8

Electric Analysis

This chapter presents the results of the electric analysis

Contents

1. ANALYSIS OVERVIEW

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

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

- Chapter 7 presents the resource adequacy analysis.

2. Determine Planning Assumptions and Identify Resource Alternatives

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

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

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

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

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

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

5. Develop Resource Plan

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

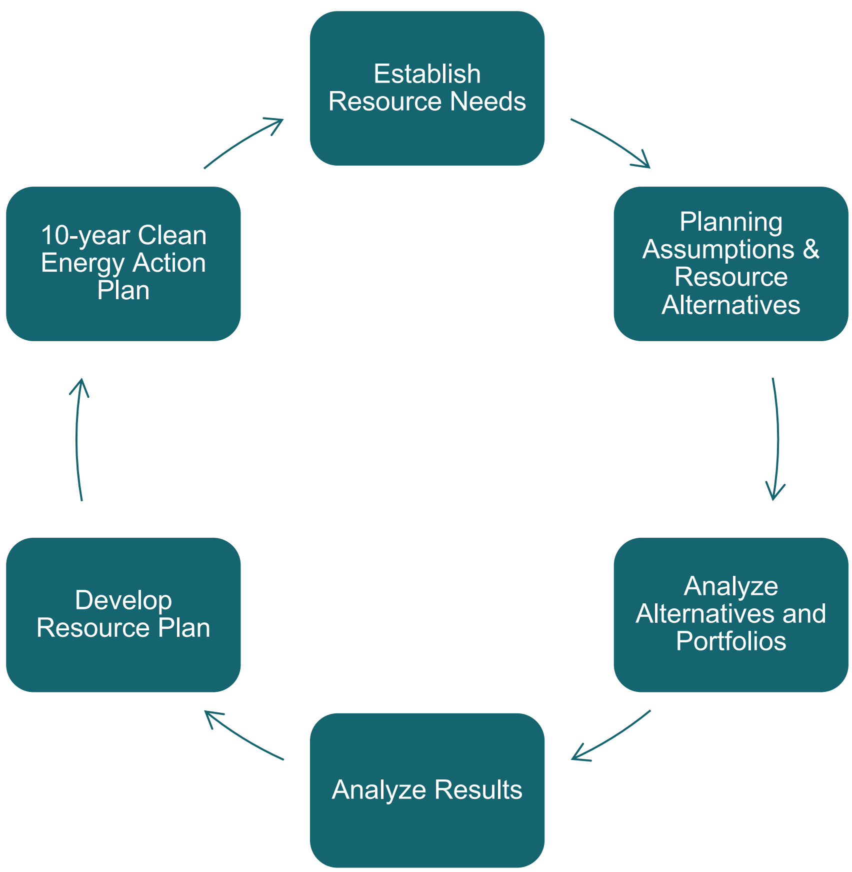
6. Create the 10-year Clean Energy Action Plan

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

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

Figure 8-1 illustrates this process.

Figure 8-1: 2021 IRP Process



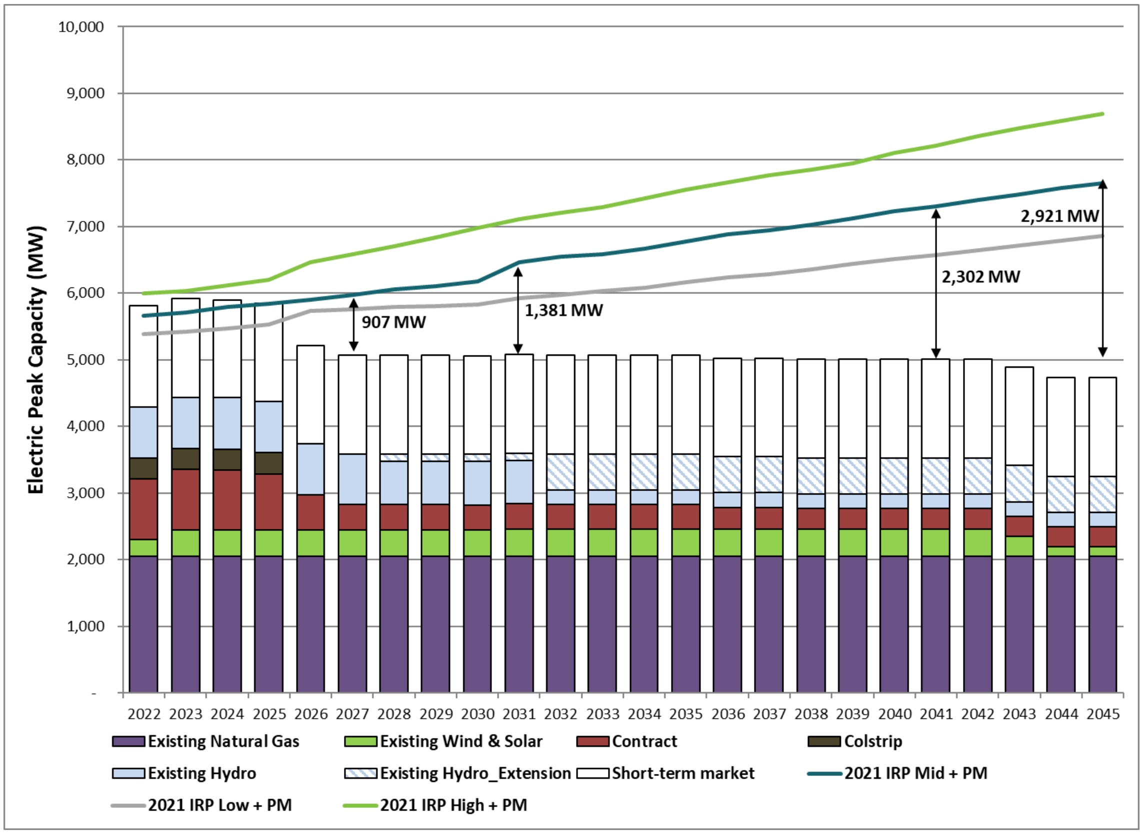
2. RESOURCE NEED

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 clean energy transformation targets.

Peak Capacity Need

Figure 8-2 shows the peak capacity need for the mid demand forecast modeled in this IRP (mid demand refers to the 2021 IRP Base Demand Forecast described in Chapter 6). Before any additional demand-side resources, peak capacity need in the mid demand forecast plus planning margin is 907 MW in 2027 and 1,381 MW in 2031. A full discussion of the peak capacity need is presented in Chapter 7, Resource Adequacy Analysis. The physical characteristics of the electric grid are very complex, so for planning purposes we simplify physical resource need into a peak hour capacity metric using PSE's Resource Adequacy Model (RAM). The RAM analysis produces reliability metrics that allow us to assess physical resource adequacy risk; these include LOLP (loss of load probability), EUE (expected unserved energy) and LOLH (loss of load hours). We can simplify physical resource need in this way because PSE is much less hydro-dependent than other utilities in the region, and because resources in the IRP are assumed to be available year-round. If PSE were more hydro-dependent, issues like the sustained peaking capability of hydro and annual energy constraints could be important; likewise, if seasonal resources or contracts were contemplated, supplemental capacity metrics may be appropriate to ensure adequate reliability in all seasons.

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



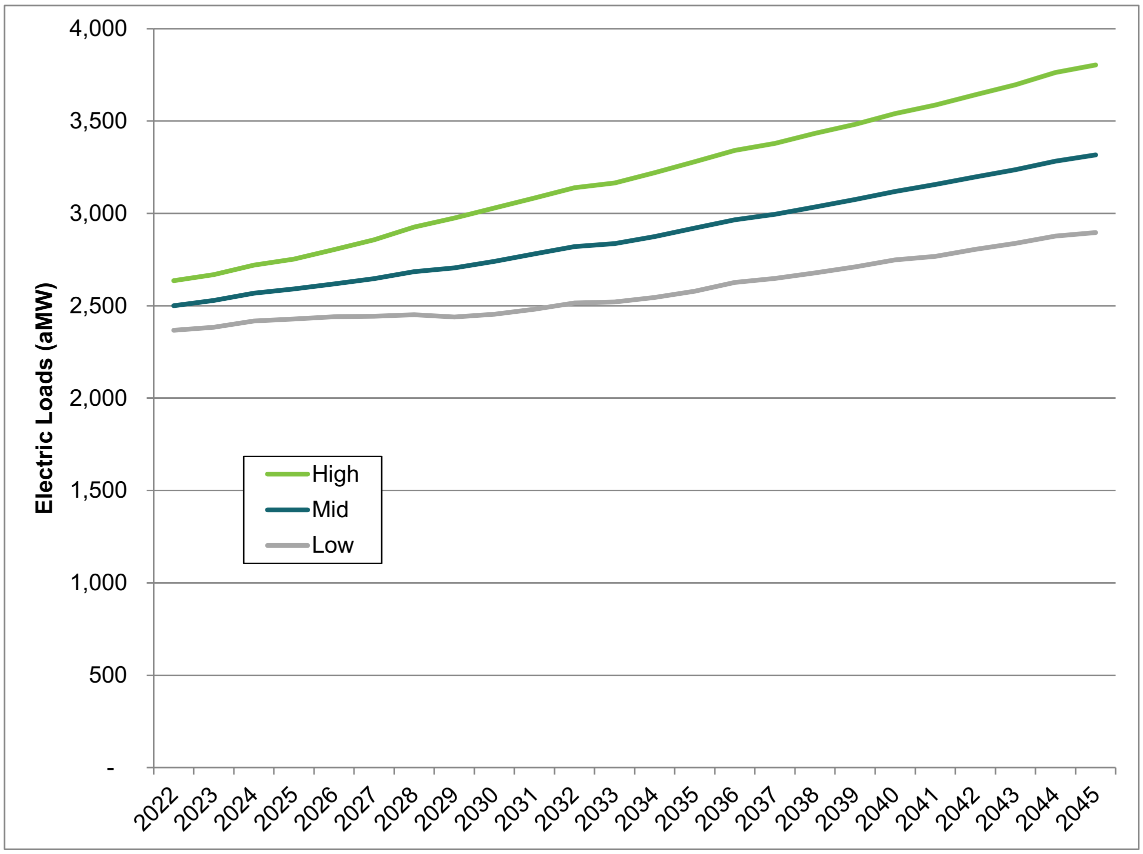
Energy Need

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

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

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

Figure 8-3: Annual Demand Forecast



Renewable Need

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

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

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

Figure 8-4 below shows the calculation for the 80 percent renewable requirement in 2030 to meet CETA. Demand-side resources are optimized in the portfolio and will provide a further reduction to the need shown in the last line of the table. Under normal hydro conditions and without the addition of new renewable/non-emitting resources, PSE will meet 40 percent of sales with renewable resources in 2022.

