3 Resource Plan Decisions

This chapter summarizes the reasoning for the additions to the electric and natural gas resource plan.

Contents

1. OVERVIEW

As discussed in Chapter 1, there are analyses, assessments and evaluations that still need to be completed for the final IRP. The decisions that went into the development of the draft preferred portfolio are included in this chapter, but we expect the results to change as the analysis is completed. The draft preferred portfolio is one of a range of portfolios that PSE modeled for this IRP that meets the requirements of the Clean Energy Transformation Act. It is informed by evaluation of portfolio results from stakeholder-selected sensitivities and tested against the Mid Scenario portfolio developed using deterministic portfolio analysis. Deterministic portfolio analysis solves for the least cost solution and assumes perfect foresight about the future, so to assess the risk of potential future changes in hydro or wind conditions, electric and natural gas prices, load forecasts and plant forced outages PSE also performs a stochastic portfolio analysis that will be completed for the final IRP.

This discussion assumes the reader is familiar with the key assumptions described in Chapter 5. 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 that resulted from the draft 2021 IRP analysis. 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 achieves a more than 70 percent reduction in direct emissions by 2029 and carbon neutrality by 2030 through energy transformation projects and other mechanisms. While implementing this highly decarbonized portfolio, the portfolio maintains required resource adequacy with the addition of flexibility capacity starting in 2030.

This draft preferred portfolio was developed from analysis of various sensitivity results and the insights gained from these analyses were applied in developing the preferred portfolio. Whereas the electric portfolio model minimizes total portfolio costs by delaying new resource additions until the last few years of the planning horizon to capture the benefit of declining resource cost curves, in reality, PSE will need to add new resources over time. The preferred portfolio takes the significant amounts of distributed resources added in the last 5 to 10 years of planning period by the model and ramps them in as must-take resources over time, starting in 2025.

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

Resource Additions (MW)	2022-2025	2026-2030	2031-2045	Total
Distributed Energy Resources				
Demand-side Resources	256 MW	360 MW	1,168 MW	1,784 MW
Battery Energy Storage	75 MW	125 MW	550 MW	750 MW
Solar - ground and rooftop	80 MW	150 MW	450 MW	680 MW
Demand Response	10 MW	161 MW	44 MW	215 MW
DSP Non-Wire Alternatives	22 MW	24 MW	72 MW	118 MW
Total DER	443 MW	820 MW	2,284 MW	3,547 MW
Renewable Resources	600 MW	1,100 MW	2,762 MW	4,462 MW
Flexible Capacity	0 MW	237 MW	711 MW	948 MW

Electric Resource Need

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

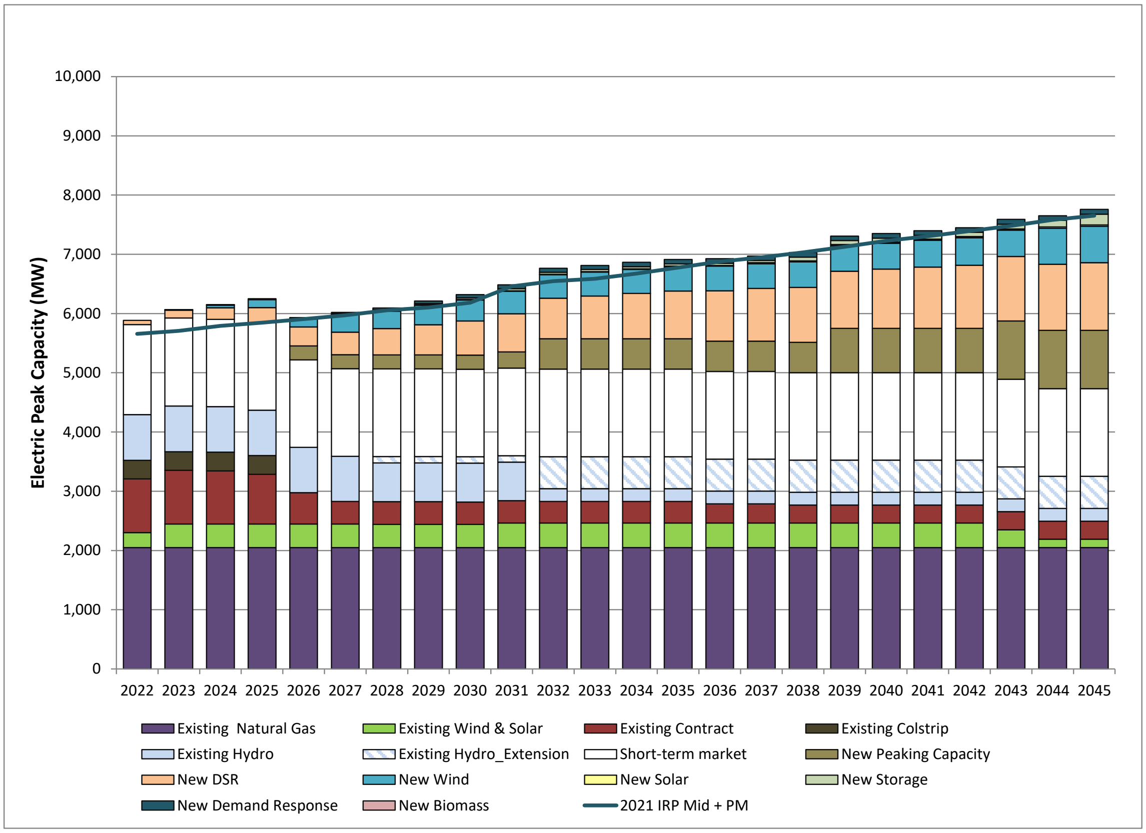
Meeting Peak Capacity Need

All of PSE customer's load obligations must be reliably met by building sufficient generating capacity to be able to meet customer demand with an appropriate planning margin. Planning margins are capacity above customer demand to ensure the system has enough flexibility to handle balancing needs and unexpected events, such as variations in temperature, hydro and wind generation, equipment failure, 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.

As an important part of resource adequacy analysis, PSE quantifies the peak capacity contribution of renewable (wind, hydro and solar) resources (its effective load carrying capacity, or ELCC) and energy limited resources (batteries, pumped storage hydro, and demand response) to assess the amount of peak capacity each resource can reliably provide A full description of the peak capacity and ELCC values is in Chapter 8.

Figure 3-2 shows the combination of draft preferred portfolio new and existing resources required to meet the peak capacity need for the mid demand forecast with an appropriate planning margin and reflects the ELCC value of these resources.

Figure 3-2: Draft Preferred Portfolio Meeting Electric Peak Capacity



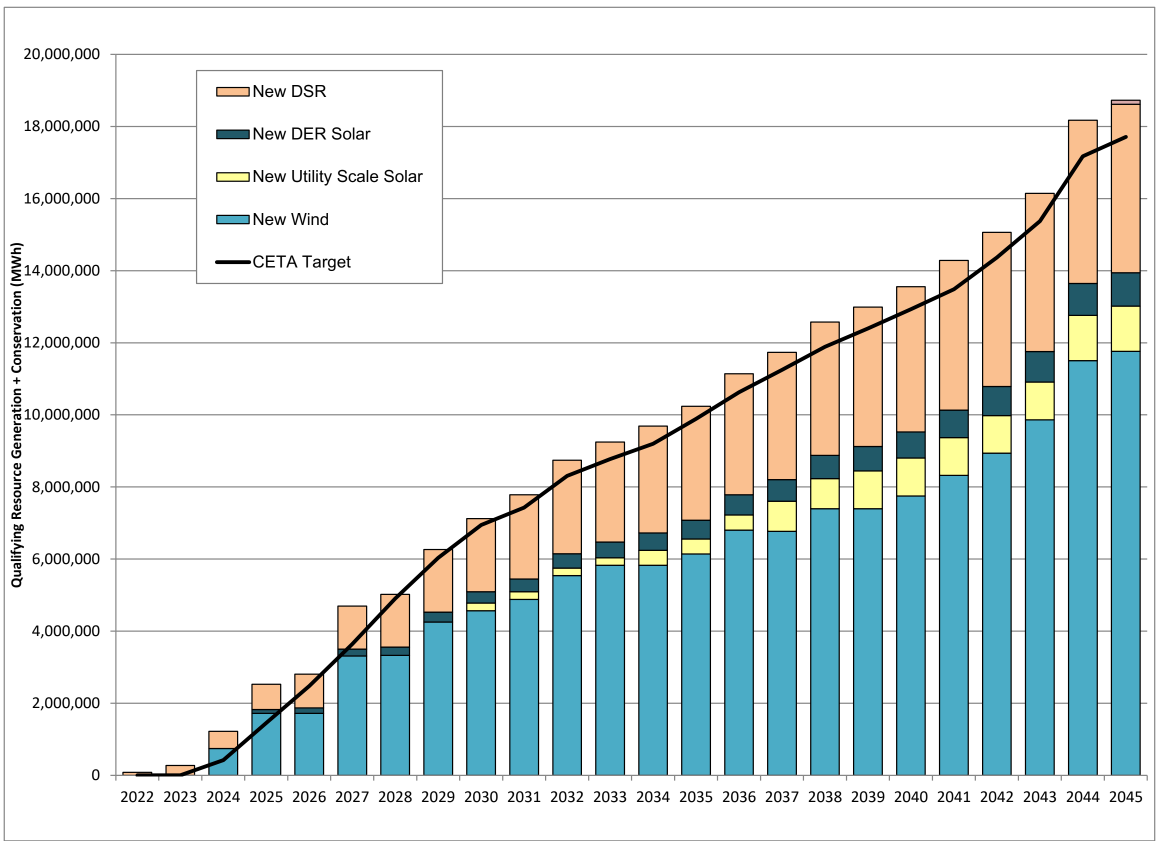
Renewable and distributed resources contribute to meeting peak capacity needs, however, flexible capacity is also needed to maintain reliability and meet the required resource adequacy standard. Over 750 MW of coal is removed from PSE's portfolio by the end of 2025 and the capacity is first replaced by demand-side resources, distributed resources and wind generation. The new flexible capacity is delayed until 2031 when the capacity need increases due to an increase in balancing requirements needed to support new intermittent renewable resources to meet the renewable energy requirements.

