3 Resource Plan Decisions

This chapter summarizes the reasoning for the additions to the electric and natural gas resource plans and demonstrates how the electric resource plan meets the clean energy transformation standards.

3 Resource Plan Decisions

Contents

1. OVERVIEW

The preferred portfolio is the outcome of robust IRP analyses developed with stakeholder input. It meets the requirements of the Clean Energy Transformation Act and is informed by deterministic portfolio analysis, stochastic portfolio analysis and the Customer Benefit Analysis. The preferred portfolio is a new requirement in the IRP, and this first preferred portfolio marks a significant shift in PSE's resource direction since the 2017 IRP. The preferred portfolio focuses on clean resources to meet CETA requirements, as well as increases in distributed energy resources.

To support the portfolio analysis to arrive at the preferred portfolio, three distinct types of analysis are used. Deterministic portfolio analysis solves for the least cost solution and assumes perfect foresight about the future. The stochastic analysis assesses the risk of potential future changes in hydro or wind conditions, electric and natural gas prices, load forecasts and plant forced outages. The Customer Benefit Analysis incorporates the equitable distribution of burdens and benefits into the resource planning process. All three of these analytic methods are used to identify and evaluate the preferred portfolio.

Further information on the analyses discussed here can be found in Chapters 5, 6, 7, 8, 9 and the Appendices.

2. ELECTRIC RESOURCE PLAN

Resource Additions Summary

Figure 3-1 summarizes the forecast of resource additions to the preferred electric portfolio. This portfolio prioritizes cost-effective, reliable conservation and demand response, and distributed and centralized renewable and non-emitting resources at the lowest reasonable cost to our customers. It reduces direct PSE emissions by more than 70 percent by 2029 and achieves carbon neutrality by 2030 through clean investments and projected compliance options. While implementing this highly decarbonized portfolio, the portfolio maintains the reliability required with the addition of flexibility capacity starting in 2026.

Figure 3-1: Electric Preferred Portfolio,
Incremental Nameplate Capacity of Resource Additions

Resource Type	Incremental Resource Additions			Total
	2022-2025	2026-2031	2032-2045	
Distributed Energy Resources				
Demand-side Resources[1]	256 MW	440 MW	1,061 MW	1,757 MW
Battery Energy Storage	25 MW	175 MW	250 MW	450 MW
Solar	80 MW	180 MW	420 MW	680 MW
Demand Response	29 MW	167 MW	21 MW	217 MW
DSP Non-wire Alternatives[2]	22 MW	28 MW	68 MW	118 MW
Total Distributed Energy Resources	412 MW	990 MW	1,820 MW	3,222 MW
Renewable Resources				
Wind	400 MW	1100 MW	1750 MW	3,250 MW
Solar	-	398 MW	300 MW	698 MW
Biomass	-	-	105 MW	105 MW
Renewable + Storage hybrid	-	-	375 MW	375 MW
Total Renewable Resources	400 MW	1,498 MW	2,530 MW	4,428 MW
Peaking Capacity with Biodiesel	-	255 MW	711 MW	966 MW
Firm Resource Adequacy Qualifying Capacity Contracts	574 MW	405 MW	-	979 MW

NOTES
1. Demand-side resources include energy efficiency, codes and standards, distribution efficiency and customer solar PV.
2. DSP Non-wire Alternatives are resources such as energy storage systems and solar generation that provide specific benefit on the transmission and distribution systems and simultaneously support resource needs.

Compliance with Clean Energy Transformation Standards

Electric utilities must meet the clean energy standards set by CETA at the lowest reasonable cost. In addition, safety, reliability and the balancing of the electric system must be protected, and electric utilities must ensure that all customers are benefiting from the transition to clean energy.

The clean energy transformation standards state that:

1. On or before December 31, 2025, each utility must eliminate coal-fired resources from its allocation of electricity to Washington retail electric customers;
2. By January 1, 2030, each utility must ensure all retail sales of electricity to Washington electric customers are greenhouse gas neutral; and
3. By January 1, 2045, each utility must ensure that non-emitting electric generation and electricity from renewable resources supply 100 percent of all retail sales of electricity to Washington electric customers.

CETA also contains an incremental cost of compliance mechanism that can be used for compliance purposes. In this IRP, PSE does not rely on the incremental cost of compliance mechanism to comply with CETA. All clean energy transformation standards are met with new resources.

MEETING CETA 2025 REQUIREMENTS. Colstrip is removed from PSE's electric supply portfolio by the end of 2025 and replaced with a combination of renewable resources, conservation, demand response, battery energy storage and a simple-cycle combustion turbines (a frame peaker) operated on biodiesel. Biodiesel fuel that is not derived from crops raised on land cleared from old growth or first growth forests is a CETA-compliant renewable resource; all new peaking resources modeled in this analysis are operated with biodiesel fuel, and it is the only fuel used for new peaking resources in the preferred portfolio. The October 2020 U.S. Department of Energy report on alternative fuel prices calculated the price of B99/B100 biodiesel for the west coast at $3.88/gallon.[1] PSE currently operates several peaking plants that can run a back-up fuel (distillate fuel oil) and therefore has experience with storage and transportation for diesel fuels. Given the limited run-time expected of the new turbines, the IRP analysis estimates that existing Washington state biodiesel production could meet new peaking resource fuel supply needs.

1 / Clean Cities Alternative Fuel Price Report, October 2020 (energy.gov)

MEETING CETA 2030 REQUIREMENTS. The preferred portfolio achieves 100 percent greenhouse gas neutrality by 2030 through coal plant retirements in 2025 and by replacing most of the energy produced by existing natural gas plants with renewable resources and projected alternative compliance options. The preferred portfolio meets 80 percent of sales with renewable resources by 2030 and the remaining 20 percent with clean investments and projected compliance options. The projected 20 percent alternative compliance is included as an additional cost starting in 2030.

Figure 3-2 shows the emissions by resource type for the preferred portfolio. There is a direct relationship between emissions and the dispatch of thermal resources. Direct emissions decreased with the retirement of Colstrip 1 & 2 in 2019 and will further decline with a projected lower economic dispatch of thermal resources and the exit of Colstrip 3 & 4 and Centralia from the PSE portfolio. The retirement of resources and forecasted drop in dispatch decreases the total portfolio emissions by more than 70 percent from 2019 to 2029. Through projected compliance mechanisms, the portfolio achieves carbon neutrality starting in 2030 through to 2045.

PSE also evaluated the costs associated with achieving 100 percent renewable resources by 2030. Reducing emissions and even achieving a 100 percent renewable portfolio by 2030 is possible with existing technologies, but the cost to do so is high. The massive investment in energy storage required to replace thermal resources results in portfolio costs that are $16 billion to $50 billion higher than the preferred portfolio.

Figure 3-2: Historical and Projected Annual Total PSE Portfolio CO_2 Emissions

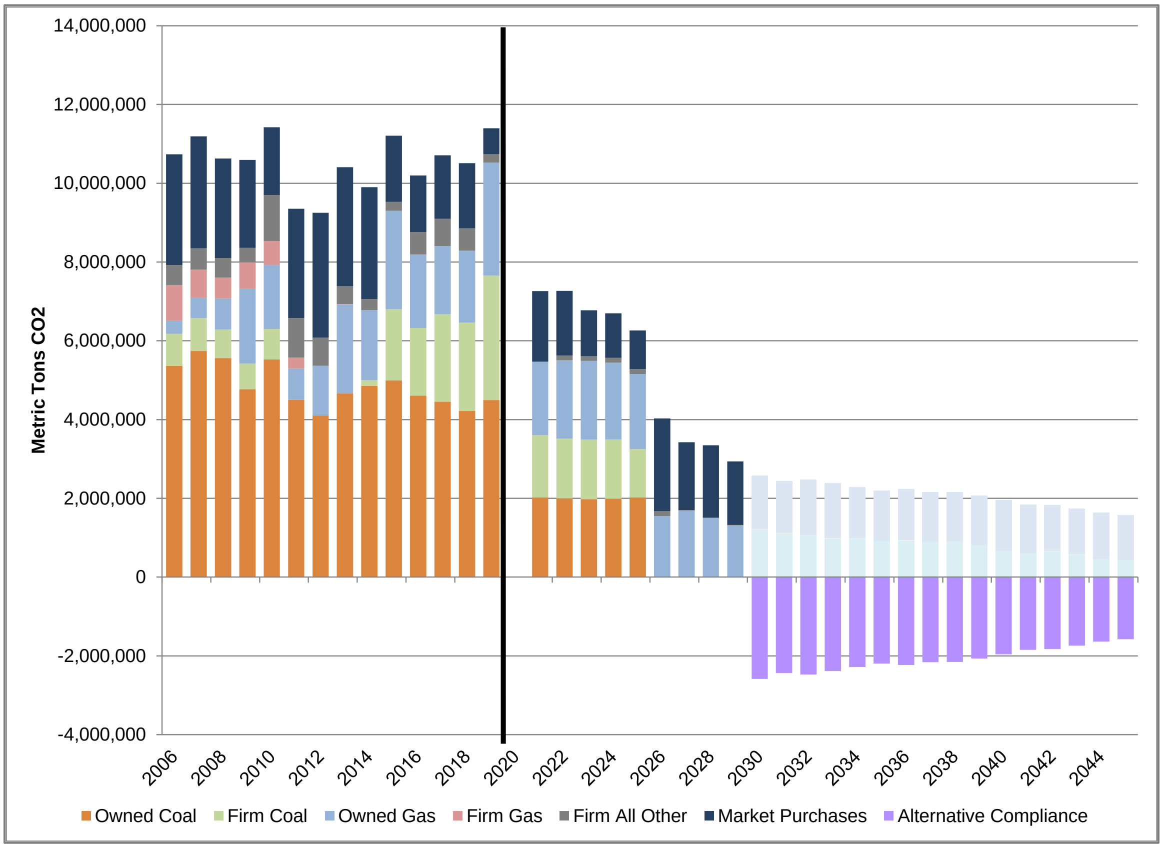
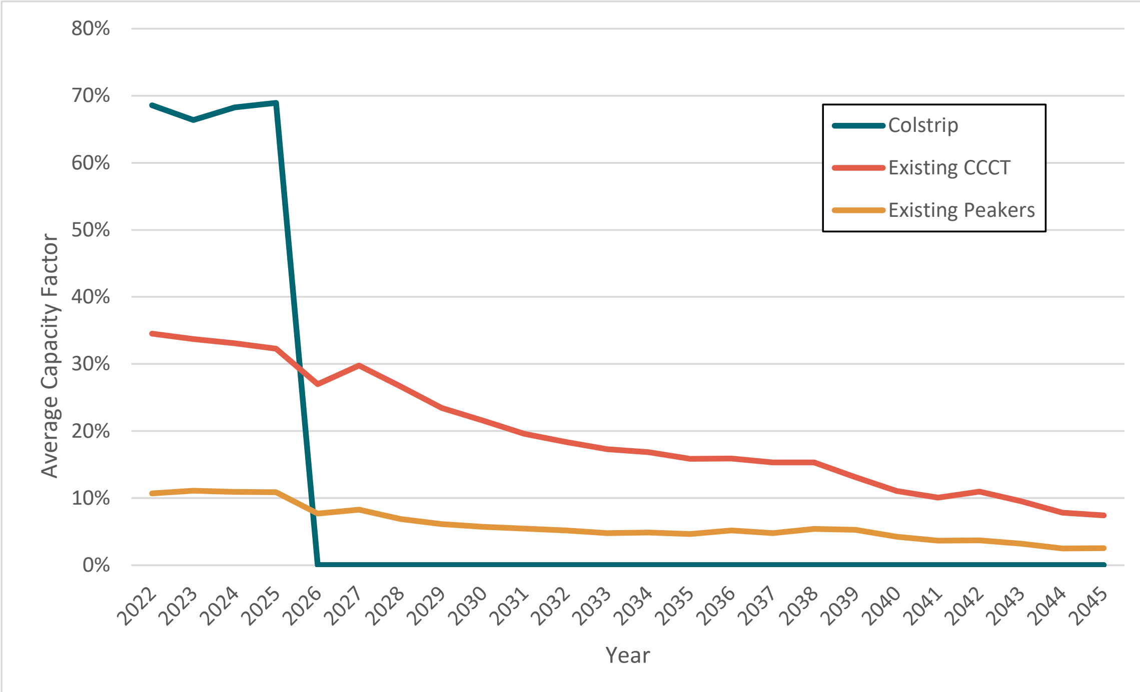


Figure 3-3 shows the annual percentage of time that the thermal resources dispatch, known as the capacity factor. Historically Colstrip dispatched around 85 percent to 90 percent of the time, but with increased costs, its dispatch has dropped below 70 percent. The existing natural gas CCCT plants average around a 35 percent capacity factor, with the highest dispatching units projected to run 60 percent to 70 of the time at the beginning of the time horizon. As new renewable resources are added to the portfolio, the projected dispatch of the existing natural gas CCCT decreases to around 7 percent by the end of the planning horizon. Existing natural gas peaking plants have always had low dispatch, since they are mostly used to maintain reliability during times of peak demand. The dispatch of the new peaking plants has an annual average capacity factor of 10 percent at the beginning of the planning horizon that drops to around 2 percent by the end of the planning horizon.

