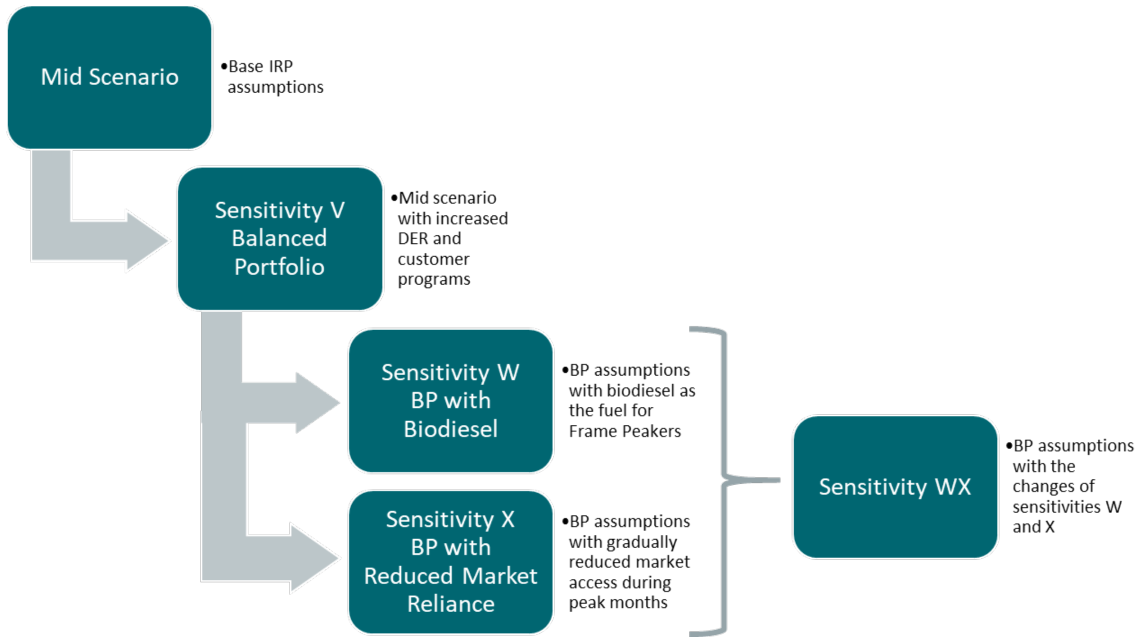


W. Balanced Portfolio with Alternative Fuel
X. Balanced Portfolio with Reduced Market Reliance
WX. Balanced Portfolio with Alternative Fuel and Reduced Market Reliance

Sensitivities W and X incorporate significant changes to Sensitivity V1, the Balanced Portfolio. Sensitivity W substitutes biodiesel for natural gas in new peaking capacity resources and Sensitivity X reduces the market reliance of the portfolio. Sensitivity WX applies the key changes in Sensitivities W and X simultaneously. Figure 8-134 illustrates how these changes are applied.

Figure 8-134: Sensitivities V, W, X and WX, and Their Relation to the Mid Scenario

BP = Balanced Portfolio



Baseline: In the Mid Scenario, new resources are acquired when cost effective and needed, and conservation and demand response measures are acquired when cost-effective.

Sensitivity W > Same as Sensitivity V1, with the addition of biodiesel as the fuel source for new frame peaker resources, similar to Sensitivity M.

Sensitivity X > Same as Sensitivity V1, but market purchases during seasonal peak conditions gradually decline by 200 MW per year down to 500 MW by 2027 in the winter months (January, February, November and December) and the summer months (June, July, and August), similar to sensitivity B.

Sensitivity WX > Additional DER and customer programs are added to the portfolio. Biodiesel is used as a fuel for newly built frame peaker resources. The portfolio has reduced access to market purchases during peak demand months.

KEY FINDINGS: SENSITIVITY W. Extending the assumptions from Sensitivity V1 to include biodiesel as a fuel source for new frame peakers resulted in an increase of $0.57 billion dollars in the 24-year levelized revenue requirement for Sensitivity W compared to the Mid Scenario. The 24-year levelized revenue requirement is $16.10 billion, an increase of less than $0.04 billion from Sensitivity V1. Even with the premium on biodiesel fuel prices compared to natural gas prices, the model selected the same amount of frame peaker resources in Sensitivity W compared to the Mid Scenario portfolio.

KEY FINDINGS: SENSITIVITY X. While ramping in distributed energy resources and customer programs over time helps to achieve increased renewable resources, introducing the reduced market reliance strategy creates tension, since Sensitivity X adds more peaking capacity resources compared to the Mid Scenario and Sensitivity V. The 24-year levelized revenue requirement for Sensitivity X is $17.21 billion, $1.68 billion more than the Mid Scenario and $1.14 billion more than Sensitivity V1.

KEY FINDINGS: SENSTIVITY WX. Portfolio WX is nearly identical to portfolio X. The same resources are selected at the same time. The only difference in builds is an increase in demand-side resources. Portfolio WX emissions decrease compared to portfolio X due to the use of biodiesel, but are higher than portfolio W due to the reduced availability of market purchases during peak hours.

ASSUMPTIONS: Sensitivity V1: Balanced Portfolio
Increased distributed energy resources and customer programs ramp in over time as follows:

- Addition of 50 MW of distributed, ground-mounted solar in 2025.
- Annual addition of 30 MW of distributed, rooftop solar from 2025 to 2045 for a total of 630 MW of nameplate capacity.
- Annual addition of all demand response programs that cost less than $300/kw-yr.
- Annual addition of 25 MW of 2-hour lithium-ion battery storage from 2025 to 2031 for a total of 175 MW of nameplate capacity.
- Adjusted forecast of customer-owned solar projects to reflect increased residential solar adoption. (The forecast matches the CPA Low-cost, Business-as-Usual residential solar adoption rate, available in Appendix E.)
- Addition of three new Green Direct programs: 100 MW of Washington wind in 2025, 100 MW of eastern Washington solar in 2027 and 100 MW of Washington wind in 2030.

ASSUMPTIONS: Sensitivity W. Sensitivity W uses the Sensitivity V1 assumptions, but also includes the use of alternative fuel for some peaking capacity resources. New frame peakers are assumed to be fueled by biodiesel instead of natural gas. Existing thermal resources, new CCCT+DF and new recip peakers continue to be fueled with natural gas throughout the modeling horizon. PSE estimated a biodiesel price of $37.20 per million British Thermal Units (MM BTU) (2020$, adjusted for inflation annually) informed by the U.S. Department of Energy's October 2020 Clean Cities Alternative Fuel Price Report.

ASSUMPTIONS: Sensitivity X. For Sensitivity X, available market purchases were constrained to capture the impact of reduced market reliance on the Balanced Portfolio. Available market purchases during peak conditions are reduced by 200 MW per year down to 500 MW by 2027 in the winter months (January, February, November and December) and the summer months (June, July, and August).

Figure 8-135 shows the Sensitivity X market purchase limits for each year and month.

Figure 8-135: Monthly Market Purchase Access in Portfolio X (MW)

MW	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2022	1544	1529	1516	1483	1442	1463	1472	1487	1569	1588	1558	1518
2023	1300	1300	1507	1466	1432	1300	1300	1300	1519	1519	1300	1300
2024	1100	1100	1536	1471	1418	1100	1100	1100	1546	1521	1100	1100
2025	900	900	1518	1455	1402	900	900	900	1529	1523	900	900
2026	700	700	1521	1457	1405	700	700	700	1530	1525	700	700
2027	500	500	1523	1460	1408	500	500	500	1532	1526	500	500
2028	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2029	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2030	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2031	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2032	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2033	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2034	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2035	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2036	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2037	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2038	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2039	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2040	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2041	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2042	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2043	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2044	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2045	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2046	500	500	1525	1462	1411	500	500	500	1533	1526	500	500
2047	500	500	1525	1462	1411	500	500	500	1533	1526	500	500

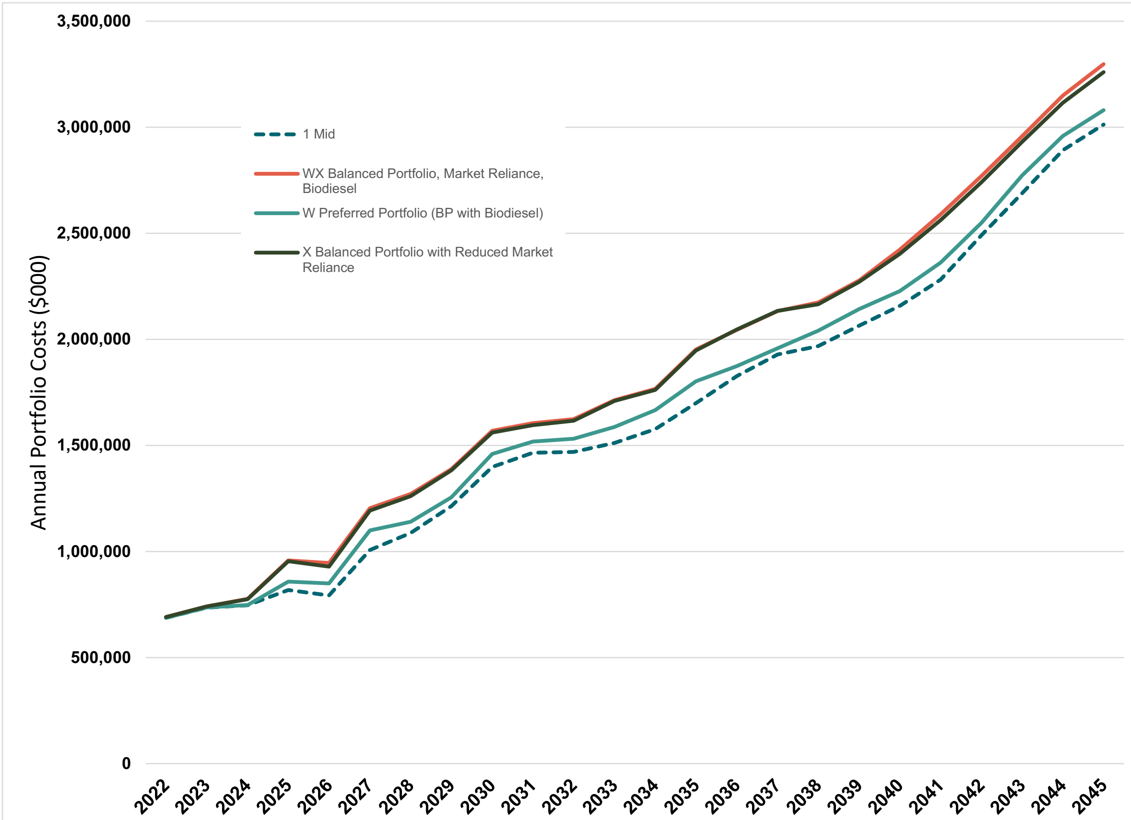
ASSUMPTIONS: Sensitivity WX. Sensitivity WX combines the changes incorporated to Sensitivity W and Sensitivity X. Therefore, biodiesel is available for new frame peakers and the portfolio has reduced market purchase limits.

ANNUAL PORTFOLIO COSTS. Figures 8-136 and 8-137 show the portfolio costs and annual revenue requirements, respectively, of Sensitivities WX, W and X, compared to the Mid Scenario. Early investments in high-cost resources such as distributed solar and storage result in higher portfolio costs for Sensitivities WX, W and X. For Sensitivity W, increased portfolio costs are driven by the increased revenue requirements of the portfolio, as shown in Figure 8-X. Sensitivity W has slightly lower SCGHG due the use of alternative fuel for new peaking resources than the Mid Scenario portfolio. In Sensitivity X, the increased portfolio costs are due to the addition of more flexible capacity resources, which also increases the SCGHG. Portfolio WX significantly increases the revenue requirement over the Mid Scenario portfolio, although less than the combined increases of the W and X portfolios over the Mid Scenario. The portfolio builds are nearly identical to portfolio X, but the use of biodiesel reduces the SCGHG costs and costs overall. The slight increase in portfolio costs compared to portfolio X is due to the use of biodiesel and increased investment in demand-side resources.

Figure 8-136: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivities WX, W and X

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
WX	Balanced Portfolio, Biodiesel, Reduced Market Reliance	$17.30	$5.06	$22.36	$1.74
W	Balanced Portfolio, Biodiesel	$16.10	$4.96	$21.06	$0.44
X	Balanced Portfolio, Reduced Market Reliance	$17.21	$5.36	$22.57	$1.95

Figure 8-137: Annual Portfolio Costs – Mid Scenario and Sensitivities WX, W and X



RESOURCE ADDITIONS. Figures 8-138 and 8-139 compare the nameplate capacity additions of Sensitivities W, X, WX and the Mid Scenario portfolios.

Portfolio builds for Sensitivity W are relatively similar to the wind and peaking capacity resource builds in the Mid Scenario. Wind is a low cost, CETA-eligible resource, so it is to be expected that all four portfolios selected similar amounts of wind capacity. Peaking capacity resources are among the lowest cost methods to meet peak demand hours. Therefore, it is also to be expected that most portfolios will include some peaking capacity. Sensitivity W has an additional 18 MW of reciprocating peaker resources compared to the quantity of peaking capacity resources in the Mid Scenario. In Sensitivity W, new frame peaker resources are fueled with renewable biodiesel instead of natural gas which therefore does not include an SCGHG cost. However, biodiesel is also much more expensive than natural gas. At the current cost projections for biodiesel, it appears that the higher fuel price and lower SCGHG cost are offsetting each other, resulting in similar peaking resource decisions.

The primary differences between the Mid Scenario and Sensitivity W are related to the forced build decisions described in the assumptions section above. Increased distributed solar builds result in less utility-scale solar builds, as these resources fill a similar niche within the portfolio. Increased demand response programs in Sensitivity W may also offset some utility-scale solar builds.

More storage is built in Sensitivity W compared to the Mid Scenario portfolio. Sensitivity W ramps in 2-hour lithium-ion battery storage from 2025 to 2031. This storage is useful, particularly paired with the increased distributed solar builds in both sensitivities. However, the storage in the Mid Scenario portfolio is comprised of 4-hour lithium-ion and 6-hour flow battery storage, which is built after year 2040. Sensitivity W shows similar late year additions of longer duration storage, despite the abundance of 2-hour storage added early in the modeling horizon. This shows that longer-duration storage is an important component of these portfolios.

With the reduced market purchase limit in Sensitivity X, more conservation resources, battery energy storage and peaking capacity resources are added to fill the energy that would have been purchased in the market.

The builds of portfolio WX are nearly identical to portfolio X, the only difference is an increase in demand-side resources. The construction timeline of resources is also the same in WX and X.