PSE evaluated early economic retirement of existing resources but that does not appear to be the least cost option. However, the economic dispatch of existing resources decreases significantly through the planning horizon and is discussed further below.

Meeting Renewable Energy Need

In Chapter 1, Figure 1-3, illustrates the renewable energy need for both RCW 19.285 and CETA, based on the 2021 IRP mid demand forecast. The draft preferred portfolio assumes a linear ramp to achieve the 80 percent Clean Energy Transformation Standard in 2030 and 100 percent standard in 2045. Figure 3-3 shows how the new renewable resources meet the 7.6 million MWh shortfall in 2030 and 17.1 million MWh shortfall 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. The wind category includes wind in Montana, Wyoming and eastern Washington, and the utility-scale solar includes solar in eastern Washington. The distributed energy resource (DER) solar includes delivery system non-wire alternatives and ground-mounted and rooftop solar PV. This chart shows the total annual energy (MWh) produced by these resources.

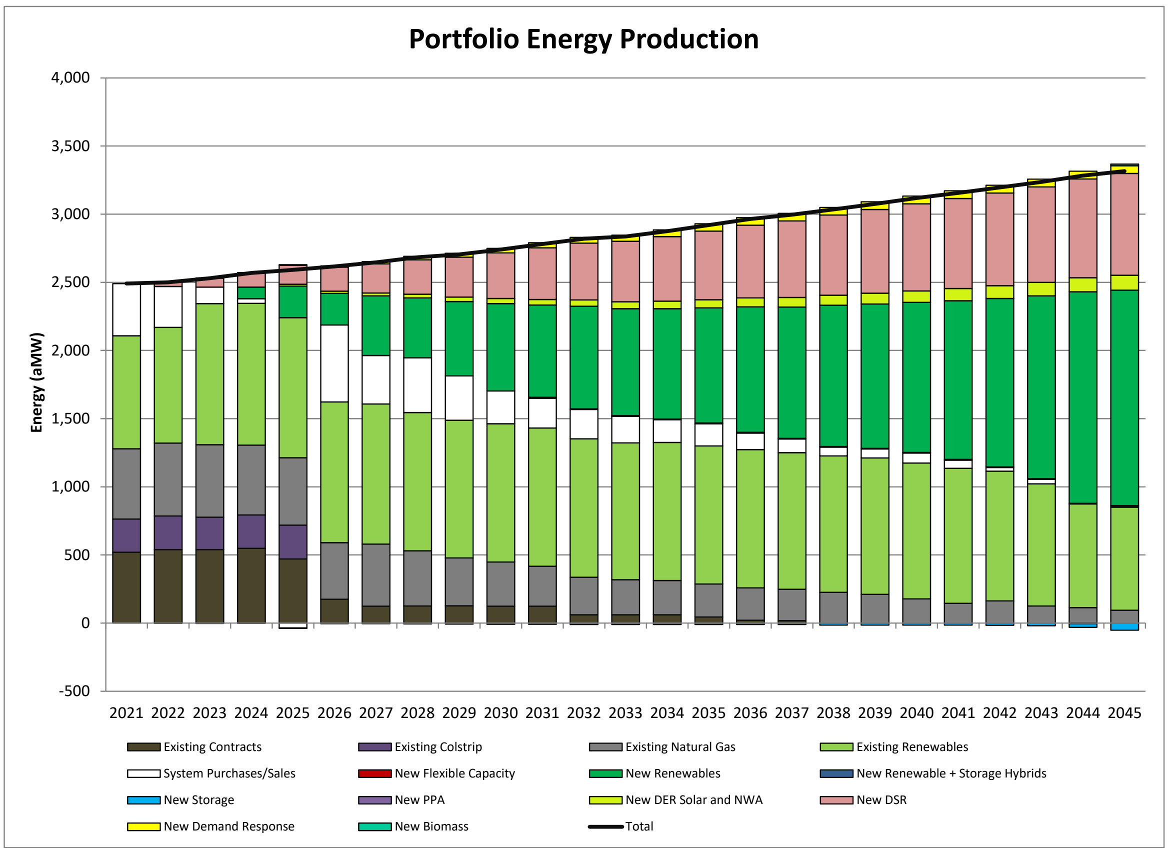
Figure 3-3: Draft Preferred Portfolio Meeting Renewable Energy Requirements



Meeting Energy Need

Figure 3-4 shows the draft 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 need is met with coal resources. The use of existing thermal resources declines, with the capacity factor of PSE's combined-cycle combustion turbines decreasing from 70 percent to 5 percent over the planning horizon. The pink bars represent demand-side resources, which significantly reduce total load. The total demand shown in the chart is for the demand at the generator, so it is grossed up for sales. Distributed energy resources are included in the portfolio but are not visible in this chart because they are a net zero resource, such that they do not produce any energy but rather store the energy that other generators have produced.

Figure 3-4: Draft Preferred Portfolio Meeting Energy Requirements



Portfolio Optimization Results

For the draft IRP, PSE examined three economic scenarios that varied demand, natural gas price, and power price, and 11 portfolio sensitivities developed through a stakeholder process described in Appendix A. Another 15 sensitivities will be analyzed for the final IRP. Sensitivities help us to understand how changing specific assumptions about customer demand, carbon policies, transmission availability, emission reductions, and conservation assumptions and costs can change the mix of resources in the portfolio, portfolio emissions and portfolio costs. The development of the draft preferred portfolio was informed by comparing the sensitivity portfolios with the least cost Mid economic scenario portfolio.

Figure 3-5 below provides a description of each of the scenarios and sensitivities. The shaded sensitivities will be analyzed for the final IRP.

Figure 3-5: 2021 IRP Electric Portfolio Scenarios and Sensitivities

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

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
	Description	**Assumptions and Alternatives Analyzed**
K	AR5 Upstream Emissions	The AR5 model is used to model upstream emissions instead of AR4.
L	SCGHG as a Fixed Cost Plus a Federal CO_2 Tax	Federal tax on CO2 is included in addition to using the SCGHG as a fixed cost adder.
EMISSION REDUCTION SENSITIVITIES		
M	Alternative Fuel for Peakers	Peaker plants can use hydrogen as an alternative fuel.
N	100% Renewable by 2030	The CETA 2045 target of 100% renewables is moved up to 2030, with no natural gas generation.
O	Natural gas Generation Out by 2045	All existing natural gas plants are retired in 2045.
P	Must-take Battery or Pumped Hydro Storage and Demand Response	Batteries or pumped hydro storage and demand response programs are added before any natural gas plants.
DEMAND FORECAST ADJUSTMENT SENSITIVITIES		
Q	Fuel Switching, Gas to Electric	Gas-to-electric conversion is accelerated in the PSE service territory.
R	Temperature Sensitivity	Temperature data used for economic forecasts is composed of more recent weather data as a way to represent changes in climate.
CETA COSTS SENSITIVITIES		
S	SCGHG Included, No CETA	The SCGHG is included in the portfolio model without the CETA renewable requirement.
T	No CETA	The portfolio model does not have CETA renewable requirement or the SCGHG adder.
U	2% Cost Threshold	CETA is considered satisfied once the 2% cost threshold is reached.
BALANCED PORTFOLIOS SENSITIVITIES		
V	Balanced Portfolio	The portfolio model must take distributed energy resources ramped in over time and more customer programs.
W	Balanced Portfolio with alternative fuel for peaking capacity	The portfolio model must take distributed energy resources ramped in over time and more customer programs plus carbon free combustion turbines using biodiesel as the fuel.