Figure 3-3: Projected Annual Thermal Resources Dispatch for PSE Existing Resources



MEETING CETA 2045 REQUIREMENTS. By 2045, 100 percent of retail sales is met by non-emitting and renewable resources. Retail sales is the total amount of energy delivered to customers. The preferred portfolio reduces the amount of energy delivered to customers by adding over 6.5 million MWh of new demand-side resources that include conservation and customer programs, and by adding almost 14.9 million MWh of new renewable resources. After demand-side resources and customer programs, PSE needs an additional 13.5 million MWh of non-emitting and renewable resources by 2045 to reach 100 percent of retail sales. The new wind, solar, biomass and hybrid resources in the preferred portfolio add 14.9 million MWh of non-emitting and renewable resources, making the preferred portfolio compliant with the 2045 CETA goal. Figure 3-4 breaks down how the preferred portfolio meets the 100 percent non-emitting and renewable resource requirement.

Figure 3-4: Calculation of 2021 IRP Preferred Portfolio CETA Compliance for 2045

	MWh
2045 Estimated Sales before Conservation[1]	29,051,232
Demand-side Resources	(6,565,285)
Line Losses	(1,529,044)
Load Reducing Customer Programs & PURPA	(1,493,096)
Sales Net of Conservation and Customer Programs	19,463,807
Existing Non-emitting and Renewable Resources[2]	(5,904,043)
Need for New Renewable/Non-emitting Resources	13,559,765
New Non-emitting and Renewable Resources	
Wind	10,767,902
Solar – Utility-scale	1,461,402
Solar – distributed ground and rooftop	963,861
Biomass	778,334
Hybrid renewable and energy storage	917,022
Total New Resources	14,888,520

NOTES
1. 2021 IRP base demand forecast with no new conservation starting in 2022.
2. Generation from existing resources assumes normal hydro conditions and P50 wind and solar.

Electric Resource Need

Reliability is the cornerstone of PSE's energy supply portfolio. For resource planning purposes, the physical electricity needs of our customers are simplified and expressed as three resource needs:

1. **Peak hour capacity for resource adequacy (reliability)**: PSE must have the capability to meet customer's electricity needs during periods of peak demand;
2. **Hourly energy**: PSE must have enough energy available in every hour to meet customer's electricity needs; and
3. **Renewable energy**: PSE must have enough renewable and non-emitting (clean) resources to meet the requirements of the Clean Energy Transformation Act.

Meeting Peak Capacity Need

Peak hour capacity need is determined through a resource adequacy analysis that evaluates existing PSE resources compared to the projected peak need over the planning horizon. Due to the retirement of existing coal resources, PSE is forecast to begin to experience a peak capacity shortfall starting in 2026. PSE uses a loss of load probability (LOLP) consistent with the Northwest Power and Conservation Council to determine the peak capacity need for its service territory. Using the LOLP methodology, before any new demand-side resources, it was determined that 907 MW of capacity would be needed by 2027 and 1,381 MW of capacity by 2031. A full discussion of the peak capacity need is presented in Chapter 7, Resource Adequacy Analysis.

The resource adequacy analysis is complex and ensures the system has enough flexibility to handle balancing needs and unexpected events, such as variations in temperature, hydro, wind and solar generation, equipment failure and plant forced outages, transmission interruption, potential curtailment of wholesale power supplies, or any other sudden departure from forecasts. Resource adequacy requires that the full range of potential demand conditions are met, even if the potential of experiencing those conditions is relatively low.

Assessing the amount of peak capacity each resource can reliably provide is an important part of resource adequacy analysis. To quantify the peak capacity contribution of renewable resources (wind, hydro and solar) and energy limited resources (batteries, pumped hydro storage and demand response), PSE calculates the effective load carrying capacity, or ELCC, for each of those resources. The ELCC of a resource is unique to each utility because it depends upon interactions between the various resources that make up each utility's unique system and is dependent on load shapes and supply availability. As a result, it is hard to compare the ELCC of PSE's resources with those of other entities and even PSE's ELCC's will change over time as system conditions change. A full description of the peak capacity and ELCC values is in Chapter 7.

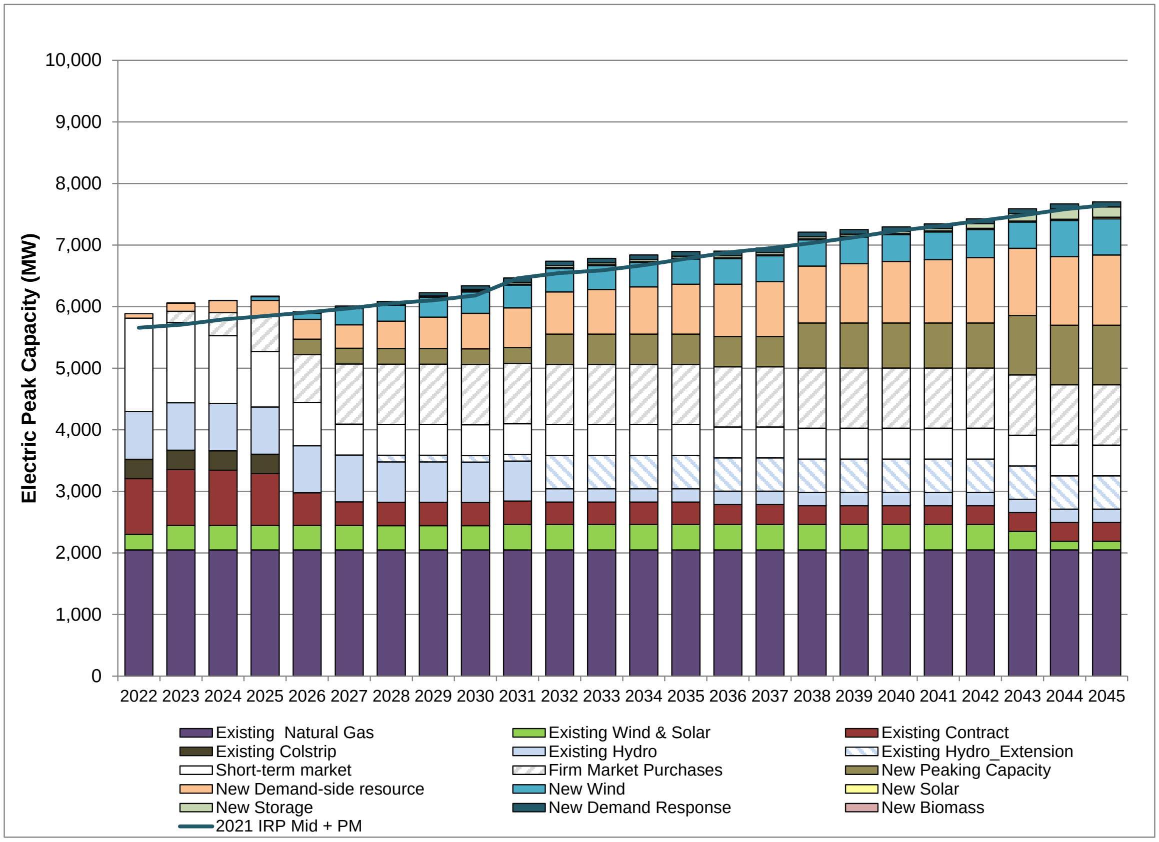
In addition to firm resources, PSE currently relies on market purchases from Mid-C to meet capacity needs. Evaluation of the existing wholesale electric market resulted in a recommendation that a portion of the available Mid-C transmission be used for firm resource adequacy (RA) qualifying capacity contracts or a reliable firm capacity resource in place of short-term energy purchases. Figure 3-5 shows, in annual increments, the conversion from short-term energy purchases to firm RA qualifying capacity purchases. As a result, in this IRP reliance on the availability of short-term market purchases at peak gradually declines over a 5-year period by 200 MW per year through the year 2027. The gray area shows PSE's total available transmission to the Mid-C market. After 2026, short-term market purchases stabilize at 500 MW and firm RA qualifying capacity purchases at 979 MW.

Figure 3-5: Short Term Market converted to Firm Resource Adequacy Qualifying Capacity Purchases

Year	Available Mid-C transmission	Short Term Market	Firm RA Qualifying Capacity Purchases
2022	1,518	1,518	-
2023	1,485	1,300	185
2024	1,472	1,100	372
2025	1,474	900	574
2026	1,476	700	776
2027	1,479	500	979
2028	1,479	500	979
2029	1,479	500	979
2030	1,479	500	979
2031	1,479	500	979

Figure 3-6 shows the preferred portfolio combination of new and existing resources required to meet the peak capacity need for the IRP mid demand forecast with an appropriate planning margin, and it reflects the peak capacity contribution of these resources. The graph also shows the market risk adjusted firm capacity (in the gray shaded bars) that will replace existing short-term Mid-Columbia energy contracts.

Figure 3-6: Preferred Portfolio Meeting Electric Peak Capacity and Reducing Market Risk



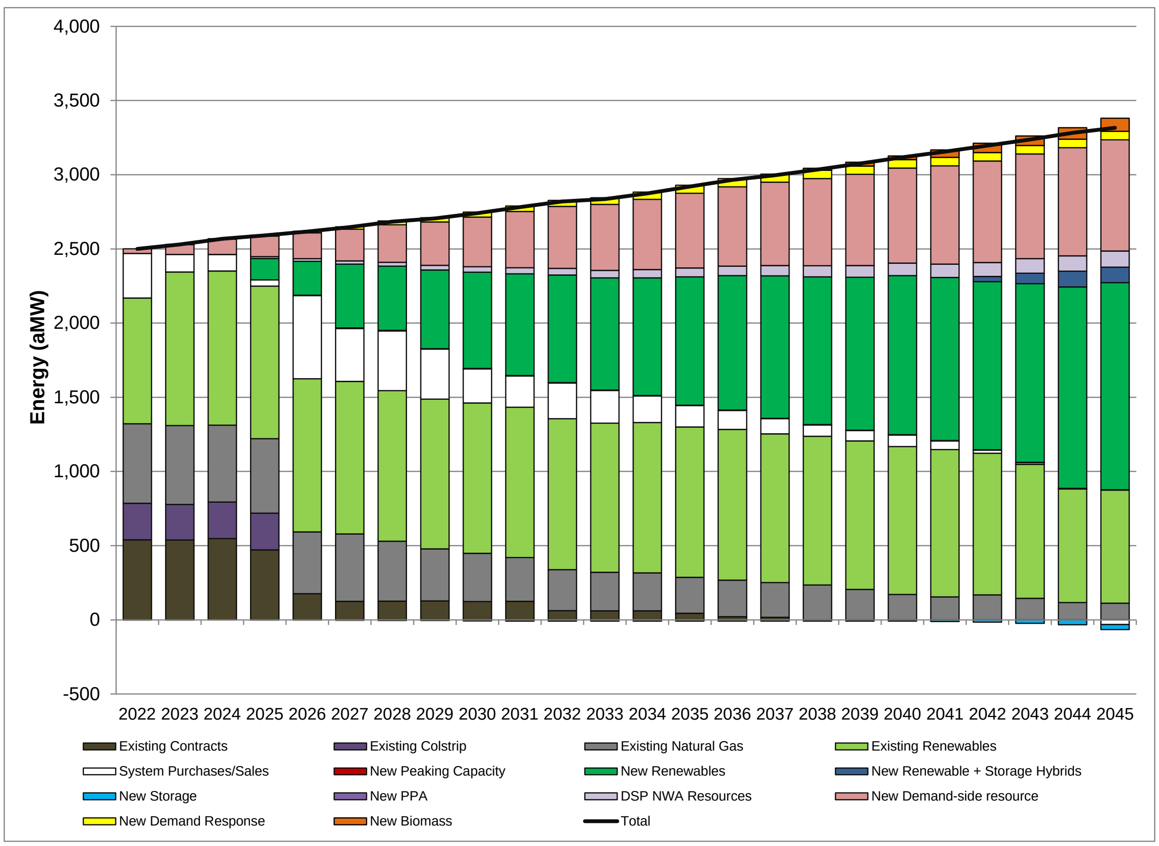
Renewable and distributed resources contribute to meeting peak capacity needs, however, peaking capacity is also needed to maintain reliability and meet required resource adequacy standards. The more than 750 MW of coal removed from PSE's portfolio by the end of 2025 is first replaced by demand-side resources, distributed energy resources and wind generation. Just 255 MW of new flexible, dispatchable capacity is added by 2026 to maintain reliability. The capacity need increases because an increase in balancing requirements is required to support the new intermittent renewable resources added to comply with CETA.

PSE evaluated early economic retirement of existing resources but that appears to increase cost. However, the economic dispatch of existing resources decreases significantly through the planning horizon as seen Figure 3-3 and is discussed further below.

Meeting Energy Need

Figure 3-7 shows the preferred portfolio combination of resources needed to meet the 2021 IRP mid demand forecast. Most of the energy need is met with renewable and distributed energy resources. The use of market purchases and sales declines over time. None of the energy requirements are satisfied with coal resources after 2025. The use of existing thermal resources significantly declines, with the capacity factor of PSE's combined-cycle combustion turbines decreasing from 70 percent for the highest dispatch units at the beginning of the planning horizon to 7 percent by the end. The pink bars represent demand-side resources, which significantly reduce total load. The black line on the chart is PSE's mid demand forecast and represents the demand at the generator, so it is grossed up for sales. This is different than the renewable need which is based on retail sales. Distributed energy storage resources are included in the portfolio but are barely visible in this chart because they are a net zero resource, meaning they do not produce any energy but rather store the energy produced by other generators. The storage resources appear as a negative value, below the line towards the end of the time horizon, and represent the energy stored.