Figure 8-138: Portfolio Additions – Mid Scenario and Sensitivities WX, W and X

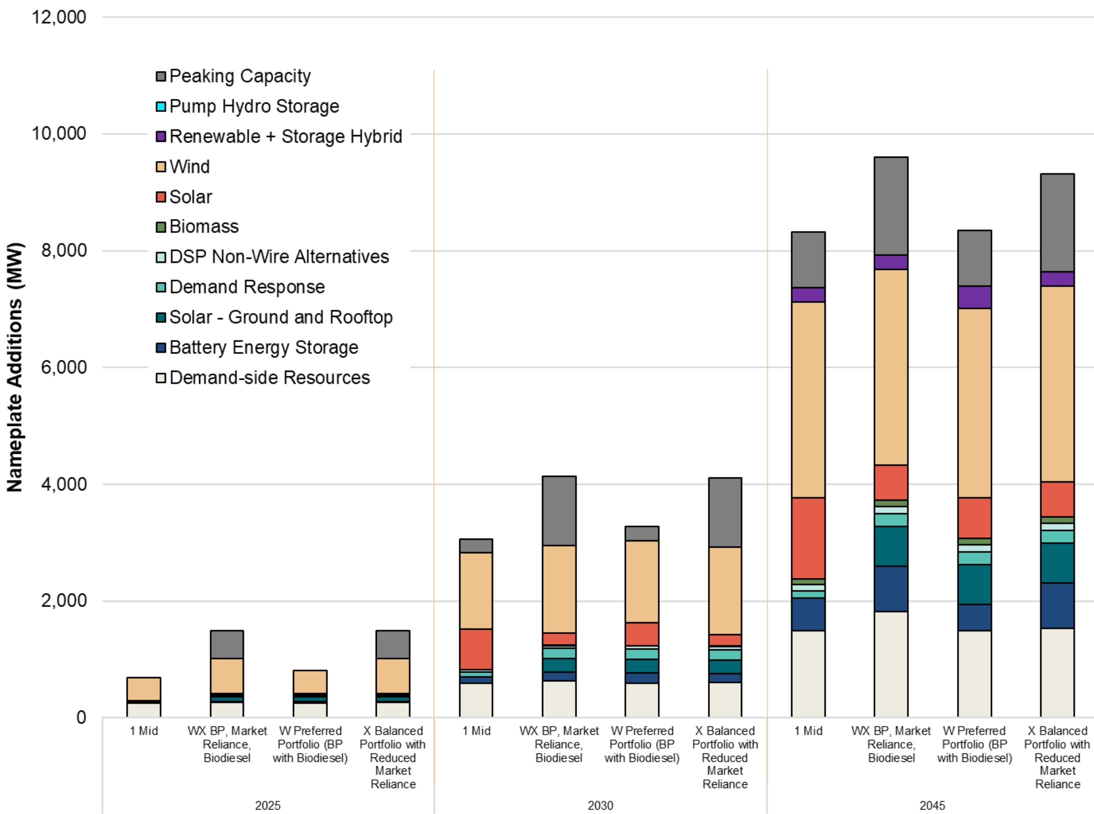
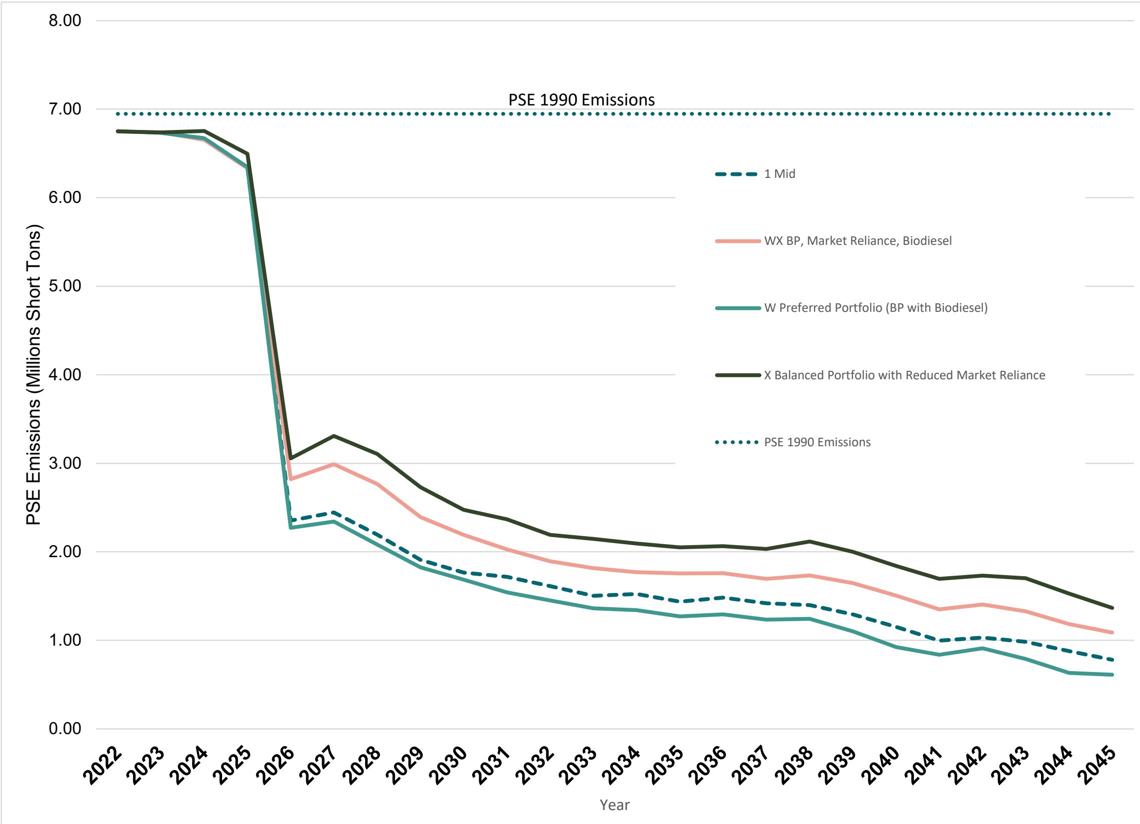


Figure 8-139: Portfolio Additions – Mid Scenario and Sensitivities WX, W and X

Resource Additions by 2045	1 Mid	WX BP, Market Reliance, Biodiesel	W Preferred Portfolio (BP with Biodiesel)	X Balanced Portfolio with Reduced Market Reliance
Demand-side Resources	1,497 MW	1,824 MW	1,784 MW	1,824 MW
Battery Energy Storage	550 MW	775 MW	450 MW	775 MW
Solar - Ground and Rooftop	0 MW	680 MW	680 MW	680 MW
Demand Response	123 MW	217 MW	217 MW	217 MW
DSP Non-wire Alternatives	118 MW	118 MW	118 MW	118 MW
Renewable Resources	4,833 MW	4,066 MW	4,051 MW	4,066 MW
Biomass	90 MW	120 MW	105 MW	120 MW
Solar	1,393 MW	596 MW	696 MW	596 MW
Wind	3,350 MW	3,350 MW	3,250 MW	3,350 MW
Renewable + Storage Hybrid	250 MW	250 MW	375 MW	250 MW
Pumped Hydro Storage	0 MW	0 MW	0 MW	0 MW
Flexible Capacity	948 MW	1,677 MW	966 MW	1,677 MW

EMISSIONS. Figure 8-140 compares direct GHG emissions from Sensitivities WX, W and X to the Mid Scenario. For Sensitivity W, emissions decrease compared to the Mid Scenario, through use of biodiesel for peaking capacity resources. For Sensitivity X, emissions increase compared to the Mid Scenario due to increased additions of peaking capacity resources. Consistent with the findings of sensitivities W and X, reducing market purchases and using of biodiesel have opposite effects on overall portfolio emissions. The overall emissions of portfolio WX fall between W and X.

Figure 8-140: Portfolio GHG Emissions – Mid Scenario and Sensitivity WX, W and X



Y. Maximum Customer Benefit

Maximizing customer benefits is a complex task. Numerous customer benefit indicators exist, and often increasing the benefit of one indicator reduces the benefit of another. Therefore, PSE's approach to maximizing customer benefits was to model a wide range of possible portfolios, many of which maximized specific customer benefit indictors. Through isolating and maximizing specific customer benefit indicators, it is possible to see trade-offs in other customer benefits and opportunities to balance those tradeoffs.

The following list highlights portfolios that maximize specific customer benefit indicators:

- Mid Scenario – The Mid Scenario, in addition to providing a basis for comparison to other sensitivities, is designed to be among the lowest cost portfolios. Over the 24-year timeframe, the Mid Scenario is ranked fourth best in terms of portfolio cost. Sensitivities G, I and M rank higher, but have only marginally lower portfolio costs and all include unique inputs which bring their costs down. Portfolio cost is directly related to the energy costs passed on to customers and should be minimized to keep energy burdens low. The AURORA portfolio model is an economic model which seeks to minimize cost; therefore, increasing other customer benefit indicators typically results in increased portfolio costs. In developing a preferred portfolio, PSE must balance portfolio cost with other customer benefit indicators.

- Sensitivity C – The distributed, transmission limited sensitivity maximizes utilization of distributed energy resources. Distributed energy resources provide significant transmission and distribution benefits, offsetting the need for long-distance transmission. In Sensitivity, C thermal resources were necessary to provide capacity during periods of peak demand resulting in higher emissions than most other portfolios. Distributed resources are also expensive compared to utility-scale resources, resulting in higher portfolio costs, but they offset potential transmission risk. Adding more distributed resources helps to optimize the customer benefit areas of environment and resiliency.
- Sensitivity N, the 100 percent renewable by 2030 sensitivity maximizes several customer benefit indicators through transitioning to a clean energy portfolio ahead of CETA targets. Sensitivity N2 (pumped hydro storage) obtains the highest rank for the 24-year timeframe for the customer benefit areas of Climate Change, Air Quality and Market Position. Sensitivity N1 (batteries) ties for the highest rank in Air Quality and achieves the highest rank in Resiliency. Sensitivity N1 uses batteries to provide capacity resulting in a much more resilient portfolio than Sensitivity N2, which relies on centralized pumped hydro storage for capacity. Early adoption of clean energy technologies carries significant benefits. However, these benefits are balanced by extremely high portfolio costs. Furthermore, both Sensitivities N1 and N2 score low in the Resource Adequacy customer benefit indicator area due to the reliance on short-term energy storage for capacity. These short-term energy storage resources are energy limited, exposing PSE's customers to risk in the event of long-duration peak events.

Other portfolios assessed in this IRP provide varying degrees of customer benefits. Results for these portfolios are available earlier in this chapter. Of particular importance, are the Balanced Portfolios (Sensitivities V, W and WX) which do not seek to maximize any single customer benefit, but to provide meaningful contributions to customer benefit indicators to develop a well-rounded, low-risk portfolio.

Z. No DSR

This sensitivity examines the value of conservation and demand response resources to the portfolio.

Baseline: Conservation resources are selected when they are cost-effective.
Sensitivity Z > No conservation or demand response measures are included.

KEY FINDINGS. Without demand response or conservation, the cost of the Mid Scenario portfolio increases by $2.48 billion, building additional solar and storage resources to reach CETA compliance, and building two additional frame peakers to maintain peak capacity.

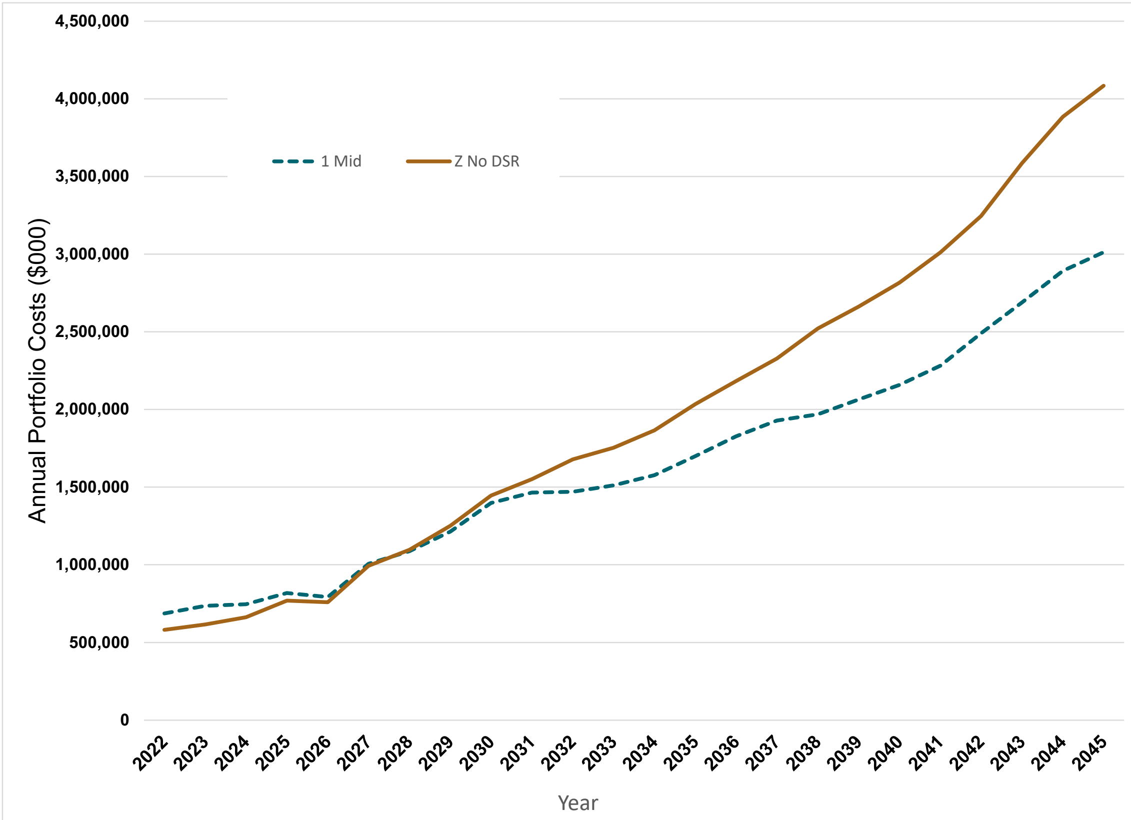
ASSUMPTIONS. Sensitivity Z keeps all the Mid Scenario modeling assumptions, except no conservation or demand response measures are included.

ANNUAL PORTFOLIO COSTS. Overall, the annual portfolio costs of Sensitivity Z and the Mid Portfolio are similar until 2030, when the removal of demand response and conservation from the portfolio reduce the costs of Portfolio Z. After 2030, growing demand that is unchecked by conservation measures combines with CETA renewable need to accelerate resource need and increase costs. Despite the up-front investment, DSR saves the Mid Scenario $2.48 billion by reducing demand and preventing the need for new resources, both renewable and thermal.

Figure 8-141: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity Z

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
Z	No DSR	$17.54	$5.56	$23.10	$2.48

Figure 8-142: Annual Portfolio Costs – Mid Scenario and Sensitivity Z



RESOURCE ADDITIONS. Figures 8-143 and 8-144 compares the nameplate capacity additions of the Mid Scenario and Sensitivity Z portfolios. To meet increased demand, Portfolio Z adds an additional two frame peakers (474 MW), 1,195 MW of eastern Washington solar, 250 MW of hybrid resources and 700 MW of 4- and 6-hour flow batteries by 2045. Solar builds begin to outpace the Mid Scenario as early as 2024, and a second round of builds enters late in the portfolio. For example, in Sensitivity Z, Washington wind capacity reaches 2,000 MW by 2039 with no further additions for the rest of the planning period compared to 1,500 MW of wind added in the Mid Scenario in 2039 which goes on to increase to 1,900 by 2045.

