ELECTRIC ANALYSIS
CHAPTER EIGHT

PUGET SOUND ENERGY

Contents

1. Introduction

Results of the electric analysis in Puget Sound Energy's (PSE's) 2023 Electric Progress Report (2023 Electric Report) from the following four-step process are illustrated in Figure 8.1. We described steps one, two, and three in detail in this chapter. We discussed step four in detail in Chapter Three: Resource Plan of the 2023 Electric Report.

Step 1. Establish Resource Needs

We identified three types of resource needs: peak capacity, energy, and CETA-renewable and non-emitting resource needs. Chapter Seven: Resource Adequacy Analysis presents our resource adequacy analysis for the peak need. Appendix C: Existing Resource Inventory describes the existing electric and CETA-eligible resources. Chapter Six: Demand Forecast shows the demand forecast we used to establish the resource needs.

Step 2. Determine Planning Assumptions and Identify Resource Alternatives

In this chapter, we discussed the reference portfolio and sensitivities developed for the 2023 Electric Report. Chapter Five: Key Analytical Assumptions presents the key analytical assumptions and a description of the sensitivities. Appendix D: Generic Resource Alternatives describes electric resource alternatives in detail.

Step 3. Analyze Alternatives Using Deterministic Portfolio, Portfolio Benefit Analysis Tool, and Stochastic Risk Analyses

The deterministic analysis identifies the least-cost mix of demand-side and supply-side resources that will meet needs, given the static assumptions defined in the scenario or sensitivity. We analyzed all scenarios and sensitivities using deterministic optimization analysis.

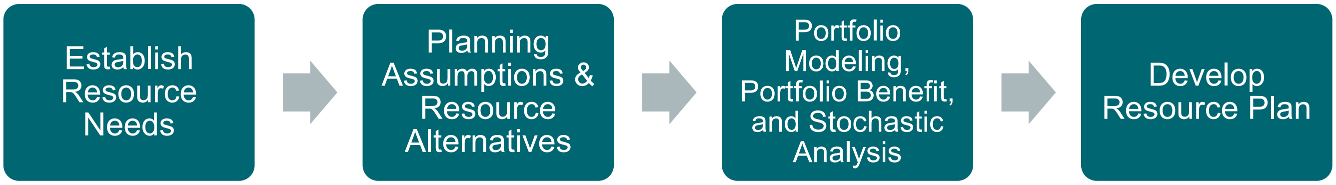
The portfolio benefit analysis tool helps support our understanding of equity-related benefits and the associated costs within each portfolio and informs our work as we strive to select a portfolio best suited to equitable outcomes for customers while also considering cost.

Stochastic risk analysis deliberately varies the static inputs to the deterministic analysis to test how the different portfolios developed in the deterministic analysis perform concerning cost and risk across a wide range of possible future power prices, gas prices, hydroelectric generation, wind generation, loads, and plant forced outages. We analyzed the reference and preferred (sensitivity 11 B2) portfolios using stochastic risk analysis.

Step 4. Develop Resource Plan

We studied the deterministic analysis, the portfolio benefits tool analysis, and the stochastic quantitative analysis results to understand the key findings that led to decisions for the preferred portfolio. We presented the analysis results in this chapter and Appendix H: Electric Analysis and Portfolio Model. Chapter Three: Resource Plan presents the resource plan decisions.

Figure 8.1: 2023 Electric Progress Report Process



2. Clean Energy Transformation Act

The 2021 Integrated Resource Plan (IRP) marked a significant departure from past IRPs due mainly to the passage of the Clean Energy Transformation Act (CETA). The new electric progress report rules, WAC 480-100-625,[1] outline the requirements for this report. Utilities must file a progress report at least every two years after the utility files its IRP, beginning January 1, 2023.

In this mandated report, the utility must update the following:

- Demand forecast
- Demand-side resource assessment, including a new conservation potential assessment
- Resource costs
- The portfolio analysis and preferred portfolio

The progress report must also update for any elements found in the utility's current clean energy implementation plan, as described in WAC 480-100-640.[2] The progress report must also include other updates necessary due to changing state or federal requirements or significant economic or market forces changes.

2.1. Demand Forecast

Puget Sound Energy's 2023 Electric Progress Report incorporates climate change in the base energy and peak demand forecast for the first time. Before this report, we used temperatures from the previous 30 years to model the expected normal temperature for the future. We then held this normal temperature constant for each future model year. This old approach was a common utility practice but did not recognize predicted climate change, which experts expect will increase temperatures, on average, over time.

Puget Sound Energy incorporated climate change into the demand forecast for the first time in this report. We heard from interested parties that climate change is important to incorporate because it affects future demand and needs, and PSE agrees. We included climate change in the base demand forecast and the stochastic scenarios.

We know the methodology for incorporating climate change in this report is the first step, and we expect it will evolve. We heard from interested parties that incorporating climate change into demand forecasting is a high priority. Puget Sound Energy provides energy for heating in the winter and cooling in the summer. It is essential to consider climate change in resource planning because of the warming trends that we expect will likely lead to, on average, less heating demand in winter and more cooling demand in summer.

1 WAC 480-100-625
2 WAC 480-100-640

Climate scientists recently developed climate model projections for the region, which we will use to calculate a normal temperature assumption that reflects climate change. We also updated the peak demand forecast, which results in normal peak temperatures for summer and winter that increase over time.

We expect electric energy demand to grow at an average annual growth rate (AARG) of 1.8 percent from 2024 to 2045 before the additional demand-side resources (DSR) we identified in the 2023 Electric Report's base demand forecast. This growth rate increased our forecast from 2,551 average megawatts (aMW) in 2024 to 3,699 aMW in 2045, faster than the 1.2 average annual energy growth rate forecasted in the 2021 IRP.

➔ See Chapter Six: Demand Forecast and Appendix F: Demand Forecast Models for details regarding how PSE incorporated climate change into our demand forecast.

2.2. Demand-side Resources

We analyzed DSR alternatives in a conservation potential assessment (CPA) and demand response assessment to develop the supply curve we used as input to the portfolio analysis. The portfolio analysis then determined the potential maximum energy savings captured without raising the overall electric or natural gas portfolio cost. This analysis identified the DSR's cost-effectiveness level to include in the portfolio.

➔ The CPA updated for the 2023 Electric Report is in Appendix E: Conservation Potential and Demand Response Assessments.

Overall, the 2023 Electric Report CPA potential is down from the 2021 IRP by about 13 percent by 2045. Several updates and new data elements contributed to the reduced potential:

- The CPA incorporated a statutory provision requiring the state to adopt more efficient building energy codes to achieve a 70 percent reduction by 2031. This change in the CPA moved some of the potential from energy efficiency into codes and standards.
- The newly incorporated impact of climate change reduced savings in the later years of the study
- Updated building stock assessments, which have more efficiency penetration compared to the last stock assessment
- Updated savings from the most recent biennium program cycle

The CPA potential is also down in the 2023 Electric Report because of the following factors:

- Climate change reduced the normal winter peaks, thereby reducing the contribution of savings at the peak
- Updated conservation measure load shapes to align with the Northwest Power and Conservation Council's 2021 Power Plan[3]

[3] https://www.nwcouncil.org/2021-northwest-power-plan/

- Updated PSE's system peak definition to reduce the morning and evening windows for very heavy load hours[4]

Demand response peak savings increased due to updates we made to the potential to align with the 2021 Power Plan and an increase in the transmission and distribution deferrals costs.

2.3. Resource Costs

Like the 2021 IRP, we aggregated publicly available generic resource costs from several sources, predominantly from the National Renewable Energy Laboratory's (NREL) 2022 Annual Technology Baseline.[5] We expect generic resource capital costs to decline as technological advances push costs down. The declining cost curves we applied to different resource alternatives came from the National Renewable Energy Laboratory (NREL) 2022 Annual Technology Baseline (ATB).

➔ A breakdown of the updated generic resource costs is in Chapter Five: Key Analytical Assumptions, with details in Appendix D: Generic Resource Alternatives.

2.4. Portfolio Analysis and Preferred Portfolio

We updated the portfolio analysis for the 2023 Electric Report. The assumptions and documentation of the model are in Chapter Five: Key Analytical Assumptions and Appendix H: Electric Analysis and Portfolio Model. The analysis results are later in this chapter, and we discussed the preferred portfolio in Chapter Three: Resource Plan.

2.5. State and Federal Requirements

Policy changes in the energy industry in Washington State and the United States have rapidly increased in the last decade. The following are the key policy changes impacting this report.

2.5.1. State Laws and Regulations

At the state level, PSE incorporated rules from the Climate Commitment Act (CCA), the Clean Energy Transformation Act (CETA), the Clean Energy Implementation Plan (CEIP), and new building codes.

2.5.2. Federal Laws

The Inflation Reduction Act (IRA) became law in August 2022. The two main incentives in the act applicable to PSE'S resource costs are the Production Tax Credits (PTCs) and Investment Tax Credits (ITCs). The IRA provides more long-term certainty in investment decisions by providing 10 years of energy tax incentive eligibility and

[4] In the 2021 IRP, we estimated the peak contribution from energy efficiency savings between peak hours, defined as: weekdays from hour ending (HE) 7–11 a.m. (6–11 a.m.) and HE 6–10 p.m. (5–10 p.m.); in the 2023 IRP this was updated to HE 8–10 a.m. and HE 6–7 p.m.

[5] https://atb.nrel.gov/

enhanced tools to accelerate or support credit monetization. Where previous tax rules for PTC (wind) and ITC (solar) were technology-specific, the new tech-neutral credit may allow the entity receiving the credit to choose the most efficient incentive type. The rules also provide bonuses for where and how operators build projects. The rules incentivize project developers to utilize domestically sourced materials, drive economic opportunity by placing projects in service in low-income communities, and leverage an existing workforce in census tracts deemed energy communities where new clean energy developments may impact fossil-fuel extraction and generation activities. The full effects of the legislation, once implemented, are not known at this time, but we were able to include some of the known effects of the federal IRA in this report.

Production Tax Credits provide an energy tax credit ($/MWh) for the first 10 years of energy output after a utility places a project in service. Before Congress enacted the IRA, PTCs expired for any new projects placed in service in 2022 and beyond. The IRA bill now extends PTCs to 100 percent for eligible projects in service before the end of 2032. The PTCs are now technology-neutral, so solar projects now qualify for PTC. We assumed PTC for wind and solar resources as the most economical use of the tax incentives.

Investment Tax Credits provide an energy tax credit based on the project's percentage of investment. Before Congress enacted the IRA, the ITC rate for projects placed in service in 2022 had phased down to 10 percent. The IRA increased the ITC rate to 30 percent. Previously, the regulations restricted ITC for battery storage projects to hybrid battery storage projects paired with solar or other renewable energy generation assets. The IRA now extends the ITC to cover all stand-alone energy storage applications. This change makes the system more flexible because the battery can charge from the grid and its paired solar project. We assumed ITC for energy storage resources.

The IRA includes subsidies for utility-scale resources and end-use customer appliances. We do not know how the federal government will implement the subsidies yet, so we cannot incorporate their impact on our customers' behavior. As we learn more about the policies to implement these subsidies, we will reflect the effects in future IRPs.

2.6. Economic or Market Forces

We incorporated the economic and market forces that affect the electric resource plan into the electric and natural gas price forecasts.

2.6.1. Electric Price Forecast

We developed this electric price forecast as part of our 2023 Electric Report. In this context, the electric price is not the rate charged to customers but PSE's price to purchase or sell one MWh of power on the wholesale market, given the prevailing economic conditions. Electric price is an essential input to this analysis since market purchases comprise a substantial portion of PSE's existing resource portfolio. The updated electric price forecast reflects higher avoided energy costs due to updated modeling methodologies and assumptions to the electric price forecast model. The levelized nominal power price for the 2023 Electric Report is $42.90/MWh compared to the 2021 IRP, which was $23.37/MWh.

➔ A detailed account of all updates to the electric price model is in Chapter Five: Key Analytical Assumptions and Appendix G: Electric Price Models.

2.6.2. Natural Gas Price Forecast

The projection for natural gas prices increased between the 2021 IRP and the 2023 Electric Report, particularly in the near term, increasing electric prices. Recent gas prices are elevated due to energy security concerns in Europe and accelerating coal retirements domestically, which leads to additional gas demand for the power sector and demand driven by liquefied natural gas (LNG) export expansion.

➔ We discuss natural gas in further detail throughout Chapter Five: Key Analytical Assumptions.

2.6.3. Alternative Fuels

For this report, we modeled two types of alternative fuels, hydrogen and biodiesel.

Hydrogen

Hydrogen is a highly flexible commodity chemical currently used in a wide range of industrial applications and poised to become a key energy carrier in the power sector. Production tax credits in the IRA reduce the market price of green hydrogen by up to $3 per kilogram, making it a cost-competitive energy carrier. We modeled green hydrogen as a fuel source for existing and new combustion turbines starting in 2030.

Biodiesel

Biodiesel is a renewable resource under RCW 19.405.020(34)[6] of CETA. Biodiesel must not be derived from crops raised on land cleared from old-growth or first-growth forests to be considered renewable. Biodiesel is chemically similar to petroleum diesel but is derived from waste cooking oil or dedicated crops. We modeled biodiesel as a fuel source for new combustion turbines starting in the model year 2024.

➔ Further discussion of hydrogen and biodiesel as fuel sources is in Appendix D: Generic Resource Alternatives.

[6] RCW 19.405.020

2.7. Elements Found in Clean Energy Implementation Plan

In December 2021, we filed our first CEIP. The plan illustrates PSE's four-year roadmap to meet the requirements of CETA and the specific actions PSE will take from 2022–2025 to meet those goals. The CEIP proposes an interim target of serving customers with 63 percent clean, CETA-eligible renewable resources by the end of 2025. We used the 63 percent target from the CEIP as the minimum for this 2023 Electric Report. The resource specific targets included in the CEIP and proposed in this report are:

- 25 MW of Distributed Energy Resources (DER) storage
- 80 MW of DER solar

We also applied certain customer benefit indicators (CBIs) identified in the CEIP that apply to resource planning.

3. Resource Need

Reliably meeting our customers' needs is the cornerstone of PSE's energy supply portfolio. For resource planning, the physical electricity needs of our customers are simplified and expressed as three resource needs: peak hour capacity need, energy need, and renewable and non-emitting energy need.

3.1. Peak Hour Capacity Need

We determined peak hour capacity need with a resource adequacy analysis that evaluated existing PSE resources compared to the projected peak need over the planning horizon. The capacity shown is the amount of effective capacity needed to maintain the resource adequacy target — the need after applying different resources' effective load carrying capacity (ELCC). Due to market reliance assumptions used in this 2023 Electric Report, the modeling indicates PSE could begin to experience a peak capacity shortfall starting in 2024. Before any conservation, the peak capacity need plus the planning margin required to maintain reliability is 2,629 MW by 2029. The 2,629 MW is the difference between the load forecast (the demand forecast plus the required planning margin) and the total peak capacity credit of existing resources. Figures 8.2 and 8.3 show the winter and summer peak capacity needs through 2045.

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Figure 8.2: Effective Peak Capacity Need — Winter

(Physical Reliability Need, Peak Hour Need Compared to Existing Resources)

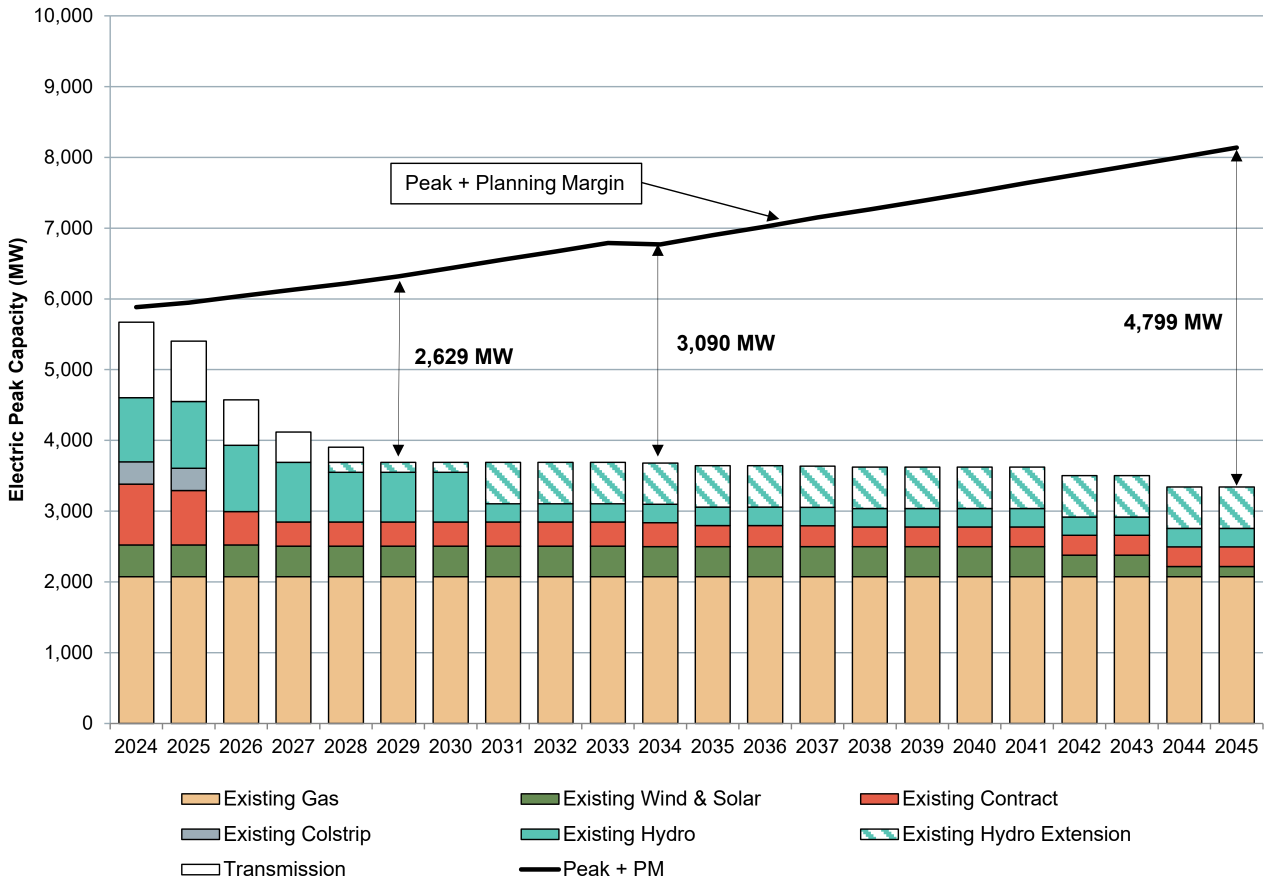
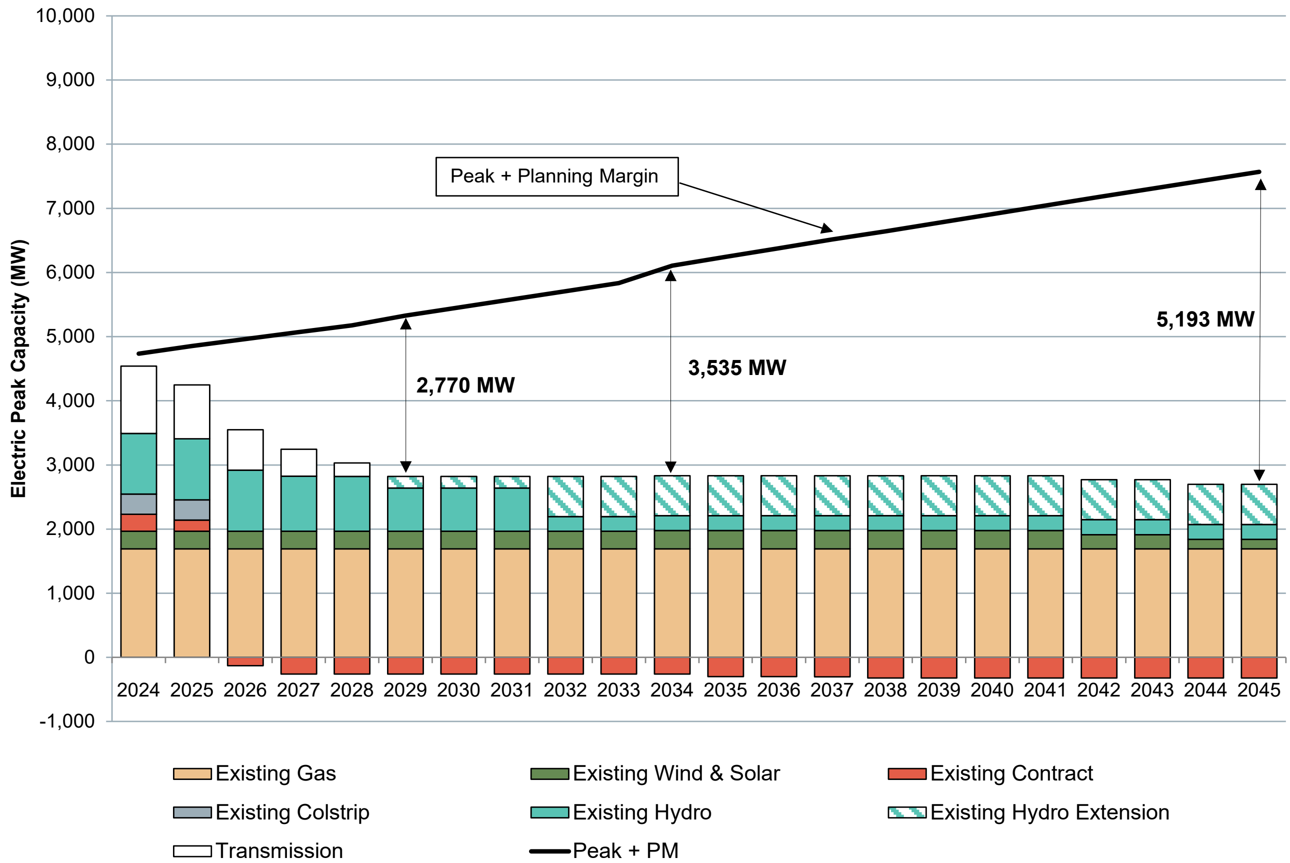


Figure 8.3: Effective Peak Capacity Need — Summer

(Physical Reliability Need, Peak Hour Need Compared to Existing Resources)



➔ See Chapter Seven: Resource Adequacy Analysis for a complete discussion of the resource adequacy analysis.