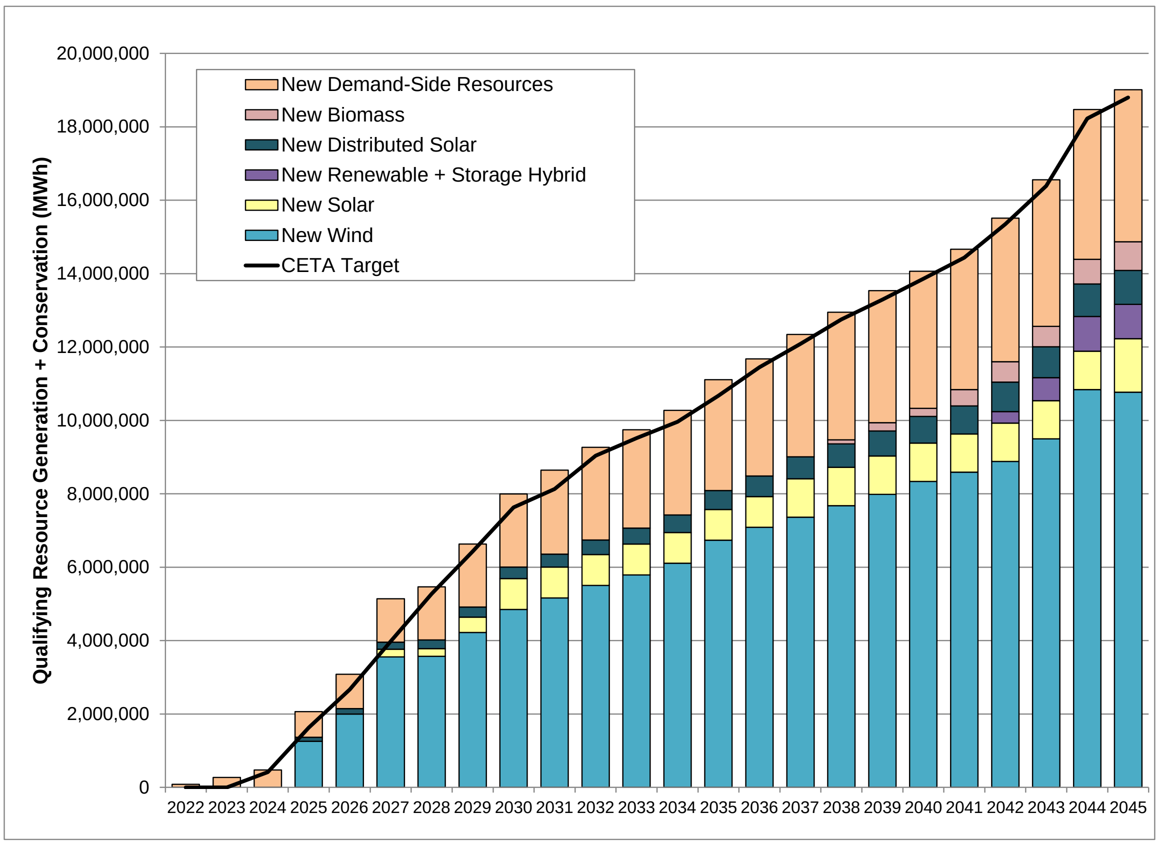
Figure 3-7: Preferred Portfolio Meeting Energy Requirements



Meeting Renewable Energy Need

The renewable energy need for both RCW 19.285 and CETA, based on the 2021 IRP mid demand forecast, is described in Chapter 8. The preferred portfolio assumes a linear ramp to achieve the 80 percent Clean Energy Transformation Standard in 2030 and 100 percent standard in 2045. Figure 3-8 shows how the new renewable resources meet the 7.6 million MWh renewable requirement in 2030 and 17.1 million MWh renewable requirement in 2045. Demand-side resources (DSR) significantly reduce loads and lower the renewable need; these include cost-effective energy efficiency, codes and standards, distribution efficiency and customer solar PV. The majority of the remaining renewable resource need is met by new wind, and then solar. Wind additions include in Montana, Wyoming and eastern Washington wind. Solar additions include utility-scale solar in eastern Washington, and distributed energy solar resources include delivery system non-wire alternatives and ground-mounted and rooftop solar PV. The chart below shows the total annual energy (MWh) produced by these resources.

Figure 3-8: Preferred Portfolio Meeting Renewable Energy Requirements



Key Findings by Resource Type

Distributed Energy Resources

There is no single perfect answer or resource that will solve all of the peak, energy and renewable needs. That is why a balanced portfolio is important, one that includes a mix of utility-scale and distributed energy resources, and a mix of intermittent, energy-limited and firm capacity resources. All of these are important components when determining the portfolio mix. The role of DERs in meeting system needs is changing, and the planning process is evolving to reflect that change. DERs make lower peak capacity contributions and have higher costs, but they play an important role in balancing utility-scale renewable investments and transmission constraints while also meeting local distribution system needs and improving customer benefits.

ENERGY EFFICIENCY. PSE has never limited the funding needed to meet energy savings targets and has consistently met and exceeded the energy savings targets called for in the Energy Independence Act (RCW 19.285). In each two-year program period from 2014 through 2019, PSE set electric savings targets that were 13 percent, 9 percent and 10 percent higher than required by the Energy Independence Act, and PSE's actual savings were 20 percent, 14 percent and 14 percent higher, respectively, than PSE's targets.

PSE encourages customers to bundle as many energy efficiency measures together as possible. This is true in both the business and residential efficiency programs. In fact, the residential program offers a bonus financial incentive for including multiple measures in a single application. PSE's program for commercial new construction and deep retrofits offers higher incentive rates for deeper reductions in energy use. The preferred portfolio includes 793 MW of the 840 MW estimated technical potential for energy efficiency found in the Conservation Potential Assessment.

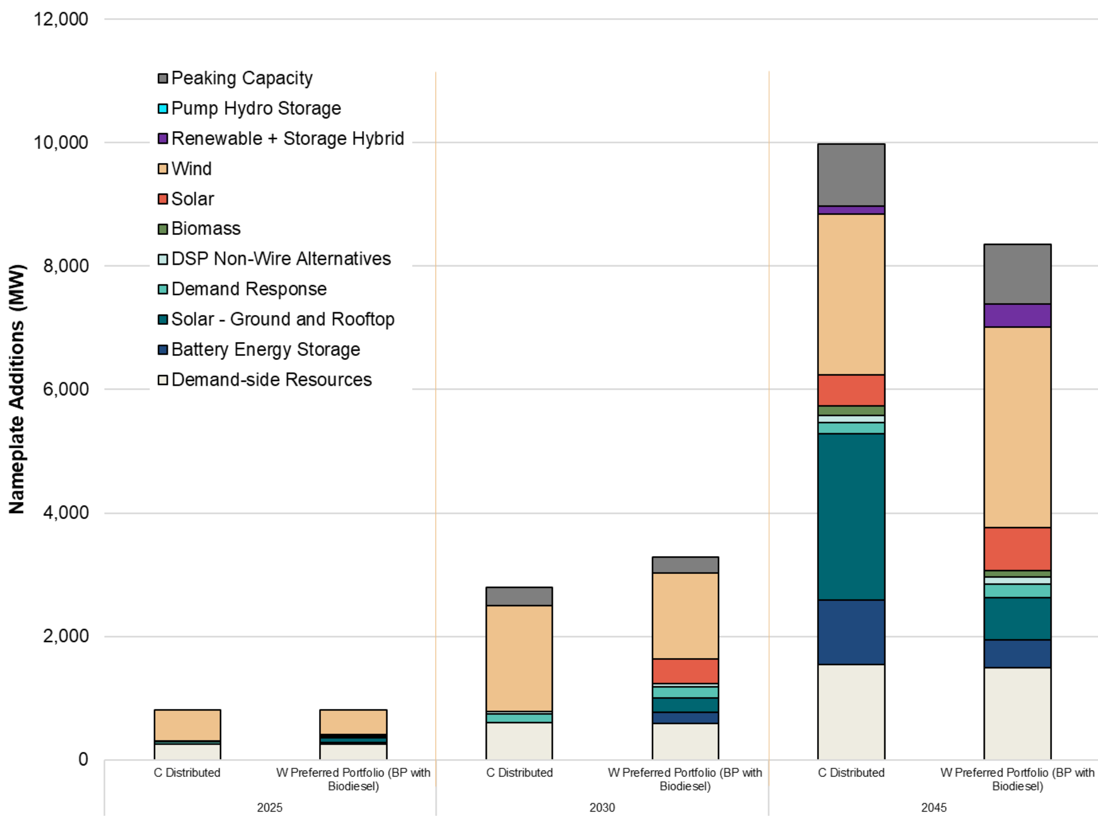
Energy efficiency is just one of the demand-side resources analyzed in this IRP. All of the demand-side resources are described in Chapter 2 and Appendix D.

BATTERY ENERGY STORAGE. The preferred portfolio includes four battery energy storage systems that range in duration from 2 to 6 hours and pumped storage hydro with a duration of 8 hours. Batteries are scalable, and fit well in a portfolio with small needs of short duration. Batteries also work as a solution for local distribution upgrades and capacity needs. In the optimized portfolio results, additional energy storage was not part of the optimized portfolio solution until the last 5 to 10 years of the planning horizon when the renewable requirement increased to more than 90 percent of delivered load. However, taking into account risk of transmission and additional customer benefits, battery energy storage is accelerated in the preferred portfolio. The lower peak capacity credit of energy storage means significantly more battery energy storage resources are needed to match the capacity provided by combustion turbines (the lowest cost resource). The preferred portfolio adds some distributed battery storage resources starting at 25 MW in 2025 and increasing to 175 MW by 2031.

SOLAR – GROUND AND ROOFTOP. Though utility-scale solar is a lower cost option for meeting CETA renewable requirements, given the transmission constraints involved in bringing remote resources to PSE's service territory, distributed solar resources have become an important part of the solution. PSE modeled both ground-mount and rooftop solar as an option to both meet CETA renewable requirements and local distribution system needs. The distributed solar includes options for both customer-owned solar (net-metering) and PSE-owned solar resources.

In Sensitivity C, which restricts transmission availability compared to the Mid Scenario portfolio, PSE analyzed the risk of obtaining new transmission contracts to eastern Washington and the availability of re-using existing transmission contracts. Based on these restrictions, more renewable resources are needed in western Washington to meet CETA renewable requirements, and the portfolio model waited until the end of the planning period to add a significant amount of distributed resources. The preferred portfolio takes the same amount of distributed resources and ramps them in over time starting in 2025 for a total of 680 MW of distributed solar. This is in addition to the 622 MW of net-metered, customer-owned solar for a total of 1,302 MW of distributed solar by 2045. Distributed solar is a good way to meet the CETA renewable requirements given transmission constraints, but it makes limited contributions toward meeting peak capacity need because it provides very little peak capacity value since PSE is a winter peaking utility. Figure 3-9 compares the preferred portfolio and Sensitivity C resource builds.

Figure 3-9: Resource Builds – 2021 IRP Preferred Portfolio and Sensitivity C (Transmission Build Constraint), Cumulative Additions by Nameplate (MW)



DEMAND RESPONSE. PSE modeled 16 demand response programs totaling 222 MW in nameplate capacity. Of those 16 programs, there are 4 different direct load control (DLC) hot water heater programs, along with critical peak pricing, DLC heating, EV charging, curtailment and critical peak pricing (CPP). The CPP programs are similar to a time-of-use (TOU) program.

To reflect the time needed to enroll customers in programs, five of the programs are ramped in starting in 2023, two programs are ramped in starting in 2025, and the remaining seven programs are ramped in starting in 2026. The five programs starting in 2023 were part of the least cost optimization in most of the portfolio sensitivities. Demand response takes a couple of years to set up before savings are achieved, so with five programs starting in 2023, the total nameplate by 2025 is 29 MW due to the time it takes to establish the programs and enroll customers. The total demand response program grows to 195 MW nameplate capacity by 2031. By 2045, an additional 21 MW of demand response is cost effective for a total of 217 MW of the 222 MW technically available.