Figure 8-143: Portfolio Additions – Mid Scenario and Sensitivity Z

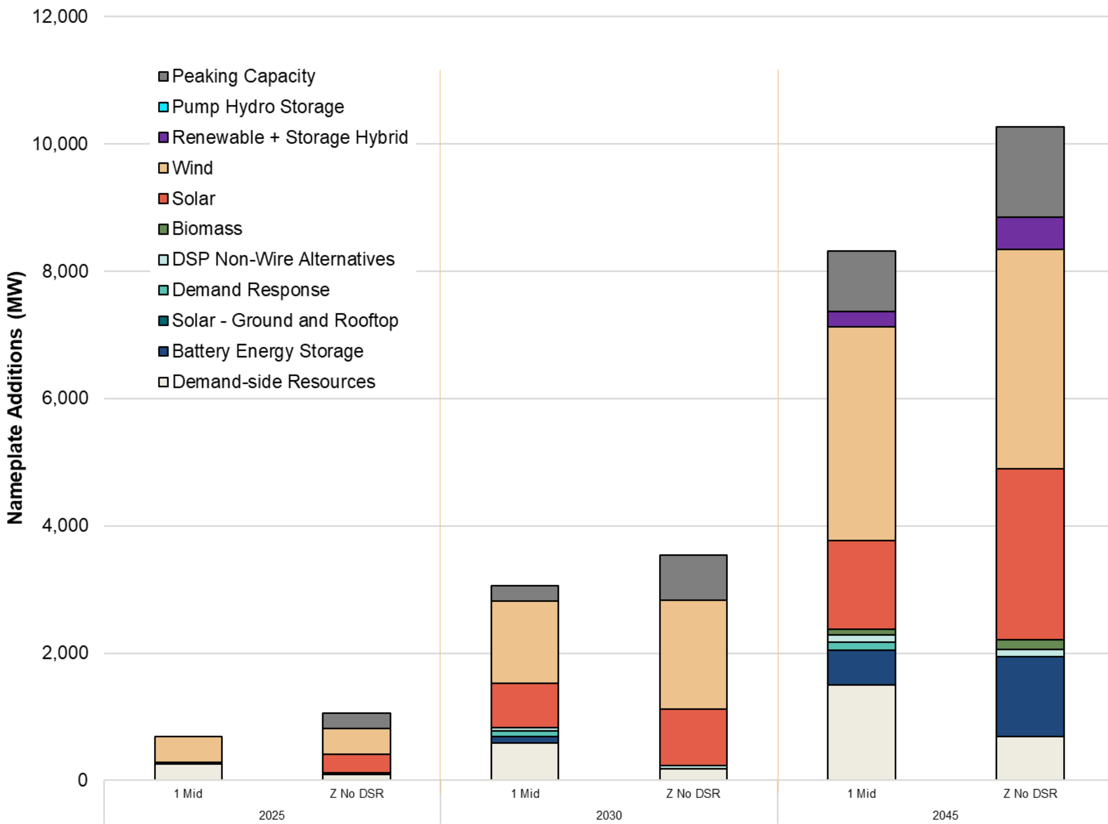


Figure 144: Portfolio Additions – Mid Scenario and Sensitivity Z

Resource Additions by 2045	1 Mid	Z No DSR
Demand-side Resources	1,497 MW	690 MW
Battery Energy Storage	550 MW	1,250 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	0 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	6,288 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	2,688 MW
Wind	3,350 MW	3,450 MW
Renewable + Storage Hybrid	250 MW	500 MW
Pumped Hydro Storage	0 MW	0 MW
Flexible Capacity	948 MW	1,422 MW

Other

AA. Montana Wind + Pumped Storage Hydro

This sensitivity examines the value of adding a hybrid resource early in the planning period.

Baseline: Hybrid resources are selected when they are cost-effective.
Sensitivity AA > A Montana wind plus pumped hydro storage hybrid resource is substituted for the eastern Montana wind resource added to the Mid Scenario in the year 2028.

KEY FINDINGS. Early addition of a hybrid Montana wind plus pumped hydro resource does not add meaningful value the portfolio. Portfolio costs are slightly higher and emissions remain the same or increase slightly. Peaking capacity additions are postponed by one or two years but are still added to the portfolio.

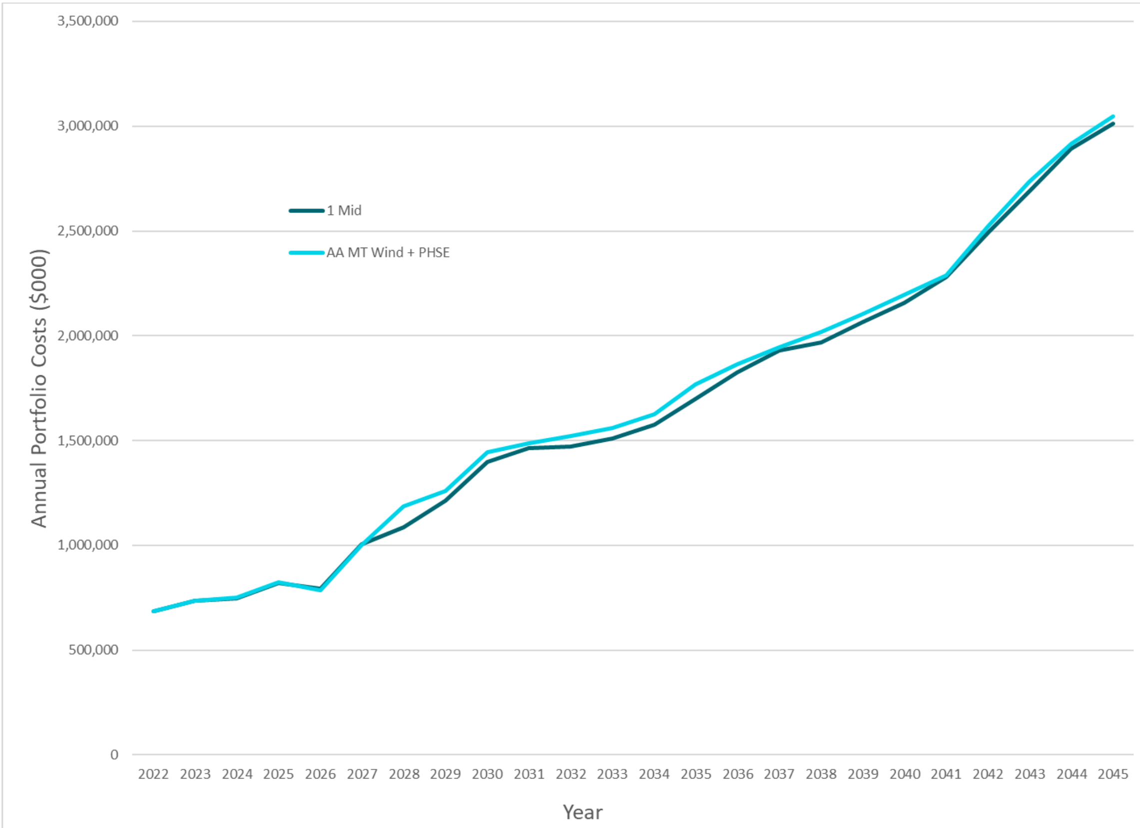
ASSUMPTIONS. Sensitivity AA keeps all the Mid Scenario modeling assumptions, except a Montana wind plus pumped storage hydro resource is forced into the portfolio in the year 2028.

ANNUAL PORTFOLIO COSTS. Overall, the annual portfolio costs of Sensitivity AA and the Mid Portfolio are similar except for the spike in revenue requirement in the year 2028 to purchase the Montana wind plus pumped hydro hybrid instead of the eastern Montana wind resource. The more costly revenue requirement of the hybrid resource is seen for the remainder of the planning period. Otherwise, portfolio costs are nearly identical.

Figure 8-145: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity AA

		24-year Levelized Costs (Billion $)			
	Portfolio	Revenue Requirement	SCGHG	Total	Change from Mid
1	Mid Scenario	$15.53	$5.09	$20.62	--
AA	MT wind + PHES	$15.84	$5.16	$20.99	$0.37

Figure 8-146: Annual Portfolio Costs – Mid Scenario and Sensitivity AA



RESOURCE ADDITIONS. Figures 8-147 and 8-148 compare the nameplate capacity additions of the Mid Scenario and Sensitivity AA portfolios. Resource additions are extremely similar between the two portfolios, the only notable differences being that Sensitivity AA adds the forced MT wind plus pumped hydro addition in 2028, 250 MW less independent storage and 300 MW less solar. Sensitivity AA adds peaking capacity on a slightly delayed schedule, but reaches the same amount of peaking capacity by 2045. Both portfolios select conservation Bundle 10.

Figure 8-147: Portfolio Additions – Mid Scenario and Sensitivity AA

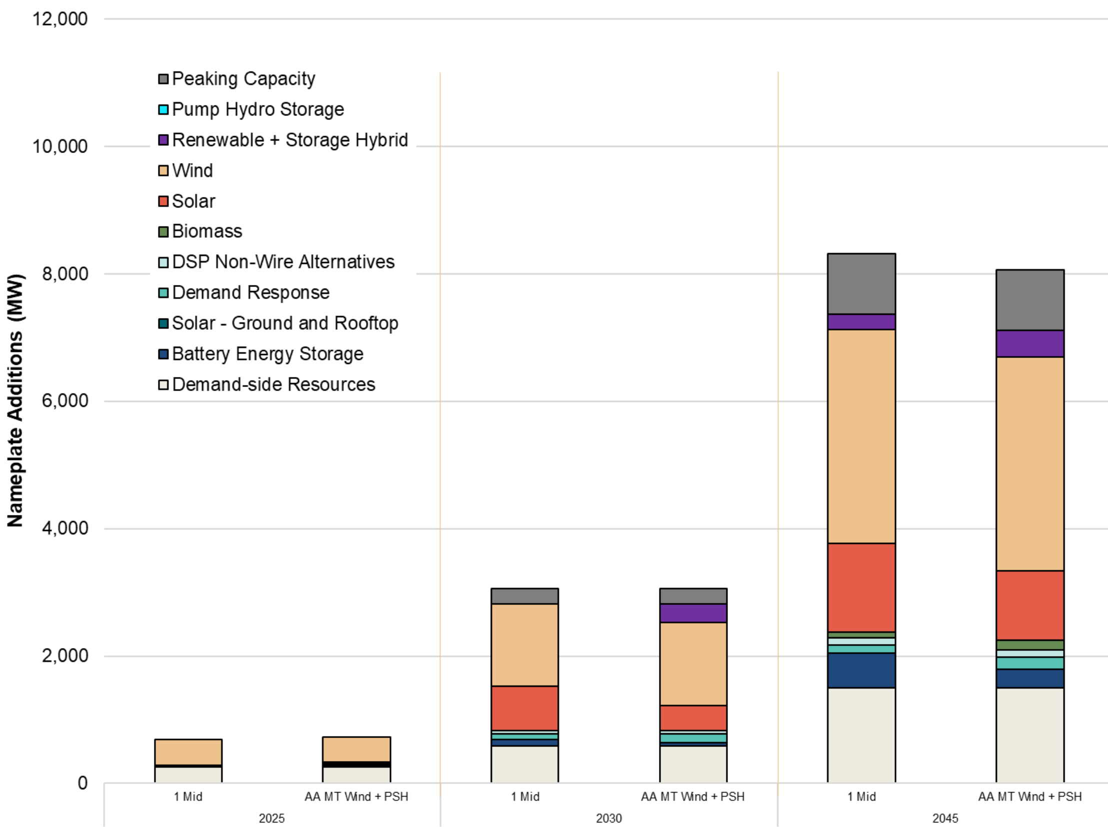
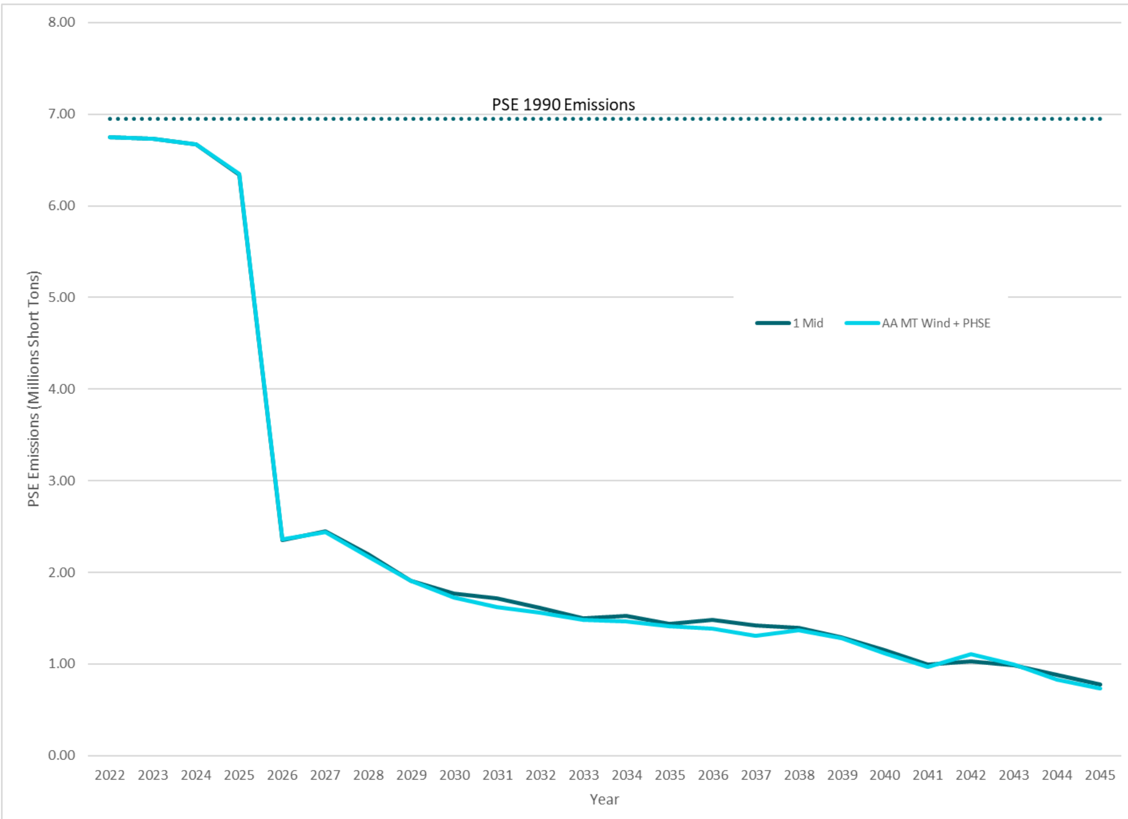


Figure 8-148: Portfolio Additions – Sensitivity AA

Resource Additions by 2045	1 Mid	AA MT Wind + PHES
Demand-side Resources	1,497 MW	1,497 MW
Battery Energy Storage	550 MW	300 MW
Solar - Ground and Rooftop	0 MW	0 MW
Demand Response	123 MW	182 MW
DSP Non-wire Alternatives	118 MW	118 MW
Renewable Resources	4,833 MW	4,594 MW
Biomass	90 MW	150 MW
Solar	1,393 MW	1,094 MW
Wind	3,350 MW	3,350 MW
Renewable + Storage Hybrid	250 MW	425 MW
Pumped Hydro Storage	0 MW	0 MW
Flexible Capacity	948 MW	948 MW

EMISSIONS. Figure 8-149 compares direct GHG emissions from Sensitivity AA to the Mid Scenario. Both portfolios have very similar direct emissions profiles.

Figure 8-149: Direct Emissions – Mid Scenario and Sensitivity AA



8. CUSTOMER BENEFITS ANALYSIS RESULTS

This section presents the results of the Customer Benefit Analysis. Not all portfolios were included in the Customer Benefit Analysis. To be included in the Customer Benefit Analysis, portfolios must meet the following criteria:

- Maintain consistency across demand and electric price forecasts
  - This criteria removed portfolios such as the Low and High Scenarios which varied demand and electric price inputs
- Must meet CETA requirements
  - This criteria removed portfolios such as Sensitivity T No CETA which does not include the CETA clean energy targets as a constraint.
- Represent current carbon regulation
  - This criteria removed portfolios such as Sensitivity L, SCGHG as a Fixed Cost Plus a Federal CO_2 Tax, which models a federal carbon tax which is yet to be enacted.

These criteria limit the analysis to portfolios that are solving for the same fundamental goals and are built from the same fundamental inputs. In other words, it allows for an “apples to apples” comparison between all the selected portfolios. The Customer Benefit Analysis is described earlier in this chapter.

Customer Benefit Analysis results are presented for two timeframes, 2031 and 2045. These timeframes correspond to the 10-year Clean Energy Action Plan and 24-year IRP planning horizons, respectively. There is value in understanding how customer benefits evolve over the planning horizon of a portfolio, and benefits which only manifest themselves in the latest years of the planning horizon may hold less value, as these years hold the most uncertainty.

All Customer Benefit Analysis results and accompanying calculations are also provided in Appendix H.

Figures 8-150 and 8-151 present the portfolio outputs selected to represent customer benefit indicators (CBIs) for the 10-year and 24-year timeframes, respectively. These outputs have been color coded, from red (least benefit) to green (most benefit).