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

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

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

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

Figure 8-5: Qualifying Energy Need to Meet RCW 19.285 and CETA Requirements

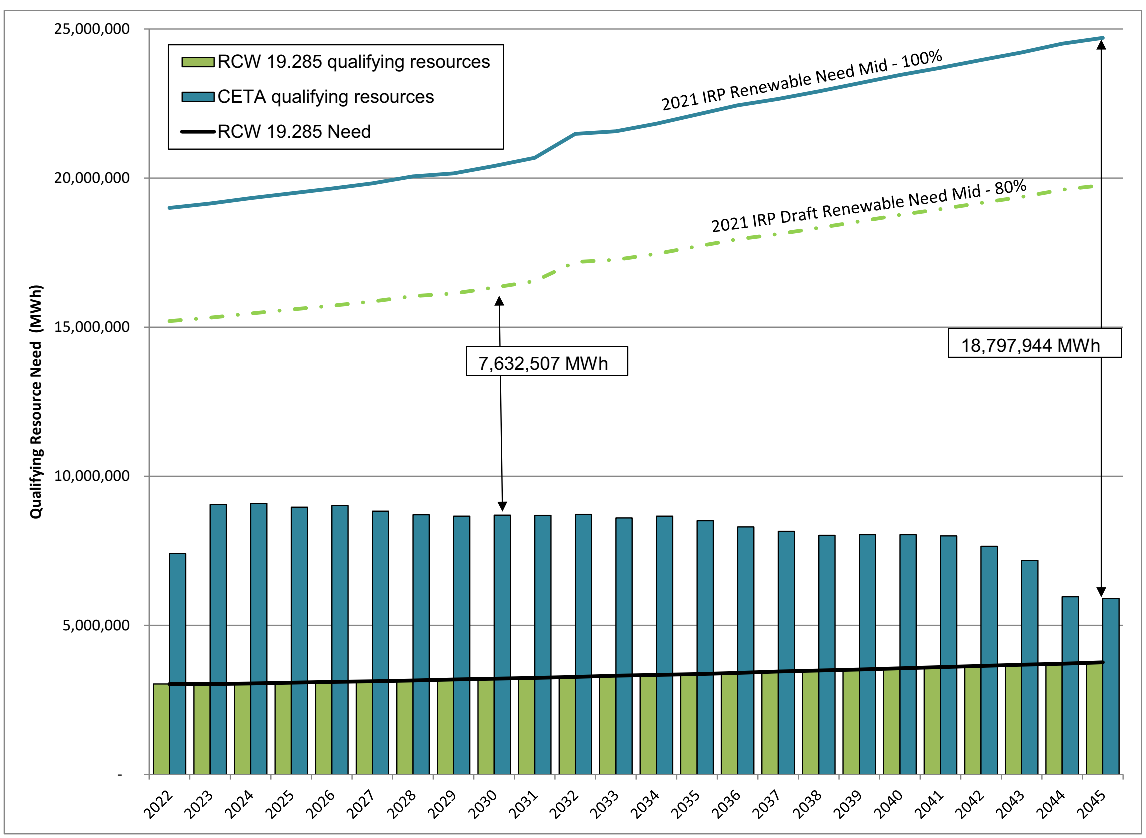
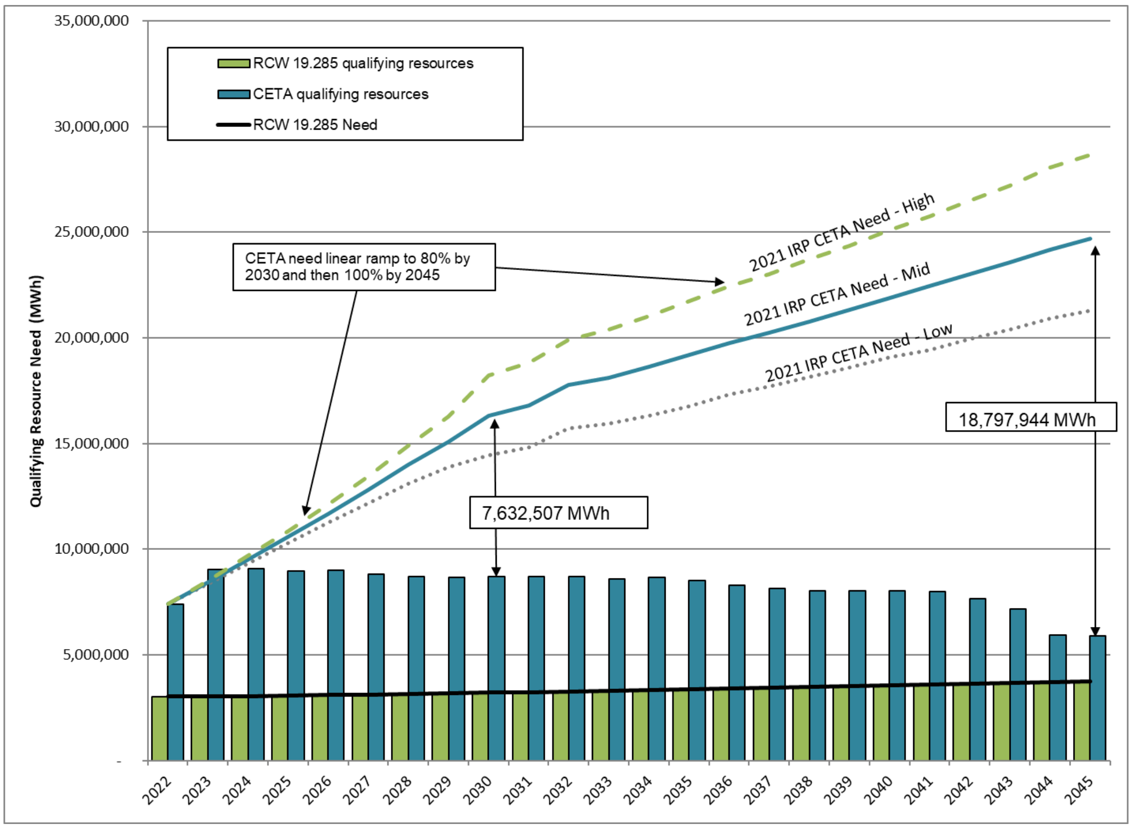


Figure 8-6 below assumes a linear ramp for CETA clean energy standards to reach the 80 percent target in 2030 and the 100 percent target in 2045. The linear ramp is needed to ensure that the portfolio model is gradually adding resources to meet clean energy targets, rather than waiting until the final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

Figure 8-6: Renewable Need and Linear Ramp for CETA



3. ASSUMPTIONS AND ALTERNATIVES

The scenarios and sensitivities used in the electric analysis are summarized here for convenience.[1]

Scenarios and Sensitivities

Scenarios enable us to test how resource portfolio costs and risks respond to changes in economic conditions, environmental regulation, natural gas prices and energy policy. Sensitivities start with the Mid Scenario assumptions and change one resource, regulation or condition; this allows us to isolate the effect of a single change on the portfolio, so that we can consider how different combinations of resources would affect costs, cost risks and emissions.

1 / Chapter 5 presents the scenarios and sensitivities developed for this IRP analysis and discusses in detail the key assumptions used to create them, including customer demand, natural gas prices, possible carbon dioxide (CO_2) prices, resource costs (both demand-side and supply-side) and power prices. Appendix D presents a detailed discussion of existing electric resources and resource alternatives.

Fig 8-8: 2021 IRP Portfolio Sensitivities

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
	Description	**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		
A	Renewable Overgeneration 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		
C	"Distributed" Transmission/Build Constraints - Tier 2	The portfolio model is performed with Tier 2 Transmission availability.
D	Transmission/Build Constraints – Time-delayed (Option 2)	The portfolio model is performed with gradually increasing transmission limits.
E	Firm Transmission as a Percentage of Resource Nameplate	New resources are acquired with firm transmission equal to a percentage of their nameplate capacity instead of their full nameplate capacity.
CONSERVATION ALTERNATIVES		
F	6-Year Conservation Ramp Rate	Energy efficiency measures ramp up over 6 years instead of 10.
G	Non-energy Impacts	Increased energy savings are assumed from energy efficiency not captured in the original dataset.
H	Social Discount Rate for DSR	The discount rate for demand-side resource measures is decreased from 6.8% to 2.5%.
SOCIAL COST OF GREENHOUSE GASES (SCGHG) AND CO_2 REGULATION		
I	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 a dispatch cost (tax) in both the electric price forecast and portfolio model.

2021 IRP ELECTRIC ANALYSIS SENSITIVITIES		
	Description	**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.
EMISSIONS REDUCTION		
M	Alternative Fuel for Peakers	Peaker plants can use either hydrogen or biodiesel as an alternative fuel.
N	100% Renewable by 2030	The CETA 2045 target of 100% renewables is moved up to 2030, with no new natural gas generation.
O	Gas Generation Out by 2045	All existing natural gas plants are retired in 2045.
P	Must-take Battery or Pumped Hydro Storage	1. Build batteries to a certain level before adding any other peaking capacity resources. 2. Build pumped hydro storage to a certain level before adding any other peaking capacity resources.
LOAD 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		
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		
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.

4. TYPES OF ANALYSIS

PSE uses deterministic optimization analysis to identify the lowest reasonable cost portfolio for each scenario. We then run a stochastic risk analysis to test different resource strategies.[2]

Deterministic Portfolio Optimization Analysis

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

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

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

Stochastic Risk Analysis

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

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

For this purpose, we take the portfolios (drawn from the deterministic scenario and sensitivity portfolios) and run them through 250 draws[3] that model varying power prices, gas prices, hydro generation, wind generation, load forecasts (energy and peak), and plant forced outages. From this analysis, we can evaluate the risk associated with each portfolio. The stochastic analysis will be completed for the final IRP and has not been included in this draft.

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

5. KEY FINDINGS

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

Economic Scenarios

1. **Mid Scenario:** *Renewable Need:* In the Mid Scenario, the renewable need is met annually across the planning horizon. 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 limited by transmission. On the other hand, WA wind is added consistently through the planning time horizon starting in 2028 since there are no transmission constraints imposed on wind resources in the Mid Scenario. In terms of conservation savings, a total of 1,497 MW nameplate of DSR resources were added to the portfolio by 2045.