Figure 3-6 summarizes the additions to PSE's existing resource portfolio for the Mid, Low and High Scenario portfolios that result from the deterministic portfolio analysis. The risks examined in these economic scenarios include a wide range of load growth assumptions and natural gas prices, which drive wholesale power prices. Figure 3-7 summarizes additions to PSE's existing resource portfolio across the different sensitivities that result from the deterministic portfolio analysis.

For each scenario and sensitivity, the analysis considered supply- and demand-side resources on an equal footing. All were required to meet three objectives: physical capacity need (peak demand), energy need (customer demand across all hours), and renewable energy need (CETA requirements).

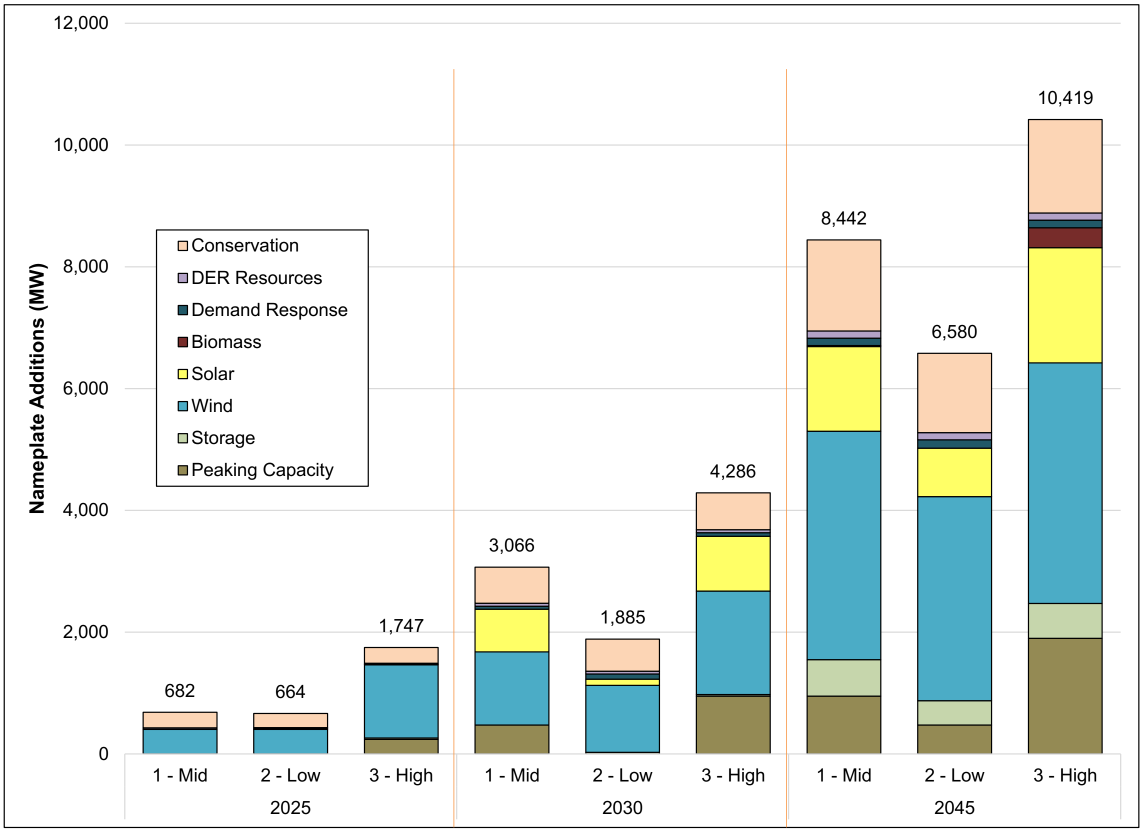
The portfolios in Figures 3-6 and 3-7 also minimize long-term revenue requirements (costs as customers will experience them in rates), given the market conditions and resource costs assumed for each scenario, thereby representing the least cost solution for that scenario or sensitivity.

In all scenarios and sensitivities analyzed, the portfolio model was able to economically retire existing generating resources, but no resources were retired in any of the scenarios and sensitivities.

SCENARIO RESOURCE BUILDS. The Mid Scenario portfolio is the least cost portfolio to meet resource needs, however it does not account for important transmission constraints. In this portfolio, transmission to eastern Washington is assumed to be unlimited and all the renewable requirements are met by utility-scale resources that require transmission back to PSE. Wyoming and Montana wind are the first wind resources added in 2025 and 2026 because their generation profile is well-matched to PSE's load profile; however, these resources are significantly limited by transmission constraints. Washington wind is added consistently throughout the planning horizon starting in 2028 since no transmission constraints are imposed on wind resources. In terms of conservation savings, a total of 1,497 MW nameplate of DSR resources was added to the portfolio by 2045. With the retirement of coal resources in 2025, 474 MW of peaking capacity resources are added to the portfolio in 2026.

The portfolio builds for all three economic scenarios look very much alike given the generic resource options. The mix of resources is similar, and the amount of resources added increased or decreased due to the higher and lower load forecasts modeled in the Low and High scenarios.

Figure 3-6: Resource Build for Mid, Low and High portfolios
Cumulative Additions by Nameplate (MW)



SENSITIVITY RESOURCE BUILDS. Figure 3-7 shows the resource builds by 2045 for each sensitivity modeled in the draft IRP. In all portfolios, new flexible capacity is added, with the exception of sensitivity N and O where flexible capacity is not allowed.

With unlimited transmission assumed, new utility-scale renewable resources are chosen as the lowest cost way to meet the renewable requirements for CETA. Sensitivity C models an important transmission constraint; it limits transmission to eastern Washington, resulting in the addition of almost 2,000 MW of distributed solar in combination with over 1,000 MW of storage in the last 5 years of the planning horizon. The insights gained from the results of Sensitivity C informed the development of the Balanced Portfolio in Sensitivity V. In Sensitivity C (and other sensitivities), the electric capacity expansion model is set to optimize total portfolio costs and therefore delays new builds until the end years of the planning period because all resource cost curves decline over time. This delay produces a lower cost portfolio, but it is not always realistic to wait till the end to add a lot of resources. In Sensitivity C, the model waits till the end years to add a significant amount of distributed resources; the Sensitivity V portfolio takes those distributed resources and ramps them in over time starting in 2025, along with adding more customer programs, to meet CETA requirements. Portfolio W is the Balanced Portfolio that includes an alternative fuel source for flexible capacity. This portfolio became the basis for the preferred plan because it is CETA compliant while also taking into consideration the transmission constraints to regions outside of PSE. The No CETA portfolio (Sensitivity T) is important to understanding the cost impacts of CETA.