Figure 8-150: 10-year Customer Benefit Analysis – Portfolio Customer Benefit Indicators – Values

Customer Benefit Indicator Area	Cost	Climate Change		Air Quality			Market Position	Environment				Resource Adequacy	Resiliency
Sensitivity / Customer Benefit Indicator	Portfolio Cost ($ Billions, NPV)	SCGHG ($ Billions, NPV)	CO2 Emissions from Generation includes upstream emissions (Short tons)	SO2	NOx	PM	Market Purchases (MWh)	Utility Scale Renewable Generation (MWh)	Energy Efficiency, Distribution Efficiency and Codes and Standards (MWh)	Distributed Solar: DSP NWA, Rooftop, Ground, Customer net metering (MWh)	Customer Programs: Green Direct, Green Power, Qualifying Facilities (MWh)	Demand Response (Nameplate MW)	Distributed energy storage includes DSP NWA (Nameplate MW)
1 Mid	$6.65	$3.43	1,706,536	15.5	695	51.7	2,993,778	12,937,098	3,270,127	42,882	1,251,124	88	138
A Renewable Overgeneration	$7.09	$3.06	1,041,372	8.6	953	30.4	3,469,768	12,388,236	3,299,397	42,882	1,244,115	148	288
C Distributed Transmission	$6.65	$3.47	1,715,375	15.4	1,450	54.1	3,416,731	12,836,902	3,314,803	73,753	1,250,796	137	38
D Transmission/build constraints - time delayed (option 2)	$6.68	$3.45	1,699,048	15.5	692	51.6	3,308,201	12,894,935	3,314,803	42,882	1,251,001	138	88
F 6-Yr DSR Ramp	$6.50	$3.45	1,686,148	15.3	683	51.1	3,226,151	12,933,532	3,246,695	42,882	1,251,092	133	163
G NEI DSR	$6.37	$3.48	1,718,391	15.7	704	52.2	3,161,303	12,831,265	3,158,255	42,882	1,251,120	145	38
H Social Discount DSR	$6.47	$3.51	1,719,776	15.7	704	52.2	3,147,714	13,145,403	2,839,232	42,882	1,251,122	109	63
I SCGHG Dispatch Cost - LTCE Model	$6.61	$3.44	1,696,923	15.4	684	51.5	3,367,791	12,722,327	3,270,127	42,882	1,251,025	138	38
K AR5 Upstream Emissions	$6.71	$3.48	1,726,261	15.6	702	52.0	3,081,879	12,830,732	3,270,127	42,882	1,251,107	102	88
M Alternative Fuel for Peakers - Biodiesel	$6.67	$3.40	1,517,306	13.1	535	43.9	3,318,592	12,731,439	3,314,803	42,882	1,251,103	137	113
N1 100% Renewable by 2030 Batteries	$10.86	$2.92	-	-	-	-	2,732,665	17,481,571	2,877,410	42,882	1,248,278	35	17,238
N2 100% Renewable by 2030 PSH	$19.92	$2.23	-	-	-	-	427,351	24,758,555	2,376,605	42,386	1,135,935	35	38
O1 100% Renewable by 2045 Batteries	$7.51	$3.46	1,491,992	12.7	497	42.6	3,361,916	13,363,504	2,879,010	42,882	1,251,094	93	6,138
O2 100% Renewable by 2045 PSH	$11.77	$2.86	1,435,497	12.1	457	40.6	1,418,112	16,378,053	3,314,519	42,882	1,250,372	175	38
P1 No Thermal Before 2030, 2Hr LiIon	$13.36	$3.88	1,866,880	20.3	1,358	68.6	5,804,376	12,305,127	3,158,254	42,882	1,243,305	136	3,738
P2 No Thermal Before 2030, PHES	$9.94	$3.19	1,457,354	12.4	479	41.5	2,691,465	14,828,639	2,878,642	42,882	1,250,530	88	663
P3 No Thermal Before 2030, 4Hr LiIon	$15.38	$3.91	1,868,834	20.9	1,490	71.4	6,659,481	11,885,433	3,158,254	42,882	1,240,394	94	3,963
V1 Balanced portfolio	$6.90	$3.42	1,617,639	14.3	862	48.6	2,975,094	11,888,235	3,270,127	428,908	2,089,041	195	238
V2 Balanced portfolio + MT Wind and PSH	$7.13	$3.43	1,596,777	14.1	600	47.1	3,366,392	11,375,806	3,270,127	428,908	2,089,066	195	313
V3 Balanced portfolio + 6 Year DSR	$6.84	$3.39	1,677,083	15.2	675	50.7	3,039,097	11,789,240	3,246,695	428,908	2,089,039	195	213
W Preferred Portfolio (BP with Biodiesel)	$6.91	$3.39	1,531,671	13.2	787	44.9	3,011,301	12,726,398	3,270,127	428,908	1,251,118	195	238
AA MT Wind + PHSE	$6.78	$3.45	1,610,870	14.3	613	47.8	3,297,371	12,633,279	3,270,127	42,882	1,251,134	139	88

Figure 8-151: 24-year Customer Benefit Analysis – Portfolio Customer Benefit Indicators – Values

Customer Benefit Indicator Area	Cost	Climate Change		Air Quality			Market Position	Environment				Resource Adequacy	Resiliency
Sensitivity / Customer Benefit Indicator	Portfolio Cost ($ Billions, NPV)	SCGHG ($ Billions, NPV)	CO2 Emissions from Generation includes upstream emissions (Short tons)	SO2	NOx	PM	Market Purchases (MWh)	Utility Scale Renewable Generation (MWh)	Energy Efficiency, Distribution Efficiency and Codes and Standards (MWh)	Distributed Solar: DSP NWA, Rooftop, Ground, Customer net metering (MWh)	Customer Programs: Green Direct, Green Power, Qualifying Facilities (MWh)	Demand Response (Nameplate MW)	Distributed energy storage includes DSP NWA (Nameplate MW)
1 Mid	$15.53	$5.02	777,018	7.6	395	25.1	2,523,005	21,177,795	5,969,983	355,423	656,726	123	639
A Renewable Overgeneration	$17.11	$4.39	348,728	3.6	2,027	18.3	3,158,061	19,067,643	5,894,513	355,423	656,726	192	1,614
C Distributed Transmission	$16.35	$5.14	1,000,086	9.7	945	33.7	2,946,470	16,652,161	6,112,842	4,351,476	656,726	178	1,139
D Transmission/build constraints - time delayed (option 2)	$15.54	$5.04	719,068	7.1	376	23.5	2,819,871	21,031,995	6,099,281	355,423	656,726	180	739
F 6-Yr DSR Ramp	$15.54	$5.09	773,251	7.5	519	25.5	2,571,955	21,697,533	5,460,256	355,423	656,726	175	714
G NEI DSR	$15.24	$5.12	784,118	7.8	406	26.1	2,542,855	21,703,446	5,455,750	355,423	656,726	188	539
H Social Discount DSR	$15.77	$5.16	729,330	7.2	375	23.8	2,716,481	21,983,087	5,082,505	355,423	656,726	195	764
I SCGHG Dispatch Cost - LTCE Model	$15.41	$5.03	701,528	6.7	759	23.6	2,691,320	21,067,257	5,987,446	355,423	656,726	188	964
K AR5 Upstream Emissions	$15.56	$5.07	790,955	7.6	383	25.4	2,449,467	21,147,646	5,985,551	355,423	656,726	140	714
M Alternative Fuel for Peakers - Biodiesel	$15.44	$4.90	618,707	5.5	244	18.2	2,585,949	20,984,943	6,110,420	355,423	656,726	185	789
N1 100% Renewable by 2030 Batteries	$32.03	$3.71	-	-	-	-	2,825,792	22,610,060	5,046,629	355,423	656,726	59	26,289
N2 100% Renewable by 2030 PSH	$66.64	$2.48	-	-	-	-	1,949,508	25,678,395	4,219,612	355,386	656,726	59	89
O1 100% Renewable by 2045 Batteries	$23.35	$4.81	-	-	-	-	3,023,029	22,350,832	5,046,580	355,413	656,726	128	24,589
O2 100% Renewable by 2045 PSH	$46.95	$3.98	-	-	-	-	2,654,604	21,421,254	6,145,637	355,423	656,726	204	89
P1 No Thermal Before 2030, 2Hr LiIon	$30.84	$6.29	1,279,104	15.0	1,087	50.9	4,411,218	20,568,897	5,427,472	355,423	656,726	178	4,389
P2 No Thermal Before 2030, PHES	$22.85	$4.71	613,093	5.4	393	18.4	2,743,151	22,366,284	5,029,928	355,423	656,726	122	1,114
P3 No Thermal Before 2030, 4Hr LiIon	$39.01	$6.60	1,432,066	16.1	1,150	54.8	5,031,036	20,040,561	5,428,824	355,423	656,726	129	4,514
V1 Balanced portfolio	$16.06	$5.00	759,074	7.4	502	25.1	2,536,212	19,117,749	5,971,509	1,552,256	1,493,182	217	539
V2 Balanced portfolio + MT Wind and PSH	$16.61	$5.06	833,441	8.2	427	27.3	2,516,854	18,879,956	5,969,903	1,550,653	1,493,182	217	464
V3 Balanced portfolio + 6 Year DSR	$16.26	$4.99	797,220	7.7	761	26.8	2,566,699	19,606,509	5,462,125	1,552,389	1,493,182	217	764
W Preferred Portfolio (BP with Biodiesel)	$16.11	$4.90	608,762	5.4	363	18.3	2,589,643	19,960,322	5,971,509	1,552,256	656,726	217	539
AA MT Wind + PHSE	$15.84	$5.09	733,210	7.2	379	23.9	2,657,404	20,940,400	5,969,607	355,423	656,726	182	389

Figures 8-152 and 8-153 rank each of the selected portfolios on each of the CBIs for the 10-year and 24-year timeframes, respectively.

Figure 8-152: 10-year Customer Benefit Analysis – Portfolio Customer Benefit Indicators – Ranks

Customer Benefit Indicator Area	Cost	Climate Change		Air Quality			Market Position	Environment				Resource Adequacy	Resiliency
Sensitivity / Customer Benefit Indicator	Portfolio Cost ($ Billions, NPV)	SCGHG ($ Billions, NPV)	CO2 Emissions from Generation includes upstream emissions (Short tons)	SO2	NOx	PM	Market Purchases (MWh)	Utility Scale Renewable Generation (MWh)	Energy Efficiency, Distribution Efficiency and Codes and Standards (MWh)	Distributed Solar: DSP NWA, Rooftop, Ground, Customer net metering (MWh)	Customer Programs: Green Direct, Green Power, Qualifying Facilities (MWh)	Demand Response (Nameplate MW)	Distributed energy storage includes DSP NWA (Nameplate MW)
1 Mid	6	11	16	17	13	16	6	7	6	6	5	19	12
A Renewable Overgeneration	14	4	3	3	19	3	20	17	5	20	19	6	7
C Distributed Transmission	5	17	17	14	21	20	19	10	1	5	15	11	18
D Transmission/build constraints - time delayed (option 2)	8	14	15	16	12	15	14	9	1	6	14	9	14
F 6-Yr DSR Ramp	3	15	13	13	10	13	12	8	13	6	12	14	11
G NEI DSR	1	19	18	19	16	18	11	11	15	6	7	7	18
H Social Discount DSR	2	20	19	20	15	19	10	6	21	6	6	15	17
I SCGHG Dispatch Cost - LTCE Model	4	12	14	15	11	14	18	15	6	6	13	10	18
K AR5 Upstream Emissions	9	18	20	18	14	17	9	12	6	6	9	16	14
M Alternative Fuel for Peakers - Biodiesel	7	8	7	7	6	7	15	13	1	6	10	11	13
N1 100% Renewable by 2030 Batteries	18	3	1	1	1	1	4	2	20	17	18	21	1
N2 100% Renewable by 2030 PSH	22	1	1	1	1	1	1	1	22	22	22	21	18
O1 100% Renewable by 2045 Batteries	16	16	6	6	5	6	16	5	18	6	11	18	2
O2 100% Renewable by 2045 PSH	19	2	4	4	3	4	2	3	4	17	17	5	18
P1 No Thermal Before 2030, 2Hr LiIon	20	21	21	21	20	21	21	18	16	19	20	13	4
P2 No Thermal Before 2030, PHES	17	5	5	5	4	5	3	4	19	6	16	20	5
P3 No Thermal Before 2030, 4Hr LiIon	21	22	22	22	22	22	22	20	17	20	21	17	3
V1 Balanced portfolio	12	9	11	10	18	11	5	19	6	1	2	1	8
V2 Balanced portfolio + MT Wind and PSH	15	10	9	9	7	9	17	22	6	1	1	1	6
V3 Balanced portfolio + 6 Year DSR	11	6	12	12	9	12	8	21	13	1	3	1	10
W Preferred Portfolio (BP with Biodiesel)	13	7	8	8	17	8	7	14	6	1	8	1	8
AA MT Wind + PHSE	10	13	10	11	8	10	13	16	6	6	4	8	14

Figure 8-153: 24-year Customer Benefit Analysis – Portfolio Customer Benefit Indicators – Ranks

Customer Benefit Indicator Area	Cost	Climate Change		Air Quality			Market Position	Environment				Resource Adequacy	Resiliency
Sensitivity / Customer Benefit Indicator	Portfolio Cost ($ Billions, NPV)	SCGHG ($ Billions, NPV)	CO2 Emissions from Generation includes upstream emissions (Short tons)	SO2	NOx	PM	Market Purchases (MWh)	Utility Scale Renewable Generation (MWh)	Energy Efficiency, Distribution Efficiency and Codes and Standards (MWh)	Distributed Solar: DSP NWA, Rooftop, Ground, Customer net metering (MWh)	Customer Programs: Green Direct, Green Power, Qualifying Facilities (MWh)	Demand Response (Nameplate MW)	Distributed energy storage includes DSP NWA (Nameplate MW)
1 Mid	4	11	15	15	12	14	4	9	9	13	4	19	15
A Renewable Overgeneration	15	4	5	5	22	7	20	20	12	20	4	7	5
C Distributed Transmission	13	19	20	20	19	20	18	22	2	1	4	13	6
D Transmission/build constraints - time delayed (option 2)	6	13	10	10	8	9	16	12	4	9	4	12	12
F 6-Yr DSR Ramp	5	16	14	14	16	16	8	7	14	13	4	15	13
G NEI DSR	1	18	16	18	13	17	6	6	15	13	4	8	16
H Social Discount DSR	8	20	11	11	7	11	14	5	18	9	4	6	10
I SCGHG Dispatch Cost - LTCE Model	2	12	9	9	17	10	13	11	5	9	4	9	8
K AR5 Upstream Emissions	7	15	17	16	10	15	2	10	6	13	4	16	13
M Alternative Fuel for Peakers - Biodiesel	3	8	8	8	5	5	9	13	3	9	4	10	9
N1 100% Renewable by 2030 Batteries	19	2	1	1	1	1	17	2	19	7	4	21	1
N2 100% Renewable by 2030 PSH	22	1	1	1	1	1	1	1	22	22	4	21	21
O1 100% Renewable by 2045 Batteries	17	6	1	1	1	1	19	4	20	21	4	18	2
O2 100% Renewable by 2045 PSH	21	3	1	1	1	1	11	8	1	7	4	5	21
P1 No Thermal Before 2030, 2Hr LiIon	18	21	21	21	20	21	21	15	17	18	4	14	4
P2 No Thermal Before 2030, PHES	16	5	7	7	11	8	15	3	21	6	4	20	7
P3 No Thermal Before 2030, 4Hr LiIon	20	22	22	22	21	22	22	16	16	18	4	17	3
V1 Balanced portfolio	10	10	13	13	15	13	5	19	8	3	1	1	16
V2 Balanced portfolio + MT Wind and PSH	14	14	19	19	14	19	3	21	10	5	1	1	19
V3 Balanced portfolio + 6 Year DSR	12	9	18	17	18	18	7	18	13	2	1	1	10
W Preferred Portfolio (BP with Biodiesel)	11	7	6	6	6	6	10	17	7	3	4	1	16
AA MT Wind + PHSE	9	17	12	12	9	12	12	14	11	13	4	11	20

Figures 8-154 and 8-155 aggregate CBIs into customer benefit indicator areas and determine an overall portfolio rank from the seven CBI areas for the 10-year and 24-year timeframes, respectively.