   Peak Need: With the retirement of Centralia and the removal of Colstrip 3&4 in 2025 as part of CETA compliance, 474 MW of peaking capacity resources are added to the portfolio in 2026.

   Energy need: The hourly energy need is met in the Mid Scenario. Energy is provided by conservation and new and existing renewable resources. However, the use of existing non-renewable resources decline overtime.

2. **Low Scenario:** Lower energy demand, lower natural gas and power price are reflected in the Low scenario. Portfolio additions are similar to the Mid Scenario, but with less resources added by 2045. The total nameplate capacity addition by 2045 is 6,589 MW, a reduction of 1,977 MW from the Mid Scenario. There are less DSR resources added to the portfolio for a total of 1,301 MW nameplate capacity by 2045.

3. **High Scenario**: In the High Scenario, there is higher customer growth, with the higher energy demand reflected in the higher natural gas and power price. More resources are added due to the higher peak capacity and renewable energy need. The total nameplate capacity addition by 2045 is 10,429 MW, an increase of 1,863 MW from the Mid Scenario. DSR savings are higher in this portfolio for a total of 1,536 MW nameplate capacity by 2045.

Portfolio Sensitivities

Future Market Availability

A. **Renewable Overgeneration Test:** Prohibiting sales to the Mid-C market reduces renewable overgeneration by shifting 1,600 MW nameplate of new Washington wind capacity into an additional 510 MW of biomass capacity and 525 MW of battery capacity. However, total portfolio costs increase significantly. In the later years of this portfolio, batteries serve as the primary source of peak energy, being charged by market purchases in excess of demand during off-peak hours.

B. **Market Reliance:** This sensitivity will be evaluated for the final IRP.

Transmission Constraints and Build Limitations

C. **"Distributed" Transmission/Build Constraints - Tier 2:** Tier 2[4] transmission constraints have relatively minimal impacts on portfolio build decisions for the first 15 years of the modeling horizon as compared to the Mid Scenario. During this period, there is ample transmission to acquire solar and wind resources in eastern, southern and central Washington. However, once this transmission capacity is exhausted, Sensitivity C selects distributed solar resources located within PSE's service territory. The model pairs these distributed solar resources with battery storage projects to better serve load when the sun is not shining. These more expensive resources drive up portfolio cost in the later years of the modeling horizon.

D. **Transmission/Build Constraints – Time-delayed (Option 2):** This sensitivity will be evaluated for the final IRP.

E. **Firm Transmission as a Percentage of Resource Nameplate:** In general, cost savings from reduced firm transmission sensitivities are marginal and likely not a viable method of reducing portfolio costs. Wind resources show the least cost benefit in transmission reduction sensitivities due to the significant portion of time wind resources generate power at or near nameplate capacity (i.e., rated power). Solar resources, which typically spend less time at rated power, show increased cost benefit relative to wind resources, but the cost benefit is still unlikely to prove valuable in resource portfolios.

Conservation Alternatives

4 / Transmission alternatives were divided into four tiers that express increasing levels of constraint. These tiers are described in Chapter 5, Key Assumptions.

F. 6-Year Conservation Ramp Rate: This sensitivity will be evaluated for the final IRP.

G. Non-energy Impacts: This sensitivity will be evaluated for the final IRP.

H. Social Discount Rate for DSR: This sensitivity will be evaluated for the final IRP.

Social Cost of Greenhouse Gases (SCGHG)

I. Social Cost of Greenhouse Gases as an Externality Cost in the Portfolio Model: The changes brought on by changing SCGHG to an externality cost are minor. The model optimizes dispatch of existing gas plants to minimize cost, while newly acquired peaking capacity is largely unused. The sensitivity resulted in more peaking capacity being built than the Mid Scenario, but the average capacity factors of the newly built plants averages to 0.3 percent by 2045.

J. SCGHG as an Externality Cost in the Portfolio Model and Hourly Dispatch: This sensitivity will be evaluated for the final IRP.

K. AR5 Upstream Emissions: This sensitivity will be evaluated for the final IRP.

L. SCGHG as a Fixed Cost Plus a Federal CO_2 Tax: This sensitivity will be evaluated for the final IRP.

Emissions Reduction

M. Alternative Fuel for Peakers: This sensitivity will be evaluated for the final IRP.

N. 100% Renewable by 2030 : In this sensitivity, the 24-year levelized portfolio costs increased by 128 percent for a total of $31.1 billion dollars in revenue requirement. With no access to thermal resources by 2030, a significant amount of batteries totaling 26,100 nameplate MW were built to keep the portfolio balanced. Market access remains important in this sensitivity, as purchases became a resource for meeting energy and peak capacity needs in addition to being a source for charging the batteries.

O. Natural Gas Generation Out by 2045 : In this sensitivity, the 24-year levelized revenue requirement is $33.9 billion dollars, an increase of $20.3 billion dollars or 149 percent. With the retirement of all existing natural gas fired and new peaking capacity resources happening in one year, the portfolio model fails to meet the peak capacity need in 2045.

There is a significant increase in the annual portfolio costs between 2044 and 2045 due to penalties related to violation of CETA constraints in the model. This sensitivity requires further work for the final 2021 IRP.

P. Must-take Energy Storage: Delaying the availability of peaking capacity resources resulted in much earlier addition of storage resources, for a total of 3,775 MW nameplate capacity by 2030. We also see an additional 7 MW nameplate capacity of demand response by 2045 compared to the 121 MW of demand response added in the Mid Scenario portfolio. Peaking capacity resources were still added to the portfolio for a total of 711 MW nameplate capacity compared to 948 MW nameplate capacity in the mid portfolio. In this sensitivity, the 24-year levelized revenue requirement is $29.1 billion dollars, an increase of $15.5 billion dollars or 113 percent.

P2. Must-take Pump Hydro Energy Storage: Without peaking capacity resources and batteries available until 2030, 2,800 MW nameplate capacity of pump hydro energy storage resources were added to the portfolio by 2028 in order to fill the peak capacity needed after the removal of Centralia and Colstrip 3&4. Interestingly, 711 MW nameplate of peaking capacity resources and 1,225 MW nameplate of 2-hr Lithium Ion batteries were added to the portfolio by 2045. For Sensitivity P2, the 24-year levelized revenue requirement is $22.4 billion dollars, an increase of $8.72 billion dollars over the Mid Scenario.

Demand Adjustments

Q. Fuel Switching, Gas to Electric: This sensitivity will be evaluated for the final IRP.

R. Temperature Sensitivity: This sensitivity will be evaluated for the final IRP.

CETA Costs

S. SCGHG Included, No CETA: Without the CETA renewable requirement, the 24-year levelized revenue requirement is $10.1 billion dollars, a $3.6 billion dollars reduction from the mid portfolio. There are no renewable resource addition to the portfolio except for a 350 MW of wind in 2044 needed to maintain compliance with the RPS requirement. A total of 1,513 MW nameplate peaking capacity was added to the portfolio by 2045. There was less conservation selected in this portfolio for a total of 1188 MW of nameplate capacity, a reduction of 319 MW from the mid portfolio.

T. No CETA or SCGHG: Without the CETA renewable requirement and SCGHG as a fixed cost adder, the 24-year levelized revenue requirement is $9.4 billion dollars, a $4.2 billion dollar reduction from the Mid Scenario portfolio. Compared to Sensitivity S, this is a further reduction of $0.7 billion dollars. Similar to Sensitivity S, there are no renewable resource additions to the portfolio except for 350 MW of wind in 2044 needed to maintain compliance with the RPS requirement. Even less conservation is selected in this portfolio for a total of 1,052 MW of nameplate capacity, 455 MW less than in the Mid Scenario portfolio.

U. 2% Cost Threshold: This sensitivity will be evaluated for the final IRP.

Balanced Portfolio

V. Balanced Portfolio: PSE developed a schedule for various resource additions during the planning horizon based on the understanding of the results from other sensitivities. Distributed energy resources and customer programs were set as must-take resources and ramped in over time. The portfolio costs were slightly higher than the Mid Scenario, because distributed solar resources are higher cost than Washington wind and solar east resources, which were found to be the optimal renewable resources following Montana and Wyoming wind resources in the Mid Scenario. In Sensitivity V, the 24-year levelized revenue requirement is $14.37 billion dollars, an increase of $0.74 billion dollars or 5 percent over the Mid Scenario.

W. Balanced Portfolio with Alternative Fuel for Peakers: Extending the assumptions from Sensitivity V to include biodiesel as fuel source for new frame peakers resulted in an increase of $0.8 billion dollars in the 24-year levelized revenue requirement for Sensitivity W compared to the Mid Scenario. The 24-year levelized revenue requirement is $14.43 billion dollars, an increase of $0.06 billion dollars from Sensitivity V. Even with the premium on biodiesel fuel prices compared to natural gas price, the model selected the same amount of combustion turbine resources in Sensitivity W compared to the Mid Scenario.

6. ECONOMIC SCENARIO ANALYSIS RESULTS

Portfolio Builds

The portfolio builds for all three economic scenarios look very much alike given all the generic resource options. The mix of resources is similar for three scenarios and the amount of resources added increased or decreased based on high and low load forecasts, respectively. Given that the Low economic scenario has a lower demand, the peak need and renewable need are lower so fewer resources are added. In the High economic scenario, more resources are added for a higher peak need and renewable need. Figure 8-7, shows the levelized cost by scenario while Figure 8-8 shows the optimal portfolio builds by scenario.