3.2. Energy Need

We must meet our customers' energy needs 24 hours a day, 365 days a year. Our models require the portfolios to supply the energy necessary to meet physical loads and examine how to do this most economically through existing resources, new resources, and purchasing and selling electricity on the energy market. Puget Sound Energy's annual energy need starts at 2,551 aMW for 2024, increases to 2,799 aMW in 2030, and reaches 3,699 aMW in 2045.

➔ See Chapter Six: Demand Forecast for a detailed discussion on energy demand.

3.3. Renewable and Non-emitting Energy Need

In addition to reliably meeting the physical needs of our customers, CETA requires that utilities meet at least 80 percent of electric sales (delivered load) in Washington State by non-emitting or renewable resources by 2030 and 100 percent by 2045.

Figure 8.4 illustrates PSE's renewable and non-emitting energy need. For the long-term IRP analysis, we assumed a linear ramp to achieve the Clean Energy Transformation Standards Act standards in 2030 and 2045 described in RCW 19.405.040;[7] however, actual resource acquisitions through implementation of the CEIP will likely produce a less linear pathway than we show. Before any conservation, the renewable energy need is over 7 million MWh in 2030 to meet the 80 percent clean energy standard. The renewable need is the difference between the green line and the teal bars in Figure 8.4.

[7] RCW 19.405.040

Figure 8.4: Qualifying Energy Need to Meet CETA Requirements

(Before Demand-side Resources)

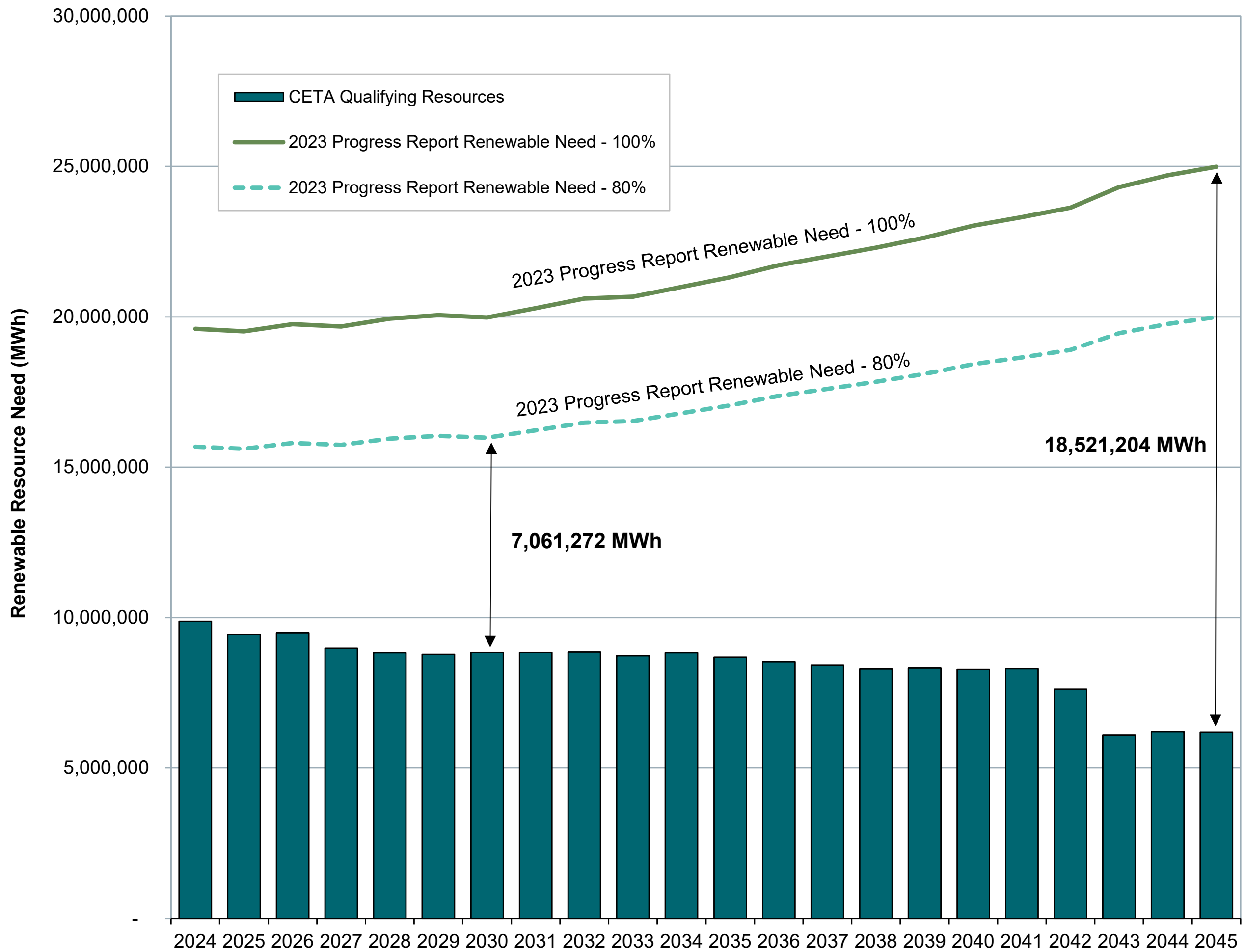
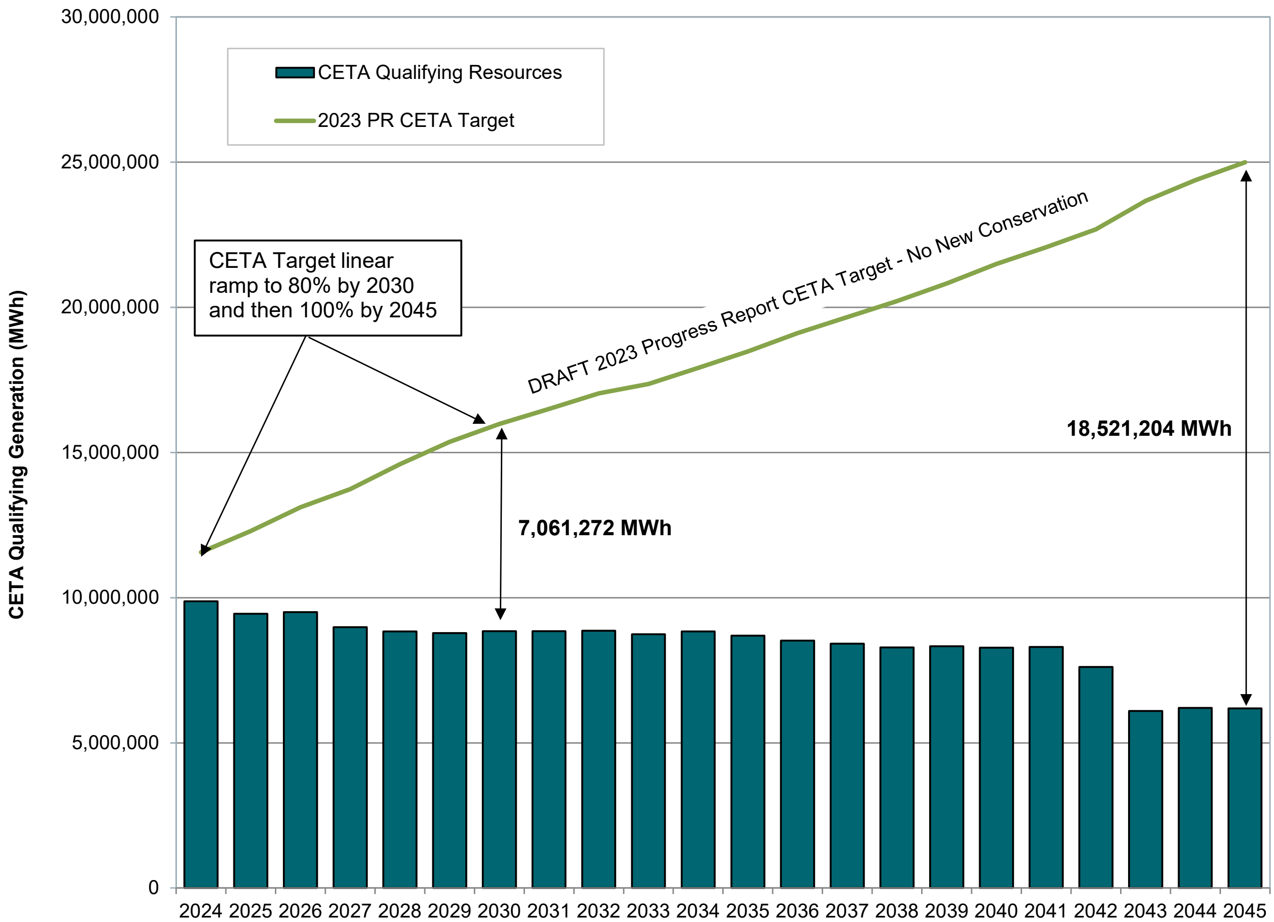


Figure 8.5 assumes a linear ramp to reach the 80 percent clean energy standard in 2030 and the 100 percent clean energy standard in 2045. We used the linear ramp to ensure the portfolio model gradually adds resources to meet clean energy standards rather than waiting until the goal's final target year to add them. The linear ramp starts in 2024, as the model assumes all new resources are self-builds, with most available to begin in 2024.

Figure 8.5: Renewable Need and Linear Ramp for CETA (Before Demand-side Resources)



4. Types of Analysis

We used deterministic optimization analysis to identify each portfolio's lowest reasonable cost. We then ran a stochastic risk analysis to test different resource strategies.[8] We used the portfolio benefit analysis to inform the equitable distribution of burdens and benefits in the resource planning process to ensure all customers benefit from the transition to clean energy.

4.1. Deterministic Portfolio Optimization Analysis

We subjected all the portfolios to deterministic analysis in the first stage of the resource plan analysis. This identifies the least-cost integrated portfolio — the lowest-cost mix of demand-side and supply-side resources that will meet the need under the given static assumptions defined in the scenario or sensitivity. This stage helped us learn how specific input assumptions, or combinations of assumptions, can impact the least-cost mix of resources.

8 To screen some resources, we also used 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.

4.2. Portfolio Benefit Analysis

The Clean Energy Transformation Act requires utilities to consider equity and ensure all customers benefit from the transition to clean energy. However, AURORA, a traditional production cost model used for portfolio modeling, only solves for the least-cost solution. Therefore, we developed and used a portfolio benefit analysis tool to support our understanding of equity-related benefits and the associated costs within each portfolio and inform our work as we strive to select a portfolio best suited to enable equitable outcomes for customers while also considering cost.

The portfolio benefit analysis measures potential equity-related benefits to customers within a given portfolio and the tradeoff between those benefits and overall cost. We evaluated these benefits using quantitative CBIs and their metrics. Customer benefit indicators are quantitative and qualitative attributes we developed for the 2021 CEIP in collaboration with our Equity Advisory Group (EAG) and interested parties. These CBIs represent the focus areas in CETA related to equity, including energy and non-energy benefits, resiliency, environment, and public health.

For this report, we evaluated each portfolio using a subset of the CBIs proposed in the 2021 Clean Energy Implementation Plan, which as of this date, is still pending Washington Utilities and Transportation Commission (Commission) approval. We selected the subset of CBIs based on whether the AURORA modeling tool could quantitatively evaluate them, i.e., AURORA already had a comparable metric. The CBIs we included in the portfolio benefit analysis are:

- **Improved access to reliable, clean energy** — measured by customers with access to distributed storage resources
- **Improved affordability of clean energy** — measured by the total portfolio cost
- **Improved outdoor air quality** — measured by sulfur oxides, nitrogen oxides, and particulate matter generated per portfolio
- **Increased number of jobs** — measured by the number of estimated jobs generated for each portfolio
- **Increased participation in Energy Efficiency, Distributed Energy Resource, and Demand Response Programs** — measured by energy efficiency capacity added and the number of customers projected to participate in distributed energy resources and demand response programs
- **Reduced greenhouse gas emissions** — measured by the total amount of CO_2-eq[9] generated per portfolio
- **Reduced peak demand** — measured by the decrease in peak demand achieved via demand response programs

The portfolio benefit analysis generates a CBI index for each portfolio, an aggregate measure of these CBIs (excluding the portfolio cost) normalized to the reference portfolio, also known as the least-cost portfolio. A higher CBI index indicates that a portfolio enables more equity-related benefits than the reference portfolio. The CBI index is then compared to its total cost (direct and externality costs).

[9] CO_2-eq or CO_2-equivelant is a measure used to compare the emissions from various greenhouse gases on the basis of their global-warming potential (GWP). Using the GWP, other greenhouse gases are converted to the equivalent amount of carbon dioxide.

➔ Appendix H: Electric Analysis and Portfolio Model includes a more detailed description of the methods used to conduct the portfolio benefits analysis.

4.3. Stochastic Risk Analysis

In this stage of the resource plan analysis, we examined how different resource strategies respond to the types of risk that reflect future uncertainty. We deliberately varied static inputs in the deterministic analysis to create simulations called draws, which we used to analyze the different portfolios.

With stochastic risk analysis, we tested the robustness of different portfolios to determine how well the portfolio might perform under various conditions. The goal is to understand the risks of varying candidate portfolios regarding costs. To assess those risks, we identified and characterized the likelihood of bad events and the likely adverse impacts they may have on a given portfolio.

To gain this understanding, we took some of the portfolios (drawn from the deterministic analysis of portfolios) and ran them through 310 draws[10] that modeled varying power prices, gas prices, hydroelectric generation, wind, and solar generation, load forecasts (energy and peak), and plant forced outages.

5. Reference Portfolio Analysis Results

The reference portfolio is the least-cost portfolio that meets CETA, energy, and reliability requirements. The reference portfolio sets the stage as the starting point that leads to an informed preferred portfolio. The reference case portfolio cost is $17.6 billion, and the social cost of greenhouse gases (SCGHG) is $3.2 billion, totaling $20.8 billion in total portfolio costs.

5.1. Reference Case Portfolio Builds

This section describes the resource additions needed for the reference portfolio to meet CETA requirements, reliability needs, and future energy growth.

5.1.1. Clean Energy Transformation Act

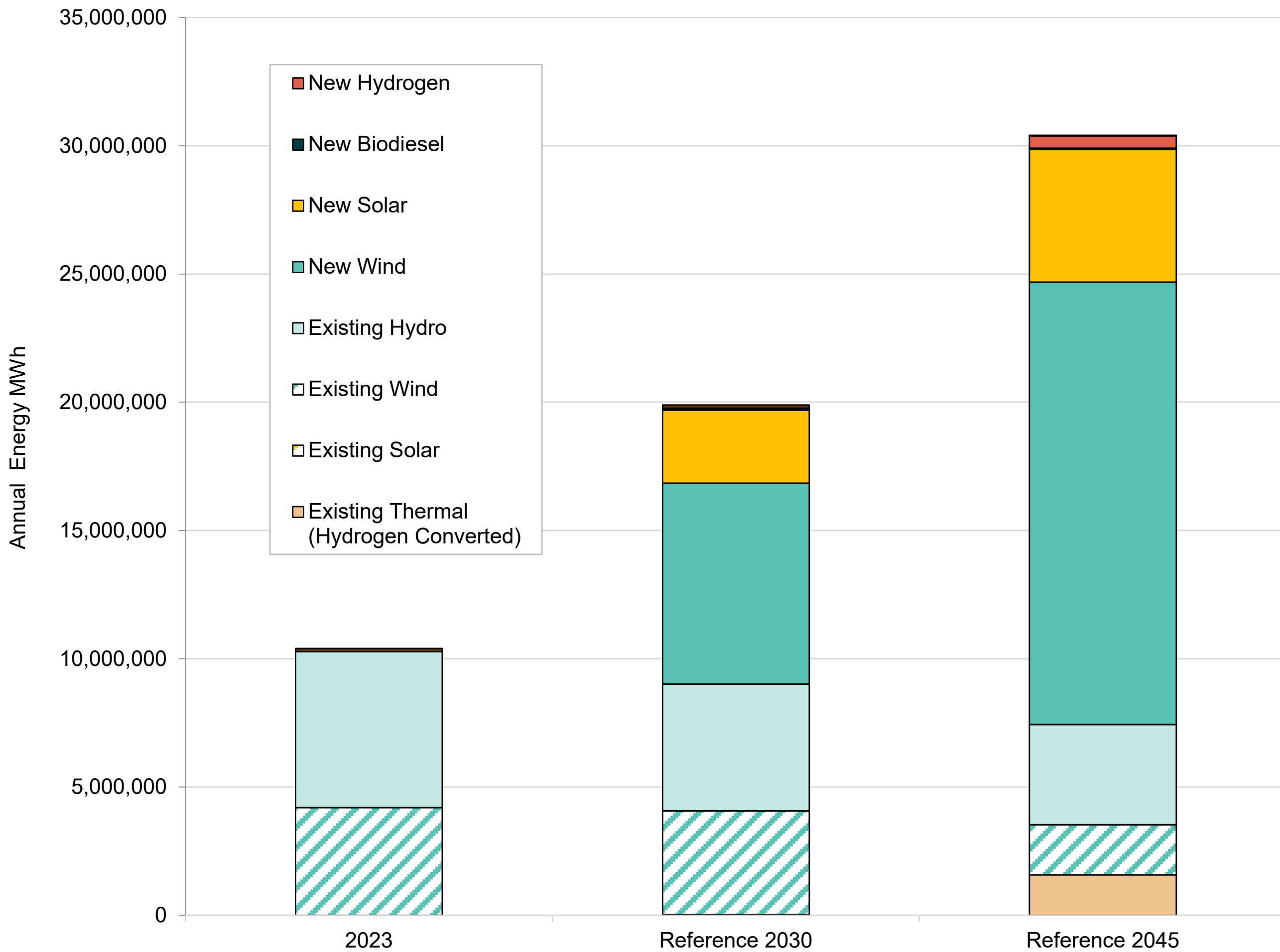
Figure 8.6 shows the energy breakdown from CETA-qualifying resources[11] for select years through 2045. Energy contribution from CETA-qualifying resources grows from over 10 million MWhs in 2023 to 20 million MWhs in 2030 and 30 million MWhs in 2045. New resources will be added to the portfolio starting in 2024, and by 2030 we will see a mix of hydroelectric, wind, solar, and hybrid resources (the renewable portion) eligible to meet CETA added to the portfolio. By 2045, energy from wind resources will make up most of the energy produced from CETA-qualifying

[10] Each of the 310 simulations is for the 22-year IRP forecasting period, 2024–2045.