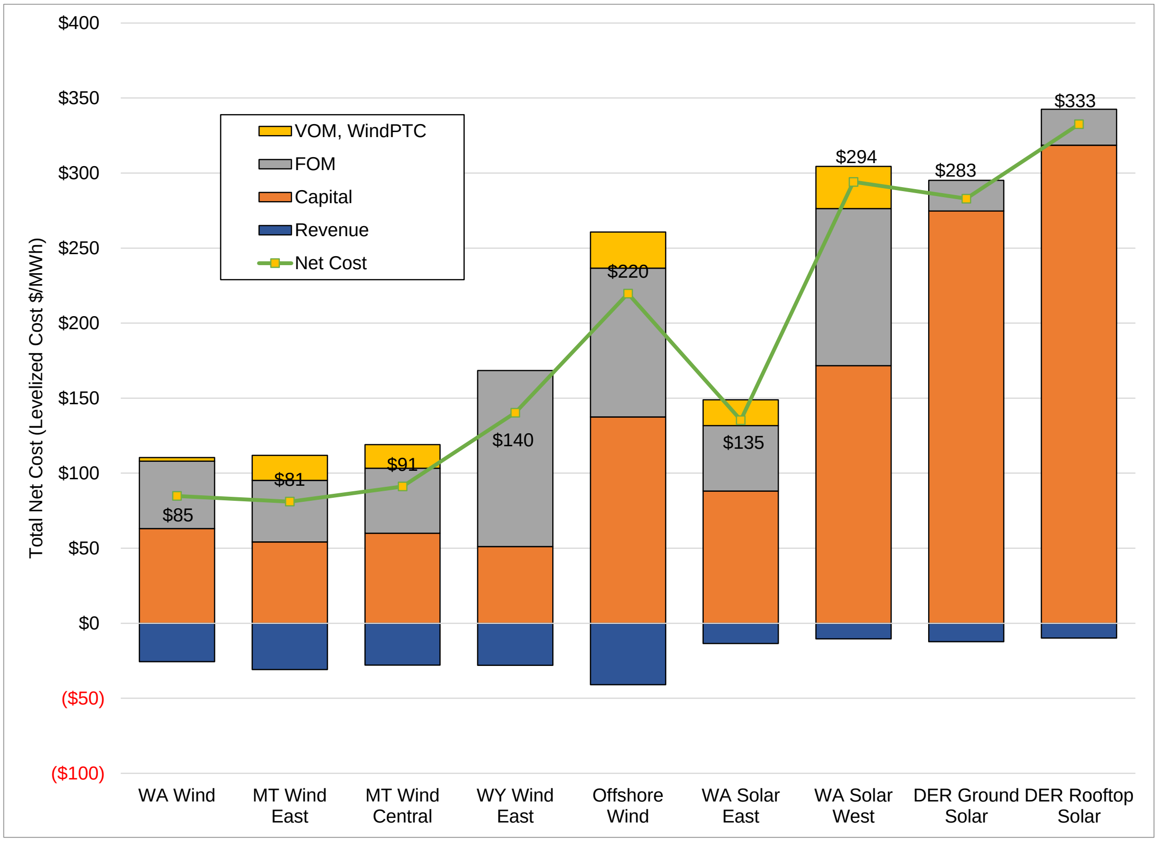
GRID MODERNIZATION. Proactive investments in grid modernization are critical to support the clean energy transition and maximize benefits. Investments in the delivery system are needed to deliver energy to PSE customers from the edge of PSE's territory and to support DERs within the delivery grid. Specific delivery system investments will become known when energy resources, whether centralized or distributed, begin to be sited through the established interconnection processes. The 10-year delivery infrastructure plans are described in Appendix M.

Utility-scale Renewable Resources

Significant investment in utility-scale renewable resources, in addition to DERs, will be needed to ensure that 100 percent of all retail electricity sales is served with renewable resources.

WIND AND SOLAR RESOURCES. The timing of renewable resource additions is driven by CETA renewable requirements. Although renewable resources also contribute to meeting capacity needs, compared to the existing, retiring coal-fired resources and other dispatchable resources, a portfolio that relies on increasing amounts of renewable resources has higher portfolio balancing requirements, which can drive up the portfolio cost. Increased renewable diversity can improve contribution to capacity needs, however resources outside of the Pacific Northwest region are limited given transmission constraints. After Montana and Wyoming wind, the costs of eastern Washington wind and solar are very close. Figure 3-10 illustrates that the levelized cost of Montana and Wyoming wind are the lowest cost renewable resources to meet CETA renewable requirements, followed by eastern Washington wind and solar. The levelized costs are calculated based on total resource costs; these include capital costs, variable operations and maintenance, and fixed operations and maintenance. Some resources include benefits from the production tax credit (PTC), and the investment tax credit (ITC). A full description of the ranges for the PTC and ITC is included in Appendix G. All resources include a benefit called revenue. This is the value of the resource in the market and is calculated as generation times the electric power price for every hour. The revenue and costs of the resources are calculated for every hour and then aggregated up to annual costs and benefit. These costs are then levelized by using net present value in 2022 dollars. Actual resource costs obtained through an RFP process could yield a different conclusion.

Figure 3-10: Levelized Cost of Wind and Solar Resources



TRANSMISSION CONSTRAINTS. Transmission capacity constraints have become an important consideration as PSE transitions away from thermal resources and toward clean, renewable resources to meet the clean energy transformation targets. Thermal resources can generally be sited in locations convenient to transmission, produce power at a controllable rate, and be dispatched as needed to meet shifting demand. In contrast, renewable resources are site-specific and have variable generation patterns that depend on local wind or solar conditions, therefore they cannot always follow load. The limiting factors of renewable resources have two significant impacts on the power system: 1) a much greater quantity of renewable resources must be acquired to meet the same peak capacity needs as thermal resources, and 2) the best renewable resources to meet PSE's loads may not be located near PSE's service territory. This makes it important to consider whether there is enough transmission capacity available to carry power from remote renewable resources to PSE's service territory. Transmission within PSE service territory will also be needed, but was assumed to be unconstrained due to delivery system planning processes and the specific projects identified in Appendix M.

The available transmission to eastern Washington can range from 700 MW to over 3,200 MW depending on the availability of new transmission contracts, upgrades on the system and the repurposing of existing contracts. PSE modeled a potentially available 750 MW of transmission from Montana and 400 MW of transmission from Wyoming. The full 750 MW of Montana wind and 400 MW of Wyoming wind appear to be cost-effective in this portfolio. There is significant risk with Wyoming wind because new transmission will need to be constructed to Wyoming, and PSE will also need to acquire new firm transmission contracts. After Montana and Wyoming wind are added to the portfolio, there is still an additional 600 MW of eastern Washington wind and 400 MW of eastern Washington solar needed by 2030. Given the risk in available transmission, over 200 MW of distributed solar is added to the portfolio to meet the 80 percent CETA renewable target in 2030. The actual location and type of renewable resources will depend on available transmission.

BIOMASS. Between 2035 and 2045, over 100 MW of biomass is added to the preferred portfolio. Although biomass has a higher capital cost than wind and solar, it is a baseload resource with an 85 percent capacity factor, which means that fewer biomass resources are needed to produce the same amount of energy that a resource such as solar can produce. PSE modeled wood waste biomass connected to lumber mills. Given the total number of mills located in western Washington, PSE estimates that around 150 MW of biomass may be feasible.

HYBRID RESOURCES. After 2040, 375 MW of hybrid wind and battery resources are added to the portfolio. Connecting a battery to an intermittent renewable resource helps to firm the capacity of the renewable resource so that it is more reliable during peak events and has a higher peak capacity contribution. However, with the battery being used to firm up the capacity of the wind resource, it is not available to meet flexibility needs, and it does not provide benefits to the transmission and distribution system. As a result, using the battery as an independent, distributed resource has more benefits to PSE than connecting it directly to a renewable resource. Hybrid resources are not cost competitive until the end of the time horizon.

Peaking Capacity with Biodiesel

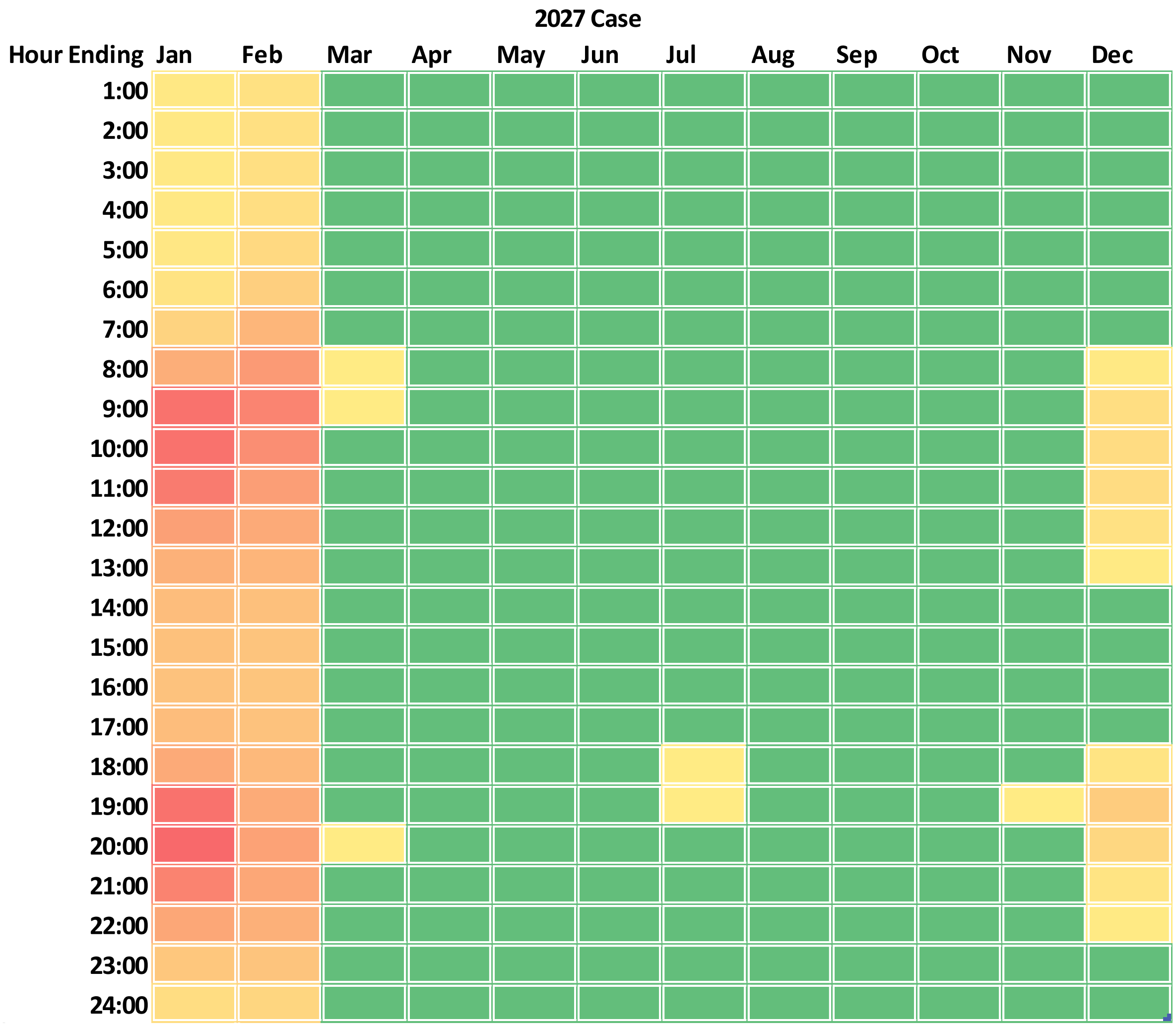
Beyond 2025, all sensitivities show a need for flexible, peaking capacity when 750 MW of coal generation is removed from PSE's portfolio in 2026. PSE is committed to pursuing all clean capacity resources first. The current modeling results show alternative fuel enabled combustion turbines as the most cost-effective resource to meet the capacity resource needs that cannot be otherwise met by demand-side resources and distributed and renewable resources. The model selected dispatchable combustion turbines as the least cost resource in particular to meet peak reliability needs, especially during periods of high load due to extremely cold weather conditions when renewable generation may be limited.

FUEL SUPPLY. In the resource adequacy analysis, PSE evaluated the biodiesel fuel supply needed for the peakers to maintain reliability. In 95 percent of simulations, the peakers are needed to run for 10,000 MWh or less to maintain resource adequacy, which is around 15 hours of run time annually. The maximum dispatch needed is 150,000 MWh, or approximately 205 hours of run time. In a report by the U.S. Energy Information Administration[2] on biofuel production, the total annual production of biodiesel in Washington state is 114 million gallons per year. To fuel 10,000 MWh of generation, peaking resources would require around 828,000 gallons of biodiesel, or about 0.7 percent of Washington State's 2020 annual production.

PEAK CAPACITY. The 12x24 table in Figure 3-11 shows the loss of load hours prior to the addition of new resources. The plot represents a relative heat map of the number of hours of lost load summed by month and hour of day. The majority of the lost load hours occur in the winter months. In this chart, the large blocks of yellow, orange, and red in January and February illustrate long duration periods, 24 hours or more, with a loss of load event. The portfolio optimization model must meet these long duration capacity shortfall events by adding new resources. Current technologies, energy storage and demand response do not completely meet the peak capacity needs because of their short duration of availability. The portfolio model needs to meet the loss of load events with resources that can be dispatched for 24 hours or more. Further discussion of the resource adequacy analysis can be found in Chapter 7.