Figure 8-7: Relative Optimal Portfolio Costs by Scenario
(dollars in billions, NPV including end effects)

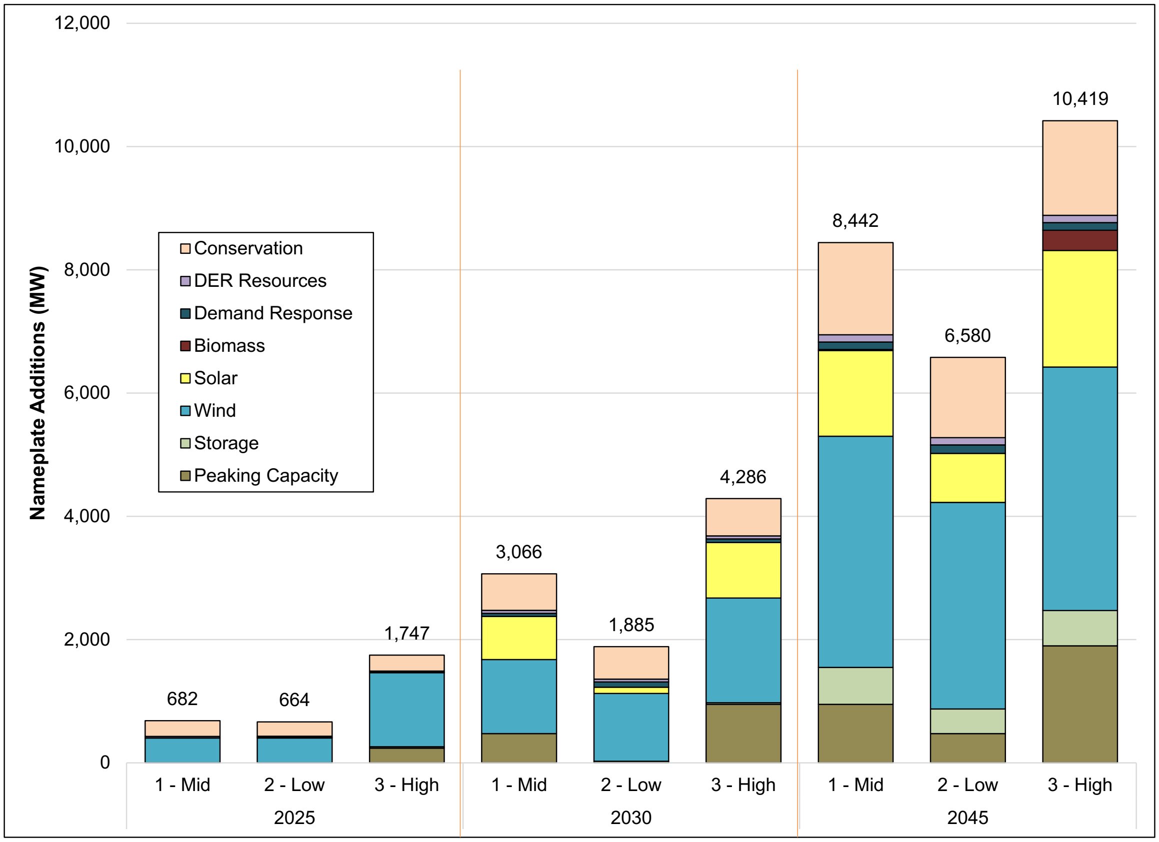
		24-Yr Levelized Costs			
	Portfolio	Revenue Requirement	SCGHG Costs	Total	Change from Mid
1	Mid Scenario	$13.63	$5.04	$18.68	
2	Low Scenario	$10.44	$4.47	$14.91	($3.77)
3	High Scenario	$17.18	$6.31	$23.49	$4.82

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

		DSR	DER Resources	Demand Response	Biomass	Solar	Wind	Storage	Peaking Capacity	Total
1	Mid	1,497	118	121	15	1,393	3,750	600	948	8,442
2	Low	1,304	118	137	-	797	3,350	400	474	6,580
3	High	1,537	118	122	330	1,891	3,950	575	1,896	10,419

Figure 8-9 below displays the megawatt additions for the deterministic analysis optimal portfolios for all three scenarios in 2025, 2030 and 2045. No new resources are added until 2024. See Appendix N, Electric Analysis, for more detailed information.

Figure 8-9: Resource Builds by Scenario, Cumulative Additions by Nameplate (MW)



Portfolio Emissions

In this section, we present emissions results associated with each sensitivity. Figure 8-10 shows CO_2 emissions for the Mid portfolio and 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. All sensitivities that meet CETA renewable requirements show significant reduction in emissions through the planning horizon. Direct emissions decrease to zero for Sensitivity N, 100% renewables by 2030.

Figure 8-10: CO_2 Emissions by Portfolio

(does not include alternative compliance to meet carbon neutral standard in 2030 and beyond)

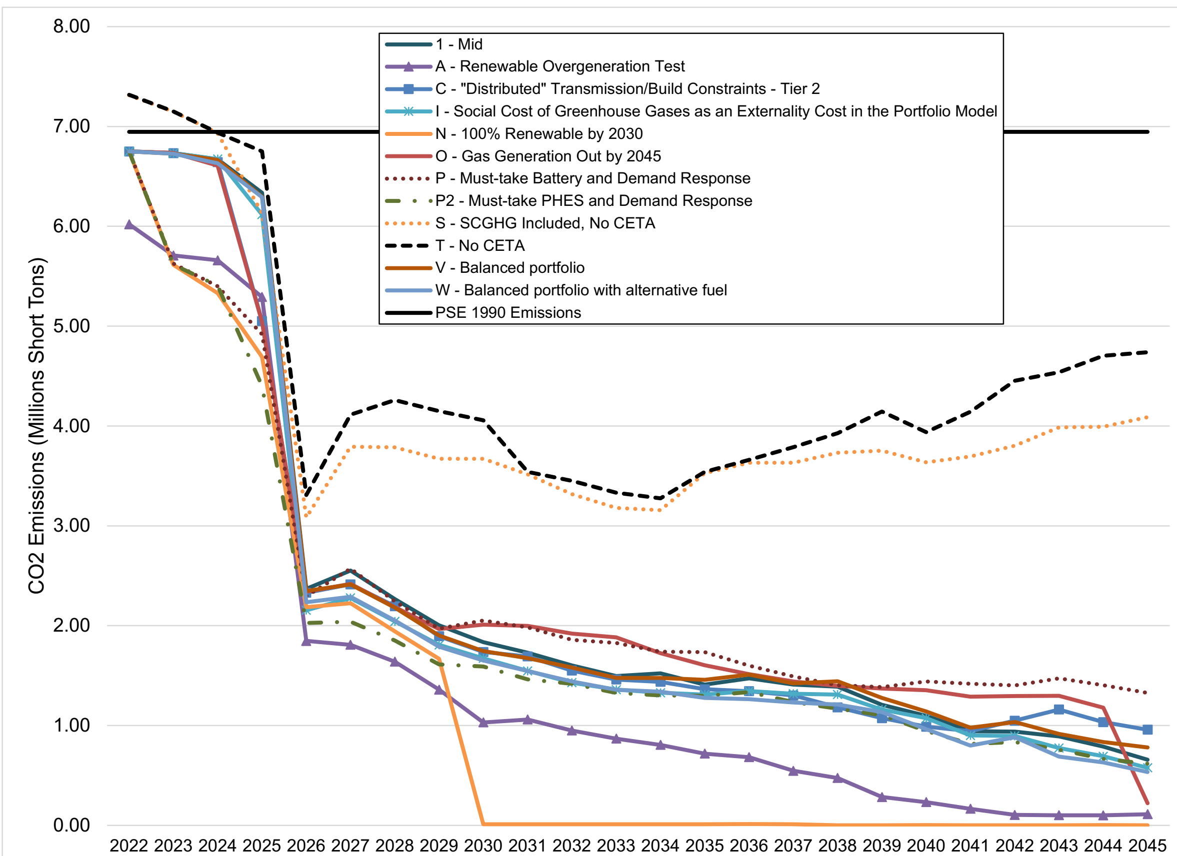
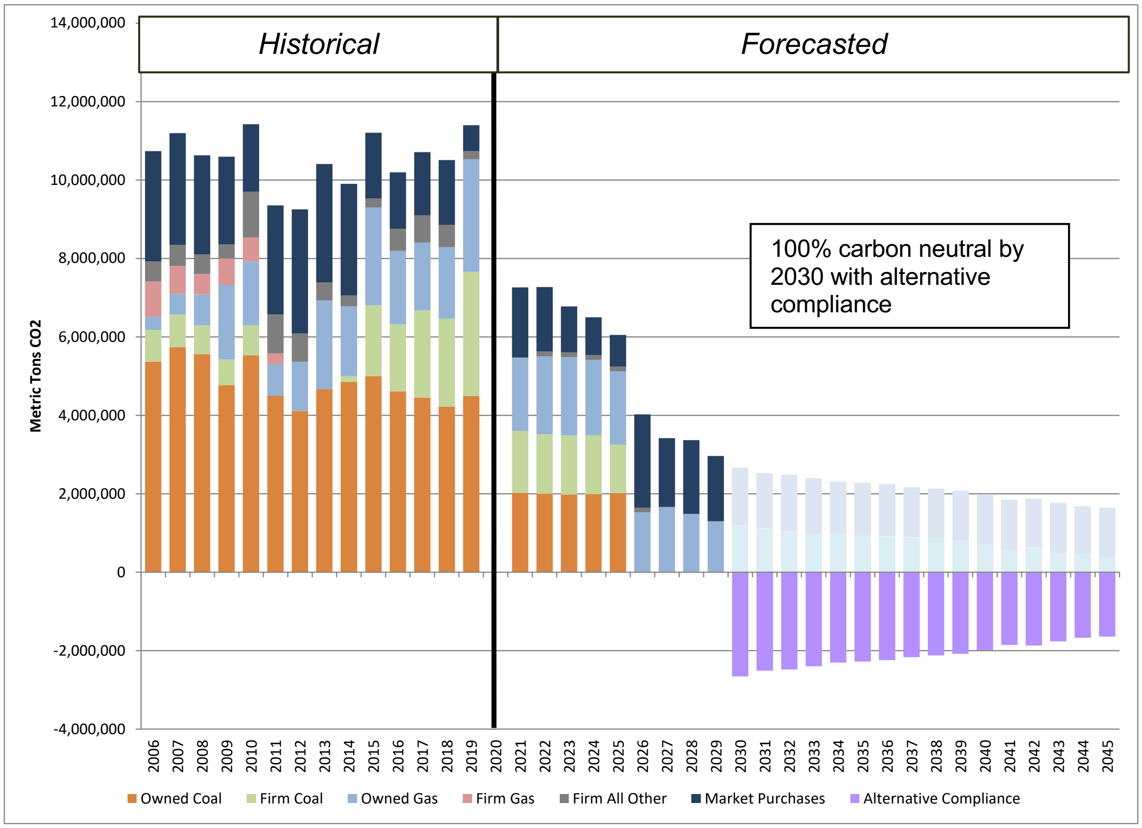


Figure 8-11, below, shows the emissions by resource type for the Mid Scenario portfolio. There is a direct relationship between emissions and the dispatch of thermal plants. Direct emissions decreased with the retirement of Colstrip 1 & 2 in 2019 and will be further reduced with a lower projected lower economic dispatch of thermal resources as well the exit of Colstrip 3 & 4 and Centralia from PSE portfolio. With the retirement of resources and forecasted drop in dispatch, the total portfolio decreases by over 75 percent from 2019 to 2029. Through alternative compliance mechanisms, the portfolio achieves carbon neutral from 2030 through to 2045.