[11] CETA-qualifying resources include all resources that qualify as renewable or non-emitting under CETA , which include renewables, hydrogen, biodiesel, and advanced nuclear as defined in RCW 19.405.020 (28) and (34)

resources. We also count energy from hydrogen and biodiesel peakers toward CETA achievement; however, those resources have a limited capacity factor and are mostly available to meet peak in high demand hours.

Figure 8.6: Energy for CETA-qualifying Resources — Reference Portfolio



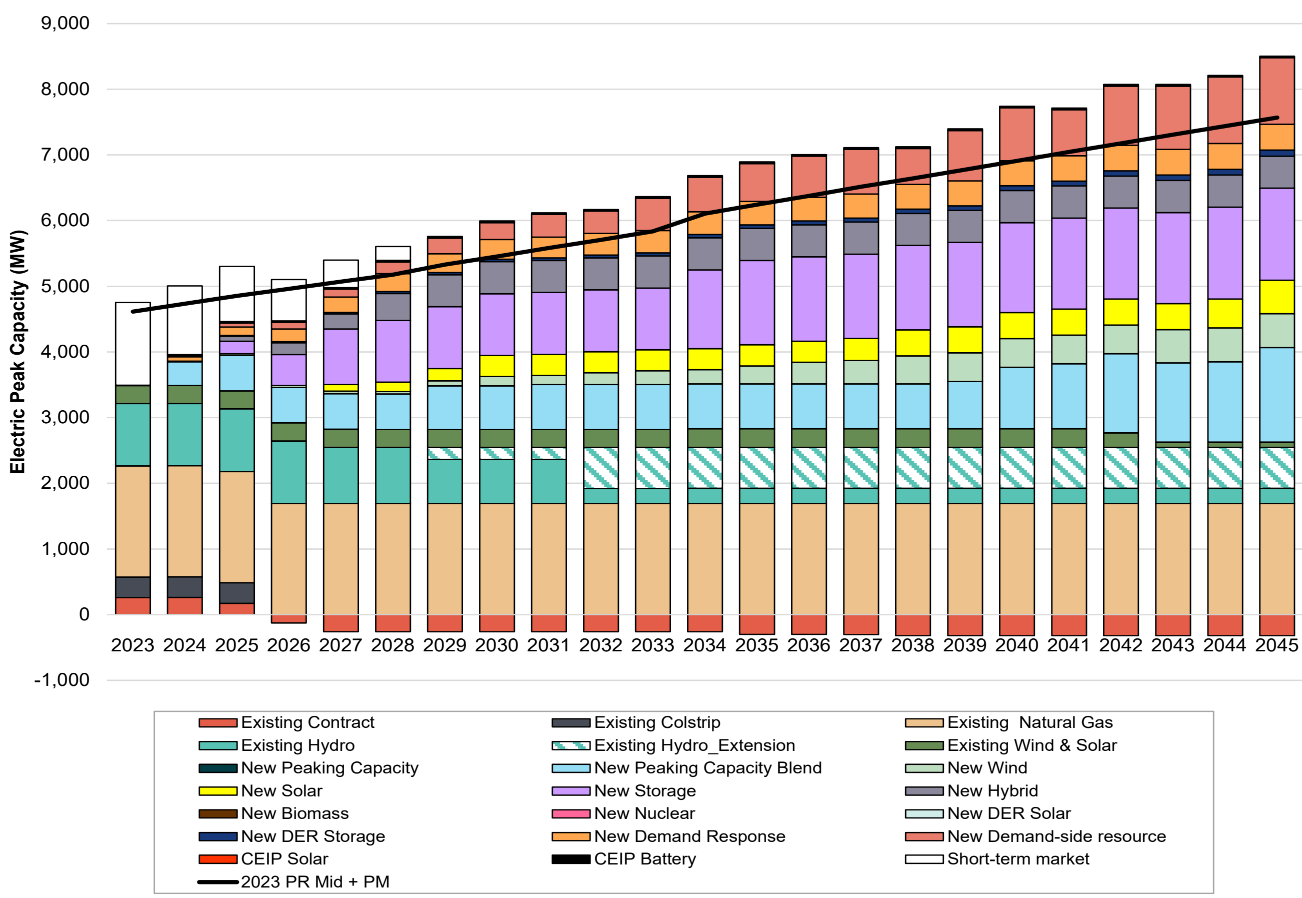
5.1.2. Meeting Reliability Needs

Many factors affect PSE's resource adequacy analysis, including climate change, electric vehicle forecast, and market reliance. Incorporating climate change data resulted in slightly lower normal winter peaks due to higher average temperatures in the winter, while the temperatures were higher on average for the summer leading to higher summer peaks. We also updated the electric vehicle forecast, which increased the winter peak demand. The increase from the electric vehicle forecast offset the decrease in normal winter peak from the climate change data.

Regarding market reliance, there is a concern about the availability of firm capacity in the short-term market. Puget Sound Energy currently has over 2,000 MW of available capacity to the Mid-Columbia (Mid-C) market, with a portion allocated to existing PSE-owned or contracted Mid-C resources, leaving PSE net about 1,400 MW to 1,500 MW of available Mid-C capacity for short term market purchases. This 1,500 MW of available Mid-C capacity was a firm resource in portfolio modeling for previous IRPs. For the 2023 Electric Report, we assumed that access to the short-term market would continue to be available but in decreasing amounts into the future. By 2029, we assumed that none of the transactions in the short-term market would be firm. The assumed reduction in market reliance increased PSE's peak needs. The winter peak need remains greater than the summer peak need through 2045.

Figure 8.7 provides a breakdown of peak capacity contribution by resource type for the summer. The solid black line in the chart represents the summer peak capacity. The combination of existing and new resource peak capacity for the reference portfolio in the summer is surplus of the summer target. Many of the resources we added to help meet CETA requirements, particularly solar resources, have a larger peak capacity contribution in the summer than in the winter. The peak contribution from energy storage resources is also larger in the summer than in the winter — PSE's system is built to meet winter peaking needs and is consequently surplus in the summer months.

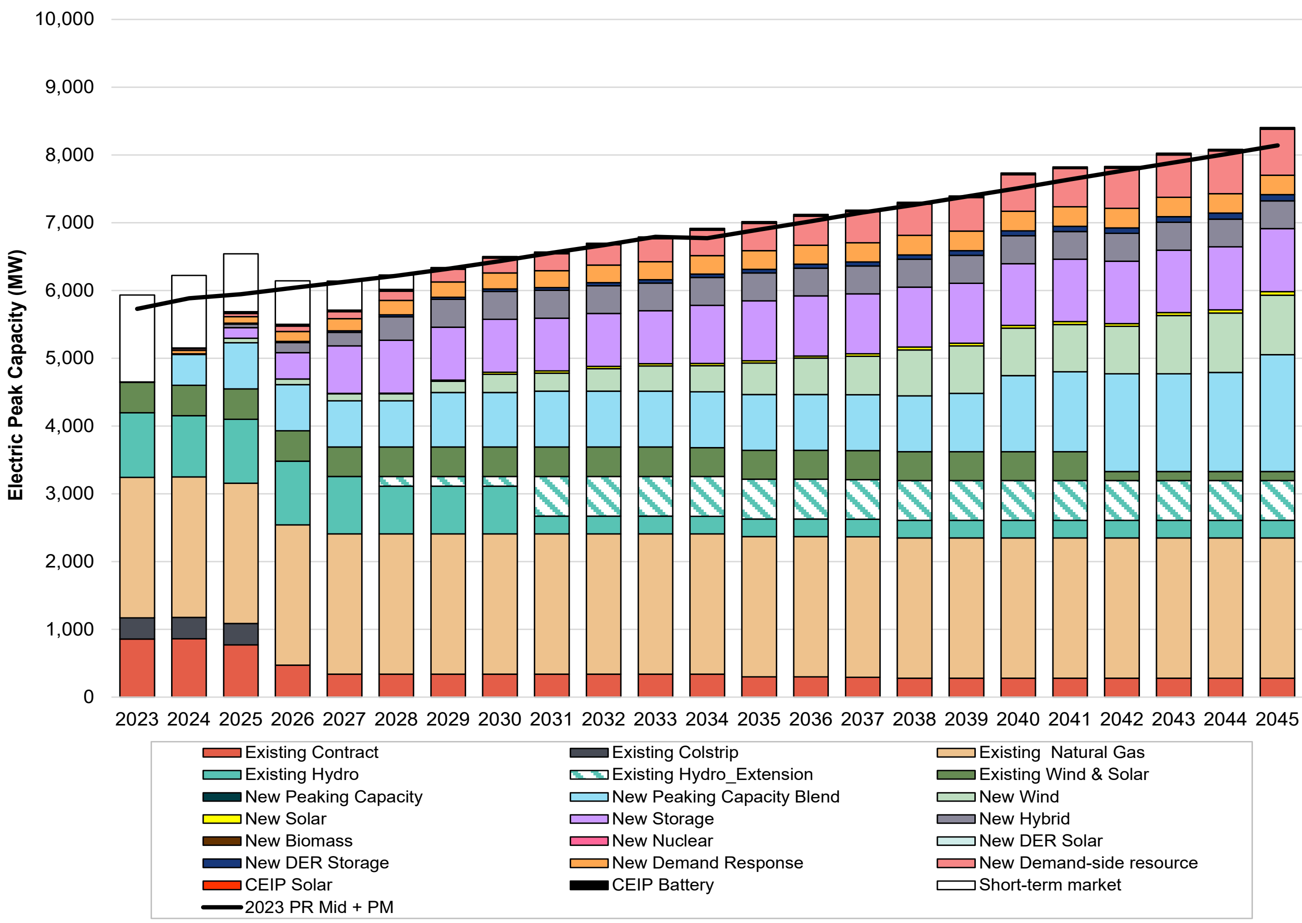
Figure 8.7: Effective Summer Peak Capacity by Resource Type – Reference Portfolio



➔ See Chapter Seven: Resource Adequacy Analysis for more details on resource adequacy.

However, new renewable resources' peak capacity is insufficient to meet winter peaks. We still need additional new peaking capacity to add to the reference portfolio. Looking at the same chart for the winter, we see the reference portfolio is no longer surplus but on target to meet the winter peak capacity. Figure 8.8 provides a breakdown of peak capacity by resource type for the winter. The solid black line in the chart represents the winter peak capacity plus the planning margin. Winter peak need drives new capacity resource builds for the reference portfolio.

Figure 8.8: Effective Winter Peak Capacity by Resource Type – Reference Portfolio



5.1.3. Meeting Future Growth

Puget Sound Energy meets our CETA, energy, and reliability requirements through a combination of conservation, demand response, distributed energy and clean energy resources, energy storage, and CETA-qualifying peaking new capacity resources. Overall cumulative capacity builds through 2045 is 14,287 MW. Table 8.1 summarizes the reference portfolio's incremental nameplate capacity for select years and the cumulative nameplate capacity.

Table 8.1: Incremental Resource Additions — Reference Portfolio (MW)

Resource Type	2024–2025 Incremental	2026–2030 Incremental	2030 Cumulative	2031–2045 Incremental	2045 Cumulative
Demand-side Resources	**184**	**369**	**553**	**547**	**1,100**
Conservation	51	175	226	469	695
Demand Response	133	194	327	78	405
Distributed Energy Resources	**182**	**252**	**434**	**1,177**	**1,612**
DER Solar	142	230	372	1,122	1,494
Net Metered Solar	59	225	284	1,109	1,393
CEIP Solar	79	-	79	0	79
New DER Solar	4	5	9	13	22
DER Storage	40	22	62	55	117
Supply-side Resources	**1,761**	**4,227**	**5988**	**5,587**	**11,575**
CETA Qualifying Peaking Capacity	711	128	839	949	1,788
Wind	600	800	1400	2,650	4,050
Solar	0	1,100	1100	1,290	2,390
Green Direct	0	100	100	0	100
Hybrid (Total Nameplate)	250	1,300	1550	0	1,550
Hybrid Wind	*100*	*800*	*900*	*0*	*900*
Hybrid Solar	*100*	*100*	*200*	*0*	*200*
Hybrid Storage	*50*	*400*	*450*	*0*	*450*
Biomass	0	0	0	0	0
Advanced Nuclear SMR	0	0	0	0	0
Standalone Storage	200	800	1000	700	1,700
Total	**2,127**	**4,849**	**6976**	**7,311**	**14,287**

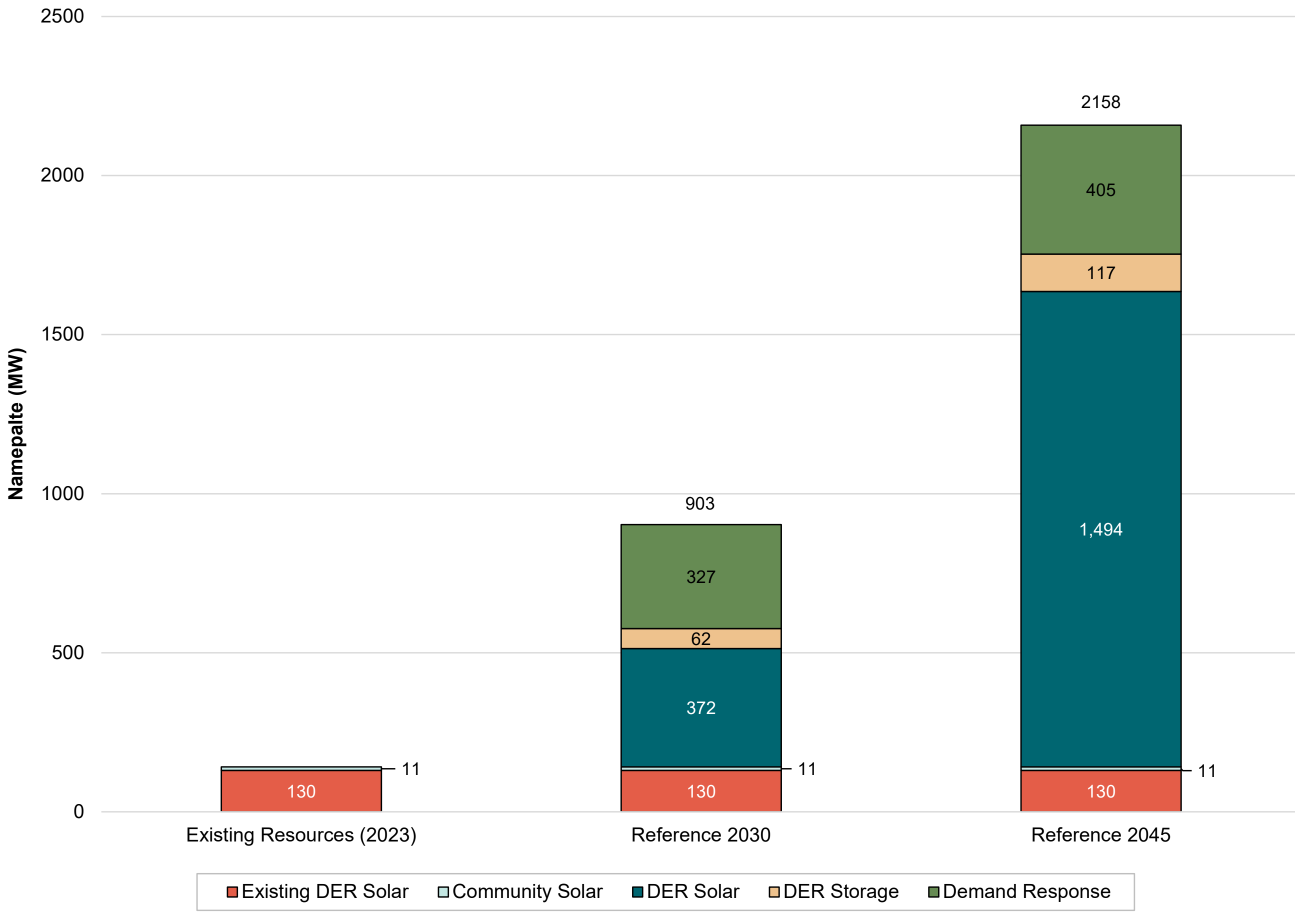
Demand-side Resources

In the AURORA model, conservation is consider a supply-side resource eligible to meet CETA requirements and competes with lower cost renewable resources during the resource selection. Conservation selected in the reference portfolio includes future effects of current Codes & Standards, Distribution Efficiency, and energy efficiency programs, with a total 695 MW added by 2045. A significant amount of demand response programs will be added to the reference portfolio for 405 MW by 2045, including a 12 MW demand response potential for interruptible customers. The high peak contribution and low program costs lead to increased amounts of demand response selected in the reference portfolio.

Distributed Energy Resources

Distributed energy resources for the reference portfolio combine net metering solar forecasts from Cadmus, PSE's forecast of DER solar additions, and DER solar targeted in the 2021 CEIP, totaling 1,494 MW by 2045. The total DER storage added to the portfolio by 2045 is 117 MW, a combination of PSE's forecast of DER storage projects and the DER storage targeted in the 2021 CEIP. Figure 8.9 shows the significant growth in distributed energy resources through 2045

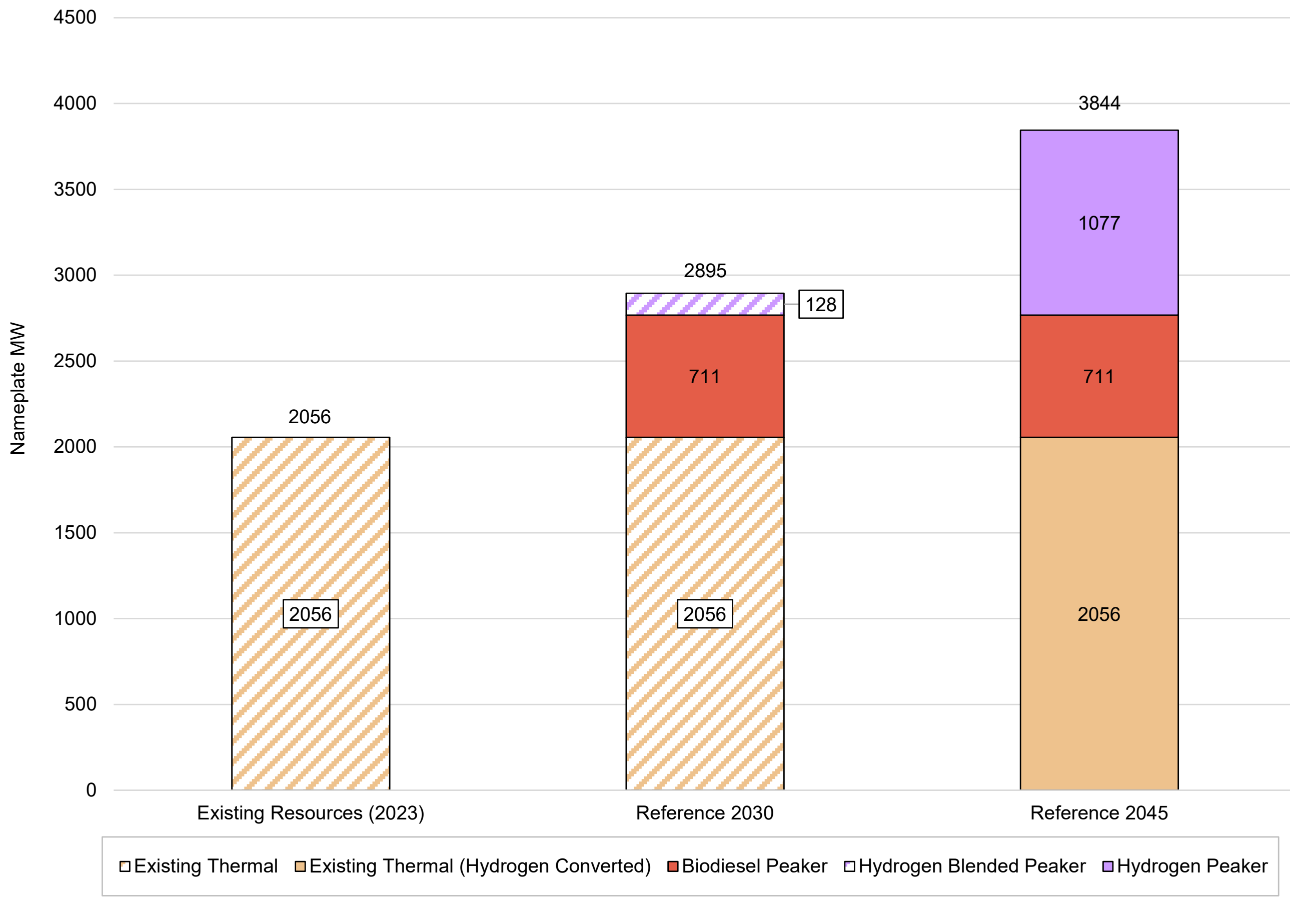
Figure 8.9: Cumulative Nameplate Capacity in MW for Distributed Energy Resources – Reference Portfolio Clean Energy Transformation Act Qualifying Peaking Capacity



CETA Qualifying Peaking Capacity Resources

By 2025, we will add 711 MW of frame peaker biodiesel plants in the reference portfolio to fill the peak need as we phase out our reliance on firm, short-term market purchases. These biodiesel peakers also help to counteract the anticipated retirement of Colstrip and Centralia power purchase agreements (PPA) by the end of 2025. By 2030, we see the addition of 128 MW of peakers using blended natural gas and hydrogen resources as firm short-term market purchases decline to zero MW. In 2031–2045, we see the addition of 711 MW of frame peaker blended natural gas and hydrogen resources and 238 MW of reciprocating peaker blended natural gas and hydrogen resources to help fill the peak needs for the portfolio in the later years. These natural gas/hydrogen blend peaking units can also have biodiesel backup capability if hydrogen is unavailable physically or economically. A discussion of the natural gas and hydrogen blending is in Appendix D: Generic Resource Alternatives. Figure 8.10 shows the cumulative additions of CETA-qualifying peaking capacity resources through 2045.