Figure 3-7: Relative Optimal Portfolio Builds by Sensitivity
(Cumulative nameplate capacity for each resource addition, in MW by 2045)

		DSR	DER Resources	Demand Response	Biomass	Solar	Wind	Storage	Flecible Capacity	Total
1	Mid	1,497	118	121	15	1,393	3,750	600	948	8,442
A	Renewable Over-generation Test	1,545	118	183	525	1,490	2,150	1,125	692	7,828
C	"Distributed" Transmission/Build Constraints - Tier 2	1,537	3,068	125	105	499	2,715	1,050	948	10,047
I	Social Cost of Greenhouse Gases as an Externality Cost in the Portfolio Model	1,372	118	141	120	1,394	3,450	600	966	8,161
N	100% Renewable by 2030	1,304	118	123	0	1,394	4,050	26,100	0	33,089
O	Gas Generation Out by 2045	1,262	118	130	0	1,397	4,150	18,625	0	25,682
P	Must-take Battery	1,304	118	128	0	1,796	3,750	3,775	711	11,582
P2	Must-take Pumped hydro storage	1,304	118	128	0	1,397	3,950	4,100	711	11,708
S	SCGHG Included, No CETA	1,179	118	155	0	0	350	0	1,513	3,315
T	No CETA	1,042	118	133	0	0	350	0	2,151	3,794
V	Balanced Portfolio	1,497	798	211	60	796	3,750	1,125	948	9,060
W	Balanced Portfolio with alternative fuel for peakers	1,658	798	215	15	697	3,750	750	984	8,706

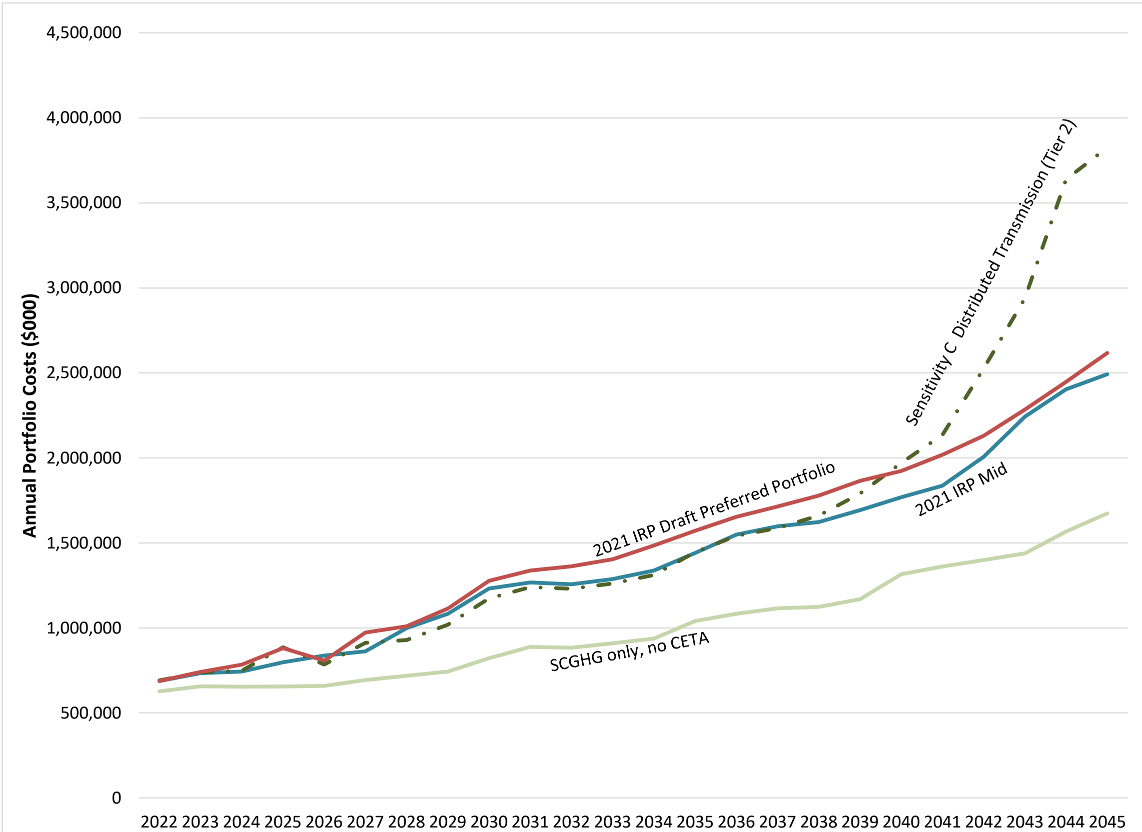
TOTAL PORTFOLIO COSTS. Figure 3-8 compares the total portfolio costs for each sensitivity with the Mid Scenario portfolio cost. The draft 2021 IRP preferred resource plan is based on portfolio W, Balanced Portfolio with Alternative Fuel for Peakers. This portfolio started with Sensitivity C and then made some adjustments. Sensitivity C accounts for the transmission constraints to eastern Washington and includes over 2,000 MW of distributed solar, with an incremental cost of $910 million more than the mid portfolio over the 24-year planning horizon. The adjustments to the portfolio for Sensitivity V brought the incremental portfolio cost down to $620 million more than the mid portfolio.

Figure 3-8: Relative Optimal Portfolio Costs by Scenario
(dollars in billions, NPV including end effects)

		24-Yr Levelized Costs ($Billions)			
	Portfolio	Revenue Requirement	SCGHG Costs	Total	Change from Mid
1	Mid Scenario	$13.63	$5.04	$18.68	
A	Renewable Overgeneration Test	$15.32	$4.24	$19.57	$0.89
C	"Distributed" Transmission/Build Constraints - Tier 2	$14.53	$5.06	$19.59	$0.91
I	Social Cost of Greenhouse Gases as an Externality Cost in the Portfolio Model	$13.65	$4.78	$18.42	($0.25)
N	100% Renewable by 2030	$31.14	$3.42	$34.56	$15.89
O	Gas Generation Out by 2045	$33.90	$6.24	$40.14	$21.46
P	Must-take Battery and Demand Response	$29.09	$6.06	$35.15	$16.47
P2	Must-take PHES and Demand Response	$22.35	$4.36	$26.71	$8.04
S	SCGHG Included, No CETA	$10.06	$9.01	$19.08	$0.40
T	No CETA	$9.40	$0.00	$9.40	($9.28)
V	Balanced Portfolio	$14.37	$5.06	$19.43	$0.75
W	Balanced Portfolio with Alternative Fuel for Peakers	$14.43	$4.86	$19.30	$0.62

ANNUAL PORTFOLIO COSTS. Figure 3-9 below compares the annual portfolio costs of the draft preferred portfolio with Sensitivity T, No CETA, and Sensitivity C, the transmission constrained portfolio. The transmission constrained portfolio sharply increases annual portfolio costs at the end of the planning horizon to minimize total costs by adding all the distributed resources at the end. The preferred portfolio ramps those distributed energy resources in earlier and over time; this smoothes the annual cost increases and closely aligns with the least cost Mid Scenario portfolio. In the 2024 through 2027 time frame, the preferred portfolio (red line) shows two small cost increases due to the demand response programs. Sensitivity S, SCGHG Included, No CETA portfolio that appears in the chart is part of the CETA incremental costs comparison analysis. In the final IRP, PSE will take the next step and evaluate the draft preferred portfolio against the 2 percent CETA cost threshold.

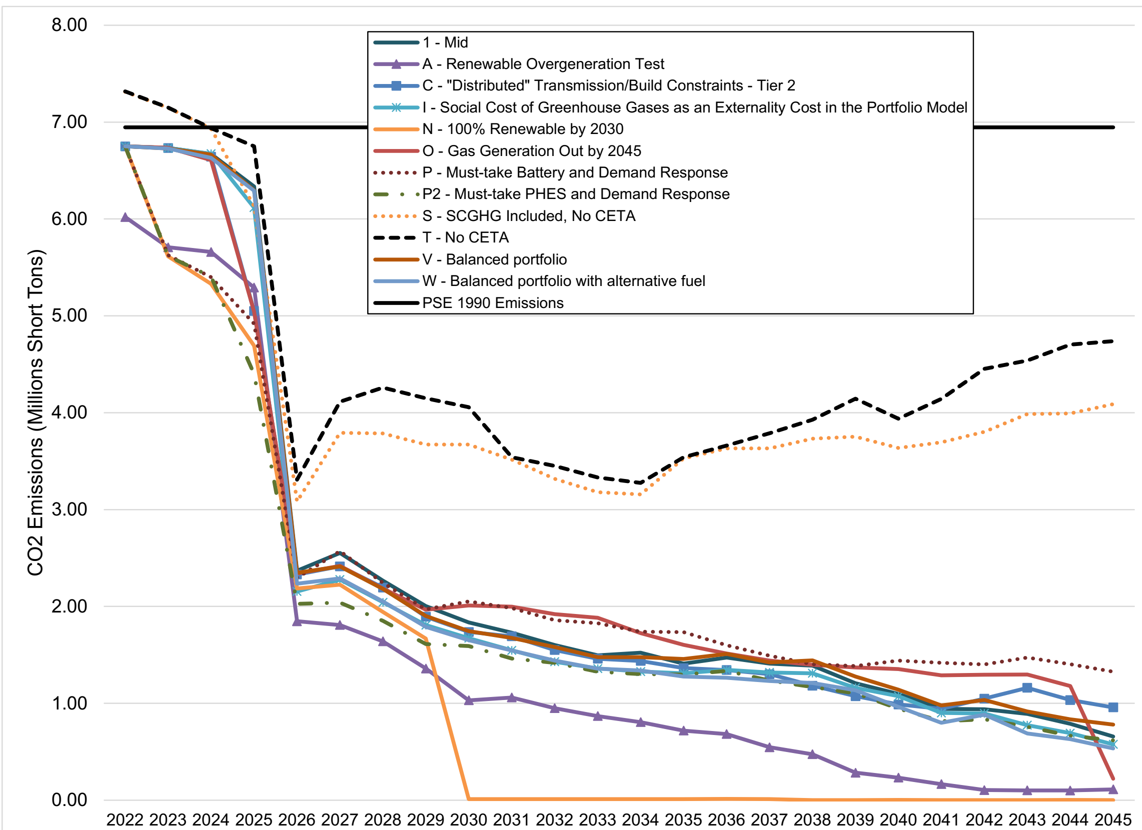
Figure 3-9: Annual Portfolio Costs of Select Sensitivities