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

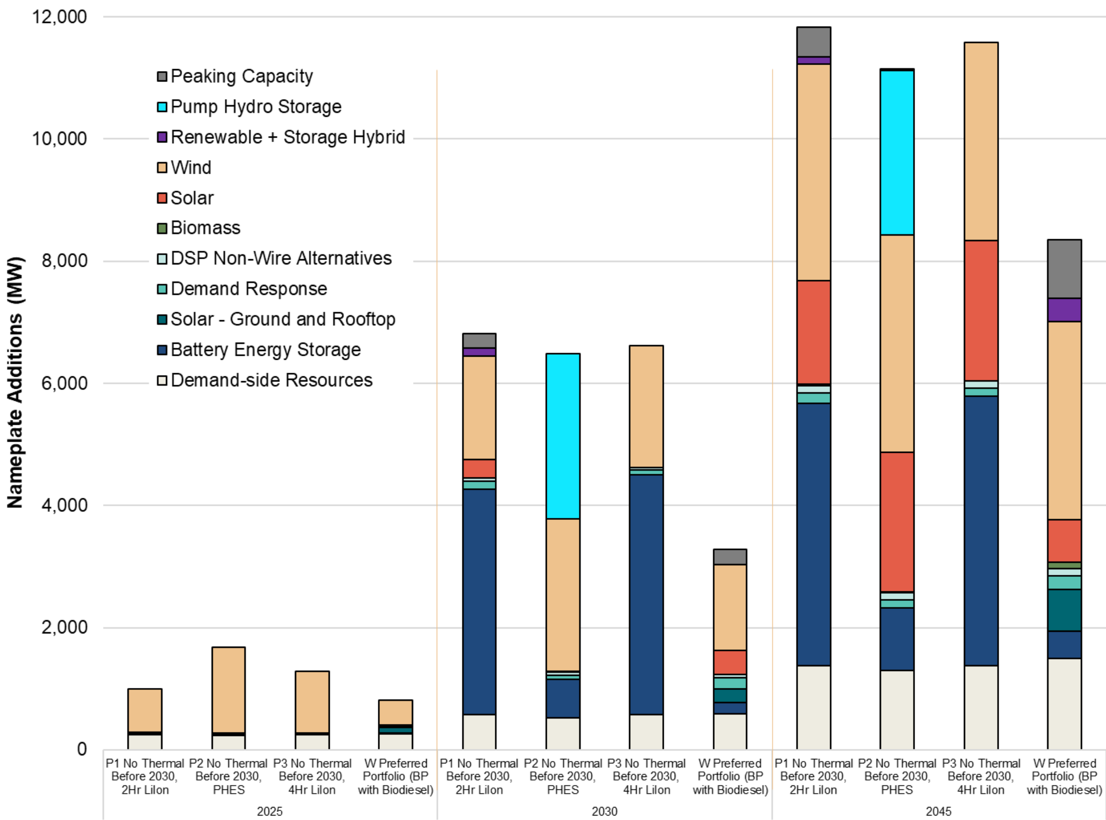
Figure 3-11: Loss of Load Hours for 2027



PSE's winter peak has notably different characteristics than a summer peak in other parts of the Western Interconnect. Summer peaking events occur in the late afternoon/evening when the day is the hottest and only last a few hours in the evening. Energy storage is a good solution for summer peaking events. In contrast, winter events can last several days at a time and temperatures can drop low during the night and stay low throughout the day. Since energy storage is a short duration resource that has a low peak capacity credit, it is not a good fit for winter peaks. With lower peak capacity credit, more energy storage resources are needed to replace the new peaking capacity added in the portfolio.

To better understand how energy storage can meet PSE's peak needs, PSE evaluated several portfolios in Sensitivity P. Sensitivity P removed new peakers as an option and forced the model to find alternative solutions. In the P1 portfolio, the first resource selected to fill peak need was 2-hour lithium-ion batteries. In the P2 portfolio, 2-hour lithium-ion and flow batteries were removed as an option and the model optimized to a solution involving a combination of pumped hydro storage and 4-hour lithium-ion batteries. The P3 portfolio removed the pumped hydro storage option and just added 4-hour lithium-ion batteries to meet peak needs. Figure 3-12 shows the total builds for the preferred portfolio and portfolios P1, P2 and P3. It takes a significant amount of energy storage and associated cost to replace the biodiesel peaker.

Figure 3-12: Resource Build for 2021 IRP Preferred Portfolio and Sensitivity P, Transmission Build Constraint, Cumulative Additions by Nameplate (MW)



Without access to the biodiesel peaker, Sensitivity P produced much higher portfolio costs. Figure 3-13 compares the total portfolio costs for 2045 for the preferred portfolio and portfolios P1, P2 and P3. The lowest cost portfolio is portfolio P2 at $22.85 billion, $6.7 billion more than the preferred portfolio.

Figure 3-13: Portfolio Cost for the Preferred Portfolio and P1, P2 and P3 Portfolios

Portfolio	Portfolio Cost (Billion $, 24-year levelized)
Preferred Portfolio	$16.11
P1: 2-hr Li-Ion	$30.84
P2: Pumped storage hydro	$22.85
P3: 4-hr Li-Ion	$39.01

While PSE hopes technology innovations in energy efficiency, demand response, energy storage and renewable resources will eclipse the need for additional peaking capacity plants of any kind in the future, alternative fuel peakers appear to be the least cost resource for meeting peak reliability needs at the time of this analysis. In all sensitivities that allowed the addition of new combustion turbines, at least one combustion turbine is added by 2026 and a second combustion turbine is added by 2030. Combustion turbines have the highest peak capacity value because of their ability to dispatch as needed with no duration limits. PSE is further exploring renewable and alternative fuel supply availability and technology.

Preferred Portfolio Decisions

A full discussion of all portfolios modeled in the 2021 IRP can be found in Chapter 8. This section focuses on the preferred portfolio and captures the decisions that informed the 10-year clean energy action plan and the 24-year resource plan.

Customer Benefits Analysis and Costs

The Clean Energy Transformation Act requires utility resource plans to ensure that all customers benefit from the transition to clean energy. As a result, the analysis of the equitable distribution of burdens and benefits is new to the resource planning process in the 2021 IRP. PSE is excited to incorporate these new ideas into the process, but acknowledges that stakeholder input and institutional learning must be allowed to evolve the process. A full discussion of how the customer benefit indicators were established is included in Chapter 8. Figure 3-14 shows the results of the

Customer Benefits Analysis and the overall portfolio rankings at the 24-year time horizon. These outputs have been color coded from red (least benefit) to green (most benefit). The Mid portfolio is the lowest cost portfolio that meets CETA requirements at $15.53 billion, but in terms of customer benefit indicators, it ranks at number 14 out of 22. To be included in the Customer Benefit Analysis portfolios must maintain consistency across demand and electric price forecasts, meet CETA requirements and represent current carbon regulation; therefore, not all portfolios were included.

Figure 3-14: Customer Benefits Analysis –Overall Portfolio Rank and Costs for 2045

Portfolio Sensitivity	Overall Rank	24-year Levelized Portfolio Cost (Billion $)
1 Mid	14	$15.53
A Renewable Overgeneration	13	$17.11
C Distributed Transmission	20	$16.35
D Transmission/build constraints - time delayed (option 2)	11	$15.54
F 6-Yr DSR Ramp	17	$15.54
G NEI DSR	10	$15.24
H Social Discount DSR	8	$15.77
I SCGHG Dispatch Cost - LTCE Model	3	$15.41
K AR5 Upstream Emissions	12	$15.56
M Alternative Fuel for Peakers – Biodiesel	1	$15.44
N1 100% Renewable by 2030 Batteries	6	$32.03
N2 100% Renewable by 2030 PSH	15	$66.64
O1 100% Renewable by 2045 Batteries	9	$23.35
O2 100% Renewable by 2045 PSH	5	$46.95
P1 No Thermal Before 2030, 2Hr Li-Ion	21	$30.84
P2 No Thermal Before 2030, PHES	18	$22.85
P3 No Thermal Before 2030, 4Hr Li-Ion	22	$39.01
V1 Balanced portfolio	4	$16.06
V2 Balanced portfolio + MT Wind and PSH	16	$16.61
V3 Balanced portfolio + 6 Year DSR	7	$16.26
W Preferred Portfolio (BP with Biodiesel)	2	$16.11
AA MT Wind + PHSE	19	$15.84

As shown in Figure 3-14, the Customer Benefit Analysis suggests Sensitivity M is the portfolio that provides the greatest benefit to PSE customers. 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 reduce transmission risk and may provide benefits on the distribution system.

Comparing the costs of Sensitivity M with Sensitivity W yields only a relatively small increase in costs and provides a greater investment in distributed energy resources, thus balancing transmission risks. Therefore, PSE has selected Sensitivity W, the Balanced Portfolio with biodiesel fuel, as the preferred portfolio.

Figure 3-15 compares the portfolio M and W builds by 2030. Portfolio W is a balanced portfolio that takes earlier action on DERs and includes more distributed solar and battery energy storage in the first 10 years of the plan than portfolio M.

Figure 3-15: Resource Build for 2021 IRP Preferred Portfolio and Sensitivity M, Transmission Build Constraint Cumulative Additions by Nameplate (MW)

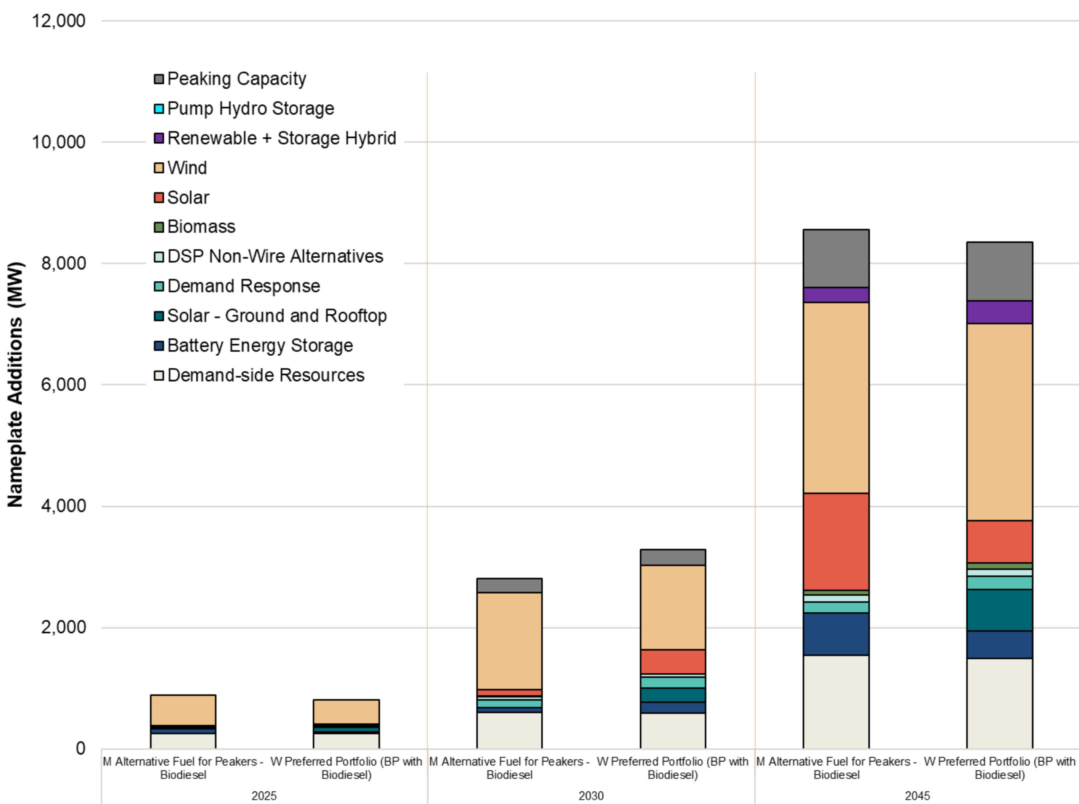


Figure 3-16 shows the results of the Customer Benefits Analysis for the 10-year time horizon. With the addition of the distributed energy resources in the early part of the planning horizon, Sensitivity W ranked number 1 in the 10-year rankings.

Figure 3-16: Customer Benefits Analysis –Overall Portfolio Rank for 2031

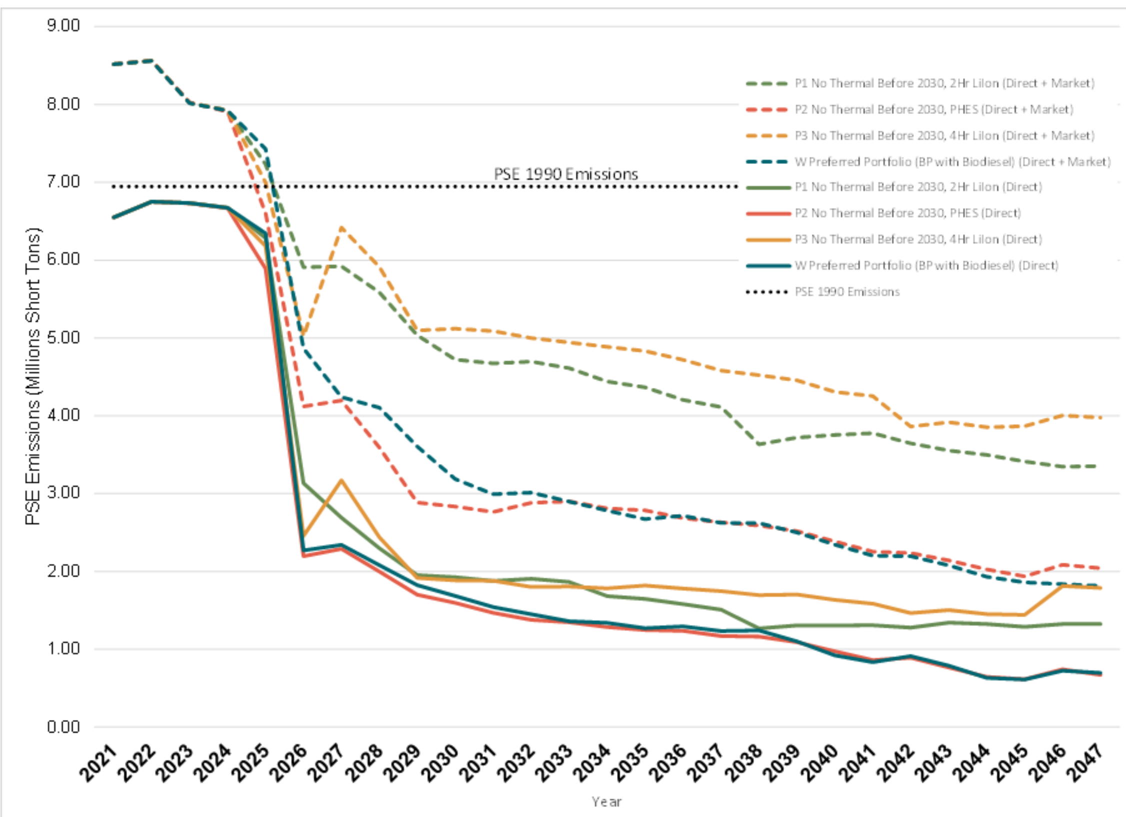
Portfolio Sensitivity	Overall Rank	10-year Levelized Portfolio Cost (Billion $)
1 Mid	12	$6.65
A Renewable Overgeneration	9	$7.09
C Distributed Transmission	20	$6.65
D Transmission/build constraints - time delayed (option 2)	15	$6.68
F 6-Yr DSR Ramp	11	$6.50
G NEI DSR	16	$6.37
H Social Discount DSR	18	$6.47
I SCGHG Dispatch Cost - LTCE Model	17	$6.61
K AR5 Upstream Emissions	19	$6.71
M Alternative Fuel for Peakers – Biodiesel	8	$6.67
N1 100% Renewable by 2030 Batteries	5	$10.86
N2 100% Renewable by 2030 PSH	14	$19.92
O1 100% Renewable by 2045 Batteries	13	$7.51
O2 100% Renewable by 2045 PSH	4	$11.77
P1 No Thermal Before 2030, 2Hr Li-Ion	21	$13.36
P2 No Thermal Before 2030, PHES	7	$9.94
P3 No Thermal Before 2030, 4Hr Li-Ion	22	$15.38
V1 Balanced portfolio	2	$6.90
V2 Balanced portfolio + MT Wind and PSH	6	$7.13
V3 Balanced portfolio + 6 Year DSR	3	$6.84
W Preferred Portfolio (BP with Biodiesel)	1	$6.91
AA MT Wind + PHSE	10	$6.78