Figure 8.10: Cumulative Nameplate Capacity in MW for CETA-qualifying Peaking Capacity Resources — Reference Portfolio



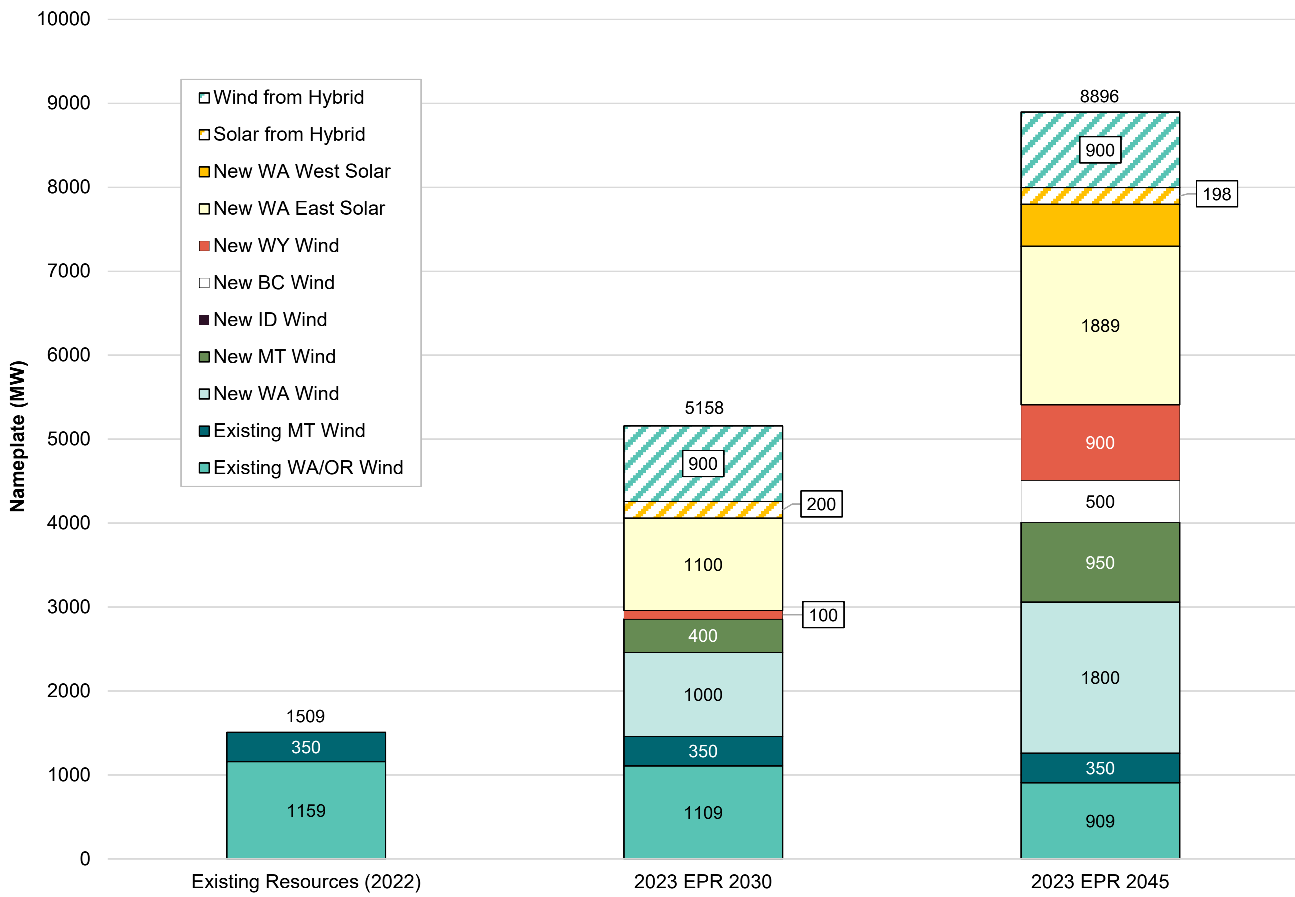
Wind and Solar Resources

We modeled multiple wind regions for this report, and we see this diversity reflected in the Reference portfolio, including Washington wind (WA), British Columbia wind (BC), Montana wind (MT), and Wyoming wind (WY) resources. Although we limited transmission for the wind resources in the near term, we assume unlimited transmission starting in 2035 for the various regions.

➔ A discussion of the transmission constraints is in Chapter Five: Key Analytical Assumptions.

By 2045, we added 5,050 MW of wind to the portfolio. This total includes a 100 MW Green Direct wind we added to the portfolio in 2026. Almost 2,100 MW of solar added to the reference portfolio comes from the WA East region and an additional 500 MW from the WA West region. We will add nearly 8,900 MW of wind and solar to the portfolio by 2045 to meet CETA requirements. Figure 8.11 shows wind and solar resources' significant growth and diversification through 2045.

Figure 8.11: Wind and Solar Resources Cumulative Nameplate Capacity – Reference Portfolio (MW)

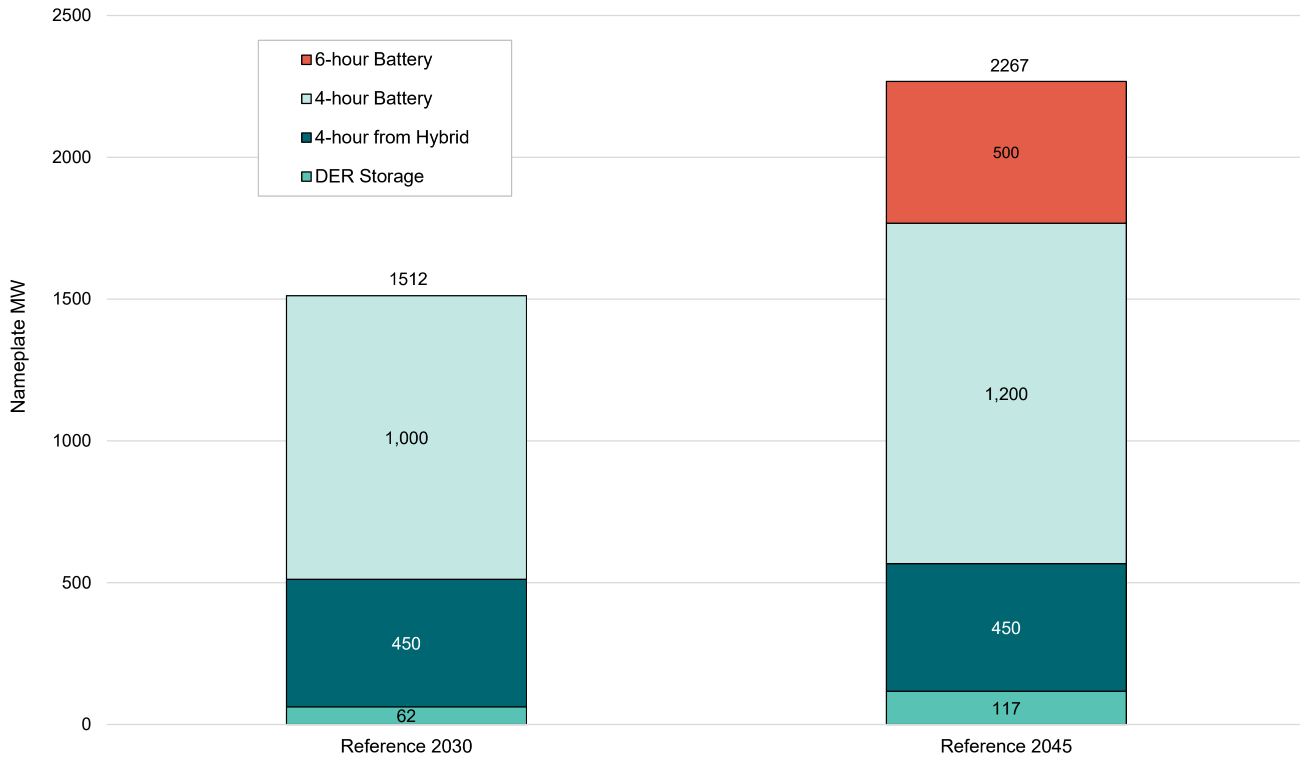


Energy Storage

Energy storage added to the portfolio comes from 1,200 MW of 4-hour batteries and 500 MW of 6-hour batteries. An additional 450 MW of 4-hour batteries are also added from the hybrid resources. Storage resources have a high effective load carrying capability (ELCC) for the first tranche of 1,000 MW, which is beneficial in meeting peak needs; however, the saturation effect can significantly impact the ELCCs. Figure 8.12 shows the storage additions through 2045.

➔ See Chapter Five: Key Analytical Assumptions for a detailed discussion of hybrid resources, and Chapter Seven: Resource Adequacy for ELCC energy storage and saturation effects.

Figure 8.12: Cumulative Nameplate Capacity in MW for Storage Resources — Reference Portfolio



Nuclear Small Modular Reactors and Biomass

Advanced nuclear small modular reactors (SMRs) and Biomass resources are CETA-qualifying resources; however, we did not add them to the reference portfolio due to higher costs than the resources.

➔ See Appendix I: Electric Analysis Inputs and Results for more detailed information on portfolio build results.

6. Sensitivity Analysis Results

Portfolio sensitivity analysis is an essential form of risk analysis that helps us understand how specific assumptions change the mix of resources in the portfolio and affect portfolio costs. Examples of a sensitivity include requiring the model to have 400 megawatts of energy storage in 2025 and 2026, relaxing transmission constraints between 2040 and 2045, or restricting any thermal resource additions during the entire planning period. This section provides the results and detailed analysis for each sensitivity.

More results, including year-by-year resource timelines, cost breakdowns, and emissions data, are in Appendix I: Electric Analysis Inputs and Results. Chapter Five: Key Analytical Assumptions includes 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. Appendix D: Generic Resource Alternatives discusses existing electric resources and resource alternatives. Appendix J: Economic, Health, and Environmental Benefits Assessment of Current Conditions details the CBIs we used in the customer benefits analysis.

6.1. Summary of Resource Modeling Assumptions

The resource alternative sensitivities schedule targeted and isolated resource additions to explore the effects on builds, cost, and emissions. Sensitivities 2–9 explore adding additional conservation, distributed resources, pumped heat electrical storage (PHES) resources, maximizing existing Montana transmission, and pursuing advanced nuclear SMR resources.

The diversified portfolio sensitivities 11 A1 and 11 B2 take what we learned from sensitivities 2–9 and combine them in a portfolio to identify an achievable portfolio of diverse resources that maximize equity-related benefits while maintaining reliability and affordability.

We modeled sensitivities 10 and 12 through 16 following requests from interested parties.

Table 8.2 describes the sensitivities we evaluated in this 2023 Electric Report.

➔ Additional details, including assumptions, are available in Chapter Five: Key Analytical Assumptions.

Table 8.2: 2023 Electric Progress Report Portfolios and Sensitivities

ID	Name	Type	Description
1	Reference	Portfolio	Least-cost and CETA-compliant
2	Conservation Bundle 10	Resource Alternative	Reference + Increase conservation to 486 aMW by 2045
3	Conservation Bundle 7	Resource Alternative	Reference + Increase conservation to 381 aMW by 2045
4	DER Solar	Resource Alternative	Reference Portfolio + 30 MW/year of DER rooftop solar from 2026–2045
5	DER Batteries	Resource Alternative	Reference + 25 MW/year of DER batteries (3-hour Li-ion) from 2026–2031
6	MT Wind PHES, All East Wind	Resource Alternative	Reference + 400 MW MT East Wind + 200 MW MT PHES in 2026
7	MT Wind PHES, Central & East Wind	Resource Alternative	Reference + 200 MW MT East Wind + 200 MW MT Central Wind + 200 MW MT PHES in 2026
8	PNW PHES	Resource Alternative	Reference + 200 MW of PNW PHES in 2026
9	Advanced Nuclear SMRs	Resource Alternative	Reference + 250 MW of advanced nuclear SMRs in 2032
11 A1	Least Diversified Sensitivity w/ Advanced Nuclear SMRs	Diversified portfolio	Reference + more conservation (Bundle 7) + 400 MW MT East Wind + 200 MW MT

ID	Name	Type	Description
			PHES in 2026 + 250 MW advanced nuclear SMRs in 2032
11 A2	Diversified + PNW PHES	Diversified portfolio	Diversified Portfolio 11 A1 + 200 MW PNW PHES in 2026
11 A3	Diversified + DER Solar	Diversified portfolio	Diversified Portfolio 11 A2 + 30 MW per year of DER rooftop solar from 2026–2045
11 A4	Diversified + DER Batteries	Diversified portfolio	Diversified Portfolio 11 A3 + 25 MW per year of DER batteries (3hr Li-ion) from 2026–2031
11 A5	Diversified + All DR Programs	Diversified portfolio	Diversified Portfolio 11 A4 + All DR Programs
11 B1	Least Diversified w/o Advanced Nuclear SMRs (11 A1 – Adv. Nuclear SMRs)	Diversified portfolio	Reference portfolio + more conservation (Bundle 7) + 400 MW MT East Wind + 200 MW MT PHES in 2026 Similar to Diversified Portfolio A1, without Adv. Nuclear SMRs
11 B2	Most Diversified w/o Advanced Nuclear SMRs (11 A5 – Adv. Nuclear SMRs)	Diversified portfolio	Diversified Portfolio 11 A5 less 250 MW Advanced Nuclear SMRs in 2032
10	Thermal builds prohibited before 2030	Requested Sensitivity	Reference + Peaker plants use biodiesel as an alternative fuel.
12	100% Renewable/Non-Emitting by 2030	Requested Sensitivity	Reference + Existing thermal retired by 2030; no new thermal allowed
13	High Carbon Price	Requested Sensitivity	Reference + CCA ceiling price used for all carbon allowances
14	No Hydrogen Fuel Available	Requested Sensitivity	Reference + Natural gas and biodiesel fuel are available, but not hydrogen fuel
15	SGHG in Dispatch	Requested Sensitivity	Reference + Model SCGHG costs as dispatch cost in the long-term capacity (LTCE) expansion model
16	WRAP Adjustment	Requested Sensitivity	Reference + Adjust PRM and ELCCs using information from WRAP

6.2. Key Findings

This section briefly summarizes the results of each sensitivity analyzed in this report.

6.2.1. Resource Alternative Sensitivities

Sensitivity 2 — Conservation Bundle 10 and Sensitivity 3 — Conservation Bundle 7

More expensive conservation measures led to a slightly lower selection of renewable resources and increased the overall portfolio costs. Increased additions of conservation measures provided near-term benefits in greenhouse gas emission reductions. However, the impact of emission reduction in the long-term, particularly in 2045, when almost all the resources in the portfolio are considered CETA-qualifying, is less significant. A further discussion of energy efficiency measures modeled can be found in Appendix E: Conservation Potential Assessment.

Sensitivity 4 DER Solar: Scheduling in additions of DER Solar at a rate of 30MW per year did not produce a substantially different portfolio but accounted for a notable increase in solar capacity and moderate change in total portfolio cost.

Sensitivity 5 DER Storage: Significant resource movement occurred due to a relatively small incremental increase in DER storage, such as 500 MW less utility-scale solar, added to the portfolio compared to the reference portfolio. This sensitivity decreased portfolio cost by $0.14 billion and decreased the total portfolio cost with SCGHG by $0.08 billion.

Sensitivity 6 MT Wind and Pumped Hydroelectric Energy Storage (PHES), All MT East Wind: Scheduled additions of eastern Montana wind and Montana pumped hydroelectric storage delay the addition of CETA qualifying peak resources, resulting in an accelerated reduction of GHG emissions but at an overall higher portfolio cost. Compared to sensitivity 7, which adds both eastern and central Montana wind and Montana PHES, sensitivity 6 provides fewer greenhouse gas reductions but significantly lower total portfolio cost. Therefore, sensitivity 6 is a more cost-effective strategy to lower greenhouse gas emissions and diversify energy storage resources.

Sensitivity 7 MT Wind and PHES, Central and East Wind: Scheduled additions of Montana east and central wind and Montana PHES slightly accelerate the reduction of greenhouse gases compared to the reference portfolio but at a higher overall portfolio cost. Compared to sensitivity 6, which adds only eastern Montana wind and Montana PHES (no central Montana wind), the greenhouse gas emission reductions for sensitivity 7 are greater, but the overall portfolio cost is also higher. Therefore, it is not a cost-effective strategy to overbuild the capacity of Montana transmission to reduce greenhouse gas emissions and diversify the energy storage resources.