Figure 8-154: 10-year Customer Benefit Analysis –
Portfolio Customer Benefit Indicator Areas and Overall Portfolio Ranks

Overall Rank	Sensitivity / Customer Benefit Indicator Area	Cost	Climate Change	Air Quality	Market Position	Environment	Resource Adequacy	Resiliency	Overall Avg
12	1 Mid	6	14	15	6	6	19	12	11.1
9	A Renewable Overgeneration	14	4	8	20	15	6	7	10.6
20	C Distributed Transmission	5	17	18	19	8	11	18	13.7
15	D Transmission/build constraints - time delayed (option 2)	8	15	14	14	8	9	14	11.6
11	F 6-Yr DSR Ramp	3	14	12	12	10	14	11	10.8
16	G NEI DSR	1	19	18	11	10	7	18	11.8
18	H Social Discount DSR	2	20	18	10	10	15	17	13.0
17	I SCGHG Dispatch Cost - LTCE Model	4	13	13	18	10	10	18	12.3
19	K AR5 Upstream Emissions	9	19	16	9	8	16	14	13.1
8	M Alternative Fuel for Peakers - Biodiesel	7	8	7	15	8	11	13	9.7
5	N1 100% Renewable by 2030 Batteries	18	2	1	4	14	21	1	8.8
14	N2 100% Renewable by 2030 PSH	22	1	1	1	17	21	18	11.5
13	O1 100% Renewable by 2045 Batteries	16	11	6	16	10	18	2	11.2
4	O2 100% Renewable by 2045 PSH	19	3	4	2	10	5	18	8.7
21	P1 No Thermal Before 2030, 2Hr LiIon	20	21	21	21	18	13	4	16.8
7	P2 No Thermal Before 2030, PHES	17	5	5	3	11	20	5	9.4
22	P3 No Thermal Before 2030, 4Hr LiIon	21	22	22	22	20	17	3	18.1
2	V1 Balanced portfolio	12	10	13	5	7	1	8	8.0
6	V2 Balanced portfolio + MT Wind and PSH	15	10	8	17	8	1	6	9.2
3	V3 Balanced portfolio + 6 Year DSR	11	9	11	8	10	1	10	8.5
1	W Preferred Portfolio (BP with Biodiesel)	13	8	11	7	7	1	8	7.8
10	AA MT Wind + PHSE	10	12	10	13	8	8	14	10.6

Figure 8-155: 24-year Customer Benefit Analysis – Portfolio Customer Benefit Indicator Areas and Overall Portfolio Ranks

Overall Rank	Sensitivity / Customer Benefit Indicator Area	Cost	Climate Change	Air Quality	Market Position	Environment	Resource Adequacy	Resiliency	Overall Avg
14	1 Mid	4	13	14	4	9	19	15	11.1
13	A Renewable Overgeneration	15	5	11	20	14	7	5	11.0
20	C Distributed Transmission	13	20	20	18	7	13	6	13.8
11	D Transmission/build constraints - time delayed (option 2)	6	12	9	16	7	12	12	10.5
17	F 6-Yr DSR Ramp	5	15	15	8	10	15	13	11.5
10	G NEI DSR	1	17	16	6	10	8	16	10.5
8	H Social Discount DSR	8	16	10	14	9	6	10	10.3
3	I SCGHG Dispatch Cost - LTCE Model	2	11	12	13	7	9	8	8.8
12	K AR5 Upstream Emissions	7	16	14	2	8	16	13	10.8
1	M Alternative Fuel for Peakers - Biodiesel	3	8	6	9	7	10	9	7.5
6	N1 100% Renewable by 2030 Batteries	19	2	1	17	8	21	1	9.8
15	N2 100% Renewable by 2030 PSH	22	1	1	1	12	21	21	11.3
9	O1 100% Renewable by 2045 Batteries	17	4	1	19	12	18	2	10.4
5	O2 100% Renewable by 2045 PSH	21	2	1	11	5	5	21	9.4
21	P1 No Thermal Before 2030, 2Hr LiIon	18	21	21	21	14	14	4	16.0
18	P2 No Thermal Before 2030, PHES	16	6	9	15	9	20	7	11.6
22	P3 No Thermal Before 2030, 4Hr LiIon	20	22	22	22	14	17	3	17.0
4	V1 Balanced portfolio	10	12	14	5	8	1	16	9.3
16	V2 Balanced portfolio + MT Wind and PSH	14	17	17	3	9	1	19	11.4
7	V3 Balanced portfolio + 6 Year DSR	12	14	18	7	9	1	10	10.0
2	W Preferred Portfolio (BP with Biodiesel)	11	7	6	10	8	1	16	8.3
19	AA MT Wind + PHSE	9	15	11	12	11	11	20	12.6

Figure 8-156 summarizes the overall portfolio rank for both the 10-year and 24-year timeframes. Generally, portfolios that ranked well in the 10-year timeframe also ranked well in the 24-year timeframe. However, there are notable exceptions, including Sensitivities I and P2.

Sensitivity I modeled the SCGHG as a dispatch cost in the LTCE model. Sensitivity I has a poorer overall rank in the 10-year timeframe but improves to be among the top-ranked portfolios in the 24-year timeframe. This suggests that Environmental and Resiliency benefits, which this portfolio ultimately scores well in, do not provide meaningful benefits until the end of the modeling horizon, and that other portfolios should be considered to deliver benefits as early as possible.

Sensitivity P2 forced the selection of pumped hydro storage resources before any flexible capacity could be added to the portfolio. Sensitivity P2 is a well-ranked portfolio in the 10-year timeframe but drops to near the bottom of the rankings in the 24-year time horizon. This suggests that too much focus on early adoption of storage resources is a costly endeavor that sets up the portfolio to be reliant on large quantities of market purchases to charge the storage resources.

Figure 8-156: Overall Portfolio Rank by 10-year and 24-year Timeframe

	10-year	24-year
1 Mid	12	14
A Renewable Overgeneration	9	13
C Distributed Transmission	20	20
D Transmission/build constraints - time delayed (option 2)	15	11
F 6-Yr DSR Ramp	11	17
G NEI DSR	16	10
H Social Discount DSR	18	8
I SCGHG Dispatch Cost - LTCE Model	17	3
K AR5 Upstream Emissions	19	12
M Alternative Fuel for Peakers - Biodiesel	8	1
N1 100% Renewable by 2030 Batteries	5	6
N2 100% Renewable by 2030 PSH	14	15
O1 100% Renewable by 2045 Batteries	13	9
O2 100% Renewable by 2045 PSH	4	5
P1 No Thermal Before 2030, 2Hr LiIon	21	21
P2 No Thermal Before 2030, PHES	7	18
P3 No Thermal Before 2030, 4Hr LiIon	22	22
V1 Balanced portfolio	2	4
V2 Balanced portfolio + MT Wind and PSH	6	16
V3 Balanced portfolio + 6 Year DSR	3	7
W Preferred Portfolio (BP with Biodiesel)	1	2
AA MT Wind + PHSE	10	19

As shown in Figure 8-156, the Customer Benefit Analysis suggests Sensitivity M as the portfolio that provides the greatest benefit to PSE customers in the 24-year IRP timeframe. PSE recognizes that this portfolio has many desirable attributes including low cost, low climate change impacts and low impacts on air quality. However, Sensitivity M does not include very many distributed energy resources, which play an important role in balancing utility-scale renewable investments and transmission constraints while also meeting local distribution system needs and improving customer benefits. Therefore, PSE has selected Sensitivity W Balanced Portfolio with Biodiesel as the preferred portfolio. Sensitivity W provides many of the same benefits as Sensitivity M, but also includes greater investment in distributed energy resources. Furthermore, Sensitivity W is shown to provide the greatest benefit in the 10-year CEAP timeframe. This shows that early investment in these distributed resources provides benefits over the entire span of the modeling horizon, whereas Sensitivity M benefits are realized most strongly in the later years.

9. SUMMARY OF STOCHASTIC PORTFOLIO ANALYSIS

With stochastic risk analysis, PSE tests the robustness of different portfolios. In other words, PSE seeks to know how well the portfolio might perform under a range of different conditions. To achieve this purpose, PSE runs select portfolios through 310 simulations, or draws,[7] that vary power prices, gas prices, hydro generation, wind generation, solar generation, load forecasts (energy and peak), and plant forced outages. From this analysis, PSE can quantify the risk of each portfolio. Four different portfolios were tested in the stochastic portfolio analysis. Figure 8-xx describes the four different portfolios.

Figure 8-157: Portfolios Tested for Stochastic Analysis

Portfolios Tested for Stochastic Analysis		
1	Mid Scenario	This is the optimal portfolio for the Base Scenario. It includes frame peakers for capacity and solar for the RPS.
W	Balanced Portfolio with Alternative Fuel for Peakers	This is the optimal portfolio for the Balanced Portfolio with Alternative Fuel for Peakers sensitivity. It includes distributed energy resources ramped in over time and more customer programs plus carbon-free combustion turbines using biodiesel as the fuel.
WX	Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak	This is the optimal portfolio for the Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak sensitivity. It includes distributed energy resources ramped in over time and more customer programs plus carbon-free combustion turbines using biodiesel as the fuel, along with a reduced access to the Mid-C market for both sales and purchases.
Z	No DSR	This portfolio is from the no DSR sensitivity.

7 / Each of the 310 simulations is for the twenty four-year IRP forecasting period, 2022 through 2045.

Risk Measures

The results of the risk simulation allow PSE to calculate portfolio risk. Risk is calculated as the average value of the worst 10 percent of outcomes (called TailVar90). This risk measure is the same as the risk measure used by the Northwest Power and Conservation Council (NPCC) in its power plans.

PSE also looked at annual volatility by calculating the standard deviation of the year-to-year percent changes in revenue requirements. A summary measure of volatility is the average of the standard deviations across the simulations, but this can be described by its own distribution as well. It is important to recognize that this does not reflect actual expected rate volatility. The revenue requirement used for portfolio analysis does not include rate base and fixed-cost recovery for existing assets. The annual volatility data can be found in Appendix H, Electric Analysis Inputs and Results.

Stochastic Results

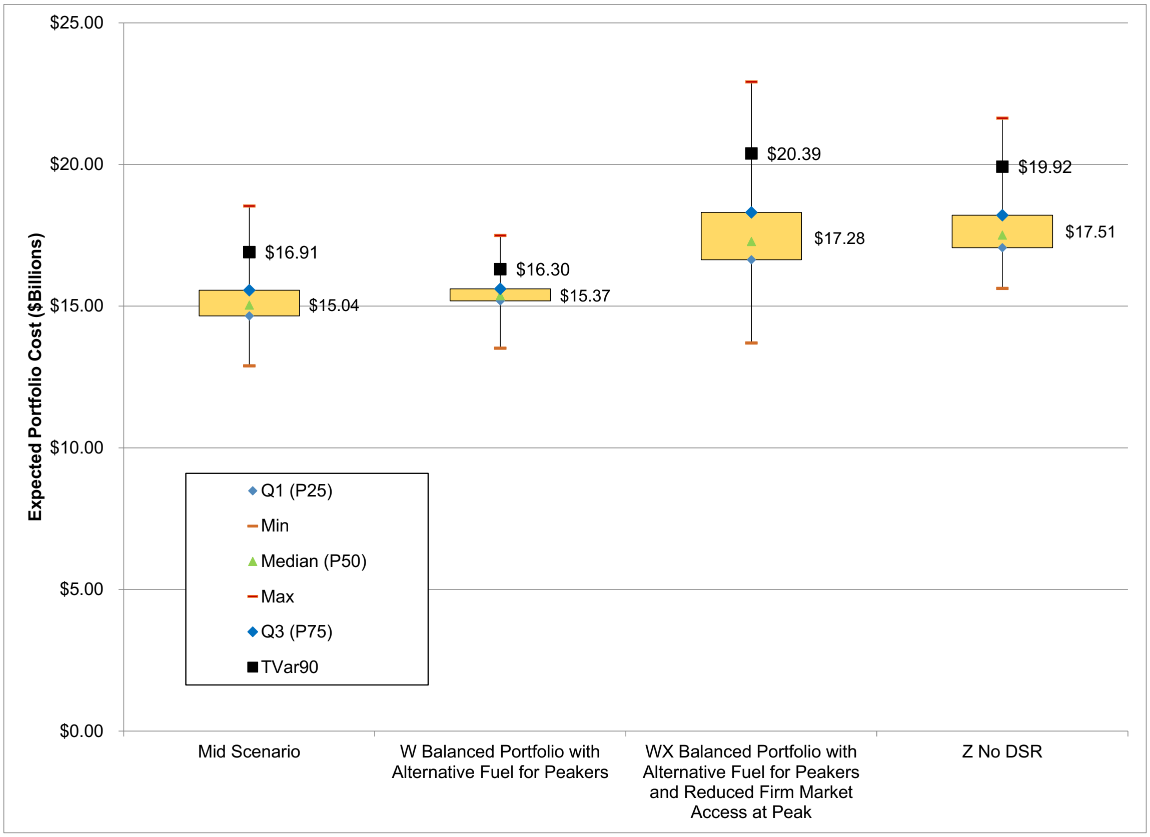
PSE's approach to the electric stochastic analysis holds portfolio resource builds constant across the 310 simulations. In reality, these resource forecasts serve as a guide, and resource acquisitions will be made based on the latest information available through the Request for Proposal and other acquisition processes. Nevertheless, the result of the risk simulation provides an indication of portfolio costs risk range under varying input assumptions. Figure 8-158 shows a comparison of the 24-year levelized costs for the deterministic run, the mean portfolio cost across 310 simulations, and the TailVar90 of portfolio cost for all 4 portfolios examined for the stochastic analysis. The mean portfolio cost of the 310 simulations is lower than the deterministic model run for 3 of the portfolios except for the No DSR portfolio.

Figure 8-158: Portfolio Costs across 310 Simulations

		24-year Levelized Costs (Billion $)					
Revenue Requirement	Portfolio	Deterministic	Difference from Mid	Mean	Difference from Mid	TVar90	Difference from Mid
1	Mid Scenario	$15.53	--	$15.18	--	$16.91	--
W	Balanced Portfolio with Alternative Fuel for Peakers	$16.10	$0.57	$15.42	$0.24	$16.30	($0.60)
WX	Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak	$18.78	$3.25	$17.53	$2.34	$20.39	$3.49
Z	No DSR	$17.54	$2.01	$17.74	$2.56	$19.92	$3.01

Figure 8-159 compares the expected portfolio costs for each portfolio. The vertical axis represents the costs and the horizontal axis represents the portfolio. The green triangle on each of the boxes represents the median for that particular portfolio. The interquartile range box represents the middle 50 percent of the data. The whiskers extending from either side of the box represent the minimum and maximum data values for the portfolio. The black square represents the TailVar90 which is the average value for the highest 10 percent of outcomes.

Figure 8-159: Range of Portfolio Costs across 310 Simulations



Key results of the analysis include:

- The interquartile range for Sensitivity W is comparatively narrow and has the lowest TailVar90 at $16.3 billion, suggesting that the overall expected portfolio costs are the least variable compared to the other portfolios.
- Sensitivity WX has the widest interquartile range and the highest TailVar90 at $20.4 billion, suggesting the highest risk in portfolio costs variability. With the reduction of market access, the risk shifts from Mid-C market price volatility to natural gas price volatility. Thermal resources replace the energy that is no longer available from the market. Portfolio fuel costs may increase or decrease depending on the simulation.
- In Sensitivity Z, the mean of the 310 simulations is $17.7 billion, which is $0.2 billion higher than the deterministic portfolio costs. In comparison to the Mid Scenario, the mean and the deterministic portfolio costs are higher for Sensitivity Z. This suggests that demand-side resources reduce both cost and market risk in portfolios.

Figures 8-160 to 8-161 below show the frequency distribution of portfolio cost for selected portfolios. Portfolio cost results for each simulation are sorted into “bins,” with each bin containing a narrow range of expected portfolio costs.