Portfolio Emissions

All sensitivities that meet CETA renewable requirements show significant reduction in emissions throughout the planning horizon. Figure 3-17 compares CO_2 emissions for Sensitivity W, preferred portfolio with Sensitivity P portfolios, where the peaking capacity is replaced with different combination of renewable or non-emitting resources. The chart shows direct emissions from the generating resources plus upstream emissions in the solid lines, and direct emissions plus upstream emissions plus market purchases in the dashed lines. The graph does not account for alternative compliance mechanisms to achieve the carbon neutral standard from 2030 to

2045. Rather direct emissions are shown for analysis. Direct emissions decrease over time as thermal resources are replaced with renewable generation. In Sensitivity P, more energy storage resources are added to the portfolio and market purchases are used to charge the storage resources since there is not enough surplus energy in PSE's portfolio. The market purchases cause a large increase in emissions; as can be seen by the difference between the solid and dashed lines for the Sensitivity P portfolios. Also, comparing the solid lines for Sensitivity W, preferred portfolio, and Sensitivity P shows that the direct emissions from PSE's resources are lower in Sensitivity W, preferred portfolio. This is because the heat rate of the new peaking resource, run on biodiesel fuel, is more efficient than the older thermal generators in PSE's fleet, the new peaking resource has lower emissions. When new energy storage resources are added in Sensitivity P portfolios, the increased generation from the existing fleet increases direct emissions.

Figure 3-17: CO_2 Emissions – Preferred Portfolio and Sensitivity P
(Solid lines show direct emissions plus upstream emissions, dotted lines show direct emissions plus upstream emissions plus market purchases. Does not include alternative compliance to meet carbon neutral standard in 2030 and beyond)



COST OF CARBON REDUCTIONS. To calculate the cost of reducing carbon emissions, PSE divided 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:

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

Figure 3-18 compares the results of this calculation for the preferred portfolio, Sensitivity N (100 percent renewable resources by 2030), Sensitivity O (where all thermal resources are retired by 2045), and Sensitivity P (new peaking capacity is replaced with alternative resources). The lower the value, the more efficient the portfolio is in reducing emissions per dollar spent. The preferred portfolio is very efficient at reducing portfolio emissions because it uses new peaking capacity fueled with biodiesel to meet peak capacity needs.

Figure 3-18: Cost of Emissions Reductions Compared – Mid Scenario, Preferred Portfolio and Sensitivities N, O and P

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 Scenario Portfolio	53.87	$15.53	-
Preferred Portfolio	52.77	$16.10	0.52
N1 100% Renewable by 2030 - Batteries	42.16	$32.03	1.41
N2 100% Renewable by 2030 - PHES	30.65	$66.64	2.20
O1 100% Thermal resources retired by 2045 - Batteries	51.83	$23.35	3.83
O2 100% Thermal resources retired by 2045 – PHES	43.54	$46.95	3.04
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

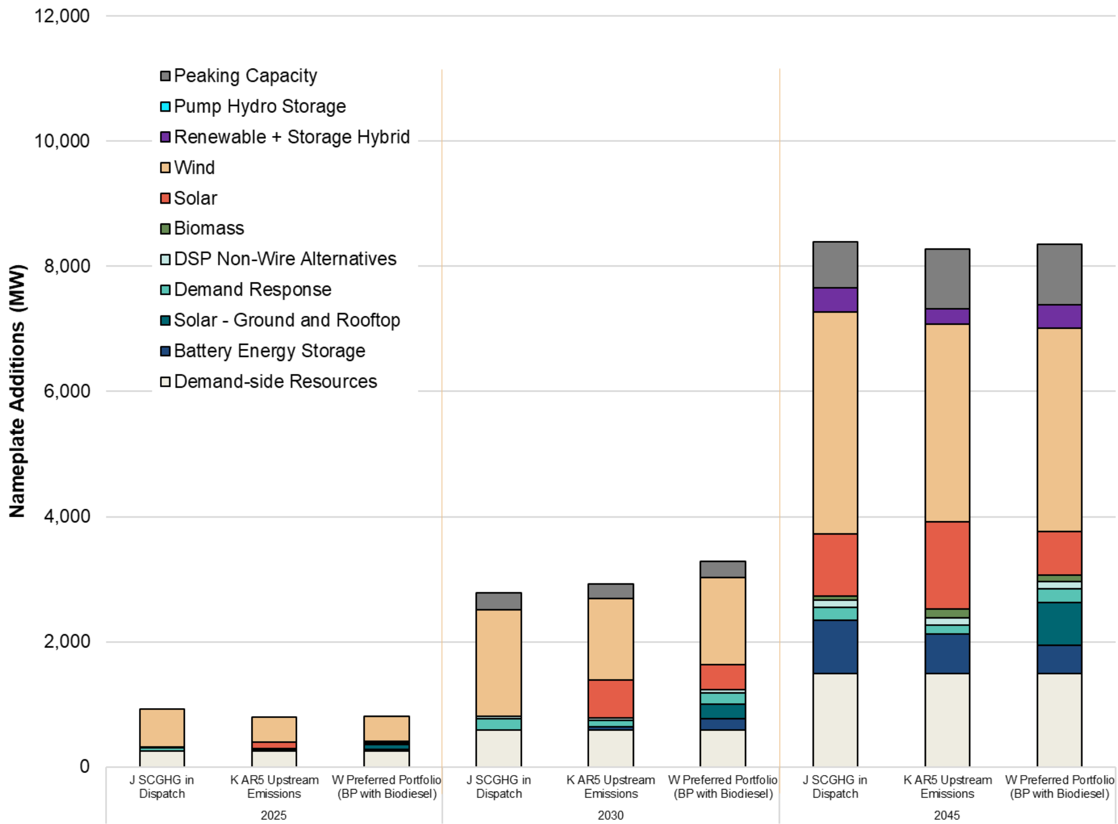
Social Cost of Greenhouse Gases (SCGHG)

CETA explicitly instructs utilities to use the SCGHG as a cost adder when evaluating conservation efforts, developing electric IRPs and CEAPs, and evaluating resource options. As a result, PSE has modeled SCGHG as an adder in the portfolio model. The SCGHG is described in more detail in Chapter 5.

In response to stakeholder requests, PSE modeled different SCGHG approaches. Utilizing different SCGHG modeling approaches does not have a material impact on the cost-effective amount of conservation, demand response and other resource additions or retirements. Renewable resource requirements to comply with CETA are the key constraint that drives portfolio resource additions and costs. The different SCGHG modeling approaches are described in detail in Chapter 8.

In response to stakeholder requests, PSE also modeled an alternate upstream emission content. PSE applied upstream emission rate consistent with Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report (AR4) in all portfolio modeling, and then evaluated a sensitivity using upstream emissions consistent with IPCC's Fifth Assessment Report (AR5). While AR5 increased upstream emissions for natural gas, it did not change resource builds or retirements compared to AR4. Figure 3-19 is a comparison of builds for the different modeling methodologies.

Figure 3-19: Resource Build for 2021 IRP Preferred Portfolio and Sensitivities J and K (Transmission Build Constraint), Cumulative Additions by Nameplate (MW)



Temperature Variations and Fuel Conversion Impacts

PSE evaluated temperature variations that increased the summer loss of load events. This temperature sensitivity is one model of possible weather changes and provides a preliminary view of a possible impact of warming temperatures as a result of climate change. The lessons from this sensitivity are useful as PSE plans for future resource adequacy analyses, but limited conclusions can be made to inform the preferred portfolio. Details are provided in Chapter 7 for the resource adequacy analysis, and portfolio results are presented in Chapter 8.

PSE will continue to model weather trends under different scenarios to better understand how summer extreme events can affect resource adequacy, but also to ensure that PSE continues to plan for winter extreme events. While average temperatures may be increasing over time due to climate change, extreme events (both hot and cold) may still occur. Further climate change modeling is needed to drive resource planning changes. In the past three years, three separate regional events outside of PSE's control have occurred, two in the winter (February 2019 and February 2021), and one in the summer (August 2020). PSE anticipates future changes to the resource adequacy analysis will include both winter and summer resource adequacy analyses, and PSE will also work to develop a winter and summer peak capacity credit to understand how different resources can contribute to both needs.

In the 2021 Washington State legislative session, some proposals have been introduced that propose to convert from natural gas to electricity for power supply. This would significantly increase electric loads and associated peak loads. Since this would convert natural gas heating to electric heating, the majority of the increased loads would happen in the winter. PSE ran a sensitivity in this IRP to examine large-scale conversion of natural gas heating to hybrid electric heat pumps. This sensitivity increased electric loads by over 35 percent by 2045 and winter peak loads by over 17 percent by 2045. Natural gas sales decreased by 74 percent by 2045. This sensitivity assumed conversion to hybrid air-source heat pumps with natural gas backup that switch from electric space heating to natural gas when the outdoor air temperature is equal to or less than 35 degrees Fahrenheit. This had little impact on natural gas peak demand since the hybrid heat pump still relies on natural gas as a backup fuel. More details on the Gas to Electric sensitivity results are presented in Chapters 8 and 9.

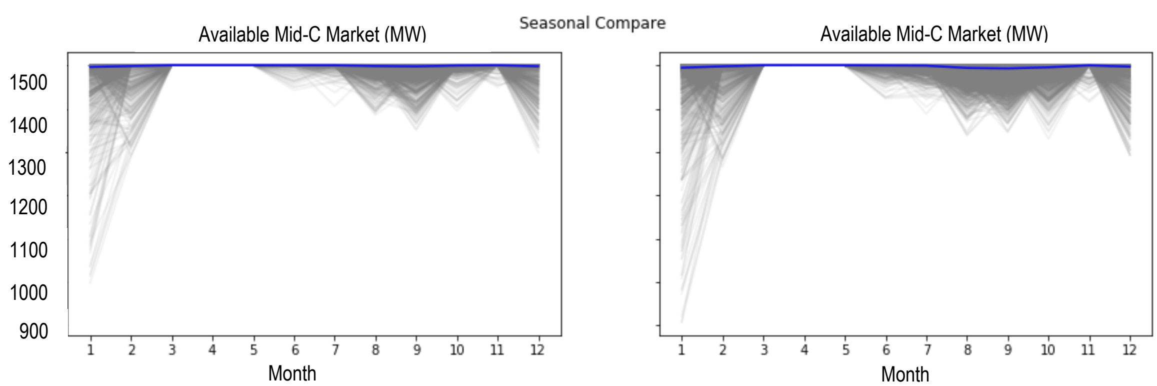
For future IRP work, PSE will look at integrating several of these scenarios to include temperature variations, gas-to-electric conversion and increased electric vehicle loads. Separately, each of these factors can change PSE's load shapes in different ways, but it is important to plan for how combined changes may affect PSE's load shapes.

Firm Resource Adequacy Qualifying Capacity Contracts

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.