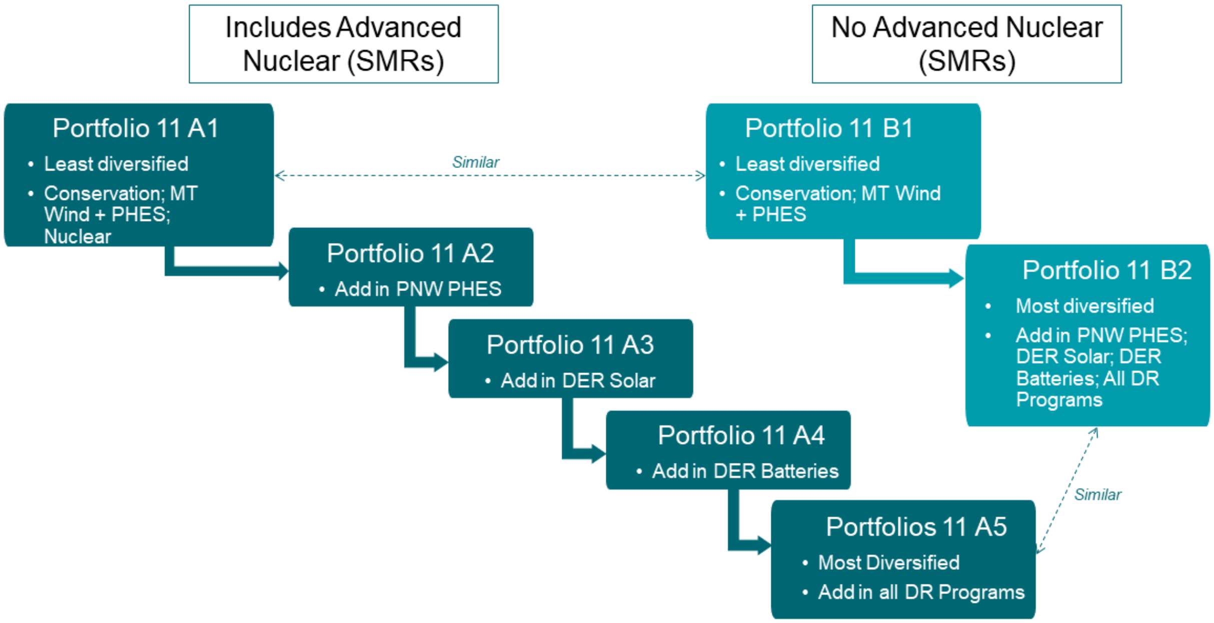
Sensitivity 8 PNW PHES: There is little difference between sensitivity 8 and the reference portfolio. Adding PNW PHES increases portfolio cost but results in little change to the overall outcome of the portfolio in terms of resource additions and greenhouse gas emissions, suggesting there is little benefit in adding PNW PHES as a means to diversify away from battery energy storage systems in the preferred portfolio.

Sensitivity 9 Advanced Nuclear Small Modular Reactors (SMRs): The ability of advanced nuclear SMRs to provide reliability and flexibility benefits for peak events while also providing the added benefit of emission-free production for meeting the CETA clean energy standards lead to the displacement of some renewable and peaking capacity resources. Overall, we see slightly lower portfolio additions by 2045 due to the addition of 250 MW of SMR; however, these advanced nuclear SMRs are more expensive and raise the portfolio costs by $1.47 billion.

6.2.2. Diversified Portfolio Sensitivities

The diversified portfolio sensitivities broaden the resource additions, lower the technology and feasibility risks, and seek to maximize equity-related benefits. Figure 8.13 illustrates the relationships between the diversified portfolios we explored in this report.

Figure 8.13 Diversified Portfolio Sensitives Map



Sensitivity 11 A1–A5 Diversified: All diversified 11 A sensitivities have higher costs than the reference portfolio. As expected, each sequential resource addition correspondingly increases the sensitivity cost: of the diversified 11 A sensitivities, 11 A1 has the least cost and 11 A5 the highest. Adding advanced nuclear SMR resources will cause an additional cost spike in 2032.

Resource additions are relatively similar across the 11 A sensitivities by 2030, with expected variation in DER resources as these are added in 11 A3 and beyond. Notably, CETA qualifying peaking capacity in 2030 is equivalent across all sensitivities, including the reference, indicating a need for dispatchable energy soon. In the longer term, the wind, solar, and hybrid resource mix becomes slightly more pronounced across the diversified 11 A sensitivities, while CETA-qualifying peaking capacity, demand-side resources, and stand-alone storage resources are relatively similar. All diversified 11 A sensitivities reduce GHG emissions compared to the reference portfolio. This reduction is greatest in sensitivity 11 A5, which produces 7 million short tons fewer emissions than the reference portfolio.

Sensitivity 11 B1 Least Diversified without Advanced Nuclear SMR: Sensitivity 11 B1 provides a little diversification relative to the reference portfolio by adding PHES and increasing energy efficiency measures. These scheduled additions result in a markedly different overall portfolio with fewer nameplate additions, made possible by selecting resources with higher peak capacities contributions, such as hybrid resources instead of stand-alone wind and solar resources. Despite adding fewer resources overall, the early addition of hybrid and storage resources inflated the portfolio cost above the reference portfolio. Greenhouse gas emission reductions are accelerated before 2030 but align with the reference portfolio 2030–2045.

Sensitivity 11 B2 Most Diversified without Advanced Nuclear SMRs: Sensitivity 11 B2 provides diversification relative to the reference portfolio by adding distributed energy resources, PHES, and additional DSR. This diversification shifts the resource mix away from utility-scale resources toward distributed energy resources and DSR. Early additions of Montana wind and distributed solar reduce existing thermal resources dispatch and accelerate the reduction of greenhouse gases before 2030. Fewer new thermal peaking capacity resources are required in sensitivity 11 B2 due to increased additions of stand-alone storage and hybrid resources. We selected this portfolio as the preferred portfolio and explained its benefits in Chapter Three: Resource Plan of the 2023 Electric Report.

6.2.3. Requested Sensitivities

Sensitivity 10 No New Thermal before 2030 and Biodiesel as the Alternative Fuel: Delaying the availability of thermal peaking capacity resources until 2030 results in an additional 3,700 MW of battery storage and 900 MW of hybrid resources before 2030, displacing 839 MW of thermal plants built during that time. Adding over 5.0 GW of batteries in six years would be challenging to accomplish, given the magnitude. As of October 2022, only 7.8 GW of utility-scale batteries are operating nationwide.[12] After we lifted the thermal restriction in the model, it added minimal batteries due to the over-saturation of batteries in meeting peak. This sensitivity is $0.91 billion more expensive than the reference portfolio.

Sensitivity 12 100 Percent Renewable/Non-Emitting by 2030: Implementing the necessary changes for this sensitivity created substantial issues for the model. The short-term resource need became too large due to mass retirements of firm capacity, and the model could not make up for this with available new resources and transmission constraints as defined in the reference case. This sensitivity did not produce a solution, which speaks to the challenges of quickly retiring large amounts of thermal capacity.

Sensitivity 13 High Carbon Price Based on the Ceiling Price Assumption: The resource mix between the reference portfolio and sensitivity 13 is very similar, indicating that increased carbon costs do not significantly impact build decisions. This sensitivity costs less than the reference, driven primarily by a lower SCGHG. These results indicate a decrease in emitting resource dispatch, as we may expect with higher market prices for carbon allowances.

Sensitivity 14 No Hydrogen Fuel Available: There is a significant difference between sensitivity 14 and the reference portfolio. Without access to hydrogen fuel, we no longer see an accelerated reduction in GHG emissions, and portfolio costs are significantly higher, suggesting a notable benefit to hydrogen fuel as an alternative fuel option. Therefore, we should continue exploring blending hydrogen with natural gas fuel.

Sensitivity 15 SCGHG in Dispatch: Including the SCGHG in the dispatch cost for the long-term capacity expansion model adversely decreases the capacity factor of PSE's thermal plants, resulting in 2,000 MW of renewable resource additions by 2025, more than the energy needed for the year. This scenario also doubles PSE's existing renewable resources of 1,700 MW in three years. The CETA requirement is the driving factor for the resource build decisions by 2045.

Sensitivity 16 WRAP Adjustment: We cannot run the long-term capacity expansion model to evaluate sensitivity 16 due to incomplete information regarding ELCC saturation curves for renewable and storage resources from the Western Resource Adequacy Program (WRAP). We also understand that the WRAP data is not intended for long-term resource planning. Our best estimate using the WRAP PRM shows a decrease in the winter peak capacity need

[12] https://www.eia.gov/todayinenergy/detail.php?id=54939

by 300 MW and a reduction in the summer peak need by 1,200 MW in 2029. We need further study to incorporate WRAP in long-term resource planning. The WRAP estimated seasonal PRMs are in Table 8.3.

Table 8.3 PRM and Peak Capacity Needs

Sensitivity Year/Season	1 Reference 2029 Winter	1 Reference 2029 Summer	16 WRAP Adjustment 2029 Winter	16 WRAP Adjustment 2029 Summer
Peak Load (MW)	5,104	4,300	4,570	3,447
PRM (MW)	1,215	1,029	956	470
PRM%	24%	24%	21%	14%
Existing Resources Peak Capacity (MW)	3,607	2,493	3,120	2,343
Additional perfect capacity for 5% LOLP (MW)	2,712	2,837	2,406	1,574

6.3. Portfolio Costs

This section describes the changes in portfolio costs for the sensitivities evaluated in the 2023 Electric Progress Report. The portfolio cost in dollars is the levelized, net present value of the annual cost impacts for 22 years excluding SCGHG costs. This includes:

- Alternative compliance costs
- CCA costs
- Decommissioning costs as part of the economic decision of plant retirements
- Fixed and variable costs of existing resources and new resources
- Fuel costs
- Net market purchases and sales

We report the SCGHG as an externality cost separately. The sum of the portfolio costs and the SCGHG costs is what we refer to as total portfolio costs in this chapter.

6.3.1. Resource Alternative Sensitivities

Table 8.4 and Figure 8.14 show the costs associated with the Resource Alternative sensitivities 2–9 described in this section.

Sensitivity 2 — Conservation Bundle 10 and Sensitivity 3 — Conservation Bundle 7: As expected, increased distribution and energy efficiency additions led to higher portfolio costs. The portfolio cost of sensitivity 2 is $0.97 billion higher than the reference portfolio. However, the SCGHG of sensitivity 2 is $0.17 billion lower than the reference portfolio. This results in a net increase in total portfolio cost of $0.81 billion for sensitivity 2 compared to the reference portfolio. For sensitivity 3, the portfolio cost is $0.35 billion higher than the reference portfolio. Similar to sensitivity 2, the SCGHG of sensitivity 3 is also lower than the reference portfolio by $0.34 billion. This results in a net increase in total portfolio cost of $0.01 billion for sensitivity 3 compared to the reference portfolio.

Sensitivity 4 DER Solar: The total portfolio cost of sensitivity 4 is higher than the reference as expected by the substantial increase in DER solar resources shown to be relatively high cost by the reference case. The difference in portfolio cost between the two is significant at $0.45 billion, but with the inclusion of the social cost of greenhouse gases (SCGHG), the total portfolio cost difference is more moderate at $0.23 billion.

Sensitivity 5 DER Storage: The total portfolio costs between sensitivity 5 and the reference case were reasonably consistent. The total portfolio cost changes slightly, making sensitivity 5 $0.08 billion less over its lifetime. There is a bigger difference between the two in portfolio cost, but some of this is offset by small changes in SCGHG costs. Emissions are similar enough in both cases that the portfolio cost comparison with and without SCGHG does not vary dramatically, and the two portfolios follow similar cost trends in both instances.

Sensitivity 6 MT Wind and PHES, All MT East Wind: The portfolio cost of sensitivity 6 is $0.2 billion higher than the reference portfolio. However, the SCGHG of sensitivity 6 is $0.18 billion lower than the reference portfolio. These two components of the total cost of the sensitivity are offsetting, resulting in the total portfolio cost for sensitivity 6, which is just $0.02 billion higher than the reference portfolio. Compared to the reference portfolio, the scheduled addition of Montana east wind and Montana PHES delay the addition of 474 MW of CETA-qualifying peaking resources from 2025–2029 and offsets dispatch of existing thermal resources resulting in an accelerated reduction in GHG emissions but at a higher overall cost.

Sensitivity 7 MT Wind and PHES, Central and East Wind: The portfolio cost of sensitivity 7 is $0.7 billion higher than the reference portfolio. However, the SCGHG of sensitivity 7 is $0.37 billion lower than the reference portfolio. This results in a net increase in total portfolio cost of $0.33 billion for sensitivity 7 compared to the reference portfolio. Compared to the reference portfolio, the scheduled addition of Montana wind and Montana PHES delays the addition of 474 MW of CETA-qualifying peaking resources from 2025 to 2027 and offsets the dispatch of existing thermal resources resulting in an accelerated reduction in GHG emissions but at a higher overall cost.

Sensitivity 8 PNW PHES: The portfolio cost of sensitivity 8 is $0.55 billion higher than the reference portfolio. However, the SCGHG of sensitivity 8 is $0.12 billion lower than the reference portfolio. This results in a net increase in total portfolio cost of $0.43 billion for sensitivity 8 compared to the reference portfolio.

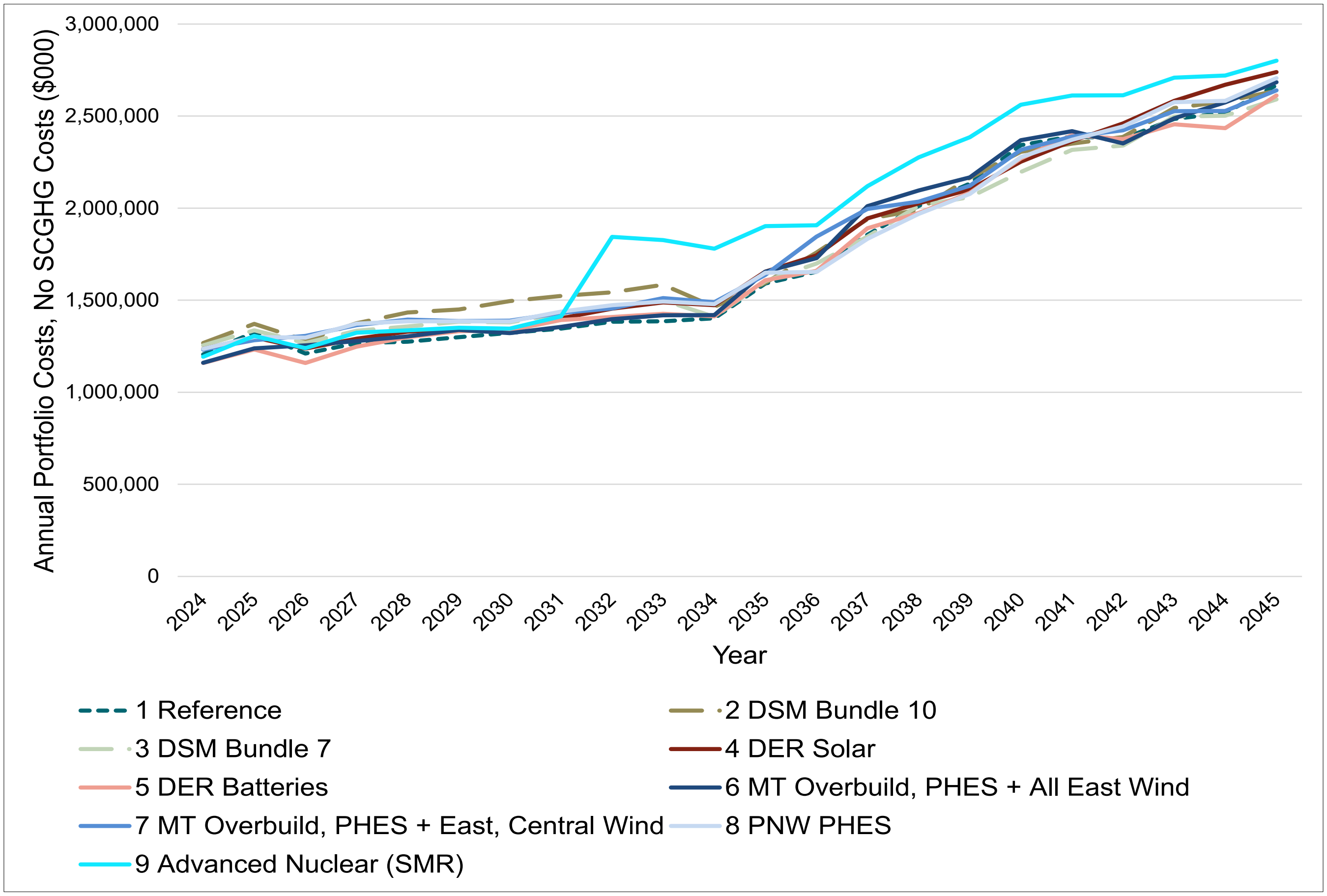
Sensitivity 9 Advanced Nuclear SMRs: Sensitivity 9 is a higher cost overall than the reference portfolio, and costs begin to diverge at a greater pace as the model added advanced nuclear SMR resources to the portfolio in 2032. This results in a net increase in total portfolio cost of $1.47 billion for sensitivity 9 compared to the reference portfolio.

Table 8.4 Resource Alternatives Portfolio Costs, 2024–2045 NPV ($ Billions)

Portfolio	Portfolio Cost ($)	SCGHG Costs ($)	Total ($)	Change from Reference ($)	Change from Reference (%)
1 Reference	17.61	3.24	20.85	0.00	-
2 DSM Bundle 10	18.58	3.07	21.65	0.81	4
3 DSM Bundle 7	17.96	2.90	20.86	0.01	0
4 DER Solar	18.06	3.02	21.08	0.23	1
5 DER Batteries	17.47	3.30	20.77	-0.08	0

Portfolio	Portfolio Cost ($)	SCGHG Costs ($)	Total ($)	Change from Reference ($)	Change from Reference (%)
6 MT Overbuild, PHES + All East Wind	17.81	3.06	20.87	0.03	0
7 MT Overbuild, PHES + East, Central Wind	18.31	2.87	21.18	0.34	2
8 PNW PHES	18.16	3.12	21.28	0.44	2
9 Advanced Nuclear SMRs	19.34	2.98	22.32	1.47	7

Figure 8.14: Annual Portfolio Costs — Resource Alternatives



6.3.2. Diversified Portfolio Sensitivities

The costs associated with the diversified portfolio sensitivities 11 A1-A5 and 11 B1-B2 are described in this section and summarized in Table 8.5 and Figure 8.15.

Sensitivity 11 A1 – A5 Diversified: All diversified 11 A sensitivities cost substantially more than the least-cost reference portfolio (Table 8.5). The least-diversified sensitivity, 11 A1, adds conservation, an advanced nuclear SMR power plant, and maximizes existing Montana transmission. These resource additions cost $2 billion (10 percent) more than the reference portfolio. Each subsequent resource addition, as observed in sensitivities 11 A2 through 11 A5, increases the total cost compared to the sensitivity proceeding it. However, adding DER solar and demand response programs cost approximately $0.02 billion each, whereas adding the Pacific Northwest PHES and DER batteries cost nearly twenty times this amount, approximately $0.4 billion each.

Generally, the diversified 11 A sensitivity costs are similar year to year through the 22-year planning period. Though costlier, they follow the reference portfolio trend through 2045 (Figure 8.15). Adding 250 MW of advanced nuclear SMRs is the notable exception: the spike above the reference portfolio in 2032 reflected the costs of this technology when we added this resource to the 11 A sensitivities.