Figure 8-160 compares the Mid Scenario to Sensitivity W. The shorter right-hand tail and lower TailVar90 value of Sensitivity W indicate there is less risk associated with Sensitivity W than the Mid Scenario, despite the higher average portfolio cost.

Figure 8-160: Frequency Histogram of Expected Portfolio Cost (Billions $) – Mid Scenario vs. Sensitivity W

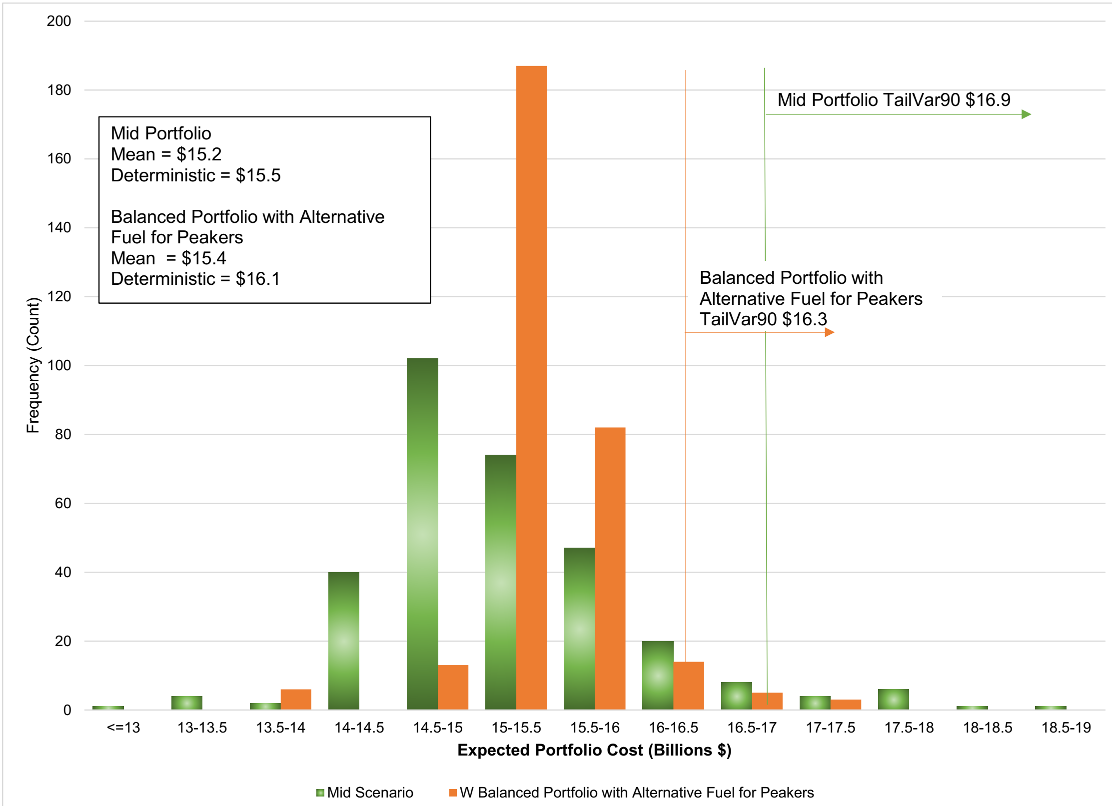


Figure 8-161 compares the Mid Scenario with Sensitivity Z. The longer tail, higher TailVar90 and higher average portfolio cost of Sensitivity Z indicate the demand-side resources are an effective way to reduce both portfolio cost and risk.

Figure 8-161: Frequency Histogram of Expected Portfolio Cost (Billions $) – Mid Scenario vs. Sensitivity Z

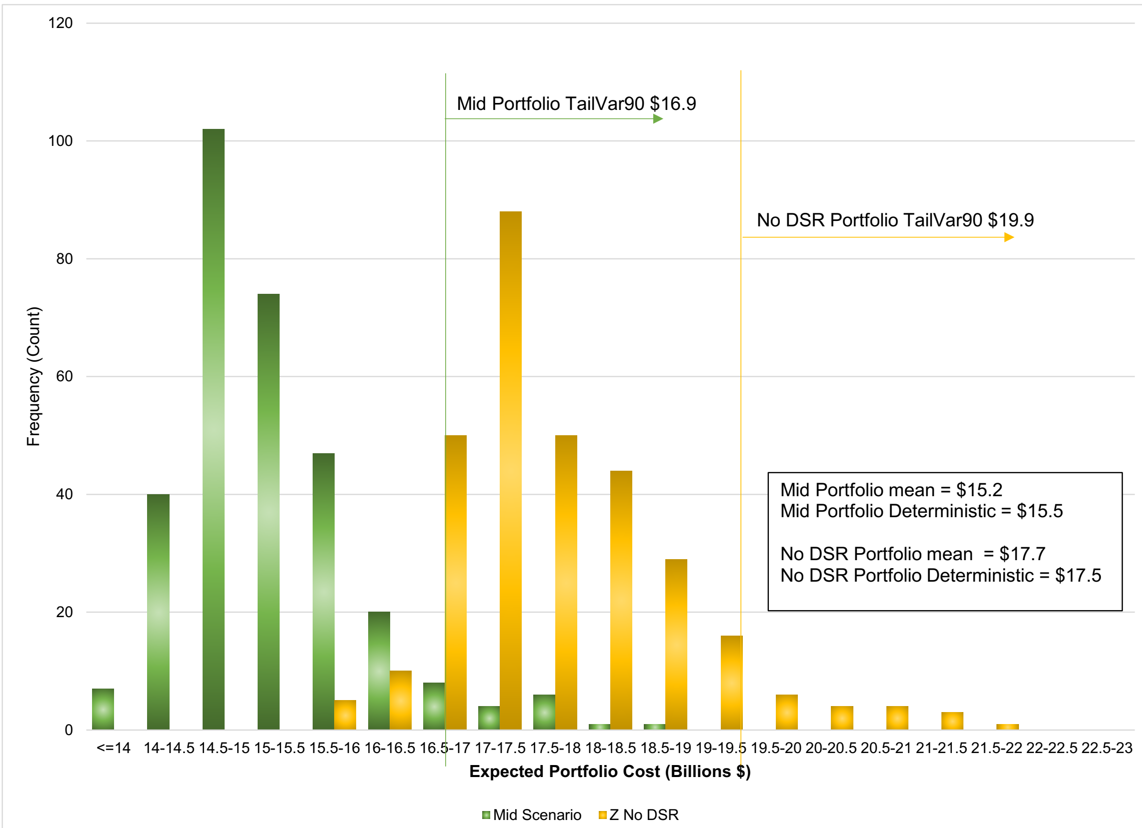
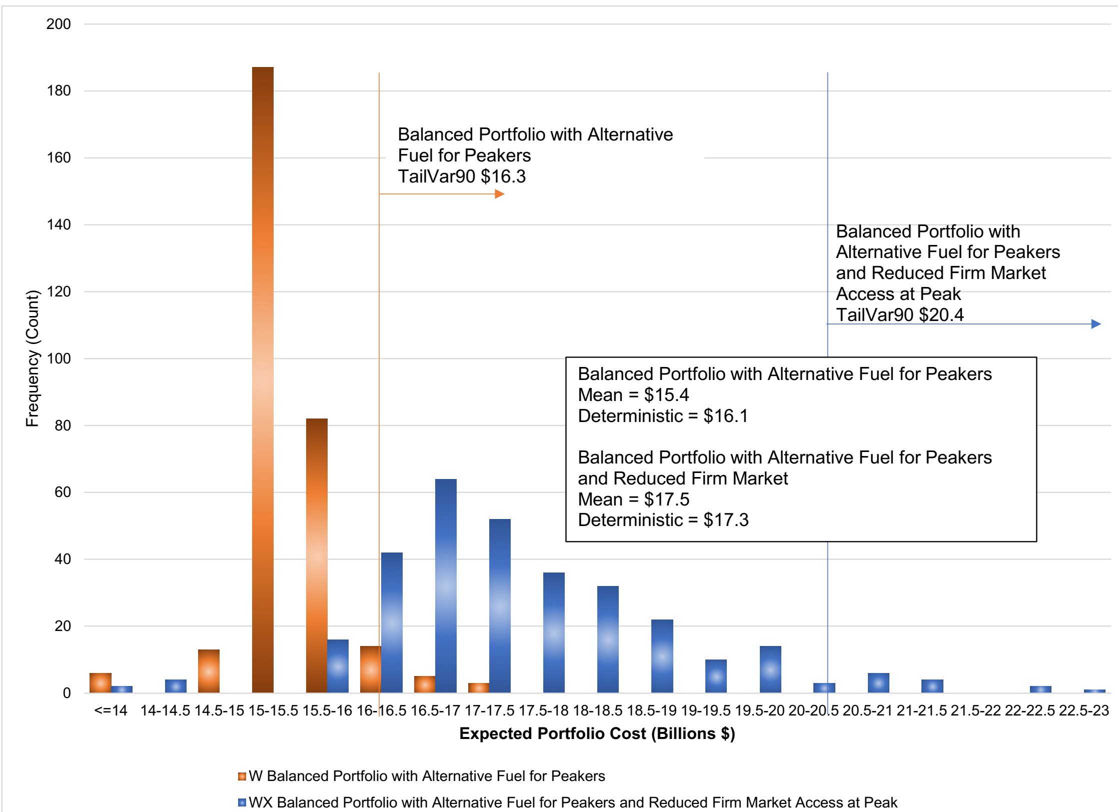


Figure 8-162 compares Sensitivity W with Sensitivity WX. The only difference between Sensitivity W and Sensitivity WX is the reduced access to market purchases during peak demand in Sensitivity WX. The longer tail, higher TailVar90 and higher average portfolio cost of Sensitivity WX show that it is both more costly and riskier than the Sensitivity W. As stated above, this added risk is associated with volatility of natural gas prices to fuel thermal resources used to replace market purchases during peak demand. Further study is needed and PSE will continue to evaluate the impacts of different types of resources.

Figure 8-162: Frequency Histogram of Expected Portfolio Cost (Billions $) – Preferred Portfolio vs. Preferred Portfolio with Market Reduction



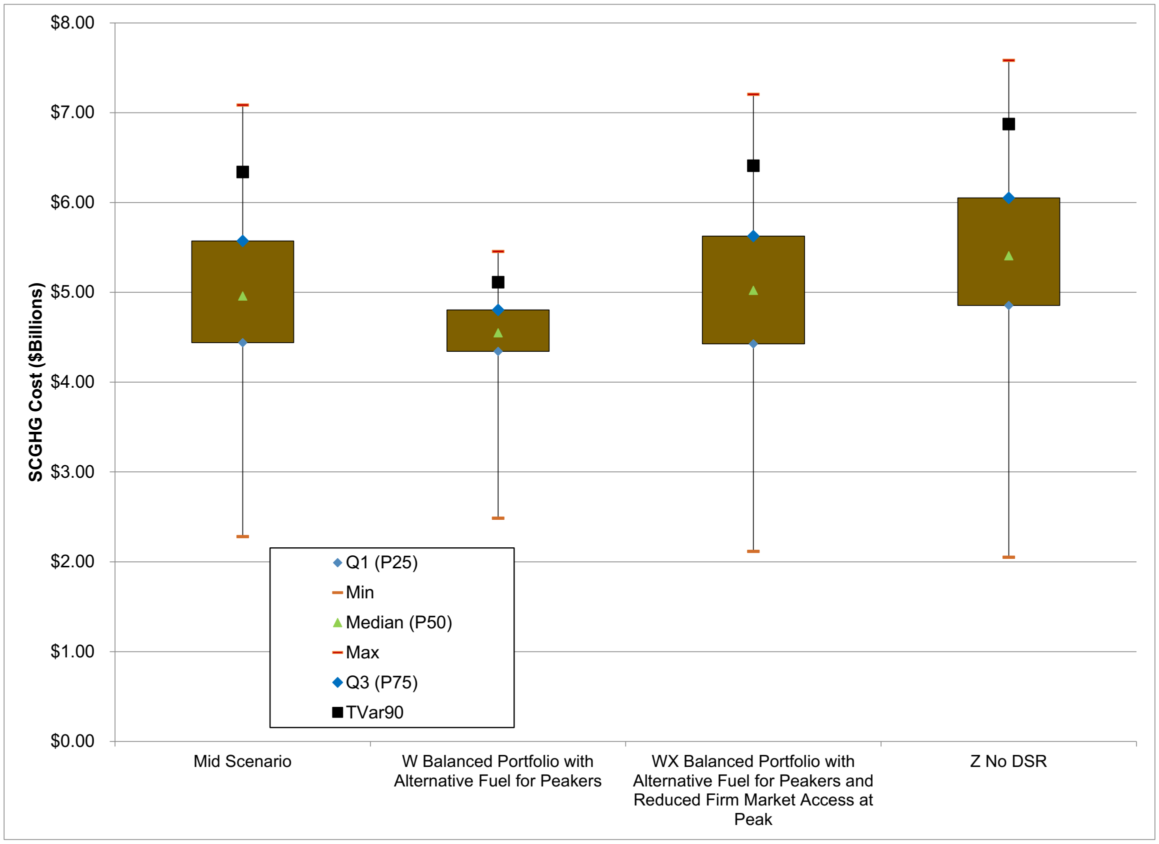
In addition to the expected portfolio costs, PSE also evaluated the expected SCGHG. Figure 8-163 and 8-164 below show a comparison of the 24-year levelized emissions costs for the deterministic run, the mean across 310 simulations, and the TailVar90 of all 4 portfolios.

Results are similar to the portfolio cost results discussed above. Sensitivity W shows the narrowest, and therefore least-risk, range of SCGHG.

Figure 8-163: SCGHG across 310 Simulations

		24-year Levelized Costs (Billion $)					
SCGHG	Portfolio	Emissions	Difference from Mid	Mean	Difference from Mid	TVar90	Difference from Mid
1	Mid Scenario	$5.09	--	$4.98	--	$4.98	--
W	Balanced Portfolio with Alternative Fuel for Peakers	$4.96	($0.13)	$4.54	($0.44)	$4.54	($0.44)
WX	Balanced Portfolio with Alternative Fuel for Peakers and Reduced Firm Market Access at Peak	$4.74	($0.35)	$5.02	$0.47	$6.41	$1.43
Z	No DSR	$5.56	$0.47	$5.42	$0.41	$6.87	$1.90

Figure 8-164: Range of SCGHG across 310 Simulations



10. ELECTRIC DELIVERY SYSTEM ANALYSIS

Overview

PSE's electric delivery system is responsible for delivering electricity safely, reliably and on demand. PSE is also responsible for meeting all regulatory requirements that govern the system. To accomplish this, we must do the following.[8]

- Operate and maintain the system safely and efficiently on an annual, daily and real-time basis.
- Ensure the system meets both peak demands and day-to-day demands at a local level and system level.
- Meet state and federal regulations and complete compliance-driven system work.
- Address reliability performance and system integrity concerns.
- Meet the interconnection needs of independent power generators and customers that choose to connect and provide energy to our system.
- Monitor and improve processes to meet future needs including customer and system trends and customer desires so infrastructure will be in place when the need arrives.

Some of these are regional responsibilities. For instance, all PSE facilities that are part of the Bulk Electric System and the interconnected western system must be planned and designed in accordance with the latest applicable and approved version of the North American Electric Reliability Corporation (NERC) Transmission Planning (TPL) Reliability Standards. These standards set forth performance expectations that affect how the transmission system – 100 kilovolts (kV) and above – is planned, operated and maintained. PSE also must follow Western Electricity Coordinating Council (WECC) reliability criteria; these can be more stringent or more specific than NERC standards at times.