Portfolio Emissions

All sensitivities that meet CETA renewable requirements show significant reduction in emissions throughout the planning horizon. Figure 3-10 compares CO_2 emissions for the Mid Scenario portfolio with each sensitivity analyzed so far. The chart shows the direct emissions from each portfolio of resources and does not account for alternative compliance mechanisms to achieve the carbon neutral standard from 2030 to 2045. Direct emissions decrease to zero for Sensitivity N, 100% Renewables by 2030.

Figure 3-10: CO_2 Emissions by Portfolio
(does not include alternative compliance to meet carbon neutral standard in 2030 and beyond)



Portfolio Optimization Results by Resource Type

Demand-side Resources (DSR): Energy Efficiency

Demand-side resources for the Mid Scenario portfolio include energy efficiency up to $175/MWh (493 aMW), codes and standards which includes the Washington State Energy Code (WSEC) along with federal and state equipment standards, and customer solar PV forecast. Some portfolio results had 381 aMW of cost-effective energy efficiency, while others showed up to 508 aMW, depending on adjustments that were made to the portfolio. Given the variation in results, the draft preferred portfolio includes the same the demand-side resources as the Mid Scenario portfolio with the exception of the customer solar PV forecast. The customer solar PV forecast is the same forecast as from the sensitivity C, the transmission-constrained portfolio.

Demand Response

Demand response (DR) is a strategy designed to decrease load on the grid during times of peak use. It involves modifying the way customers use energy – particularly *when* they use it. For instance, businesses might work with PSE to voluntarily adjust their operations during a specified time range. Residential customers might automate their usage with smart thermostats or water heaters. While there are often financial incentives to participate in DR pilots and programs, it is also a way for both PSE and customers to increase efficiency and reduce their carbon footprints.

Demand response programs are voluntary, and once enrolled, customers usually receive notifications in advance of forecasted peak usage times. Depending on the program, this might mean that their thermostat automatically warms their home or building earlier than usual. Because of the remote function of demand response, no action is required from customers to initiate their reduction in load, and they can always choose to opt out of an event.

Demand response programs, evaluated in this IRP, are organized into four categories. These include:

- Direct Load Control (DLC)
- Commercial and Industrial (C&I) Curtailment
- Dynamic Pricing or Critical Peak Pricing (CPP)
- Behavioral DR

This IRP evaluated 16 different demand response programs. PSE modeled the DR programs as being available to start in any year of the planning period. Figure 3-11 below is a breakdown of the cost effective DR programs for each sensitivity and the start year of the program. The numbers in the first column of Figure 3-11 correspond to the following programs:

1. Residential Dynamic Pricing or Critical Peak Pricing – No Enablement
2. Residential Dynamic Pricing or Critical Peak Pricing – with Enablement
3. Residential Direct Load Control Heat-Switch
4. Residential Direct Load Control Heat-BYOT
5. Residential Direct Load Control ERWH-Switch
6. Residential Direct Load Control ERWH-Grid-Enabled
7. Residential Direct Load Control HPWH-Switch
8. Residential Direct Load Control HPWH-Grid-Enabled
9. Small Commercial Direct Load Control Heat-Switch
10. Medium Commercial Direct Load Control Heat-Switch
11. Commercial & Industrial Curtailment-Manual
12. Commercial & Industrial Curtailment-AutoDR
13. Commercial Dynamic Pricing or Critical Peak Pricing – No Enablement
14. Commercial Dynamic Pricing or Critical Peak Pricing – with Enablement
15. Residential EV Direct Load Control
16. Residential Behavioral DR

.

Figure 3-11: Cost-effective Demand Response
(year of program start for each portfolio)

	Program Type	Nameplate (MW)	Sensitivity								
			1	A	C	I	N	O	P	S	T
1	40 hours per season, day ahead	64.5	2025	2022	2022	2022	2022	2022	2022	2022	2022
2	40 hours per season, day ahead	1.9			2022	2022				2022	2029
3	40 hours per season, real time	50.2		2024							
4	40 hours per season, real time	3.2								2022	2029
5	40 hours per season, real time	10.6									
6	Unlimited	57.7	2022	2022	2022	2022	2022	2022	2022	2022	2022
7	40 hours per season, real time	0.2								2027	
8	Unlimited	0.9	2022	2022	2022	2022	2022	2022	2022	2022	2022
9	40 hours per season, real time	6.6		2033		2022				2024	
10	40 hours per season, real time	5.1		2032				2040	2022	2023	2029
11	40 hours per season, day ahead	3.0								2022	
12	40 hours per season, real time	3.0								2027	
13	40 hours per season, day ahead	1.3								2022	
14	40 hours per season, day ahead	1.0				2022				2022	
15	40 hours per season, day ahead	8.5									
16	40 hours per season, day ahead	8.8				2022		2042		2034	

The most-selected DR programs are the unlimited programs which are direct load control programs After that, DLC programs that are more limited in the number of calls per season and the residential critical peak pricing program is picked up in several portfolios. The critical peak pricing program is very similar to a time-of-use (TOU) program. Four programs show up in several portfolios. To determine the cost effectiveness of these programs across multiple sensitivities, there is also a bigger theme regarding the CETA renewable requirement. In

Sensitivity T No CETA, six different demand response programs are selected because without CETA renewable requirements, the capacity need is the dominant factor for selecting resources. There is more demand response and much less energy efficiency (up to 208 aMW in Bundle 2). Similar observations can be made for Sensitivity S, SCGHG only, No CETA. Without the CETA renewable requirement, but with the SCGHG cost adder, 13 demand response programs are cost effective and energy efficiency is selected up to Bundle 6 (or 291 aMW). Still, the capacity need is the driving constraint since there is no renewable need. Once the CETA renewable requirement is included in all the other sensitivities, the portfolio shifts to the energy need being the dominant factor. As a result, the cost-effective energy efficiency bundles increase from 381 aMW to 508 aMW, but demand response decreases because it is limited in helping to meet the CETA renewable requirement. The new renewable resources added to the portfolio have some capacity contribution, so less capacity resources are needed as well.