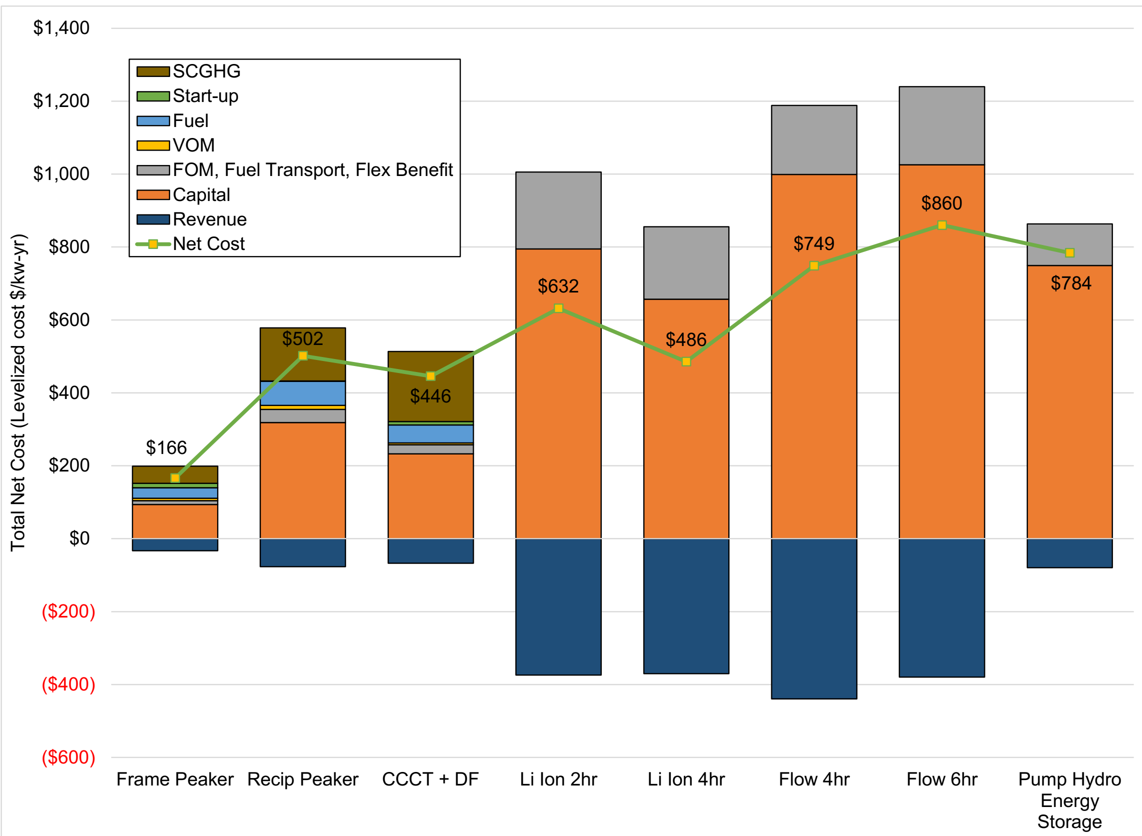
Figure 8-11: Historical and Projected Annual Total PSE Portfolio CO_2 Emissions for the Mid Scenario Portfolio



Levelized Cost of Capacity

Figure 8-12 compares the cost of peakers, baseload gas plants and energy storage resources in the Mid Scenario portfolio. The levelized cost of capacity is based on the peak capacity value. For example, the nameplate of a 2-hour lithium-ion battery is 25 MW, but it has an ELCC of 12.4 percent, so the peak capacity value is 3.1 MW. (The total cost of the lithium-ion battery is divided by 3.1 MW instead of the 25 MW which is why it has a high levelized cost of capacity.) The SCGHG costs are added to the total costs when calculating the levelized cost of capacity of new peakers and baseload gas plants. For frame peakers, the levelized cost of capacity increased from $119 to $166 when SCGHG costs are added.

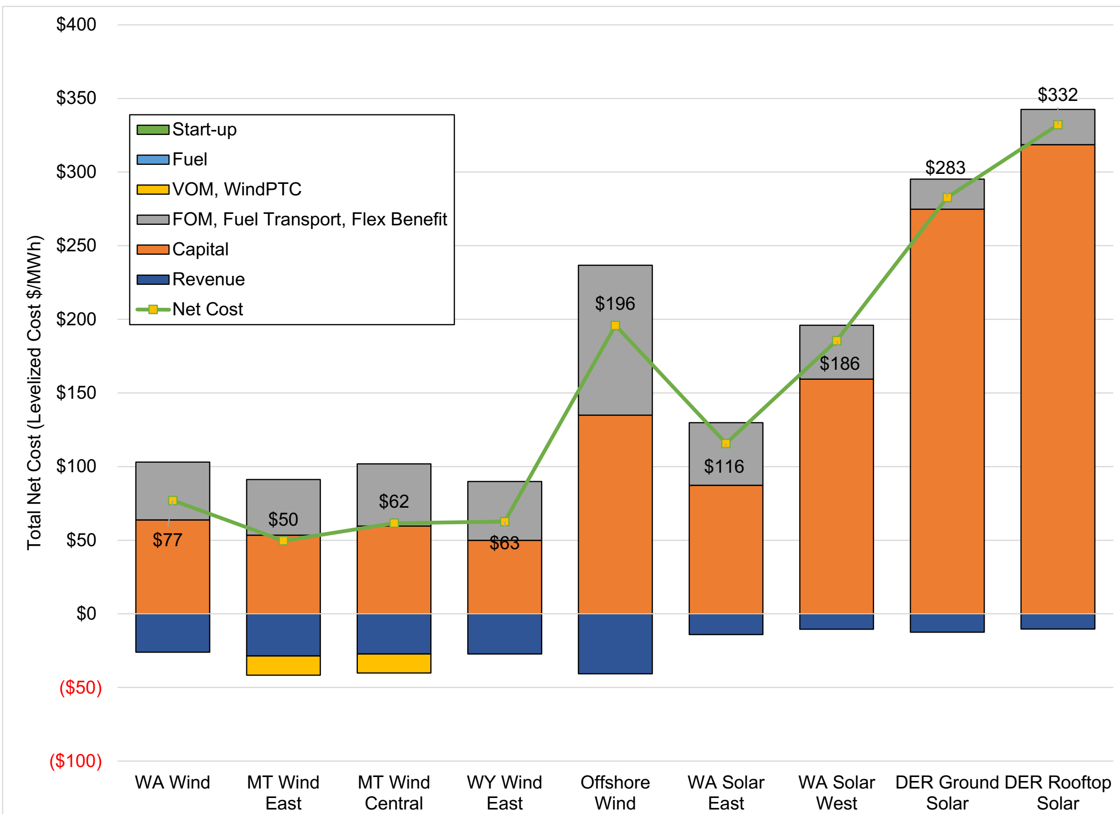
Figure 8-12: Net Cost of Capacity in the Portfolio Model



Levelized Cost of Energy

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 will be limited. After the Montana and Wyoming wind, costs between eastern Washington wind and solar are very close. Figure 8-13 illustrates that the levelized cost of Montana and Wyoming wind are the lowest cost renewable resource to meet CETA, followed by eastern Washington wind and solar.

Figure 8-13: Wind and Solar Cost Components



7. SENSITIVITY ANALYSIS RESULTS

Portfolio sensitivity analysis is an important form of risk analysis. It helps us understand how specific assumptions can change the mix of resources in the portfolio and affect portfolio costs. Figures 8-14 and 8-15 illustrate the breakdown of costs and resource builds between the Mid Scenario and the various Sensitivities modeled for this IRP.

Figure 8-14: Relative Optimal Portfolio Costs by Sensitivity (dollars in billions, NPV including end effects)

		24-Yr Levelized Costs			
	Portfolio	Revenue Requirement	SCGHG Costs	Total	Change from Mid
1	Mid Scenario	$13.63	$5.04	$18.68	
A	Renewable Over-generation 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

Figure 8-15: Relative Optimal Portfolio Builds by Sensitivity (cumulative nameplate capacity in MW for each resource addition by 2045)

	Portfolio	DSR	DER Resources	Demand Response	Biomass	Solar	Wind	Storage	Peaking Capacity	Total
1	Mid Scenario	1,497	118	121	15	1,393	3,750	600	948	8,442
A	Renewable Overgeneration Test	1,545	692	183	525	1,490	2,150	118	4,165	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	-	1,394	4,050	26,100	-	33,089
O	Gas Generation Out by 2045	1,262	118	130	-	1,397	4,150	18,625	-	25,682
P	Must-take Battery and Demand Response	1,304	118	128	-	1,796	3,750	3,775	711	11,582
P2	Must-take PHES and Demand Response	1,304	118	128	-	1,397	3,950	4,100	711	11,708
S	SCGHG Included, No CETA	1,179	118	155	-	-	350	-	1,513	3,315
T	No CETA	1,042	118	133	-	-	350	-	2,151	3,794
V	Balanced Portfolio	1,658	798	211	60	796	3,750	1,125	948	9,346
W	Balanced Portfolio with Alternative Fuel for Peakers	1,784	798	215	15	697	3,750	750	984	8,993

A. Renewable Over-generation Test

What happens if PSE is unable to sell excess energy to the Mid-C Market?

Baseline: PSE can sell 1500 MW of energy to the Mid-C market at any given hour.

Sensitivity: PSE cannot sell any energy to the Mid-C market at any hour.

Key Findings

Prohibiting sales to the Mid-C market reduces renewable over-generation by shifting 1,600 MW of built Washington wind capacity into an additional 510 MW of biomass capacity and 525 MW of battery capacity. In the later years of this portfolio, batteries serve as the primary source of peak energy, being charged by market purchases in excess of demand during off-peak hours.