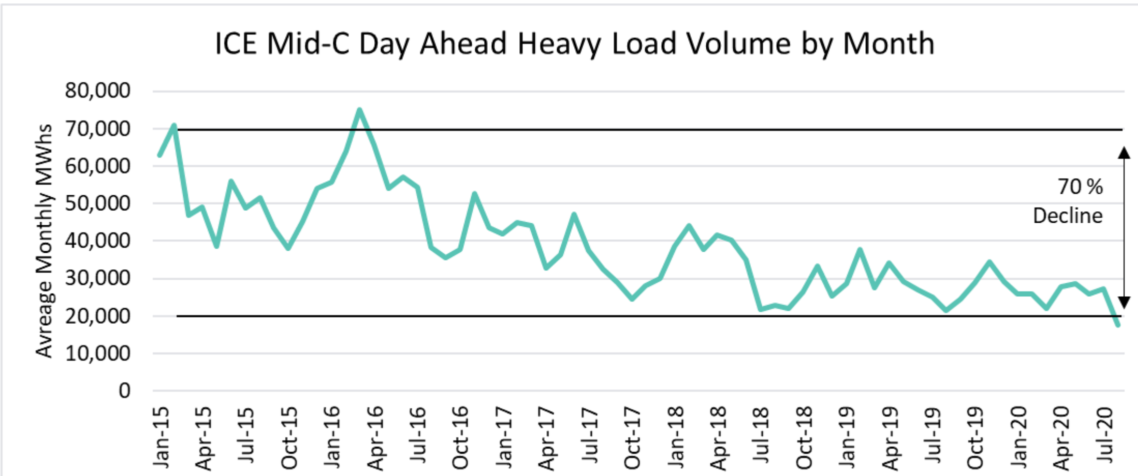
Figure 3-20 shows the results of the resource adequacy modeling. Over the last few years, several studies from regional organizations show that the Pacific Northwest may experience a capacity shortfall in the near term. PSE's resource adequacy model takes curtailment events from the Northwest Power and Conservation Council's resource adequacy model and allocates a portion of the curtailments to PSE's portfolio. The chart illustrates the average of PSE's share of the regional deficiency. The results show the deficiency in each of the 7,040 simulations (gray lines) and the mean of the simulations (blue line). The mean deficiency is close to zero, but in some simulations the market purchases may be limited by 500 MW (in January 2027) and 600 MW (in January 2031). This means that of the 1,500 MW of available Mid-C transmission, PSE was only able to fill 1,000 MW in January 2027.

Figure 3-20: Reduction to Available Mid-C Market



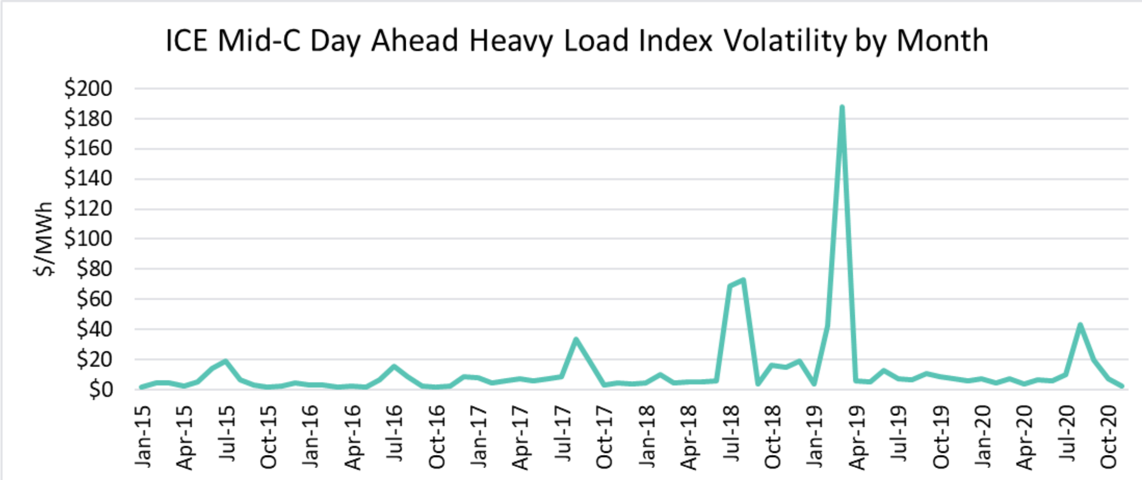
In the market risk assessment, PSE took this assessment further and analyzed the availability of the market during more recent events. Reductions in traded volume in the day-ahead market indicate constrained market supply/demand fundamentals; less generation is available, so there is less capacity available for market participants to trade. This also is suggestive of more energy being transacted before the month of delivery, so it is not available to be traded in the day-ahead market. Trading volume in the day-ahead market has declined 70 percent since 2015. Figure 3-21 shows the average monthly trading volume between January 2015 and July 2020 on the Intercontinental Exchange.

Figure 3-21: Mid-C Day-ahead Heavy Load Volume Timeline



The market risk analysis also shows that price volatility has increased since 2015 in response to tighter supply/demand fundamentals, with energy prices spiking precipitously when there is limited supply. Such increases in market volatility were notable in the summer of 2018, when high regional temperatures coincided with forced outages at Colstrip; in March 2019, when regional cold coincided with reduced Westcoast pipeline and Jackson Prairie storage availability; and most recently in August 2020, during a west-wide heat event. The volatility of day-ahead heavy load prices is shown in Figure 3-22.

Figure 3-22: Volatility of Heavy Load Mid-C Day-ahead Prices



Coinciding with the retirement of legacy baseload capacity and the decline of market availability, several regional investor-owned utilities (IOUs) have reduced their assumptions of available market purchases in their IRPs. Compared with other IOUs in the region, PSE's market purchases are much higher than other IOUs, putting PSE at risk if short-term market purchases are not available.

Taking into account the results from the resource adequacy analysis, the downward trend in trading volumes over the last five years and the low availability of market during regional events, PSE proposes to reduce its reliance on short-term market purchases to 500 MW by 2027 and convert a portion of its 1,500 MW of Mid-C transmission to firm resource adequacy qualifying capacity contracts instead of relying on the short-term market. This means that the firm transmission is still available and will be evaluated during the RFP process for the lowest reasonable cost way to firm up the resources behind the transmission.

Reducing market purchases to 500 MW increases the peak capacity deficit in 2027 from 906 MW to 1,853 MW. In Sensitivity WX, PSE evaluated a portfolio in which available transmission to Mid-C was reduced and replaced with new peakers to address the capacity deficit. The result was a portfolio that added approximately 1,000 MW of peaking resources. 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. PSE's transmission can be used to procure new firm contracts or resources that can be delivered to Mid-C market hub and then used to deliver energy to PSE. The total cost of the preferred portfolio already includes estimates of the wholesale market price for the firm contracts proposed, but does not include any capacity premium that may be added. It is this premium that is difficult to predict, and PSE will learn more about those costs and what is available in the next RFP.

The regional resource adequacy program is currently under development and will impact PSE's capacity need should PSE decide to participate. Sufficient program design details are not yet available to evaluate the program's impact on PSE's resource adequacy analysis, however, we know that the program will define the types of contracts that will qualify to meet resource adequacy. PSE will be able to assess program impacts in time for the IRP update in two years.

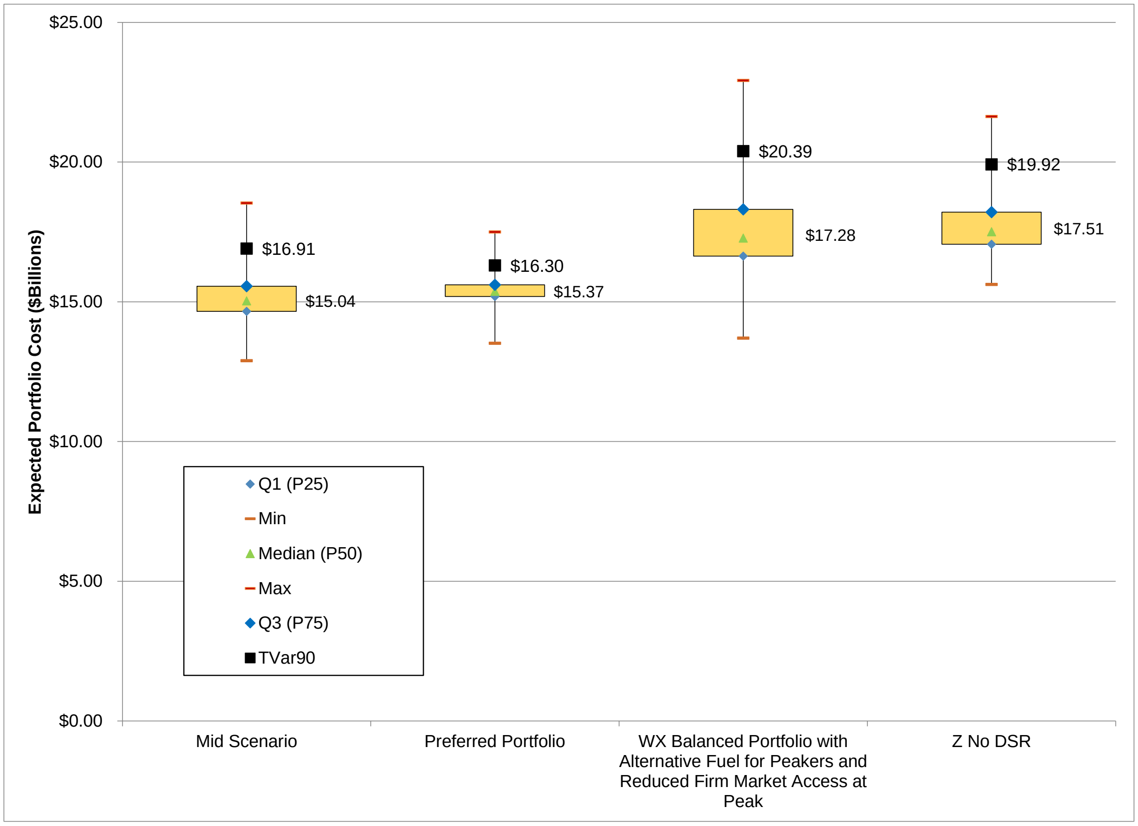
Summary of Portfolio Risk

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. For this purpose, PSE takes the portfolios (drawn from the deterministic scenario and sensitivity portfolios) and runs them through 310 draws[3] that model varying power prices, natural gas prices, hydro generation, wind generation, solar generation, load forecasts (energy and peak), and plant forced outages. From this analysis, PSE can observe how risky the portfolio may be and where significant differences occur when risk is analyzed.

PSE's approach to the electric stochastic analysis hold 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. Nevertheless, the result of the risk simulation provide an indication of portfolio costs risk range under varying input assumptions. In Figure 3-23, the expected portfolio costs for each portfolio are being compared across four portfolios; Mid, Preferred Portfolio, Sensitivity WX (Balanced portfolio with Market reduction), and Sensitivity Z (No DSR). The left axis represents the costs and the right axis represents the portfolio. The green triangle on each of the boxes represents the median for that particular portfolio and is a measure of the center of the date. The interquartile range box represents the middle 50% 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.

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

Figure 3-23: Range of Portfolio Costs across 310 Simulations



The interquartile range for the Preferred Portfolio with Biodiesel is comparatively narrow and has the lowest TailVar90 at $16.3 billion dollars suggesting that the overall expected portfolio costs is the least variable compared to the other portfolios. The smaller range on the preferred portfolio indicates that this portfolio has the lowest volatility and the lowest risk than the other portfolios tested. Including conservation in the portfolio reduces both costs and risks, as can be seen in the comparison of costs and ranges with Sensitivity Z, No DSR. Sensitivity WX replaces the 1,000 MW of short-term market with frame peakers. In this portfolio, the costs are higher because of the cost of new resources, which is why the median cost is higher than the preferred portfolio. This portfolio also has a large range in costs, indicating higher volatility and risk. The conclusion of this simulation is that replacing the short-term market with natural gas plants does not reduce risk, it is simply exchanging market price risk for natural gas fuel risks. Further study is needed and PSE will continue to evaluate the impacts of different types of resources.

3. NATURAL GAS SALES RESOURCE PLAN

Resource Additions Summary

The additions to the natural gas sales portfolio are summarized in Figure 3-24, followed by a discussion of the reasoning that led to the plan. Peak use during the winter heating seasons must be met in the natural gas analysis. PSE's winter heating season is from November to February; as a result, the years shown here reference the natural gas year, so 2025/26 means the natural gas year from November 2025 through October 2026.

Figure 3-24: Natural Gas Sales Resource Plan – Cumulative Capacity Additions (MDth/day)

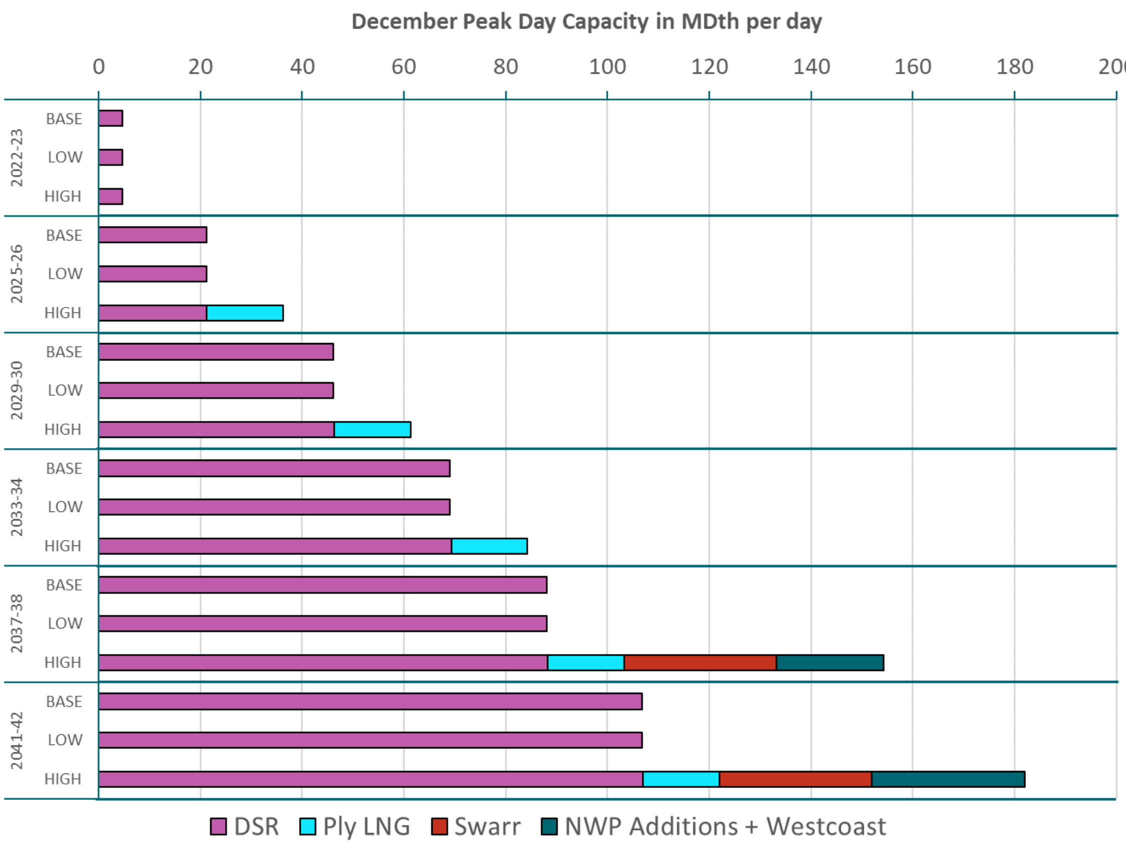
	2025/26	2030/31	2041/42
Conservation	21	53	107

The natural gas sales resource plan integrates demand-side and supply-side resources to arrive at the lowest reasonable cost portfolio capable of meeting customer needs over the 20-year planning period. In the draft 2021 IRP, conservation was the most cost effective resource, and it alone was enough to meet the need over the entire study period.