Distributed Energy Resources: Battery Energy Storage

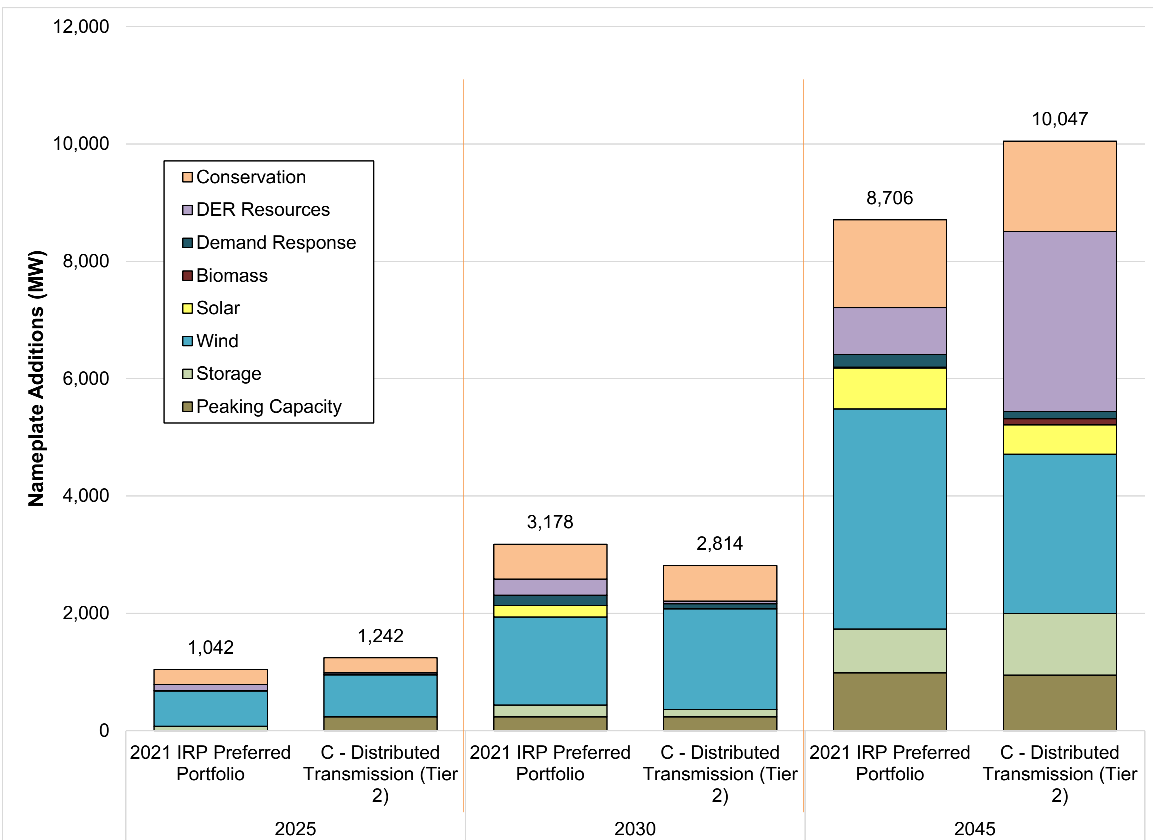
This IRP includes four battery energy storage systems that range from 2 to 6 hours duration along with pumped hydro storage with a duration of 8 hours. Batteries are scalable, and fit well in a portfolio with a small, flat need. Batteries also work as a solution for local distribution upgrades and capacity needs. In all the 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. As observed in Sensitivity P, after over 750 MW of coal resources are removed from the portfolio in 2026, energy storage does not appear to be a cost-effective way to replace the capacity. Given the lower peak capacity credit for energy storage, significantly more resources are needed to match the same capacity as the combustion turbines, which are the lowest cost resource. The preferred portfolio includes some additional distributed battery storage resources starting at 25 MW in 2025 and increasing to 175 MW by 2031. With the addition of more distributed resources, one of the peaking capacity resources needed to meet the 2026 capacity shortfall is delayed until 2030.

Distributed Energy Resources: Solar – ground and rooftop

Though utility-scale solar is a lower cost option for meeting CETA renewable requirements, given 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. Sensitivity C portfolio that restricts transmission availability more than the Mid Scenario portfolio does by analyzing 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. As discussed earlier, in Sensitivity C the portfolio model waits until the end to add a significant amount of distributed resources. The preferred portfolio ramps in the same amount of distributed resources starting in 2025 and ramps them in over time for a total of 680 MW of distributed solar added to the resource plan as a way to comply with CETA requirements. Solar provides very little peak capacity value to PSE, since PSE is a winter peaking utility. Distributed solar is a good way to meet the CETA renewable requirements given transmission constraints, but it makes limited contributions toward meeting the peak capacity need.

Figure 3-12 compares the portfolio builds for the 2021 IRP draft preferred resource plan with Sensitivity C.

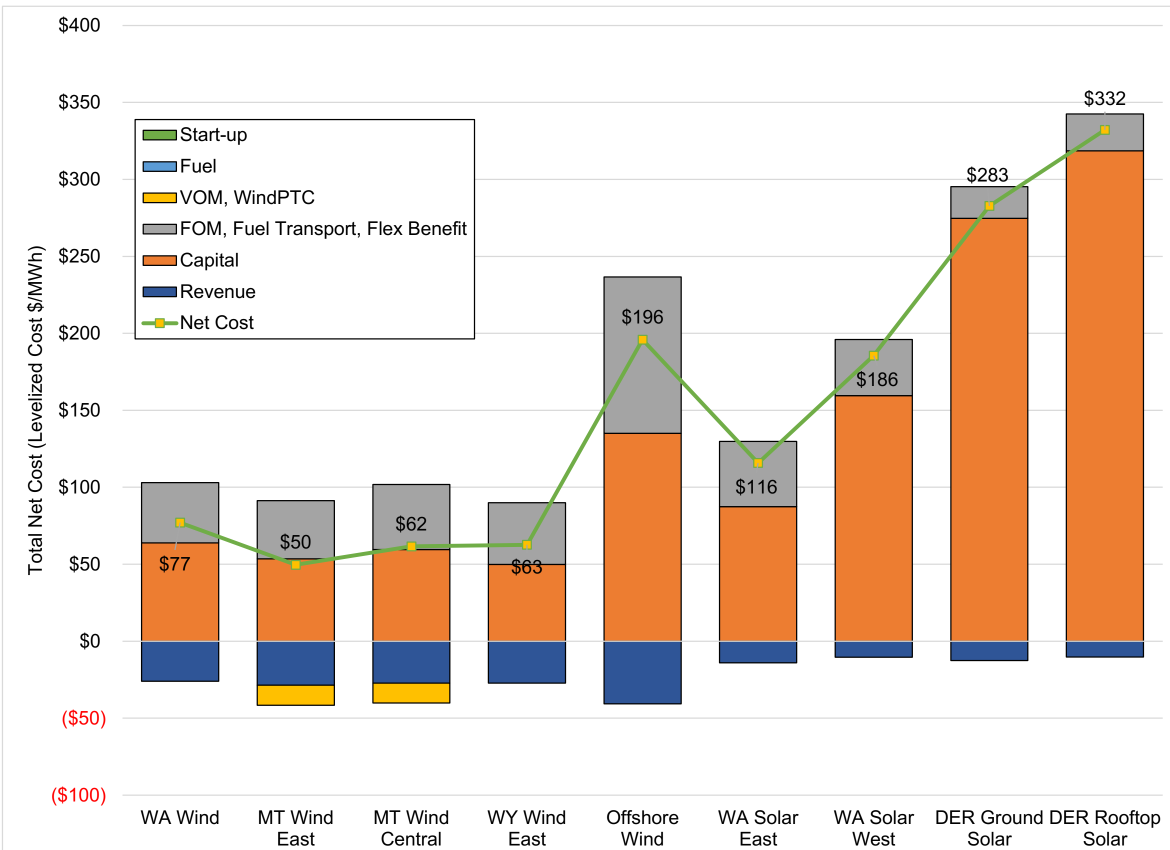
Figure 3-12: Resource Build for Draft 2021 IRP Preferred Portfolio and Sensitivity C, Transmission Build Constraint, Cumulative Additions by Nameplate (MW)



Renewable Resources

The timing of renewable resource additions is driven by CETA renewable requirements. Although renewable resources do contribute to meeting capacity needs, compared to the existing, retiring coal-fired resources and other dispatchable resources, a portfolio relying on increasing amounts of renewable resources has higher portfolio balancing requirements, which can drive up the cost of resource portfolios. This IRP found that Montana and Wyoming wind power is expected to be more cost effective than wind and solar from the Pacific Northwest. Given transmission constraints, resources outside of the Pacific Northwest region are limited. After the Montana and Wyoming wind, costs between eastern Washington wind and solar are very close._Figure 3-13 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. Actual bids in an RFP process could yield a different conclusion.