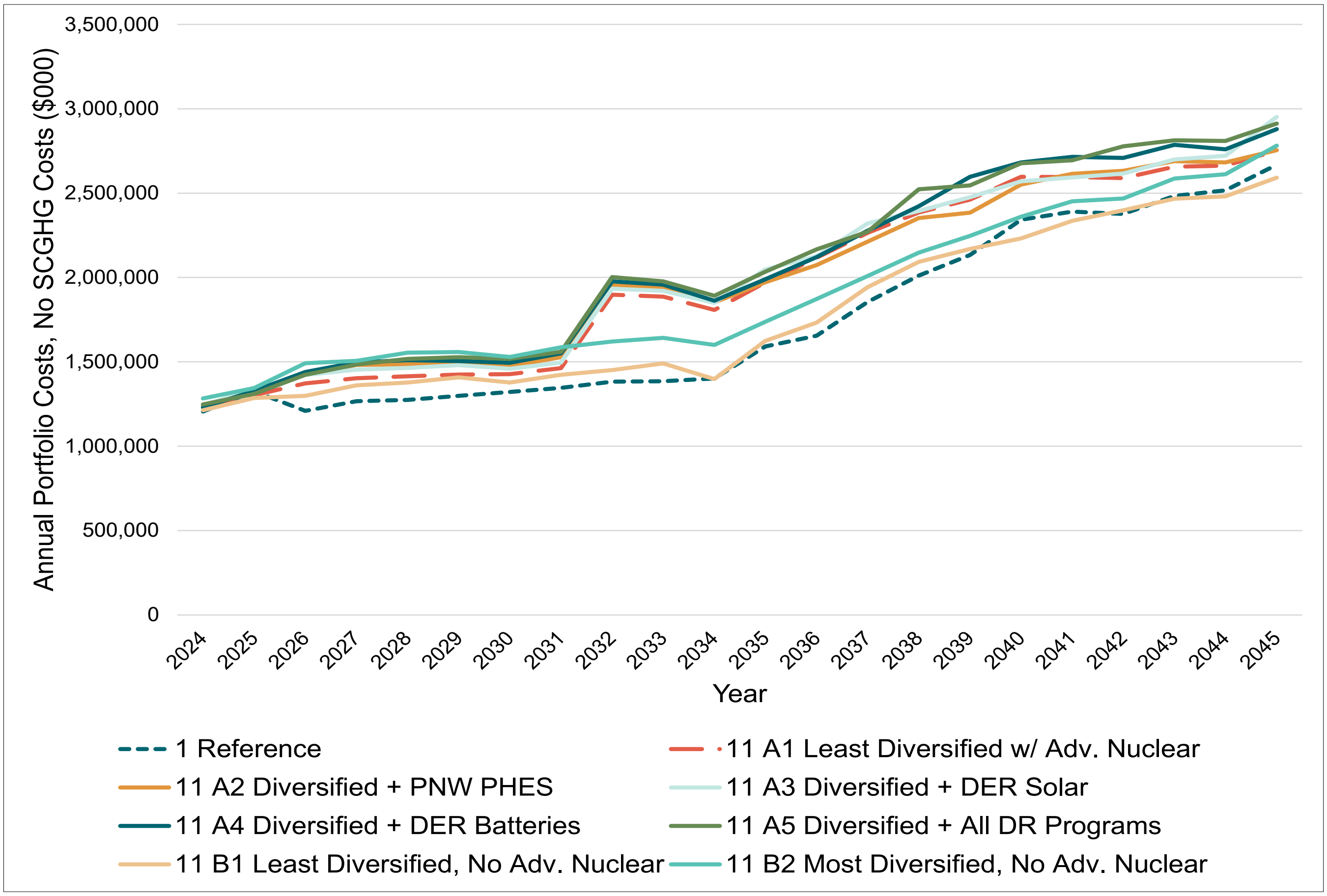
Sensitivity 11 B1 Least Diversified without Advanced Nuclear SMRs: The cost of sensitivity 11 B1 is $0.48 billion higher than the reference portfolio. However, the SCGHG of sensitivity 11 B1 is $0.24 billion lower than the reference portfolio. This results in a net increase in the total cost of $0.24 billion for sensitivity 11 B1 compared to the reference portfolio. Early additions of hybrid and storage resources resulted in increased capital spending on resources in the years before 2030. Despite fewer nameplate additions overall, sensitivity 11 B1 results in a higher cost due to generally higher cost resources added earlier in the modeling horizon.

Sensitivity 11 B2 Most Diversified without Advanced Nuclear SMRs: The portfolio cost of sensitivity 11 B2 is $1.95 billion higher than the reference portfolio. However, the SCGHG of sensitivity 11 B2 is $0.29 billion lower than the reference portfolio. This results in a net increase in the total cost of $1.66 billion for sensitivity 11 B2 compared to the reference portfolio.

Table 8.5: 11 A Diversified Portfolio Costs, 2024–2045 NPV ($ Billions)

Portfolio	Portfolio Cost ($)	SCGHG Costs ($)	Total ($)	Change from Reference ($)	Change from Reference (%)
1 Reference	17.61	3.24	20.85	0.00	0
11 A1 Least Diversified w/ Adv. Nuclear SMRs	20.01	2.82	22.83	1.99	10
11 A2 Diversified + PNW PHES	20.32	2.93	23.25	2.40	12
11 A3 Diversified + DER Solar	20.44	2.83	23.27	2.42	12
11 A4 Diversified + DER Batteries	20.74	2.90	23.64	2.80	13
11 A5 Diversified + All DR Programs	20.89	2.78	23.67	2.82	14
11 B1 Least Diversified w/o Advanced Nuclear SMRs	18.09	3.00	21.09	0.24	1
11 B2 Most Diversified w/o Advanced Nuclear SMRs	19.56	2.95	22.51	1.66	8

Figure 8.15: Annual Portfolio Costs — Diversified Portfolios



6.3.3. Requested Sensitivities

The costs associated with sensitivities 10 and 12-16 are described in this section and summarized in Table 8.6 and Figure 8.16.

Sensitivity 10 No New Thermal before 2030 and Biodiesel is the Alternative Fuel: The portfolio cost of sensitivity 10 is $1.67 billion higher than the reference portfolio. However, the SCGHG of sensitivity 10 is $0.77 billion lower than the reference portfolio. These two components of the total cost of the sensitivity are offsetting, resulting in the total portfolio cost for sensitivity 10, which is just $0.91 billion higher than the reference portfolio. The restriction on thermal additions before 2030 results in the addition of more expensive stand-alone storage and hybrid resources in the near term and offsets dispatch of existing thermal resources resulting in reduced GHG emissions but at a higher overall cost.

Sensitivity 12 100 percent Renewable/Non-Emitting: This sensitivity did not solve due to the issues we discussed in the Key Findings section and consequently did not produce any portfolio cost metrics.

Sensitivity 13 High Carbon Price Based on the Ceiling Price Assumption: The portfolio cost without the SCGHG adder for this sensitivity is $0.50 billion higher than the reference case, likely driven by higher market prices. However, the SCGHG adder is $0.52 billion less than the reference case, resulting in an overall portfolio cost of $0.02

billion less than the reference case. This sensitivity illustrates that the higher market prices for carbon allowances result in decreased emitting resource dispatch, as shown by the lower SCGHG.

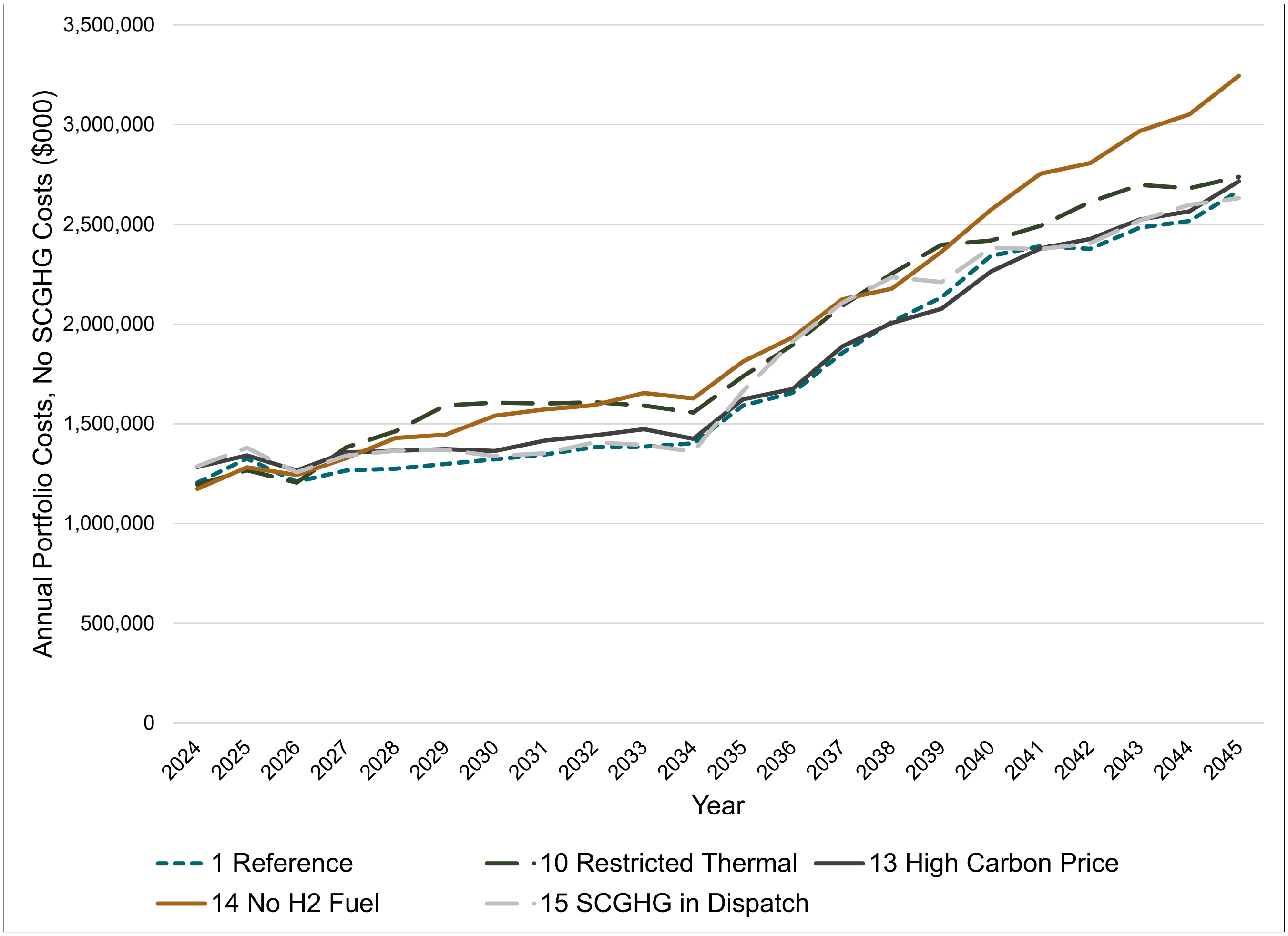
Sensitivity 14 No Hydrogen Fuel Available: The portfolio cost of sensitivity 14 is $2.03 billion higher than the reference portfolio. We also see an increase in SCGHG costs for sensitivity 14, which is $2.19 billion higher than the reference portfolio. This results in a net increase in total portfolio cost of $4.23 billion for sensitivity 14 compared to the reference portfolio.

Sensitivity 15 SCGHG in Dispatch: The portfolio costs are higher for sensitivity 15, with a portfolio cost of $18.34 billion. Though the sensitivity 15 portfolio cost is $0.73 billion higher than the reference portfolio, it greatly decreases the emission costs to $2.47 billion. The total cost of sensitivity 15 ($20.81 billion) is 0.04 billion lower than the reference portfolio total cost ($20.85 billion).

Table 8.6: Other Requested Sensitivities Portfolio Costs, 2024–2045 NPV (Billions)

Sensitivity	Portfolio Cost ($)	SCGHG Costs ($)	Total ($)	Change from Reference ($)	Change from Reference (%)
1 Reference	17.61	3.24	20.85	0.00	-
10 Restricted Thermal	19.28	2.47	21.75	0.91	4
13 High Carbon Price	18.11	2.72	20.83	-0.01	-0.1
14 No H2 Fuel	19.64	5.43	25.07	4.23	20
15 SCGHG in Dispatch	18.34	2.47	20.81	-0.04	0.2

Figure 8.26: Annual Portfolio Costs — Other Requested Sensitivities



6.4. Modeling Builds

This section describes the changes in resource builds for the sensitivities evaluated in this 2023 Electric Report.

6.4.1. Resource Alternative Sensitivities

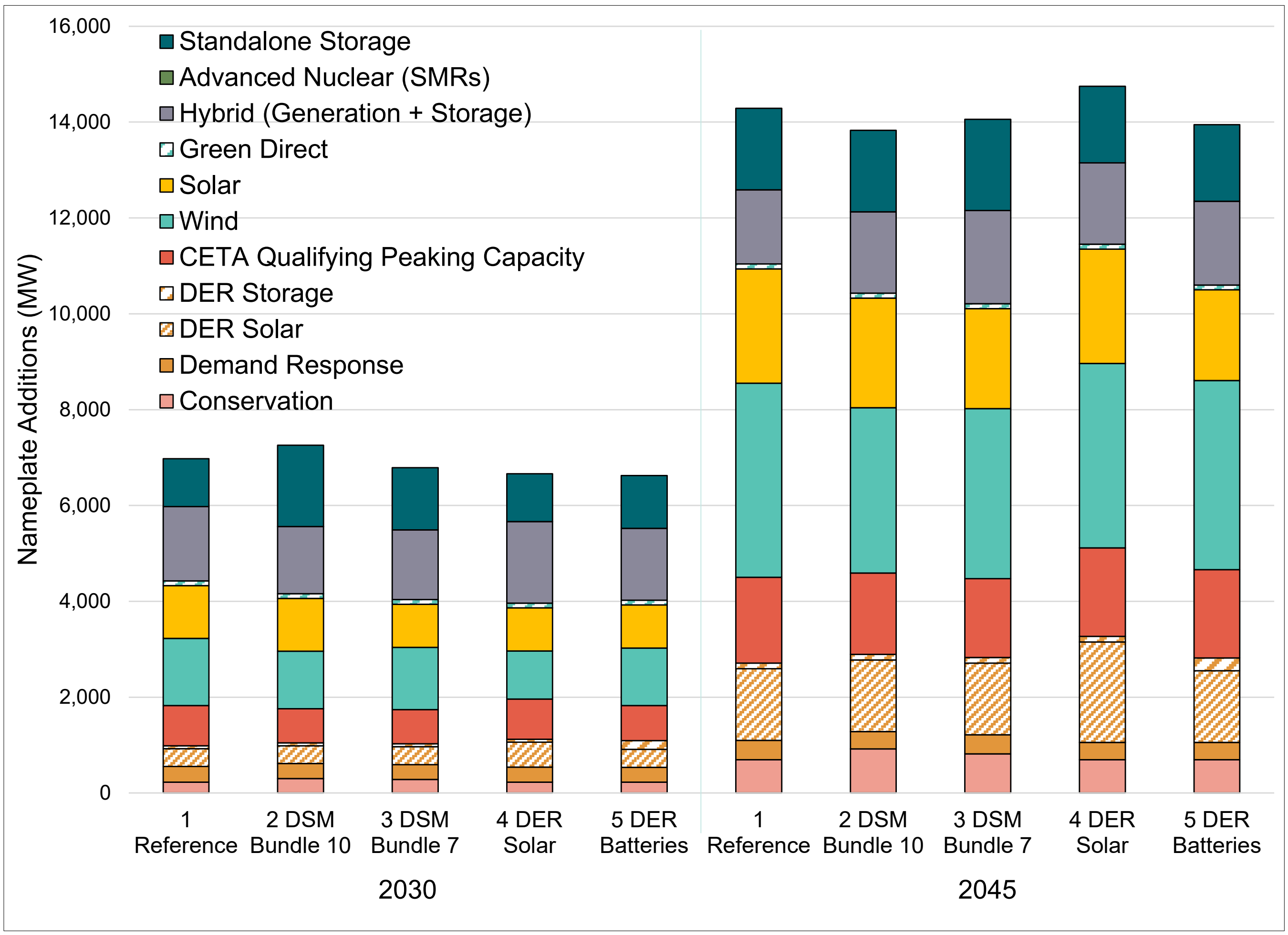
In this section, we described the resources added in the Resource Alternative sensitivities 2–9 and summarized them in Figures 8.17 and 8.18.

Sensitivity 2 — Conservation Bundle 10 and Sensitivity 3 — Conservation Bundle 7: Overall builds are similar, except for the increased addition of distributed and energy efficiency measures and slightly fewer renewable resources needed to meet CETA requirements in sensitivity 2 and sensitivity 3.

Sensitivity 4 DER Solar: Aside from the increase in DER solar capacity for sensitivity 4, it adds a similar mix of capacity by 2045 compared to the reference portfolio, although the timing of resource additions is quite different. Notable differences include a 450MW reduction in CETA-qualifying peaking capacity and a 400MW increase in utility-scale solar before 2025 for sensitivity 4. However, these resource groups end up in almost identical places at the end of the planning horizon. One consistent difference is that sensitivity 4 picks up less demand response than the reference portfolio, totaling a 41MW winter peak difference by 2045. At a coarser level, all capacity addition resource groups in sensitivity 4 are within 200 MW of their analogous group in the reference case.

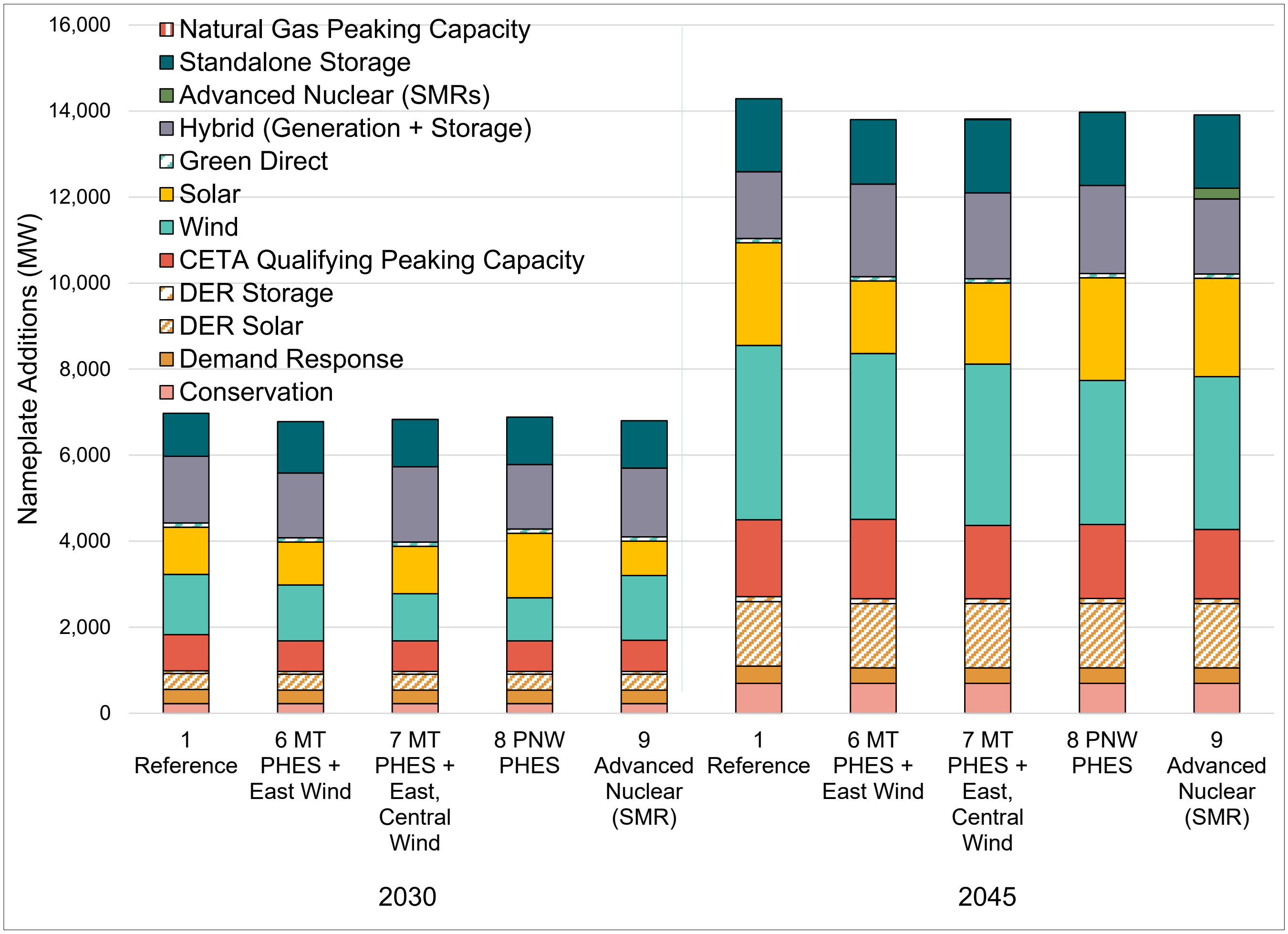
Sensitivity 5 DER Storage: A comparison between sensitivity 5 and the reference portfolio in terms of resource additions shows significant movement in certain resource groups. Most notably, by 2045, it will pick up 500 MW less solar than the reference portfolio. Other observed changes besides the prescribed DER storage increase (150 MW) include roughly 200 MW more hybrid capacity, 45 MW less demand response, a 55 MW increase in CETA-qualifying peaking capacity, and 100 MW less stand-alone storage — all by 2045. The reference portfolio builds resources earlier than sensitivity 5, building 500 MW more capacity by 2025, which lessens to a 341 MW capacity difference in 2045 at the end of the planning period.