8 / These obligations are defined by various codes and best practices such as Washington Administrative Code (WAC) 296 - 45 Electric Power Generation, Transmission, and Distribution; WAC 480-100 Electric Companies; WAC 480-108 Electric companies - Interconnection with Electric Generators; WAC 480-100-358:398 Part VI Safety and Standard Rules; National Electric Safety Code (NESC) Parts 1, 2 and 3; NERC Reliability Standards; WECC Regional Reliability Standards; Code of Federal Regulations (CFR) Title 18; CFR Title 49; FERC Order 1000; Occupational Safety and Health Administration; Washington Industrial Safety and Health Administration; National Electric Code; and Institute of Electrical and Electronics Engineers.

Ever more important today is to ensure that the system is flexible enough to adapt to coming changes. Smart and flexible equipment, customer distributed resources and demand response programs are some of the effective solutions the industry is moving toward, and PSE's electric delivery system needs to be prepared to integrate them for the benefit of our customers. Figure 8-XX depicts PSE's grid modernization framework for electric system improvements.

Figure 8-165: Grid Modernization Framework

The goal of PSE's planning process is to help us fulfill these responsibilities in the most cost-effective manner possible. Through it, we evaluate system performance and bring issues to the surface; we identify and evaluate possible solutions; and we explore the costs and consequences of potential alternatives. This information helps us make the most effective and cost-effective decisions going forward.

Delivery system planners prepare both 10-year plans required for the IRP and annual implementation plans. This section describes the current process for developing both. Planning begins with assessing needs followed by evaluating solution alternatives and recommendations. Need assessments begin with county- and local-level load forecasts and an evaluation of the system's current performance and future needs based on data analysis and modeling tools. Planning considerations include internal inputs such as reliability indices, company goals and commitments, and the root causes of historic outages. External inputs include service quality indices, regulations, municipalities' infrastructure plans, customer complaints and ongoing service issues. Solution assessment includes identifying alternatives to meet the need and comparing these alternatives against one another. A recommended alternative(s) is identified that will proceed to project planning if approved. PSE identifies the portfolio of projects that will proceed based on optimizing benefit and cost for a given funding level that is supported by approval within the overall company budget. The process is the same for both long-term and short-term planning. Typically, utilities align investment in non-revenue producing infrastructure to customer revenue associated with growth, which further defines a given funding level or constraint for optimization of the portfolio of infrastructure work.

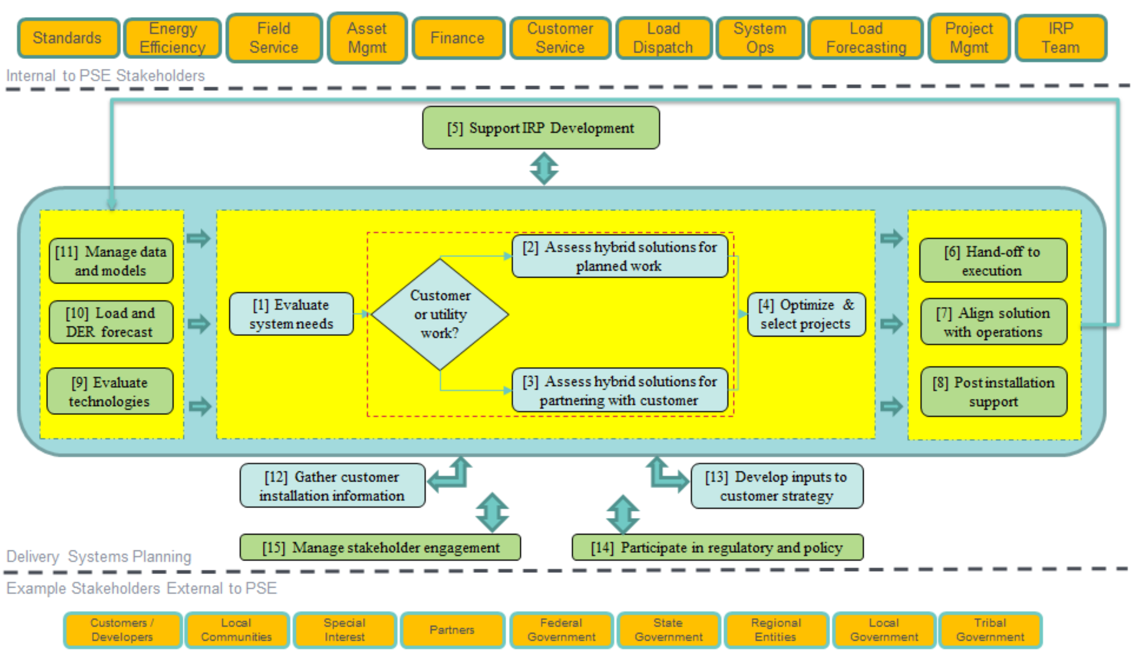
Key Findings

PSE's 10-year plan is included as Appendix M of this IRP.

Analysis Process and Needs Assessment

PSE follows a structured approach to analyze delivery system needs and potential solutions. The Delivery System Planning (DSP) operating model incorporates inputs from both external stakeholders and groups within PSE; gathers input data for planning studies (represented by the yellow box on the left in Figure 8-166 below); analyzes system needs; develops solutions (which may consider customer-side assets and be a hybrid of traditional and non-traditional alternatives); selects preferred project alternatives (depicted in the central yellow box); and communicates the selected projects for execution of detailed design, construction/implementation, integration with operations and post-installation support (described in the yellow box on the right).

Figure 8-166: PSE Delivery System Planning Operating Model



Electric delivery system needs are driven by a number of different key factors as described below. All of these factors to be considered to identify the right needs across the system.

DELIVERY SYSTEM DEMAND AND PEAK DEMAND GROWTH. Demands on the overall system increase as the population of PSE's service area grows and economic activity increases, despite the increasing role of energy-conserving demand-side resources. Within the service area, however, demand is uneven, with much higher demand growth in the central business districts surrounding the urban centers. Peak loads occur when the weather is most extreme. PSE carefully evaluates system performance during peak load periods each year, updates its system models and compares these models against future demand and growth forecasts. Taking these steps prepares PSE to determine where additional infrastructure investment is required to meet peak firm loads. System investments are sometimes required to serve specific "point loads" that may appear at specific locations in PSE service area. For example, PSE has requests from several data centers, industrial facilities, etc., that plan to connect in the next few years with projected loads between 5 and 15 MW.

Energy efficiency consists of measures and programs that replace existing building energy using components and systems such as lighting, heating, water heating, insulation, appliances, etc., with more energy efficient ones. These replacements can reduce both peak demand and overall energy consumption for residential and commercial customers. Customers who agree to reduce their energy use during periods of system stress, system imbalance or in response to market prices are participating in demand response (DR). Interruptible rates are a subset of demand response. When used to relieve loading at critical times, demand response can offset anticipated loads and reduce the need for traditional delivery infrastructure. Interruptible rates are used in PSE's service area, and there is a high dependence on curtailment of these customers in order to meet demand.

RESOURCE INTEGRATION. FERC and state regulations require PSE to integrate generation resources into our electric system according to processes outlined in federal and state codes. A new generation facility, whether it is owned and operated by PSE or by others, can require significant electric infrastructure investment to integrate and maintain appropriate electrical power flows within our system and across the region. Also, if natural gas is the generation feedstock, large plants will require careful planning to ensure the availability of fuel.

AGING INFRASTRUCTURE. Aging infrastructure refresh is an important element of modernizing the delivery system. Equipment that has reached end of life and is incapable of supporting the digitization of the grid includes substation assets, circuit breakers and remote terminal units. Assets whose age and condition create reliability and resilience issues include direct buried high molecular weight underground distribution cable, poles and cross arms, and substation transformers.

RELIABILITY. Improving areas across the delivery system to minimize both the total number and duration of outages is important to customers today. This will become increasingly important in a modern grid as we anticipate customers will be even more reliant on electrical power as transformation such as transportation conversions continue to occur.

OPERATIONAL FLEXIBILITY. The ability to switch circuits to transfer load is important in responding to unplanned and planned outages, and the ability to perform necessary maintenance on equipment.

DISTRIBUTED ENERGY RESOURCES. At sufficient scale, distributed energy resources such as roof-top solar can reduce demand or provide operational flexibility. If uncontrolled, they can increase demand such as charging batteries during peak times or triggering voltage or power quality concerns if there are too many or they don't operate appropriately.

SAFETY AND REGULATORY REQUIREMENTS. These requirements drive action for mitigation in short order and/or are dictated through contractual agreements and as a result are identified and resolved outside of this long term planning process.

The energy delivery system is reviewed each year to improve the reliability of service to existing customers. Past outage experience, equipment inspection, maintenance records, customer feedback, PSE employee knowledge and analytic tools identify areas where improvements are likely required and where such improvements bring the most customer benefit. PSE collects system performance information from field charts, remote telemetry units, SCADA, employees and customers. Some information is analyzed over multiple years to normalize the effect of variables like weather that can change significantly from year to year. PSE gives additional consideration to system enhancements that will improve resiliency, such as the ability to deliver electricity via a second line, possibly from another substation, to make the grid more self-healing. Programs are also in place to address aging infrastructure by replacing poles and other components that are nearing the end of their useful life.

External inputs such as new regulations, municipal and utility improvement plans, and customer feedback, as well as company objectives such as PSE's asset management strategy and Grid Modernization strategy, are also included in the system evaluation. PSE obtains the annual updates to local jurisdiction six-year Transportation Improvement Plans to gain long-term planning perspective on upcoming public improvement projects. As the transportation projects develop through design, engineering and construction, PSE works with the local jurisdictions to identify and minimize potential utility conflicts and to identify opportunities to address system deficiencies and needs. PSE also collects public input regarding the need for infrastructure improvement through the PSE and WUTC complaint process, as well as through open forums that result from less than satisfactory service. These inputs help us to understand commitments and opportunities to mitigate impact or improve service at least cost.

PSE actively reviews and evaluates new technologies that can support delivery system needs. These technologies are identified, cataloged, and evaluated by an internal, cross-functional group of experts for business alignment, potential value, and feasibility. Cybersecurity continues to be a top consideration when evaluating products that are new in the market. PSE also seeks to leverage existing investments wherever possible when selecting and implementing new technologies. Following a successful evaluation, new technologies can be tested in a lab or piloted *in situ*. Results are documented and reviewed by all impacted teams. As new technologies complete the pilot process, they can be deployed at scale to meet the delivery system needs described above.

PSE relies on several tools to help identify needs or concerns and to weigh the benefits of alternative actions to address them. Figure 8-167 provides a brief summary of these tools, the planning considerations (inputs) that go into each and the results (outputs) that they produce. Each tool is used to provide data independently for use in iDOT,[9] which then creates the full understanding of all the benefits and risks.

[9] / *Investment Decision Optimization Tool which is a software tool called Folio by PwC.*

Figure 8-167: Delivery System Planning Tools

TOOL	USE	INPUTS	OUTPUTS
Synergi®	Gas and Electric network modeling	Gas and electric distribution infrastructure from GIS and load characteristics from CIS; load approvals; load forecast	Predicted system performance
Power World Simulator – Power Flow	Electric network modeling	Electric transmission infrastructure from WECC base case and load/generation characteristics from CIS; load approvals; load forecast	Predicted system performance
Electric Predictive Spreadsheet	Electric outage predictive analysis	Electric outage history from SAP	Predicted outage savings
Estimated Unserved Energy (EUE) Spreadsheet	Electric financial analysis	Estimated project costs; hourly load data from EMS; load growth scenarios from load forecast	Net Present Value; income statement; load growth vs. capacity comparisons; EUE
Asset Management Assessment	Electric maintenance analysis	Electric infrastructure operating or maintenance concerns from various databases	Program funding options to mitigate higher risk facilities
All data collected by the tools above are input into iDOT			
Investment Decision Optimization Tool (iDOT)	Gas and electric project data storage & portfolio optimization	Project scope, budget, justification, alternatives and benefit/risk data collected from above tools and within iDOT; resources/financial constraints	Optimized project portfolio; benefit cost ratio for each project; project scoping document

PSE's electric distribution model is a large integrated model of the entire delivery system using a software application (Synergi® Electric) that is updated to reflect new customer loads and system and operational changes. This modeling tool predicts capacity constraints and system performance on a variety of temperatures and under a variety of load growth scenarios. Results are compared to actual system performance data to assess the model's accuracy.

To simulate the performance of the electric transmission system, PSE primarily uses Power World Simulator. This simulation program uses a transmission system model that encompasses infrastructure across 11 western states, two provinces in western Canada and parts of northern Mexico. The power flow and stability data for these models are collected, coordinated and distributed through regional organizations that have included ColumbiaGrid, NorthernGrid, and WECC (one of eight regional reliability organizations under NERC). These power system study programs support PSE's planning process and facilitate demonstration of compliance with WECC and NERC reliability performance standards. While PSE utilizes a regional model for system evaluation and coordination, the focus is on local concerns and projects. Appendix J, Regional Transmission Resources, describes regional transmission planning and the role of the Regional Planning Organization (RPO). PSE has been a member of the ColumbiaGrid since 2006, succeeded by NorthernGrid in 2020. The RPO has had substantial responsibilities for transmission planning, reliability and other development services in order to improve the operational efficiency, reliability and planned expansion of the Pacific Northwest transmission grid. PSE is one of eight utilities that coordinate regional planning through the RPO, which has provided transparency and encourages broad participation and interaction with stakeholders, including customers, transmission providers, states and tribes.

Modeling is a three-step process. First, a map of the infrastructure and its operational characteristics is built from the GIS and asset management system, or in the case of transmission, provided by WECC. For electric infrastructure, this includes conductor cross-sectional area, impedance, length, construction type, connecting equipment, transformer equipment, voltage settings, and any DER that is controllable on the system. Next, PSE identifies customer loads, either specifically (for large customers) or as block loads for address ranges. Existing customer loads come from PSE's customer information system (CIS) or actual circuit readings. DERs that are not controllable require PSE to consider the load without them operating due to the need for the system to serve as backup. Finally, PSE takes into consideration seasonal variations, types of customers (interruptible vs. firm), time of daily peak usage, the status of components (valves or switches closed or open) and forecast future loads to model scenarios of infrastructure or operational adjustments. The goal is to find the optimal solution to a given issue. Where issues surface, the model can be used to evaluate alternatives and their effectiveness. PSE augments potential alternatives with cost estimates and feasibility analysis to identify the lowest reasonable cost solution for both current and future loads. DERs that are on the system that may not be controllable may serve as solutions if and when control and aggregation technologies are added.

The performance criteria that lie at the heart of PSE's infrastructure improvement planning process are summarized below in Figure 8-168. Evaluation begins with a review of existing operational challenges, load forecasts, demand-side management (DSM), commitments, obligations and opportunities. Planning triggers are specific performance criteria that trigger a need for a delivery system study. There are different triggers or thresholds for transmission and distribution, as well as for capacity and reliability. A "need" is identified when performance criteria is not met.

Figure 8-168: Performance Criteria for Electric Delivery System

Electric delivery system performance criteria are defined by:
Safety and compliance with all regulations and contractual requirements (100 percent compliance)
The temperature at which the system is expected to perform (normal winter peak, extreme winter peak) with expected reliability conservation
The nature of service and level of reliability that each type of customer has contracted for (firm or interruptible)
The minimum voltage that must be maintained in the system (no more than 5 percent below standard voltage)
The maximum voltage acceptable in the system (no more than 5 percent above standard voltage)
Thermal limits of equipment used to deliver power to load centers and transmission customers (per PSE Transmission and Distribution Planning Guidelines)
The interconnectivity with other utility systems and resulting requirements, including compliance with NERC planning standards (100 percent compliance) and all required planning scenarios and sensitivities.
The historical or future reliability performance that may be unacceptable or beyond benchmarks which may be caused by aging infrastructure, vegetation, third party damage, equipment condition, or animal interference.
The ability to remove equipment from service for maintenance and provide flexibility for outage restoration.