Figure 3-13: Levelized Cost of Wind and Solar Resources



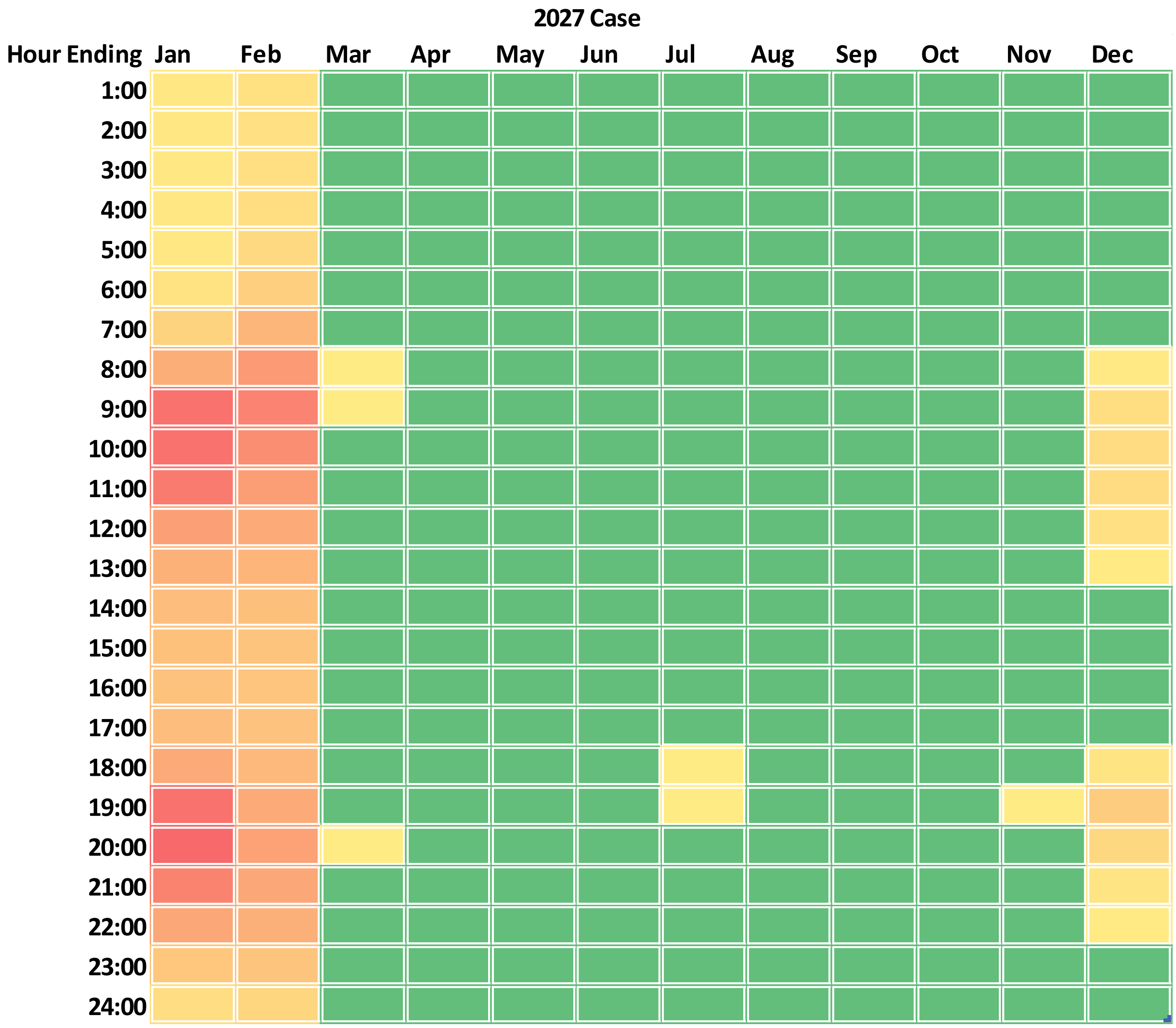
Flexible Capacity

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 non-emitting 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.

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 to meet the peak reliability needs at the time of this analysis. In all sensitivities that allowed the addition of new combustion turbines, at least one is added by 2026 and the second is added by 2030. The combustion turbines have the best 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.

Figure 3-14 is a 12x24 table that shows the loss of load hours prior to the addition of new resources. The plot represents a relative heat map of the number hours of lost load summed by month and hour of day. The majority of the lost load hours still occur in the winter months. From 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 using generic resources. Given 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 meets the capacity shortfall with resources that can be dispatched for 24 hours or more.

Figure 3-14: Loss of Load Hours for 2027



Transmission Constraints

Transmission capacity constraints have become an important modeling consideration as PSE transitions away from thermal resources and toward clean, renewable resources to meet the clean energy transformation targets. In contrast to thermal resources, which can generally be sited in locations convenient to transmission, produce power at a controllable rate, and be dispatched as needed to meet shifting demand, renewable resources are site-specific and have variable generation patterns dependent upon 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 be needed, but was assumed unconstrained due to delivery system planning process and specific identified projects.

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 repurposing existing contracts. PSE modeled a potentially available 750 MW of transmission to Montana and 400 MW of transmission to Wyoming. The full 750 MW of wind in Montana and 400 MW of wind in Wyoming 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 there is still an additional 700 MW of wind to eastern Washington and 200 MW of solar in eastern Washington needed by 2030. The location and type of renewable resources will depend on available transmission. Given the risk in available transmission, over 200 MW of distributed solar is added to the portfolio to meet the 80% CETA renewable target in 2030.

3. NATURAL GAS SALES RESOURCE PLAN

Resource Additions Summary

The natural gas sales resource plan is summarized in Figure 2-15, followed by a discussion of the reasoning that led to the plan. The years shown here reference the gas year, so 2025/26 means the gas year starting November 2025 through October 2026.

Figure 3-15: Natural Gas Sales Resource Plan – Cumulative Capacity Additions (MDth/day)

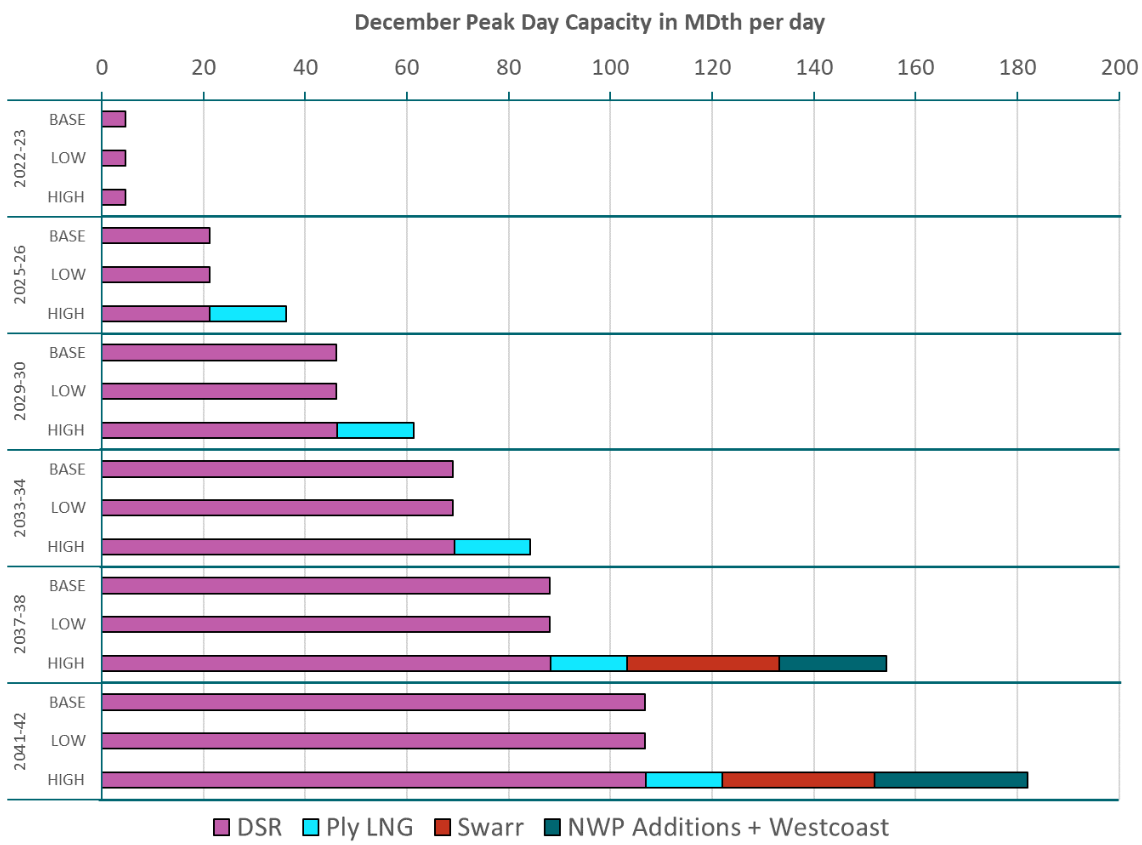
	2025/26	2030/31	2041/42
Conservation	21	53	107

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 2-16 illustrates the lowest reasonable cost portfolio of resources across various potential future conditions.