Figure 8.37: Resource Additions — Resource Alternatives Part 1



Sensitivity 6–9: Overall builds are similar for each sensitivity and the reference portfolio, except for the scheduled addition of the resource we tested for the sensitivity.

Figure 8.48: Resource Additions — Resource Alternatives Part 2



6.4.2. Diversified Portfolio Sensitivities

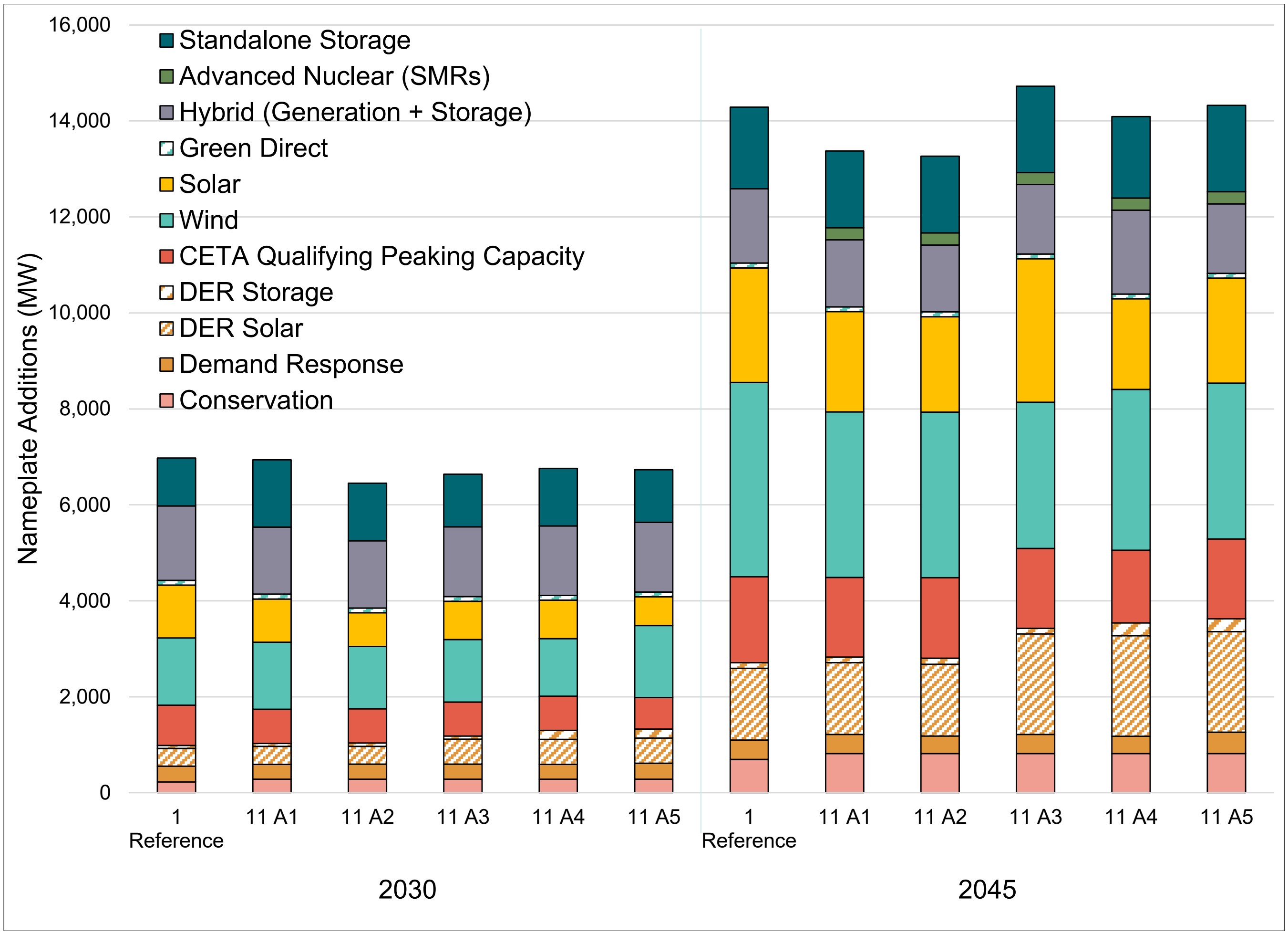
The resources added in the diversified portfolio sensitivities 11 A1–11 A5, and 11 B1–11 B2 are described in this section and summarized in Figures 8.19 and 8.20.

Sensitivity 11 A1– A5 Diversified: In the first two years of the planning period, between 2024 and 2025, the demand-side and distributed resource additions in the diversified 11 A sensitivities mirror the reference portfolio. However, this very near-term look highlights several strategies for meeting energy needs. Sensitivities 11 A1 and 11 A2 displace all three early CETA-qualifying peaking plants built in the reference portfolio with various combinations of renewable and storage resources (wind, solar, stand-alone storage, and hybrid). Peaking capacity is reduced but not replaced entirely in sensitivities 11 A3, 11 A4, and 11 A5, to 237, 474, and 18 MW, respectively. However, by 2030, CETA-qualifying peaking capacity will be equivalent across all diversified 11 A sensitivities at 711 MW, except for 11 A5, which builds slightly less at 657 MW. This indicates a constant need for dispatchable energy in the near-term planning horizon.

In the longer term, between 2031 and 2045, the resource mix becomes slightly more pronounced between the diversified sensitivities. Distributed solar and battery additions increase as expected in sensitivities 11 A3, 11 A4, and

11 A5, where we required the model to select these resource additions. Wind, solar, and hybrid resources are added in varying amounts across the 11 A sensitivities but generally sum to similar quantities by 2045. CETA-qualifying peaking capacity is a stable addition across all sensitivities, even with 250 MW of advanced nuclear SMRs, which diversifies dispatchable resources but does not displace the equivalent peaking capacity from the 11 A sensitivities. Battery storage and DSR are relatively constant across sensitivities by 2045, but both peak in 11 A5.

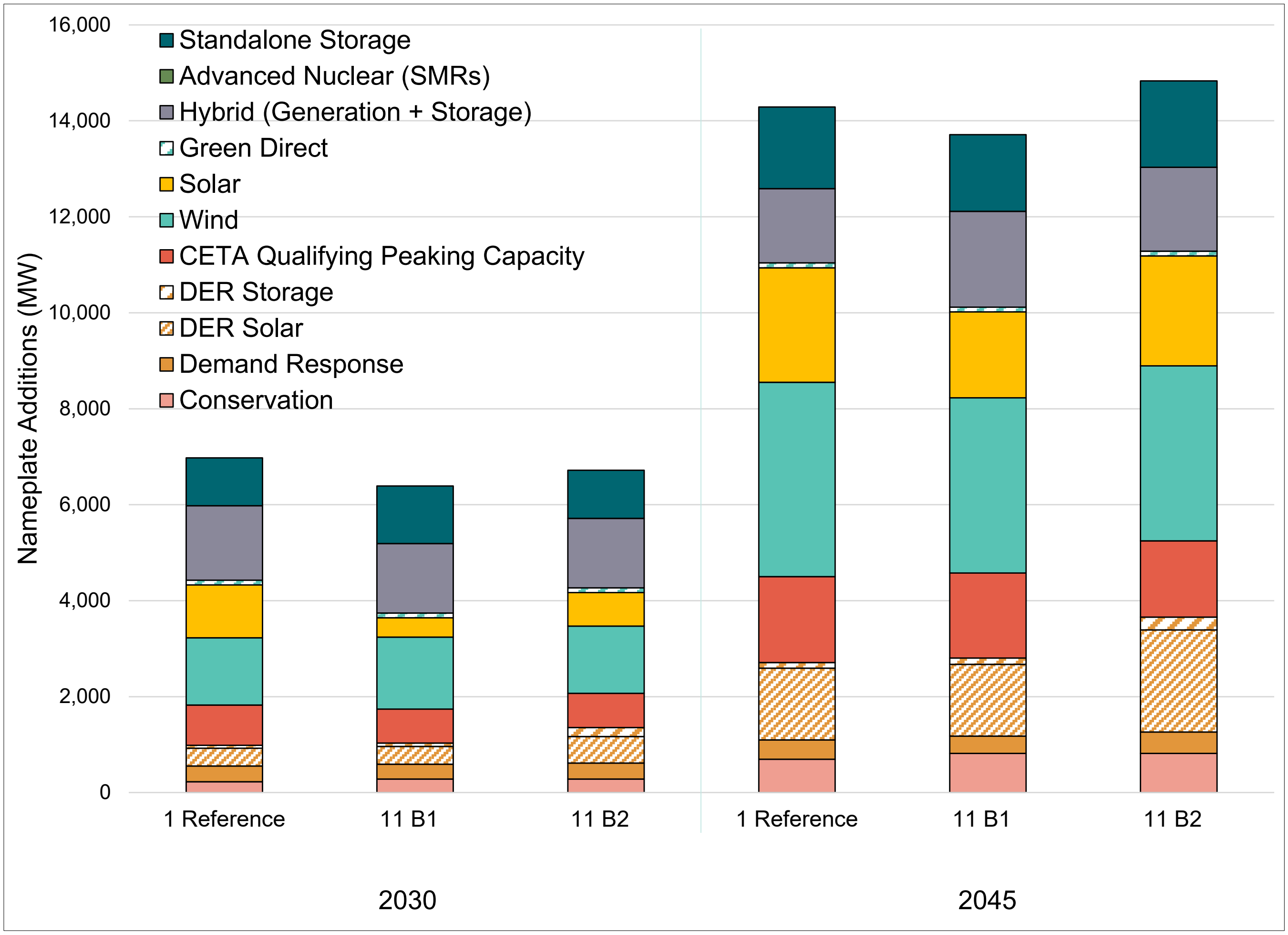
Figure 8.19: Resource Additions — Diversified Portfolio Sensitives Part 1



Sensitivity 11 B1 Least Diversified without Advanced Nuclear SMRs: Overall resource builds are similar between the reference and sensitivity 11 B1 but with a few notable differences. Sensitivity 11 B1 results in nearly 600 MW fewer nameplate capacity additions by favoring resources with a greater peak capacity contribution, such as energy efficiency measures and shifting from stand-alone wind and solar to hybrid resources. Sensitivity 11 B1 defers the addition of thermal peaking capacity resources through the earlier addition of hybrid and storage resources compared to the reference portfolio.

Sensitivity 11 B2 Most Diversified without Advanced Nuclear SMRs: Overall resource builds are similar between the reference and 11 B2 sensitivities. Sensitivity 11 B2 incorporates 780 MW more distributed solar and storage resources through scheduled resource additions than the reference case. The distributed energy resource additions in sensitivity 11 B2 reduce the capacity of stand-alone, utility-scale wind and solar resources added to the sensitivity. The percentage of demand-side and distributed resources in the sensitivity portfolio resource mix increases from 19 percent in the reference portfolio to 25 percent in sensitivity 11 B2. Increased addition of resources with high peak capacity contributions, including stand-alone storage, hybrid resources, and energy efficiency measures, reduce the total thermal peaking capacity added to sensitivity 11 B2 by 200 MW compared to the reference portfolio.

Figure 8.20: Resource Additions — Diversified Portfolio Sensitivities Part 2



6.4.3. Requested Sensitivities

We described the resources added in sensitivities 10 and 13–16 in this section and summarized in Figure 8.21.

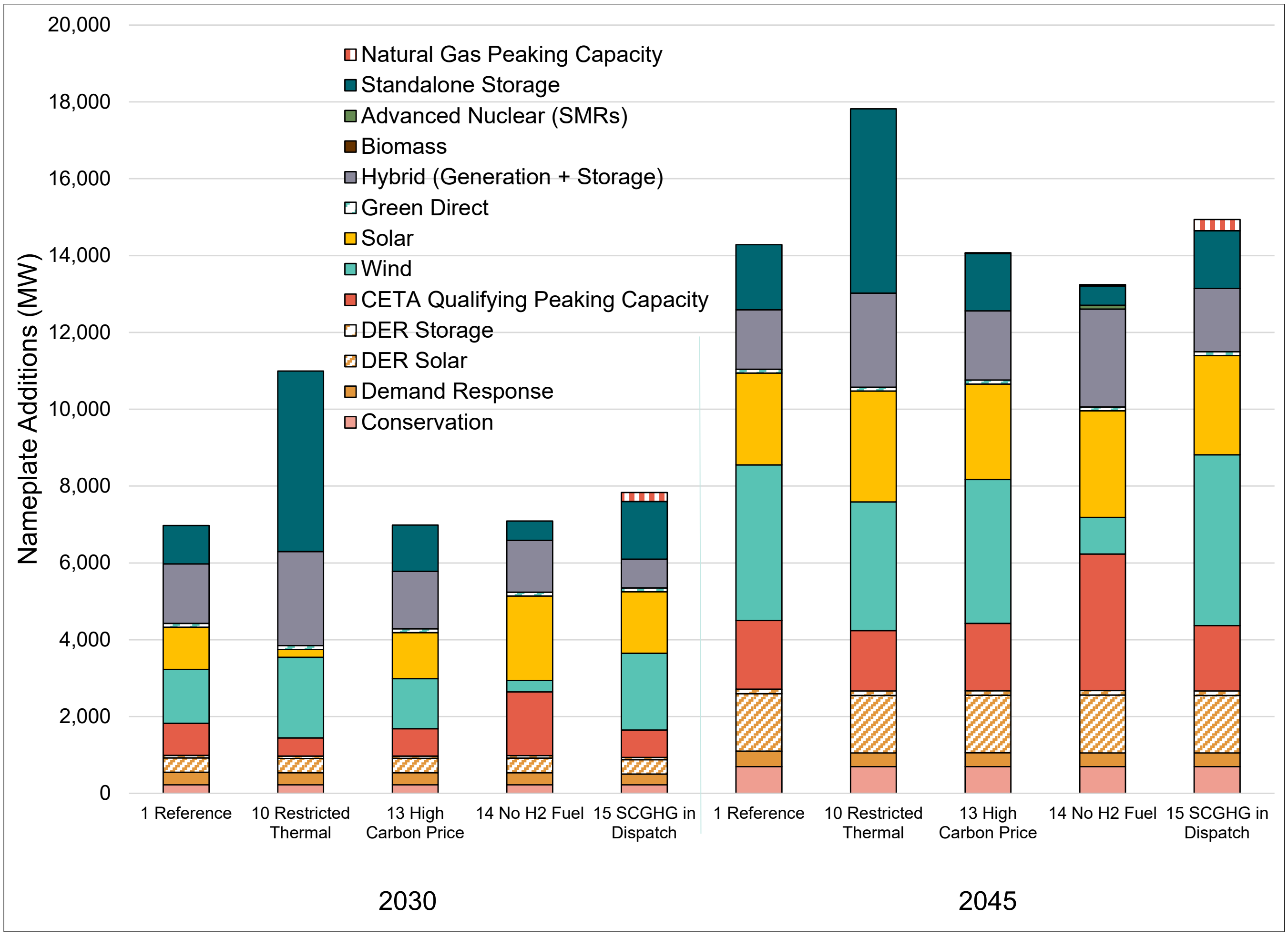
Sensitivity 10 No New Thermal before 2030, and Biodiesel as the Alternative Fuel: Sensitivity 10 adds 4,700 MW of storage to the portfolio through 2030. Once we removed the thermal restriction, an additional 1,569 MW of CETA-qualifying peaking resources were added to the portfolio, while only 100 MW of storage was added to the portfolio. The major difference between sensitivity 10 and the reference portfolio is an additional 4,000 MW of storage and hybrid resources and 200 MW less of CETA-qualifying peaking resources. We can explain this difference because as the portfolio becomes saturated with storage, the ELCC decreases.

Sensitivity 13 High Carbon Price based on the Ceiling Price Assumption: Overall builds are similar for sensitivity 13 and the reference portfolio. By 2045, sensitivity 13 has 100 MW less wind and solar resources, 50 MW less storage resources, 41 MW less of demand response, and nearly identical CETA-qualifying resources.

Sensitivity 14 No Hydrogen Fuel available: Without access to hydrogen fuel, sensitivity 14 incorporates 3,555 MW of frame peaker biodiesel resources. Interestingly, the increase in frame peaker biodiesel resources reduces the total capacity of stand-alone storage and utility-scale wind resources added to the portfolio. To meet the CETA requirement, we see a shift to increased utility-scale solar resources added in sensitivity 14. We also see the addition of 100 MW of advanced nuclear SMR resources in 2045.

Sensitivity 15 SCGHG in dispatch: Overall, we see more renewable resources added to the portfolio in the near term and a total of 8,400 MW of renewable resources added by 2045. Though surprising, we see one natural gas frame peaker and two hydrogen blend peakers added in 2024 in sensitivity 15 compared to one biodiesel peaker in the reference portfolio for the same year. These peakers are added to meet the peak capacity needs and resource adequacy requirements. The levelized cost of the capacity of the natural gas frame peaker plant with the SCGHG as an externality cost is $114/kw-yr, whereas the levelized cost of capacity with the SCGHG in dispatch is $104/kw-yr. When modeling SCGHG in dispatch, there are adverse effects on the cost of capacity of peaking resources which, in this case, led to increased resource additions earlier in the time horizon.

Figure 8.21: Resource Additions — Requested Sensitivities



7. Portfolio Benefit Analysis Results

This section describes the results of the portfolio benefit analysis.

➔ Appendix I: Electric Analysis Inputs and Results provides all underlying data, calculations, and a summary of the results in an Excel spreadsheet and may be a useful reference while reading this section.

7.1. Reference Portfolio

All results from the portfolio benefit analysis are relative to the reference portfolio. We used relative measures in this analysis because prescriptive guidelines on creating an equitable energy portfolio are currently unavailable. Relative measures provide us with an understanding of how one portfolio may enable more equitable outcomes than another.

The reference portfolio includes many aspects of an equity-enabling portfolio. The reference portfolio is the least-cost solution[13] identified by the AURORA long-term capacity expansion model: because electricity affordability is essential in enabling equitable outcomes, a low-cost portfolio is desirable. The reference portfolio produces more greenhouse gas emissions than most other portfolios analyzed but reaches zero greenhouse emissions by 2045. Similarly, the reference portfolio has higher outdoor air quality emissions (SO_2, NO_x, and PM) than most other portfolios but sees significant reductions by the end of the planning horizon.

The reference portfolio adds an estimated 45,736 jobs from new resource additions, more than many other portfolios analyzed. The reference portfolio is in the top third of portfolios for demand response peak capacity and demand response customer participation metrics. However, the reference portfolio lacks customer participation in distributed energy resources for both solar and storage. While the reference portfolio may have a CBI index of zero, it provides various customer benefits and represents a strong starting point for other portfolios.

Table 8.7 presents the reference portfolio CBI metrics against which we compared all other portfolios.