Natural Gas Sales Results across Scenarios

As with the electric analysis, the natural gas sales analysis examined the lowest reasonable cost mix of resources across a range of scenarios. Three scenarios were tested in the 2021 IRP: Mid, Low and High. Figure 3-25 illustrates the lowest reasonable cost portfolio of resources across these three potential future conditions.

Figure 3-25: Natural Gas Sales Portfolios by Scenario (MDth/day)

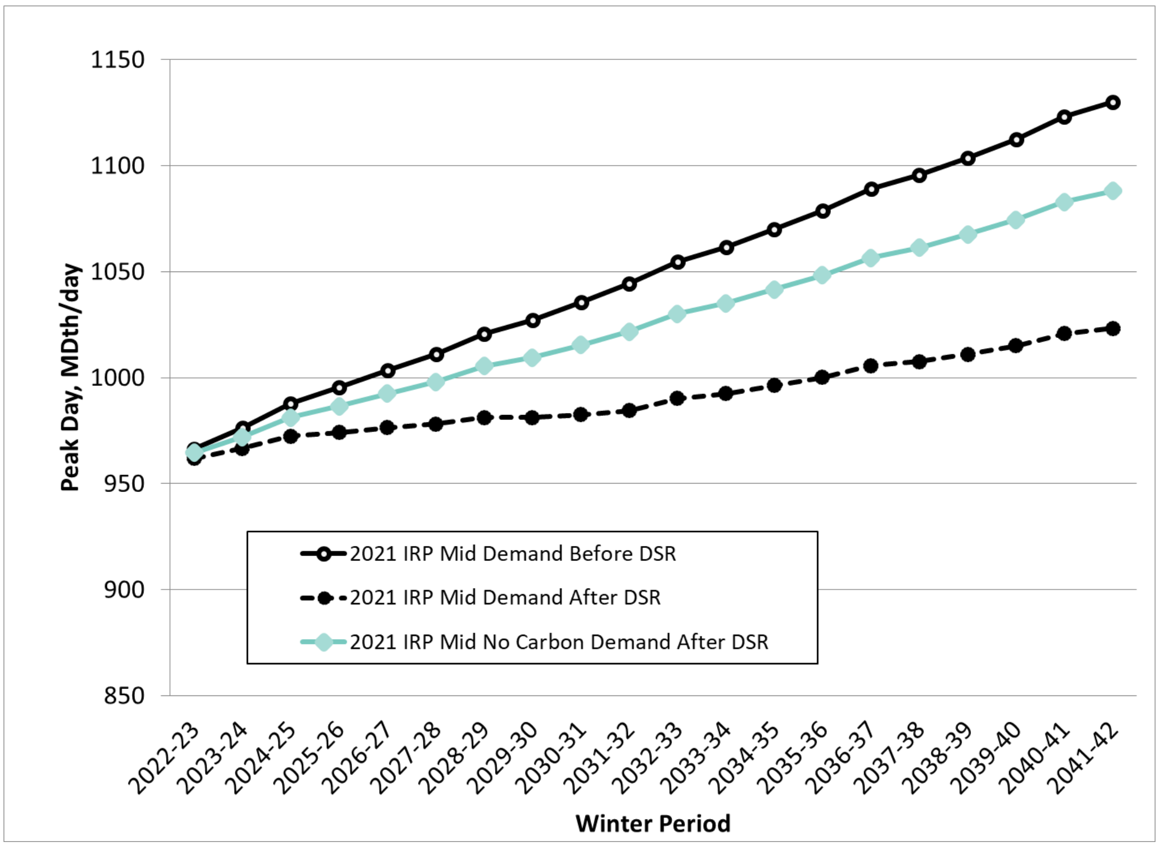


Key Findings by Resource Type

Demand-side Resources

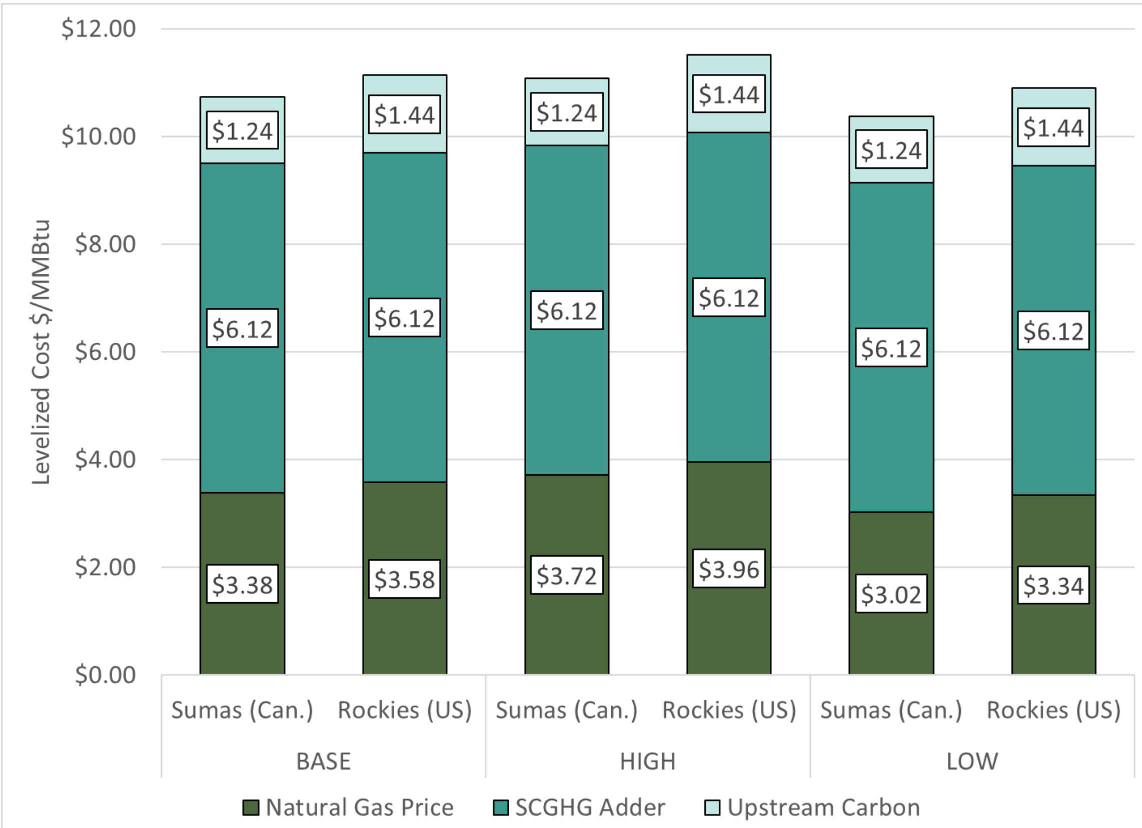
Cost-effective DSR (conservation) does not vary across scenarios. In other words, the same level of conservation is chosen in all of the scenarios. The conservation is driven by the total natural gas costs, which now includes additional costs for upstream emissions, more than by other factors such as resource need. Figure 3-26 shows the results of cost-effective DSR for the Mid Scenario with and without the carbon adders, and that the amount of cost-effective DSR is significantly lower when the total cost of natural gas consists of only the natural gas commodity costs.

Figure 3-26: DSR Cost Effective Levels are Driven by Total Natural Gas Costs



Conversely, in Figure 3-27, When the carbon adders are included, the total cost of natural gas varies only slightly from one scenario to the next, and this results in the same level of DSR being selected in all three scenarios.

Figure 3-27: Total Cost of Natural Gas (Commodity + SCGHG + Upstream Emissions)



Swarr Upgrades

Upgrades to PSE's propane injection facility, Swarr, is a least cost resource in the High scenario. The timing of the Swarr upgrade is driven by the load forecast. In the High load scenario, Swarr is needed by 2037/38. Upgrades to Swarr are essentially within PSE's ability to control, so PSE has the flexibility to fine-tune the timing. PSE has less control over pipeline expansions, since expansions often require a number of shippers to sign up for service in order for an expansion to be cost effective. The Swarr upgrade has a short lead-time, and PSE has the flexibility to adjust it as the future unfolds.

Plymouth LNG

The Plymouth LNG peaker contract was selected as a least cost resource in the High Scenario. The plant is in PSE's electric portfolio, and the contract is up for renewal in April 2023, at which point the natural gas sales portfolio could buy the contract. In the High load scenario, the plant was selected to start service in the 2023/24 winter, and it has an associated pipeline capacity of 15 MDth per day on Northwest Pipeline to deliver the natural gas to PSE.

NWP + Westcoast Pipeline Additions

Additional firm pipeline capacity on Northwest and Westcoast Pipelines north to Station 2 is cost effective in the High Scenario, which adds 21 MDth/day in 2034/35, increasing to 30 MDth/day by the end of the planning horizon.

Resource Plan Forecast – Decisions

The forecast additions described above are consistent with the optimal portfolio additions produced for the Mid Scenario by the SENDOUT gas portfolio model. SENDOUT is a helpful tool, but its results must be reviewed based on judgment, since real-world market conditions and limitations on resource additions are not reflected in the model. The following summarizes key decisions for the resource plan.

Conservation (DSR)

The resource plan incorporates cost-effective DSR from the Mid Scenario – the same as in the Low and High Scenarios. Natural gas prices appear to have little impact on DSR, regardless of the load growth forecast. The primary variable that affects the resource decision is the assumption for SCGHG adders. The SCGHG adders are derived from requirements stated in HB1257, which became law during the 2019 legislative session and require the SCGHG adders to be incorporated in the planning analysis as part of capacity expansion decisions. The results show that cost-effective conservation in the Mid Scenario is likely to be a safe decision, since the same level of conservation is cost effective regardless of whether the demand forecast is as low as the 10th percentile in the Low Scenario or as high as the 90th percentile in the High Scenario.

The level of cost-effective DSR found in the deterministic Mid, Low, and High Scenarios is a robust result. The stochastic analysis found this level of DSR was the preferred resource in over 80 percent of the 250 stochastic runs in which demand and natural gas prices were varied randomly. Cost-effective DSR reduced both cost and risk in the natural gas portfolio according to the stochastic analysis. Therefore, the risk of over-building or under-building DSR appears to be low.

Supply-side Resources

The supply-side resources – Plymouth LNG peaker contract, Swarr, and pipeline expansions – represent the High Scenario resource additions. No supply-side resources are needed in the Mid and Low Scenarios. Even in the High Scenario, the only resource needed in the near term is the Plymouth LNG peaker contract. The lead time to acquire this resource contract is short, so no decisions are needed until at least 2022. Swarr and NWP plus Westcoast pipeline additions are needed only in the High Scenario in the back half of the study period, thus no decision will be required in the near term. There will be opportunities to review these resources in future IRP cycles before any decisions are necessary.

4. TECHNICAL MODELING ACTION PLAN

Since the 2017 IRP, PSE has made significant advancements in the analytical tools and methods used, and these advancements have been applied to the 2021 IRP. The improvements are documented throughout this IRP. PSE has also identified several improvements for future IRPs. These are described below.

ELECTRIC RESOURCE PLANNING

1. Adopt winter and summer resource adequacy analyses, and develop a winter and summer peak capacity credit to understand how different resources can contribute to both needs.
2. Evaluate the benefits and impacts of the regional resource adequacy program and integrate into PSE's resource planning if appropriate.
3. Integrate the electric and natural gas portfolio modeling to better evaluate future impacts associated with a rapid replacement of natural gas end uses with electricity.
4. Evaluate technology solutions to reduce model run times for the electric portfolio and stochastic models.
5. Continue to refine energy storage modeling.
6. Explore transmission planning optimization tools to help understand the impacts of transmission in electric supply portfolio modeling.

NATURAL GAS RESOURCE PLANNING

1. Evaluate available natural gas portfolio models for long-term resource planning and implement new model for the 2023 IRP.
2. Integrate the electric and natural gas portfolio modeling to better evaluate future impacts associated with a rapid replacement of natural gas end uses with electricity.
3. Evaluate the ongoing use of the existing natural gas peak day planning standard and study the impacts of changing the planning standard.