Figure 2-16: Natural Gas Sales Portfolios by Scenario (MDth/day)

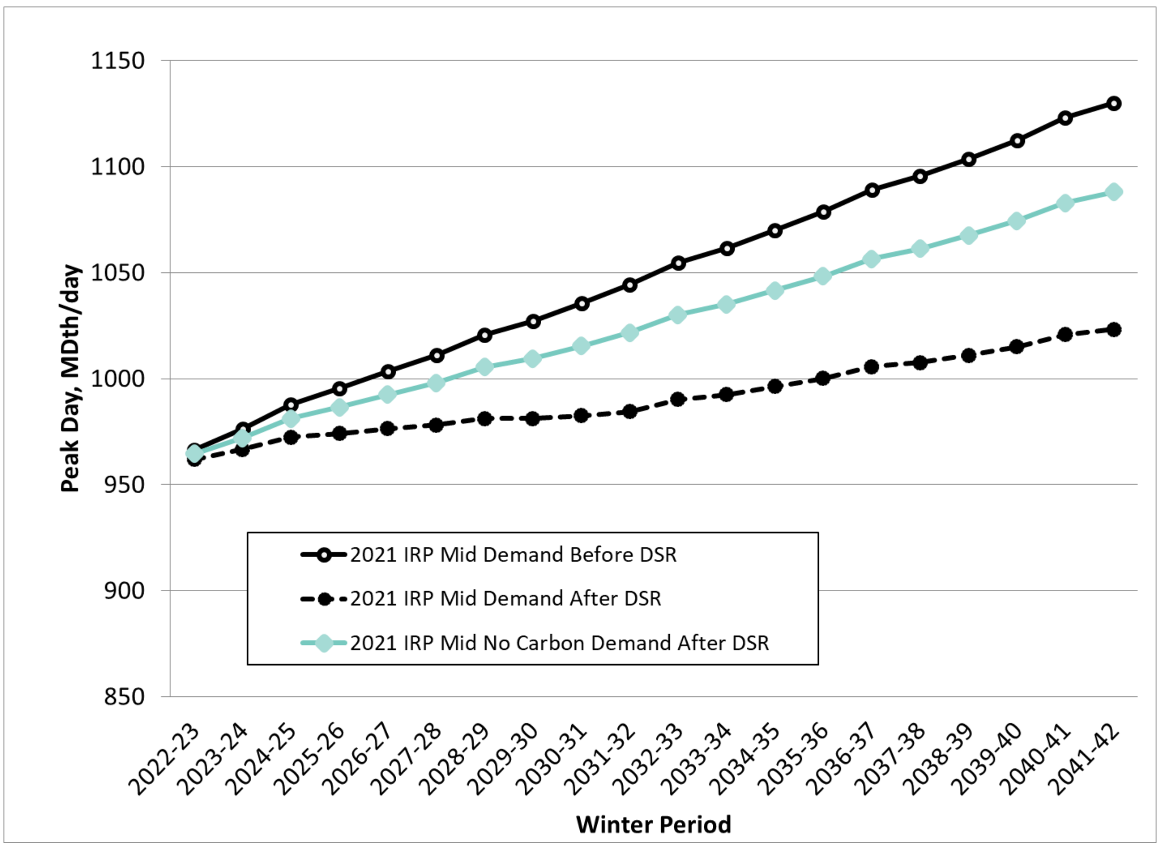


Key Findings by Resource Type

Demand-side Resources

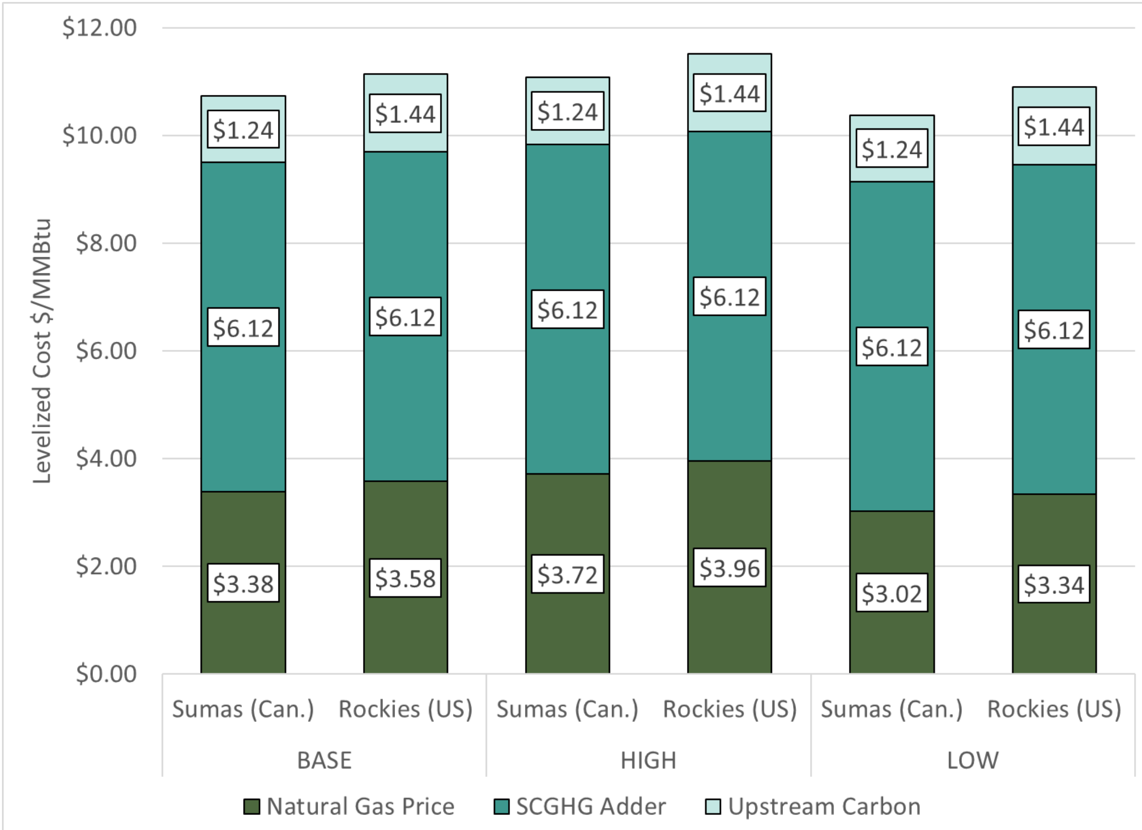
Cost effective DSR (conservation) does not vary across scenarios. In other words, the same level of conservation is chosen in all the scenarios. The conservation is driven by the total natural gas costs more than it is to the other factors such as the resource need. Figure 2-17, below, shows the results of cost-effective DSR for the mid scenario with and without the carbon adders, and we see that the amount of cost effective DSR is significantly lower when the total cost of natural gas consists of the gas commodity costs only. This in contrast to the earlier stated results of the cost effective DSR is not changing when the resource need changed from Low to High Scenarios.

Figure 2-17: DSR Cost Effective Levels are Driven by Total Natural Gas Costs



Conversely, in Figure 3-18, we see that the total cost of natural gas once the carbon adders are included varies only slightly from one scenario to the next. This results in the same level of DSR being selected in all the three scenarios.

Figure 3-18: 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 we have the flexibility to fine-tune the timing. PSE has less control over pipeline expansions, as expansions often require a number of shippers to sign up for service in order for an expansion to be cost effective. The upgrade has a short lead-time, and PSE has the flexibility to adjust 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 the Power 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 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. In the high load growth scenario, 21 MDth/day is added in 2034/35, growing to 30 MDth/day by the end of the planning horizon.

Resource Plan Forecast – Decisions

The resource plan forecast additions described above are consistent with the optimal portfolio additions produced for the Mid Scenario by the SENDOUT gas portfolio model analysis tool, including results. SENDOUT is a helpful tool, but 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 the Low and High Scenarios, as shown in the table in Figure 2-18, above. 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. Figure 2-18 illustrates the different SCGHG adders. The SCGHG adders are derived from requirements stated in HB1257 which became law in 2019 legislative session, the SCGHG adders are to be incorporated into 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 as the same level of conservation is still cost effective even when the demand forecast varies as low as the 10th percentile and as high as the 90th percentile represented by the Low and High Scenarios respectively.

Supply-side Resources

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