Table 8.7: Reference Portfolio CBI Metrics

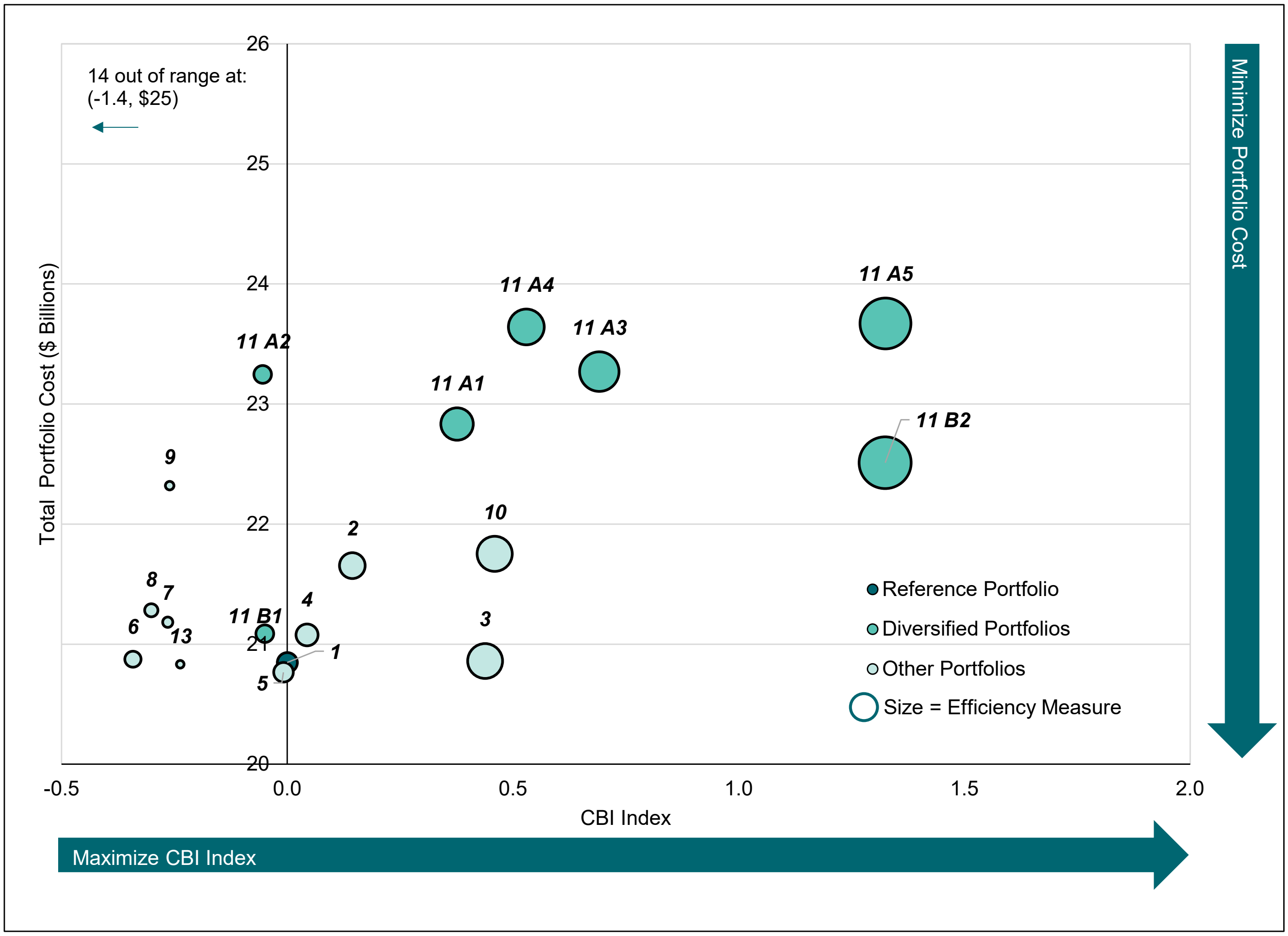
CBI Metric	Reference Portfolio
Cost (, Billions)	20.85
GHG Emissions (Short Tons)	48,824,734
SO_2 Emissions (Short Tons)	28,841
NO_x Emissions (Short Tons)	11,426
PM Emissions (Short Tons)	9,036
Jobs (Total)	45,736
Energy Efficiency Added (MW)	695
DR Peak Capacity (MW)	291
DER Solar Participation (Total New Participants)	12,115
DR Participation (Total New Participants)	513,238
DER Storage Participation (Total New Participants)	8,125

Figure 8.22 shows the results of the portfolio benefit analysis for all portfolios. Each portfolio is plotted with its CBI index value on the x-axis and total portfolio cost on the y-axis to show the tradeoff between equity enabling value and cost. The most desirable portfolios appear in the lower right corner of the plot, where cost is minimized and the CBI index is maximized. The point size estimates the CBI index per dollar spent on the portfolio, where larger points represent greater value per cost.

We plotted the reference portfolio at the CBI index equals zero line. We plotted portfolios containing elements that improve upon the reference portfolio's ability to enable equitable outcomes to the right of this line and those which may detract from equitable outcomes to the left of this line.

[13] Portfolios 5 and 13 are slightly lower cost than the reference portfolio by $80 million and $10 million, respectively. These small decreases in cost are within the 1 percent study precision tolerance of the AURORA long-term capacity expansion model.

Figure 8.22: Portfolio Benefit Analysis Results



7.1.1. Energy Efficiency

Our analysis shows portfolios that include increased energy efficiency measures tend to enable more equitable outcomes than the reference portfolio, as observed by the relationship between portfolios 2, 3, the diversified portfolios, and the reference portfolio. Portfolios 2, 3, and the diversified portfolios include increased energy efficiency measures. The reference case economically selected up to 695 aMW of conservation by 2045. We tested a large increase in energy efficiency by adding 923 aMW of conservation by 2045 in portfolio 2. This resulted in a relatively small increase in the CBI index, +0.14, but a much higher cost, +810 million. Understanding that increasing conservation results in diminishing returns, we tested slightly less conservation in portfolio 3 by adding 818 aMW and observed a larger increase in CBI index, +0.44, and a smaller increase in cost, +10 million.

The relationship between portfolios 2 and 3 illustrate the complexity of interaction between individual CBI metrics, the overall CBI index, and cost. Energy efficiency is one of the metrics used in this CBI index calculation, so intuitively, increasing its value should increase the overall CBI index. However, by reducing the amount of energy efficiency from 923 aMW to 818 aMW, portfolio 3 added other resources, which improved the CBI index for other metrics resulting in a higher overall CBI index at a lower cost.

As we developed the diversified portfolios, we incorporated 818 aMW of conservation, given the large increase in the CBI index for the relatively small increase in total portfolio cost.

7.1.2. Pumped Hydroelectric Storage

Portfolios that include PHES tend to have a lower CBI index than the reference portfolio. Portfolios 6, 7, 8, and the diversified portfolio include PHES. PHES is a costly resource and was not selected economically by any portfolios, so we tested scheduled additions of PHES to understand any benefit in diversifying energy storage away from solely battery energy storage.

We found that PHES delays the need to add thermal peaking capacity and reduces the dispatch of existing thermal resources when added to a portfolio resulting in fewer greenhouse gas emissions. Unfortunately, adding PHES tends to reduce the number of jobs expected from portfolios and reduces the amount of demand response selected by the portfolio resulting in an overall CBI index of less than zero or worse than the reference portfolio and portfolios 6, 7, and 8. Given the reduction of greenhouse gas emissions and diversification benefits of PHES, we decided to add PHES to the diversified portfolios. In portfolios 11 A5 and 11 B2, we controlled for the negative CBI index impacts of PHES by scheduling distributed solar and battery resources, discussed in Section 7.1.3, and maximizing demand response programs, resulting in portfolios with the highest overall CBI indices.

7.1.3. Distributed Energy Resources

We tested portfolios 4 and 5, which scheduled additions of distributed energy resources, solar, and storage, respectively, to understand how adding these resources would impact the cost. Distributed energy resources tend to cost more than their utility-scale counterparts and, therefore not selected in the reference portfolio. However, we created customer benefit indicators precisely to monitor customer participation in distributed solar and distributed storage technologies. We thought adding these resources to the portfolio would significantly increase the overall CBI index. However, portfolio 4, which adds distributed solar, only scores marginally better than the reference portfolio, and portfolio 5 scores worse. Adding distributed energy resources tends to reduce the number of jobs associated with the portfolio, and the amount of demand response added. These changes result in little net benefit for the increased DER participation metrics.

However, when we added DERs in coordination with other resources, the benefit became much stronger, as demonstrated in diversified portfolios 11 A3, 11 A4, 11 A5, and 11 B2, which have overall CBI indices much greater than the reference portfolio.

7.1.4. Diversified Portfolios

Diversified portfolios include several scheduled resource additions to create a diverse mix of resources within the portfolio. Increased diversification enables more equitable outcomes through greater participation in DER, more demand response programs, and lower greenhouse gas and outdoor air quality emissions. Portfolios 11 A5 and 11 B2, the most diversified portfolios, tie for the highest overall CBI index at +1.32 from the reference portfolio. Considering the tradeoff between the CBI index and cost, 11 B2 provides the better value, given that it is 1.16 billion less expensive than 11 A5.

8. Stochastic Portfolio Analysis Summary

We test the robustness of different portfolios with stochastic risk analysis to learn how well the portfolio might perform under various conditions. In this analysis, we run select portfolios through 310 simulations or draws[14] that vary power prices, gas prices, hydroelectric generation, wind generation, solar generation, load forecasts (energy and peak), and plant forced outages. From this analysis, we can quantify the risk of each portfolio. We tested two different portfolios in the stochastic portfolio analysis, as and described in Table 8.8.

Table 8.8: Portfolios Tested for Stochastic Analysis

ID	Name	Description
1	Reference Portfolio	The reference portfolio is a least-cost, CETA-compliant portfolio that allows the AURORA long-term capacity expansion model to optimize resource selection with as few constraints as possible. The reference portfolio is a basis against which to compare other portfolios.
11 B2	Preferred Portfolio	This sensitivity is the most diversified portfolio we developed in this report, but without adding advanced nuclear SMR technology to the portfolio. We built this portfolio on the least-cost reference portfolio; it increases conservation and adds pumped hydroelectric storage, distributed energy, and demand response.

8.1. Risk Measures

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

8.2. Stochastic Results

Our electric stochastic analysis holds portfolio resource builds constant across the 310 simulations. These resource forecasts are a guide. We will make resource acquisition decisions based on the latest information from the 2021 All-Source RFP[15] and other acquisition processes. The risk simulation results, however, indicate the portfolio costs risk range under varying input assumptions. Table 8.9 compares the portfolio costs for the deterministic run; the mean portfolio cost across 310 simulations, and the TailVar90 of portfolio cost for the two portfolios examined for the stochastic analysis. The mean portfolio cost of the 310 simulations is lower than the deterministic model runs for the reference and preferred portfolios.

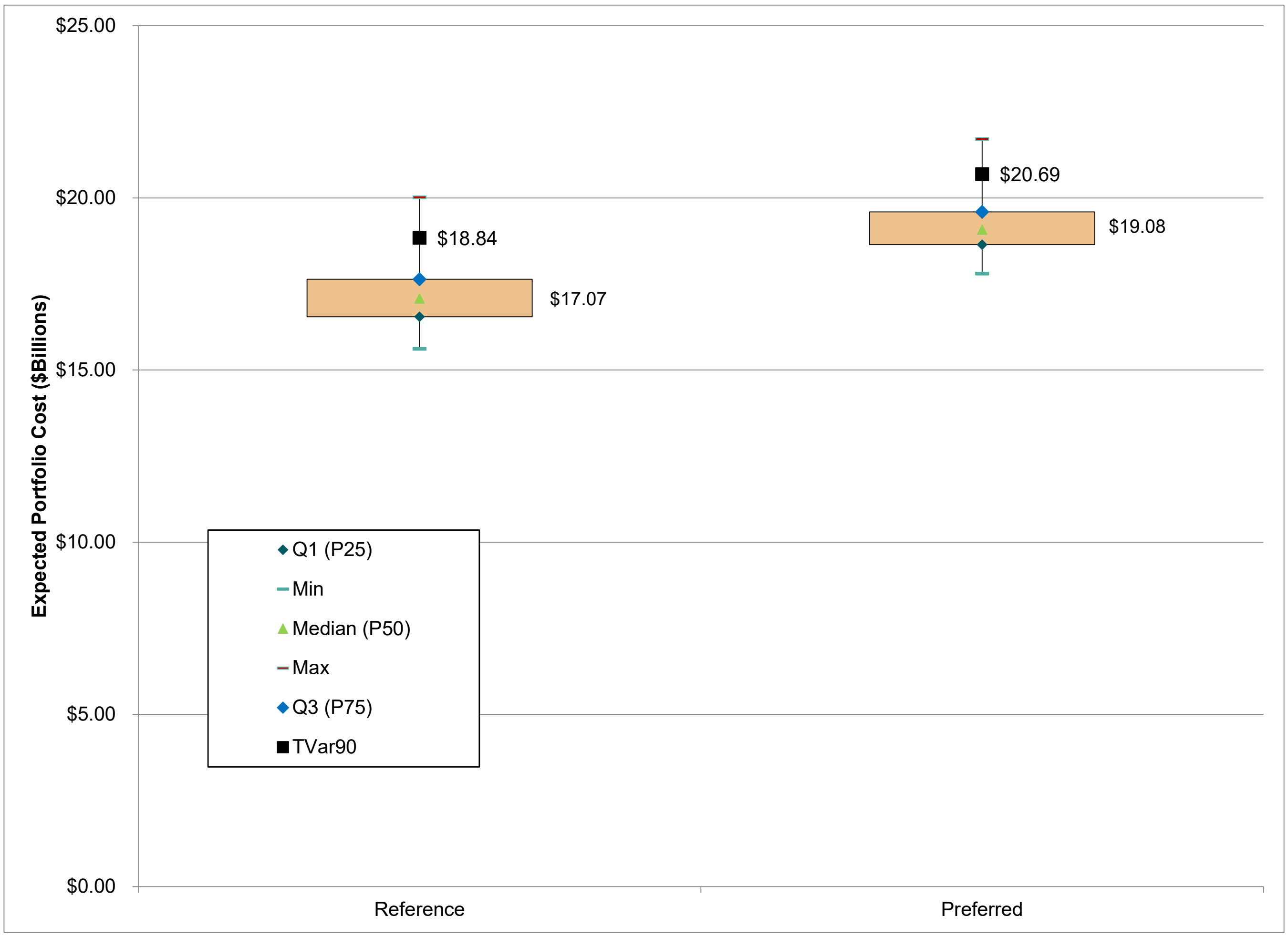
[14] Each of the 310 simulations is for the 24-year IRP forecasting period, 2022-2045.
[15] https://www.pse.com/en/pages/energy-supply/acquiring-energy

Table 8.9: Portfolio Costs Across 310 Simulations (Billion$)

Revenue Requirement	Portfolio	Deterministic ($)	Difference from Reference ($)	Mean ($)	Difference from Reference ($)	TVar90 ($)	Difference from Reference ($)
1	Reference	17.60	--	17.20	--	18.80	--
11 B2	Preferred	19.60	2.00	19.20	2.00	20.70	1.90

Figure 8.23 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 box represents the median for that portfolio. The interquartile range box represents the middle 50 percent of the data. The whiskers extending from either side of the box represent the portfolio's minimum and maximum data values. The black square represents the TailVar90, the average value for the highest 10 percent outcomes.

Figure 8.23: Range of Portfolio Costs across 310 Simulations



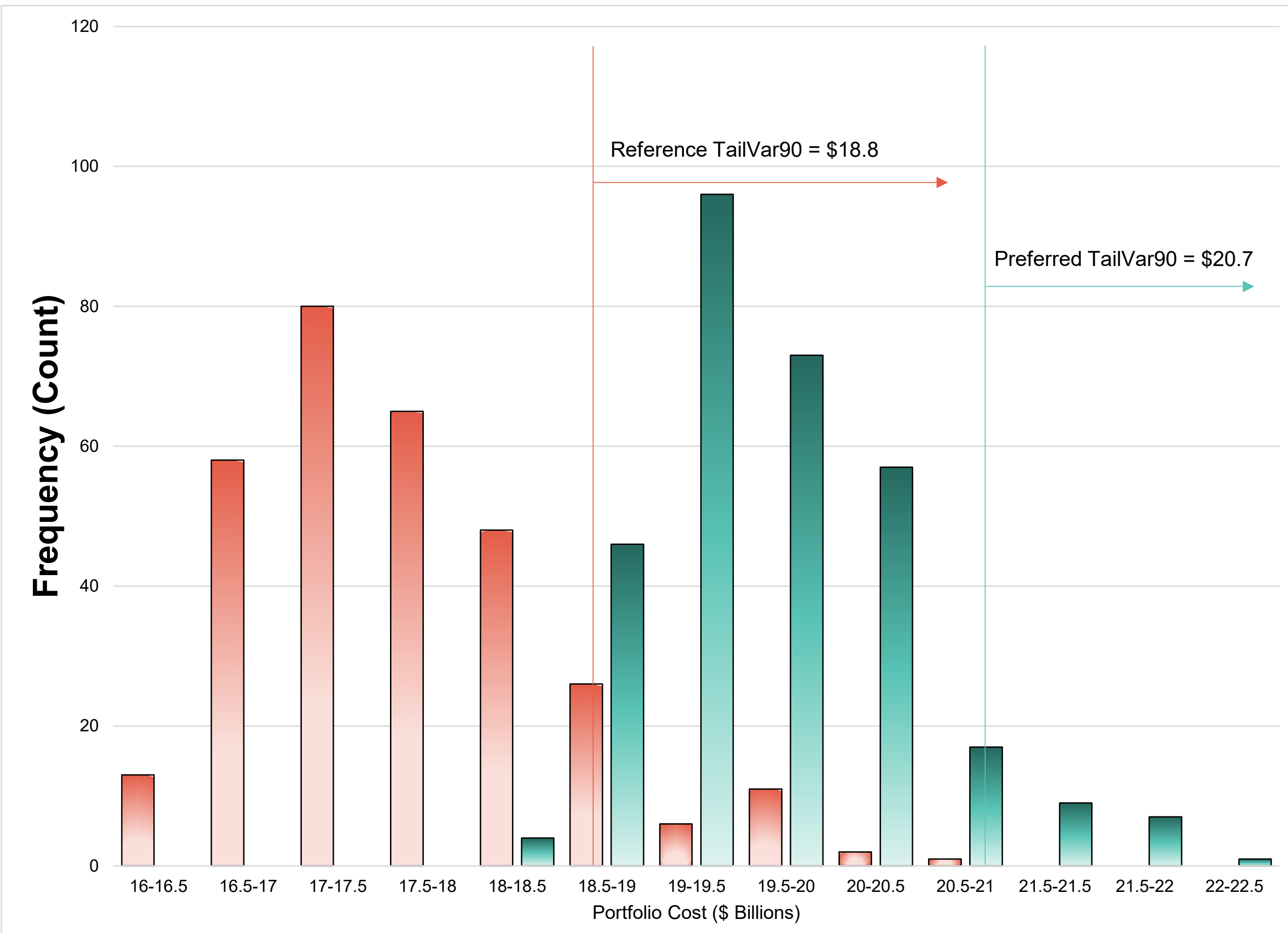
Key results of the analysis include:

- The mean value for the sensitivity 11 B2 portfolio is higher than the reference portfolio, suggesting that diversifying the resource mix results in higher portfolio costs.

- The range for sensitivity 11 B2 is narrower than the reference portfolio, indicating that the varied inputs have less of an impact on the overall portfolio costs.
- While the interquartile range for sensitivity 11 B2 portfolio is comparatively narrower than the reference portfolio, suggesting that the expected portfolio costs are less variable and higher, TailVar90, at 20.7 billion, indicates a risk of higher costs for this portfolio.

Figure 8.24 compares the reference to sensitivity 11 B2. We sorted each simulation's portfolio cost results into bins containing a narrow range of expected portfolio costs. The shorter right-hand tail and lower TailVar90 value of sensitivity 11 B2 indicate less risk associated with sensitivity 11 B2 than the reference portfolio, despite the higher average portfolio cost.

Figure 8.24: Frequency Histogram of Expected Portfolio Cost ($ Billions) — Reference vs. Sensitivity 11 B2



In addition to the expected portfolio costs, we evaluated the expected SCGHG. Table 8.10 and Figure 8.25 compare the SCGHG costs for the deterministic run, the mean across 310 simulations, and the TailVar90 of the two portfolios.

Key results of the analysis include:

- In contrast, the mean value for the sensitivity 11 B2 portfolio is higher than the reference portfolio, suggesting that diversifying the resource mix to include more conservation and distributed energy resources results in lower average emissions.
- The range for sensitivity 11 B2 is more comprehensive than the reference portfolio, indicating the inputs were varied have a bigger impact on the overall SCGHG costs.

Table 8.10: SCGHG across 310 Simulations ($ Billions)

SCGHG	Portfolio	Emissions ($)	Difference from Mid ($)	Mean ($)	Difference from Mid ($)	TVar90 ($)	Difference from Mid ($)
1	Reference	3.24	--	3.59	--	5.02	--
11 B2	Preferred	3.33	0.09	3.33	(0.26)	4.79	(0.23)

Figure 8.25: Range of SCGHG Costs across 310 Simulations