Assumptions

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

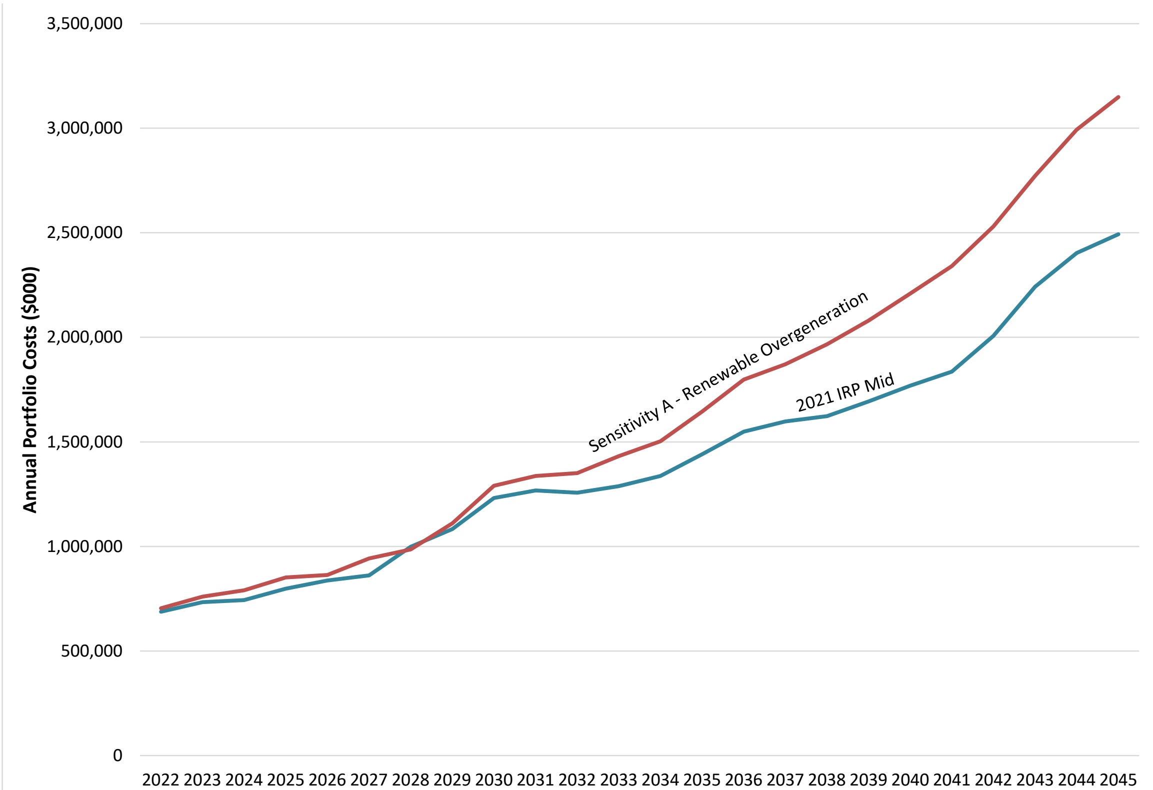
Annual Portfolio Costs

Figures 8-16 and 8-17 illustrate the breakdown of costs between the Mid Scenario and Sensitivity A portfolios. The costs of the portfolio remain similar until the year 2030, where costs begin to diverge. This is driven by the increased builds of biomass and battery resources, which cost more than the Mid Scenario build of Washington wind resources and peaking capacity. Most of these costs are incurred in the later years of the model, which carries less weight in the levelized costs of the portfolio. As a result, total portfolio costs increase less than 5 percent driven mostly by the increased revenue requirement. SCGHG costs come down as the market purchases of the portfolio decrease slightly.

Figure 8-16: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity A

		24-Yr Levelized Costs			
	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

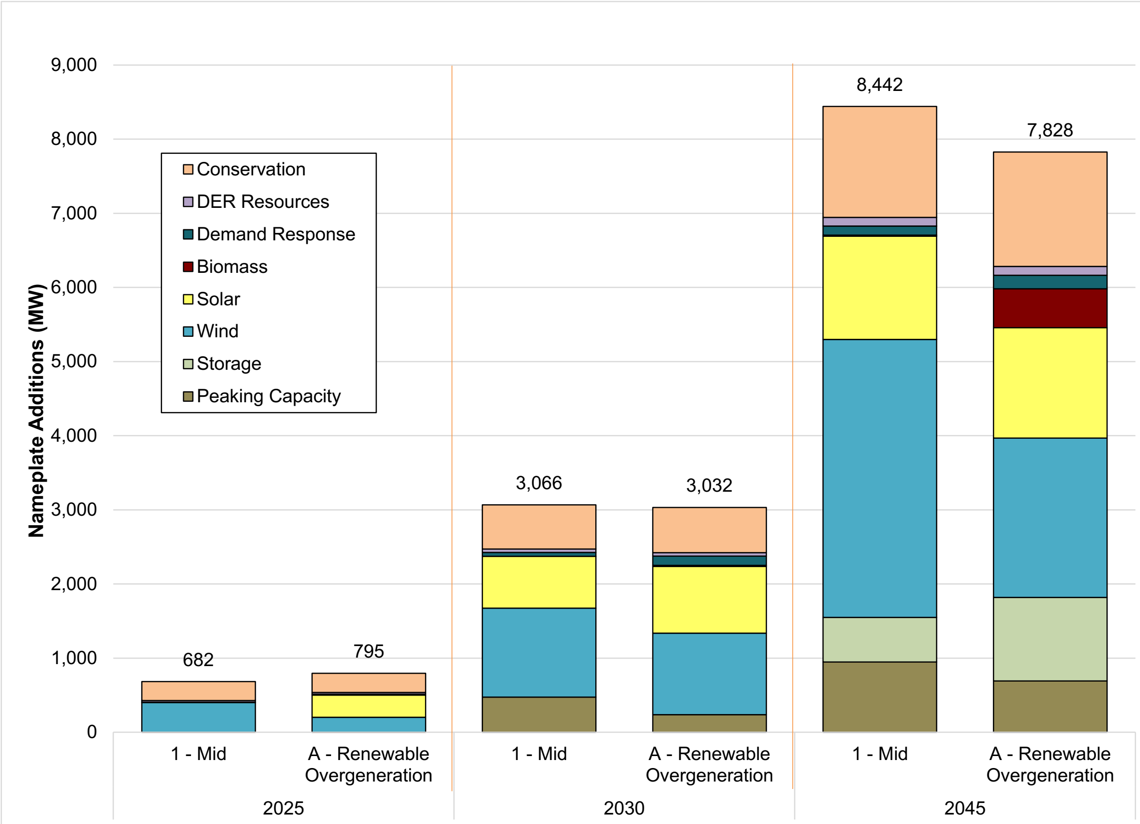
Figure 8-17: Annual Portfolio Costs – Mid Scenario and Sensitivity A



Resource Additions

Figure 8-18 compares the nameplate capacity additions of the Sensitivity A and Mid Scenario portfolios. Sensitivity A builds a similar amount of nameplate capacity as the Mid Scenario, but the distribution of those resources moves away from wind generation and toward biomass and battery storage. Seventy-five percent of the batteries built are 6-hour flow batteries, and no pumped hydro storage is built. Conservation reaches Bundle 12 in this sensitivity. No PSE resources, new or existing, were retired in this sensitivity.

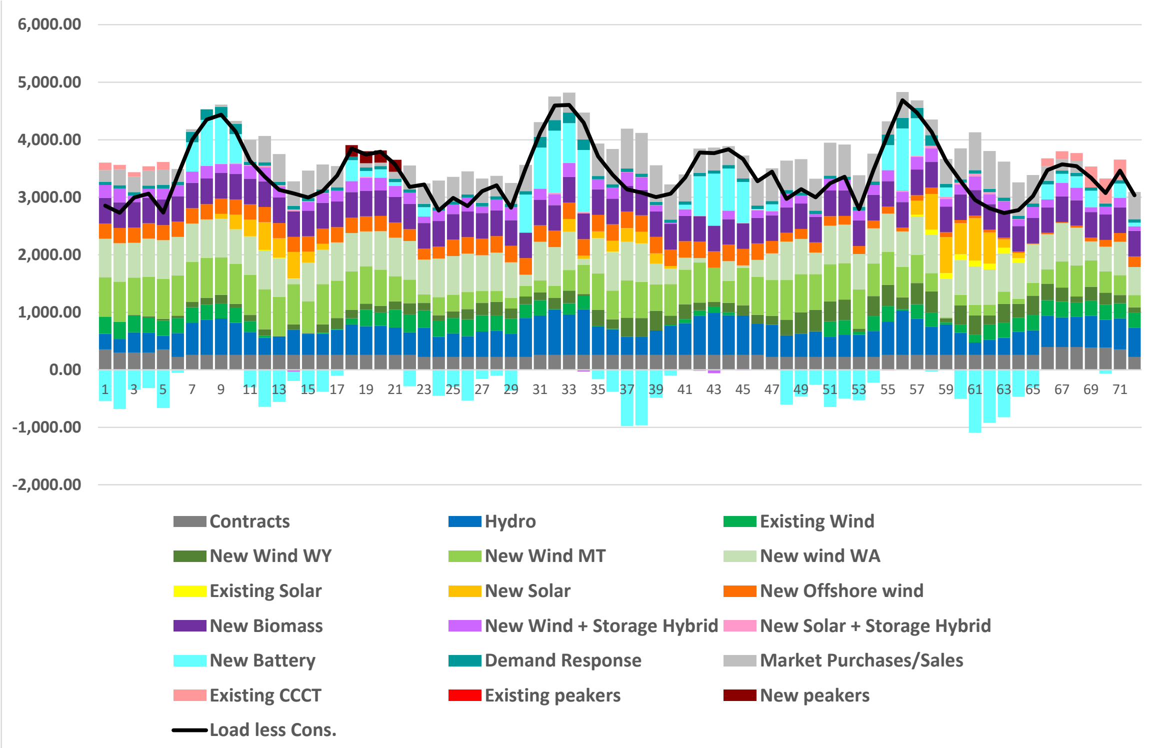
Figure 8-18: Portfolio Additions, Sensitivity A – Renewable Overgeneration



Other Findings

PEAK NEED: In 2045, the peak capacity behavior of the new resources in the sensitivity portfolio become apparent. Figure 8-19 shows the peak demand of 2045 resources in the hourly dispatch model. Battery resources cycle constantly in order to make it through peak demand hours, which is likely driving the selection of 6-hour flow batteries for their longer duration than 4-hour or 2-hour options. To charge these batteries the portfolio relies on market purchases to provide excess energy, as the PSE supply-side resources do not provide enough surplus at these times.

Figure 8-19: 2045 Peak Demand Period of Sensitivity A, December 28-30 2045



The relationship between the market purchases being made by the model and the battery activity can be seen by examining the times at which the market purchases are occurring. Figure 8-20 shows the percentage of hours each month where market purchases are being made by PSE in the year 2045 of the sensitivity. Figure 8-21 shows the percentage of hours each month where market purchases are being made while batteries are being charged or discharged. Market purchases are being made nearly constantly through the winter. When batteries are charging during off-peak hours, these purchases provide the energy for them to charge. When batteries are discharging during peak hours, these purchases help to meet demand.