PSE expects the planning assumptions, described in Chapter 5, guidelines, and performance criteria to change over time due to the current policies pursing electrification, distributed energy resources dependency at the local circuit level, and deferral of traditional infrastructure network. PSE expects that customers will have higher expectations of reliability and economic impact of outages to be greater, requiring a delivery system with better reliability and resiliency than today. PSE expects delivery system planning margins to increase to account for operating concerns relating to distributed energy resource including behavior based conservation and demand response programs. PSE's delivery system planning assumptions relative to conservation and demand response have historically incorporated outputs generically, but these assumptions while appropriate for resource planning may not be appropriate for circuit level decisions and reliability. Higher cost conservation is likely customer type specific and as a result greater study and specific application of targeted conservation programs is necessary in order for conservation to be reliable. PSE may also need to develop assumptions regarding demand response programs as customer adoption may change as home occupancy changes over time.

PSE meets with jurisdictions in various forums such as quarterly roundtable discussions that include other utilities and agencies and in formal public presentations required through agreement or local regulation in order to gather input about concerns and coordinate solutions. For example, PSE and the City of Bellevue meet annually to exchange plans related to community development and utility system improvements, which provides an opportunity for interested stakeholders to ask questions and raise issues and concerns. Similarly, PSE engages in a multi-year coordination with Bainbridge Island stakeholders to discuss reliability and gather input regarding improvements.

Solutions Assessment and Criteria

The alternatives available to address delivery system needs including capacity, reliability, aging infrastructure, and operational flexibility are listed below. Each has its own costs, benefits, challenges and risks.

Figure 8-169: Alternatives for Addressing Electric Delivery System

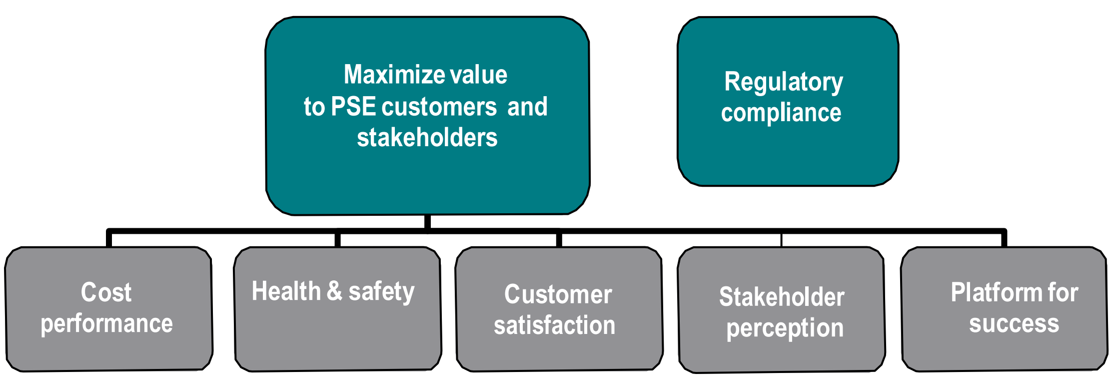
ELECTRIC SYSTEM ALTERNATIVES	
Add energy source	Substation; Distributed energy resource
Strengthen feed to local	New conductor; Replace conductor
Improve existing facility	Substation modification; Expanded right-of-way; Uprate system; Modify automatic switching scheme
Load reduction	Rebalance load; Fuel switching; Battery storage; Natural gas conversion; Conservation/Demand response; Load control equipment; Possible new tariffs

Load reduction alternatives are a focus of improvement in the planning process. Alternatives may depend on customer participation for siting, control or actionable behavior, and PSE continues to gain understanding and confidence in these as deferral and permanent solution alternatives are considered. Energy storage can be incorporated in both large-scale and small-scale projects (such as paired with rooftop solar DERs). Conservation above cost-effective measures and demand response can be incorporated as alternatives as our understanding of their effectiveness and the role of customer participation increases. Additionally, reducing the voltage at an end-user's site by a small percentage can result in energy savings without compromising the operation of customers' equipment. Finally, in sufficient quantities, distributed energy generated close to load (such as rooftop solar) can also defer investments in traditional delivery system infrastructure and potentially defer the need for additional generation.

Technical and non-technical solution criteria are established to ensure PSE implements the right solutions that fully address the needs. Based on the need identified, a Solutions Study is performed in which project alternatives are developed. The Solutions Studies will consider the opportunity to partner with customers, PSE programs or a PSE pilot. The solution alternatives are vetted and evaluated to meet specific solution criteria. Technical solution criteria includes meeting all performance criteria as described in Figure 8-169 as well as consideration of the substation utilization, avoidance of adverse impacts to reliability or operating characteristics, and the requirement of solution longevity delaying the need to retrigger additional investments for an established number of years, considering customer rate burden as investments are recovered. Non-technical solution criteria includes feasible permitting, environmental and community acceptance as facilitated through permitting processes, reasonable project cost, the maturity of technology, and constructability within a reasonable timeframe.

To evaluate alternatives, PSE compares the relative costs and benefits of various solutions (i.e., projects) using the iDOT Tool. iDOT is a project portfolio optimization based on PriceWaterhouseCooper's Folio software that allows us to capture project and program criteria and benefits and score them across thirteen factors associated with 6 categories. These include meeting required compliance with codes and regulations; net present value of the project; improvement to reliability and safety; future possible customer/load additions; deferral or elimination of future costs; customer satisfaction; improved external stakeholder perception; and opportunities for future success gained by increasing system flexibility or learning about new technologies and methods or drivers of specific company objectives. iDOT makes it easier to conduct side-by-side comparisons of projects and programs of different types, thus helping us evaluate infrastructure solutions that will be in service for 30 to 50 years.

Figure 8-170: Benefit Structure to Evaluate Delivery System Projects



Project costs are calculated using a variety of tools, including historical cost analysis and unit pricing models based on estimated internal engineering costs and service provider contracts. Cost estimates are refined as projects move through detailed scoping. Through this process, alternatives are reviewed and recommended solutions are vetted and undergo an internal peer review process. Projects that address routine infrastructure replacement, such as pole or meter replacements, are proposed at a program level and incorporated into a parallel path within the iDOT process. Risk assessment tools are used to prioritize projects within these programs. An example is the cable remediation program which prioritizes based on risks such as number of past failures, number of customers impacted and system configuration that prevents timely restoration.

iDOT builds a hierarchy of the value these benefits bring to customers and stakeholders against the project cost. The benefits are reviewed and reassessed periodically with senior management to ensure proper weight and priority is assigned throughout the evaluation process. Using project-specific information, iDOT optimizes total value across the entire portfolio of non-mandated or discretionary system infrastructure projects (electric and natural gas) which results in a set of capital projects that provide maximum value to PSE customers and stakeholders relative to given financial constraints. Further minor adjustments are made to ensure that the portfolio addresses resource planning and other applicable constraints or issues such as known permitting or environmental process concerns. Periodically, PSE has reviewed this process and the optimization tool along with the resulting portfolio with WUTC staff.

The iDOT tool also helps PSE examine projects in greater detail than a simple benefit/cost measure. iDOT includes factors such as brand value, health and safety improvements, environmental impact, sustainability, customer value and stakeholder perception. As a result, projects that contribute intangible value receive due consideration in iDOT.

PSE recently expanded the capabilities of iDOT to help us evaluate and compare the relative costs and benefits of wire, non-traditional and hybrid alternatives for the Bainbridge, Seabeck, Lynden and Kitsap pilot projects. New non-traditional benefits mapped to existing iDOT categories include generation capacity deferral entered as a cost reduction. Future iDOT enhancements could incorporate benefits such as battery-produced generation capacity deferral and extended asset life, etc., more transparently. PSE recognizes that carbon emissions reduction is an important objective as it builds implementation plans towards meeting CETA compliance, 100% clean electricity by 2045. The IRP captures greenhouse gas benefits relative to electric energy and so in order to prevent double counting of benefits, delivery system projects, may be more appropriately focused capturing these types of benefits as they relate to the manufacturing or transportation of the different types of assets that support different alternatives. As non-wire analysis is pursued, it essentially helps to find the most ideal location for distributed energy resources that are identified through the IRP recommended portfolio, adding value to what has already been captured in that process. Finally, PSE's delivery system planning process will also mature with clarity of the customer benefit assessment process prescribed in CETA, specifically as energy security and resilience is defined and the considerations and applications of energy and non-energy benefits relative to vulnerable populations and highly impacted communities evolves through required advisory group engagements.

Non-Wire Alternative Analysis

PSE's planning process has incorporated non-wire alternative analysis. The planning process may result in a lengthy project initiation phase as the need and alternatives are evaluated with a broader team. PSE's non-wire alternative analysis is a screening process that breaks down of the problem to understand what different pieces may be provided by a distributed energy resource, evaluates the technical distributed energy resource potential, performs an economic analysis, and then results in a recommended solution. The planning process is a comparison of alternatives searching for the least cost solution that maximizes value for customers and stakeholders and as such evaluates a traditional wired solution, a full non-wire solution, and potential hybrids across the problem components.

All types of distributed energy resources are considered. With the problem deconstructed to better understand the timing and costs specific portions of the need, a basis analysis tool helps to identify typical distributed energy resources that could solve the problem and whether more detailed analysis is warranted. Leveraging the structure and conservation potential process and tools of the IRP, the analysis may then map distributed energy resource potential to zip codes and estimate hourly load shapes based on specific customer loads to understand the potential further. The analysis may result in a heuristic-based DER potential and cost analysis graphic to help understand what is possible. Understanding the length of investment benefit or lifecycle is important as well such as lifespan of a battery or even demand response programs as home ownership transitions the benefit may change from initial results. The next step of economic analysis determines the costs of alternatives, using traditional cost estimating tools for traditional alternatives, and leveraging IRP cost assumptions and consultant's expertise to understand current and future costs based on developing maturity. This allows for testing optimistic, high benefit value low cost, and pessimistic, low benefit value high cost, considerations through the process. As discussed previously, iDOT can then be used to help evaluate alternatives for benefit to cost and further consider benefits not traditionally quantified. The result of the process is a recommended solution that meets the technical and non-technical solution criteria that then is documented in the solution assessment and the project moves to the project planning phase.

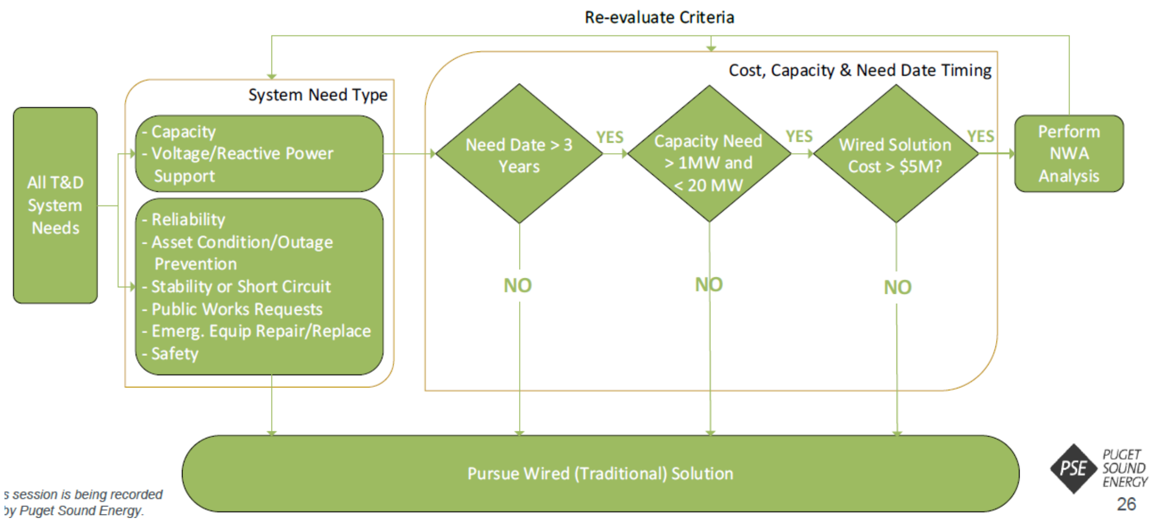
PSE embarked on non-wire analysis in 2018, committing to perform this analysis in four different areas of the system to learn and develop the process. PSE engaged the broad expertise of Navigant and Quanta Technologies to perform and develop its non-wire process and analysis. Non-wire analysis was completed for Bainbridge Island which had a capacity, reliability, aging infrastructure, and operational flexibility need, the entire Kitsap County which had a capacity, aging infrastructure and operational flexibility need, Seabeck which had a smaller circuit capacity and reliability need, and Lynden which had a local capacity, reliability, aging infrastructure, and operational flexibility need. The analysis on these four areas spanned almost 2 years which highlights the complexity of this type of analysis. More detail can be found for each of these area needs in Appendix M.

As a result of this analysis, there are some lessons learned relative to results and where this lengthy complex analysis is most valued. Key findings thus far are that:

- Capacity needs can be effectively met using non-wire alternatives when right sized, maximizing behavior based solutions first. Distributed energy resources that are too large begin to exceed traditional alternatives due to higher cost and long duration of need. Recharging requirements of batteries become as great of a challenge as discharging in some cases.
- Reliability needs are more challenged using non-wire alternatives depending on the length of reliability concern and location of need. Resilience needs, while not discussed much, may be ideal for future distributed energy resource supporting microgrids and locations where critical facilities exist for resilience such as train stations, refueling locations, life support facilities, and commerce.
- Aging infrastructure needs are challenged using non-wire alternatives as they are generally specific locational needs and equipment that if removed cause a wide duration and impact as a result of the connectivity of the grid.
- Non-wires analysis is a time intensive process requiring skilled resources and as a result costs more. Deploying this analysis where the project initiation cost brings value is important to consider in the scheme of the total project costs.
- Non-wire solutions may take time to implement depending on the type of distributed energy resource, PSE's experience, and grid readiness. Solutions such as demand response or behavior based solutions will take time to implement and build reliable confidence to defer traditional solutions. As PSE completes AMI and ADMS implementation and additional grid modernization investments, cost effectiveness of non-wire solutions will increase.

PSE has drafted an initial non-wires screening as a result, Figure 8-171, and through the 2021 IRP began seeking feedback from IRP stakeholders. PSE has performed additional analysis since the initial four areas were identified and these continued studies along with operational experience from previous installations such as PSE's battery in Glacier, Washington as well as on-going pilots will be used to inform this study screening process. This process will be adjusted as technology mature and cost decrease as well.

Figure 8-171: Non-wire Alternative Screening Criteria



Project Planning and Implementation Phase

nce the above process for a particular project and portfolio is completed, reviewed by senior management and approved for funding, the Delivery System Planning initiation phase is complete and the project planning phase begins. The outcome of project initiation is a needs assessment and solutions assessment document. For small projects this may be captured in PSE's SAP system through a notification process or supported from a business case that addresses needs programmatically. The project planning phase involves detailing engineering and technical specifications, pursuing real estate right-of-way needs, planning stakeholder communications and considering potential coordination with other projects in the area. Implementation risks are assessed and mitigation plans are developed as needed. PSE's 10 year plan included in Appendix M reflects projects that are largely in project initiation. Once a project moves to the project planning phase, the need has been established and IRP stakeholder engagement ends while community engagement begins.

Once project need and initiation recommendations are reviewed, annual and two-year work plans are developed for project planning and implementation feasibility. Work plans are coordinated with other internal and external work and resource plans are developed. Final adjustments may be made as the system portfolio is compared with other objectives of the company such as necessary generator or dam work, or customer initiatives. While annual plans are considered final, throughout the year they continue to be adjusted based on changing factors (such as public improvement projects that arise or are deferred; changing forecasts of new customer connections; or project delays in permitting) so that the total portfolio financial forecast remains within established parameters. As plans and projects develop through the design and permitting phases, cost and benefit are routinely evaluated and confirmed before progressing. Alternatives may be reviewed through project lifecycle phase gates and through detailed routing and siting discussions.

Long-range plans are communicated to the public through local jurisdictional tools such as the city and county Comprehensive Plans required by the Washington State Growth Management Act. Often this information serves as the starting point for demonstrating the need for improvements to local jurisdictions, residents and businesses far in advance of a project moving to project planning, design, permitting and construction. Project maps and details are updated on PSE.com as well.