Figure 8-20: Percentage of Each Month Where Market Purchases are Being Made in Each Hour for Sensitivity A

Purchase	1	2	3	4	5	6	7	8	9	10	11	12
0	81%	89%	84%	27%	0%	0%	16%	58%	90%	68%	63%	87%
1	81%	89%	87%	30%	0%	0%	13%	58%	90%	71%	67%	90%
2	81%	86%	84%	27%	0%	0%	19%	52%	80%	71%	67%	90%
3	81%	89%	84%	23%	0%	0%	19%	52%	80%	71%	63%	87%
4	84%	89%	71%	23%	0%	0%	10%	48%	83%	68%	67%	87%
5	84%	82%	74%	17%	0%	0%	10%	48%	87%	68%	67%	84%
6	84%	68%	68%	20%	0%	0%	19%	77%	83%	61%	67%	74%
7	81%	61%	71%	7%	0%	0%	23%	77%	83%	71%	60%	77%
8	84%	79%	74%	10%	0%	0%	26%	87%	83%	65%	60%	77%
9	84%	79%	68%	7%	0%	3%	23%	87%	80%	68%	57%	87%
10	84%	82%	74%	13%	0%	3%	23%	87%	80%	68%	57%	87%
11	81%	86%	77%	13%	0%	0%	23%	87%	83%	68%	57%	87%
12	81%	86%	77%	27%	3%	0%	16%	84%	80%	65%	57%	94%
13	81%	86%	77%	27%	3%	0%	23%	84%	83%	68%	60%	94%
14	84%	86%	74%	20%	3%	3%	26%	77%	80%	65%	60%	90%
15	84%	82%	77%	13%	3%	3%	13%	77%	80%	68%	67%	94%
16	84%	79%	74%	10%	0%	0%	19%	61%	77%	71%	73%	90%
17	74%	82%	71%	13%	0%	0%	19%	48%	57%	68%	70%	87%
18	77%	82%	68%	20%	0%	3%	23%	45%	60%	65%	63%	84%
19	84%	86%	68%	17%	3%	3%	29%	35%	57%	58%	70%	84%
20	84%	86%	68%	13%	3%	3%	23%	52%	73%	71%	70%	81%
21	81%	89%	77%	17%	3%	3%	29%	58%	90%	68%	67%	90%
22	81%	86%	84%	23%	6%	3%	19%	55%	97%	74%	70%	87%
23	81%	86%	84%	17%	3%	3%	19%	61%	97%	77%	73%	94%
	Average	Average	Average	Average	Average	Average	Average	Average	Average	Average	Average	Average
	82%	83%	76%	18%	1%	1%	20%	65%	81%	68%	65%	87%

Figure 8-21: Percentage of Each Month Where Market Purchases are Being Made in Each Hour While Batteries are Charging and Discharging for Sensitivity A

Charge, Purchase	1	2	3	4	5	6	7	8	9	10	11	12
0	61%	50%	45%	3%	0%	0%	0%	10%	17%	32%	33%	81%
1	71%	57%	48%	7%	0%	0%	0%	13%	27%	35%	43%	84%
2	71%	50%	52%	10%	0%	0%	3%	10%	17%	42%	47%	81%
3	65%	54%	45%	0%	0%	0%	3%	6%	10%	26%	37%	77%
4	84%	86%	35%	3%	0%	0%	0%	3%	3%	13%	67%	87%
5	48%	43%	26%	3%	0%	0%	0%	23%	23%	42%	43%	71%
6	10%	21%	16%	0%	0%	0%	13%	52%	13%	6%	13%	19%
7	6%	7%	29%	0%	0%	0%	23%	71%	70%	26%	7%	10%
8	0%	32%	42%	3%	0%	0%	26%	87%	77%	32%	17%	3%
9	23%	36%	48%	7%	0%	3%	19%	84%	77%	39%	27%	26%
10	39%	57%	55%	13%	0%	3%	19%	87%	73%	55%	23%	45%
11	52%	71%	74%	13%	0%	0%	19%	84%	80%	58%	40%	58%
12	65%	68%	68%	27%	0%	0%	13%	84%	80%	48%	47%	94%
13	71%	79%	77%	27%	0%	0%	23%	81%	77%	55%	47%	81%
14	74%	75%	74%	20%	0%	3%	26%	74%	67%	52%	43%	81%
15	77%	64%	71%	10%	0%	0%	13%	71%	67%	48%	37%	65%
16	26%	43%	48%	3%	0%	0%	13%	45%	67%	13%	3%	16%
17	3%	11%	0%	0%	0%	0%	10%	10%	3%	3%	0%	3%
18	0%	7%	0%	0%	0%	0%	0%	0%	0%	3%	3%	13%
19	0%	4%	0%	0%	0%	0%	3%	0%	0%	3%	7%	6%
20	6%	25%	6%	0%	0%	0%	0%	3%	3%	6%	17%	13%
21	45%	46%	10%	0%	3%	0%	0%	6%	13%	23%	37%	71%
22	16%	21%	42%	3%	3%	0%	3%	6%	23%	58%	13%	23%
23	58%	32%	32%	0%	0%	0%	3%	6%	13%	19%	27%	58%
	Average	Average	Average	Average	Average	Average	Average	Average	Average	Average	Average	Average
	40%	43%	39%	6%	0%	0%	10%	38%	38%	31%	28%	49%

Discharge, Purchase	1	2	3	4	5	6	7	8	9	10	11	12
0	10%	29%	35%	23%	0%	0%	13%	48%	70%	35%	23%	3%
1	3%	25%	32%	20%	0%	0%	10%	45%	60%	35%	20%	0%
2	6%	25%	26%	13%	0%	0%	16%	42%	63%	29%	20%	10%
3	13%	36%	29%	20%	0%	0%	13%	45%	70%	35%	20%	6%
4	0%	0%	32%	17%	0%	0%	10%	42%	77%	55%	0%	0%
5	29%	29%	48%	13%	0%	0%	3%	23%	50%	23%	17%	10%
6	74%	39%	52%	13%	0%	0%	0%	16%	53%	52%	50%	52%
7	74%	46%	35%	3%	0%	0%	0%	6%	10%	35%	53%	65%
8	84%	43%	32%	3%	0%	0%	0%	0%	3%	19%	37%	74%
9	52%	39%	13%	0%	0%	0%	3%	3%	3%	26%	27%	58%
10	32%	21%	13%	0%	0%	0%	3%	0%	7%	10%	30%	42%
11	23%	14%	3%	0%	0%	0%	3%	3%	3%	10%	10%	13%
12	10%	11%	10%	0%	0%	0%	0%	0%	0%	10%	7%	0%
13	6%	7%	0%	0%	0%	0%	0%	3%	7%	6%	7%	10%
14	10%	7%	0%	0%	3%	0%	0%	3%	3%	10%	13%	10%
15	6%	18%	6%	3%	3%	3%	0%	3%	13%	19%	10%	19%
16	39%	32%	16%	3%	0%	0%	3%	3%	10%	58%	60%	68%
17	71%	71%	68%	13%	0%	0%	6%	26%	43%	65%	70%	84%
18	77%	75%	58%	17%	0%	3%	13%	45%	60%	58%	57%	71%
19	81%	82%	68%	13%	0%	3%	23%	35%	57%	48%	60%	77%
20	68%	61%	61%	10%	3%	3%	23%	48%	70%	58%	47%	52%
21	32%	43%	65%	17%	0%	3%	29%	52%	77%	39%	30%	19%
22	58%	64%	39%	20%	3%	3%	13%	48%	63%	13%	57%	65%
23	6%	46%	45%	17%	0%	3%	13%	52%	80%	55%	37%	26%
	Average	Average	Average	Average	Average	Average	Average	Average	Average	Average	Average	Average
	36%	36%	33%	10%	1%	1%	8%	25%	40%	33%	32%	35%

Removing access to market sales eliminates an economic incentive for PSE to over-generate renewable energy, and does not allow the model to count sold energy towards CETA goals. As a result, renewable overgeneration is reduced in the model. This portfolio builds 1,600 MW less of Washington wind capacity and 255 MW less of peaking capacity. That capacity is redistributed to an additional 510 MW of biomass and 525 MW of battery resources in order to manage peak needs in the winter months. Market purchases in excess of load become an integral part of the portfolio for charging batteries during the later years in order to meet peak demand.

RENEWABLE OVERGENERATION. Eliminating market sales reduced renewable over-generation in the portfolio as a result of the decreased wind resources in Washington. Figure 8-22 compares the amount of renewable overgeneration in the Mid Scenario and Sensitivity A.

Figure 8-22: Renewable Over-generation – Mid Scenario and Sensitivity A

	2030			2045		
Portfolio	Hours of Over-generation	MWh of Over-generation	% of total load with conservation	Hours of Over-generation	MWh of Over-generation	% of total load with conservation
Mid Scenario	1,226	286,296	1.4%	4307	3,262,871	14.6%
Sensitivity A	1,322	65,054	0.3%	391	14,698	0.06%

These results indicate that the elimination of market sales was effective at curbing over-generation of renewable resources. In the Mid Scenario portfolio, renewable overgeneration can provide value through sales. Without the ability to sell excess energy, the model can only curtail that production or use it to charge battery resources. Once the battery resources are at capacity, there is no option left but to curtail the energy. By 2045 in the sensitivity, renewable overgeneration is effectively eliminated and CETA is met without including the sale of energy to the Mid-C market.

Next Steps

The Mid Scenario portfolio overbuilds renewable resources in order to meet CETA while counting the sales of renewable energy to Mid-C towards CETA goals. Sensitivity A effectively steers the portfolio away from the CETA counting problem, but leans heavily on market purchases and biomass capacity. The amount of biomass and market purchases used in this sensitivity are unlikely to be available in reality, and further investigation is needed into the behavior of the portfolio when market availability is limited.

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

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

Baseline: The baseline assumes the transmission constraints described by Tier 0. PSE's system is subject to few transmission constraints including 1500 MW toMid-C market purchases and build limitations for Montana, Idaho and Wyoming based resources.
Sensitivity: Sensitivity C assumes the transmission constraints described by Tier 2. PSE's system is subject to more restrictive transmission constraints, including those described in the baseline plus build limitations for eastern, southern and western Washington-based resources.

Key Findings

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

Assumptions

Sensitivity C assumes transmission capacity outside of PSE's service territory will be limited to 3,070 MW. Figure 8-23 summarizes the Tier 2 transmission capacity assumptions for each resource group region. (A complete description of the four transmission tiers and resource group regions is provided in Chapter 5.)

Figure 8-23: Sensitivity C Transmission Constraints – Tier 2

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

In addition to the transmission constraints described in Tier 2, several additional constraints were incorporated into the optimization to encourage realistic resource selections:

- Biomass cogeneration facilities were limited to 105 MW given the limited number of pulp and timber mills located within Washington state.
- Utility-scale, western Washington solar projects were limited to 500 MW. PSE's transmission system west of the Cascades would require significant upgrades to accommodate an additional transmission load of greater than 500 MW. Furthermore, given the large amount of land needed, siting and permitting of large-scale solar projects west of the Cascades is known to be difficult.
- The forecast of customer-owned, residential solar projects was adjusted to reflect increased adoption of residential solar. The forecast matches the Conservation Potential Assessment Low-cost, Business-As-Usual residential solar adoption rate. This assumption aligns with a portfolio focused on distributed energy resources.
- Build limitations on ground-mounted and rooftop distributed solar were lifted to encourage a focus on distributed resource selection.

Portfolio Costs

Compared to the Mid Scenario portfolio, the Sensitivity C portfolio is more expensive over the modeling time horizon as shown in Figure 8-24. Increased generic resource revenue requirements are the major driver of the increased portfolio cost. Distributed solar resources cost substantially more to install than utility-scale solar resources, resulting in increased generic resource revenue requirements.

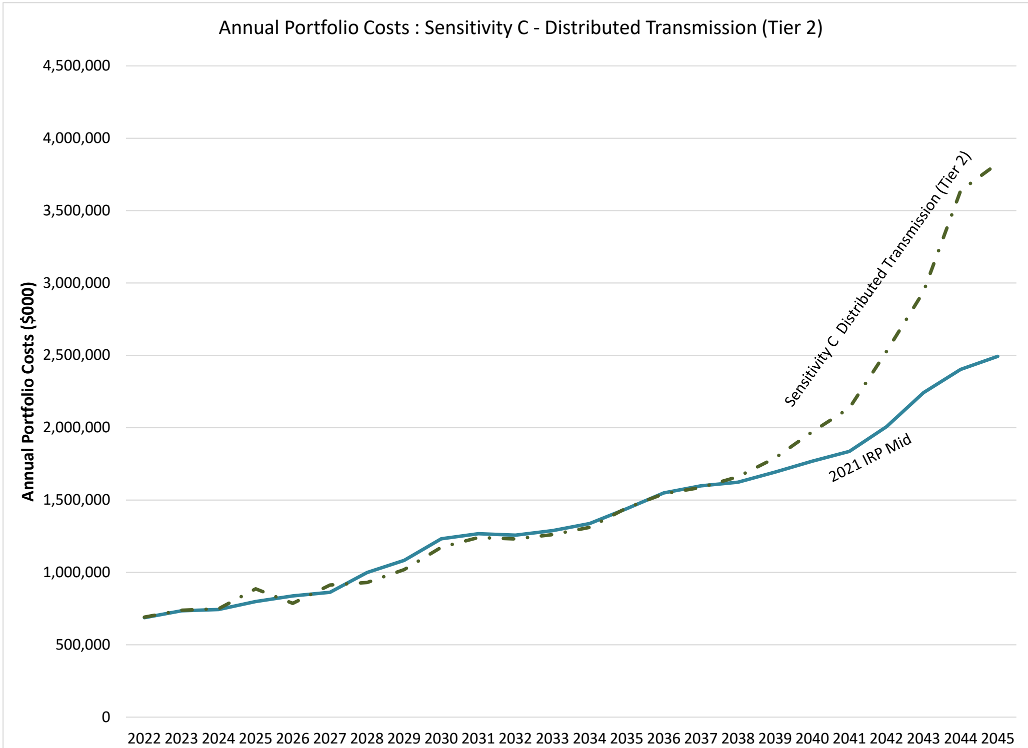
SCGHG costs are within $16 million between the Mid Scenario and Sensitivity C portfolios over the 24-year time horizon. In Sensitivity C, existing gas plants and new peaking capacity contribute more emissions in later years, but early retirement of Colstrip Unit 3 in 2024 significantly reduces near-term emission costs.

Figure 8-24: Portfolio Cost Comparison – Mid Scenario and Sensitivity C

		24-Yr Levelized Costs			
	Portfolio	Revenue Requirement	SCGHG Costs	Total	Change from Mid
1	**Mid Scenario**	$13.63	$5.04	$18.68	
C	**Distributed – Transmission/Build Constraints Tier 2**	$14.53	$5.06	$19.59	$0.91

Until year 2038, the Mid Scenario and Sensitivity C portfolios project similar annual revenue requirements as shown in Figure 8-25. After year 2038, Sensitivity C exhausts all available transmission outside of PSE’s service territory and is forced to select more costly distributed solar resources, resulting in a sharp increase in annual revenue requirement in the later years.

Figure 8-25: Annual Portfolio Costs – Mid Scenario and Sensitivity C



Resource Additions

Sensitivity C is marked by a transition from utility-scale wind and solar resources in central, eastern and southern Washington to distributed solar resources within the PSE service territory. Given that the effective load carrying capability of distributed solar resources is low, battery storage resources are added to the portfolio to meet load during peak hours. Biomass resources within PSE service territory are added to help accommodate base load and meet CETA energy targets. New peaking capacity resource additions remain unchanged from the Mid Scenario. Colstrip Unit 3 is economically retired in 2024, one year ahead of its planned retirement date in 2025.

Sensitivity C selects conservation Bundle 11, equating to 1,537 MW of conservation by year 2045. This is more conservation than was selected in the Mid Scenario, which selected Bundle 10. The increased conservation is attributed to the increased resource costs of distributed solar resources.

These resource build decisions are summarized in Figures 8-26 and 8-27.

Figure 8-26: Portfolio Additions, Sensitivity C – Distributed Transmission Tier 2

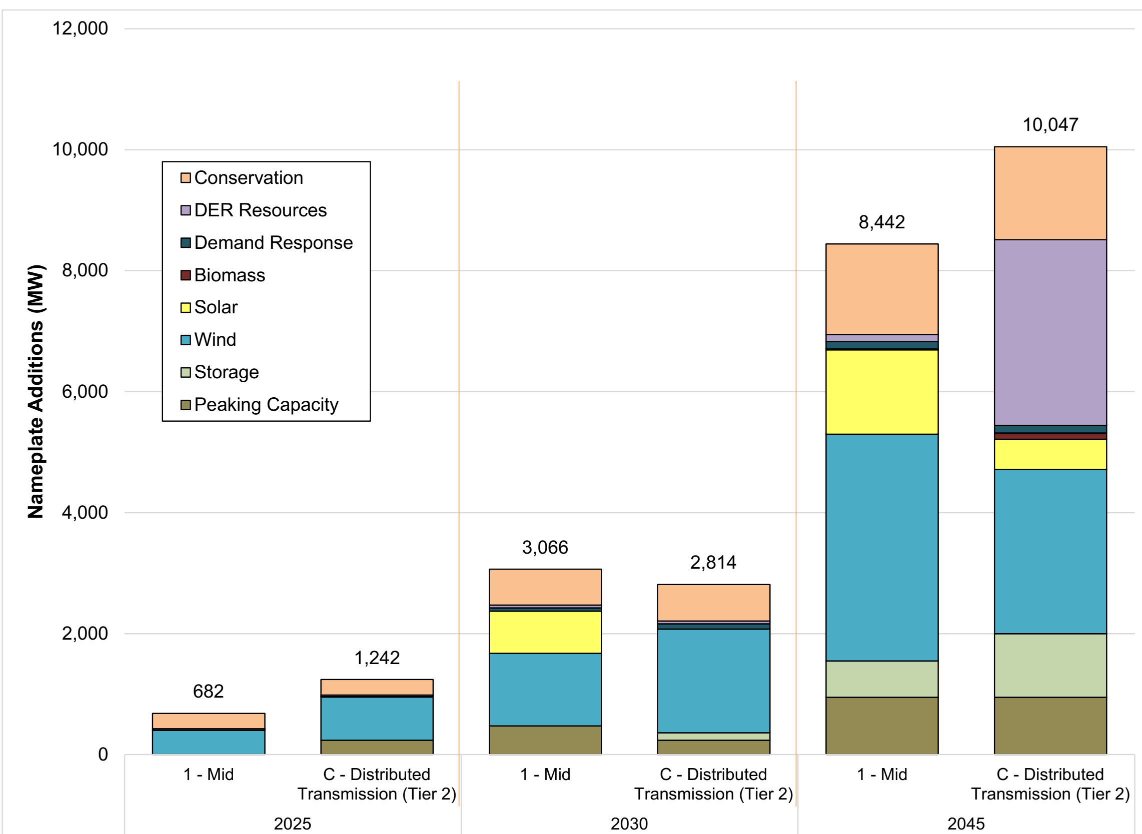


Figure 8-27: Portfolio Additions by 2045, Sensitivity C – Distributed Transmission Tier 2

Resource Additions by 2045	Mid	Sensitivity C - Distributed Transmission (Tier 2)
Conservation	1,497 MW	1,537 MW
DER Resources	118 MW	3,068 MW
Demand Response	121 MW	125 MW
Renewable Resources	5,158 MW	3,319 MW
Biomass	15 MW	105 MW
Solar	1,393 MW	499 MW
Wind	3,750 MW	2,715 MW
Storage	600 MW	1,050 MW
Peaking Capacity	948 MW	948 MW

Other Findings

Distributed energy resources (DERs) are capable of meeting a significant portion of load as shown in Figure 8-28. DERs contribute approximately 14 percent of total energy load in 2045. However, DERs are a poor resource for providing peak capacity need, with an effective load carrying capability (ELCC) of less than 2 percent. This means that other resources are needed to provide capacity during peak need events. Sensitivity C selected peaking capacity resources to meet this need. The same quantity of peaking resource capacity was added to Sensitivity C as was added to the Mid Scenario portfolio, but in Sensitivity C the peaking capacity resources were dispatched more often. This results in increased emissions for Sensitivity C in the later years of the modeling horizon. In 2045, the Mid Scenario generated 0.66 million tons of greenhouse gases (GHGs), while Sensitivity C generated 0.96 million tons of GHGs. Figure 8-29 compares the emissions from the Mid Scenario and Sensitivity D portfolios in millions short tons.

Figure 8-28: Annual Energy Production by Resource Type (aggregated) – Sensitivity *C*

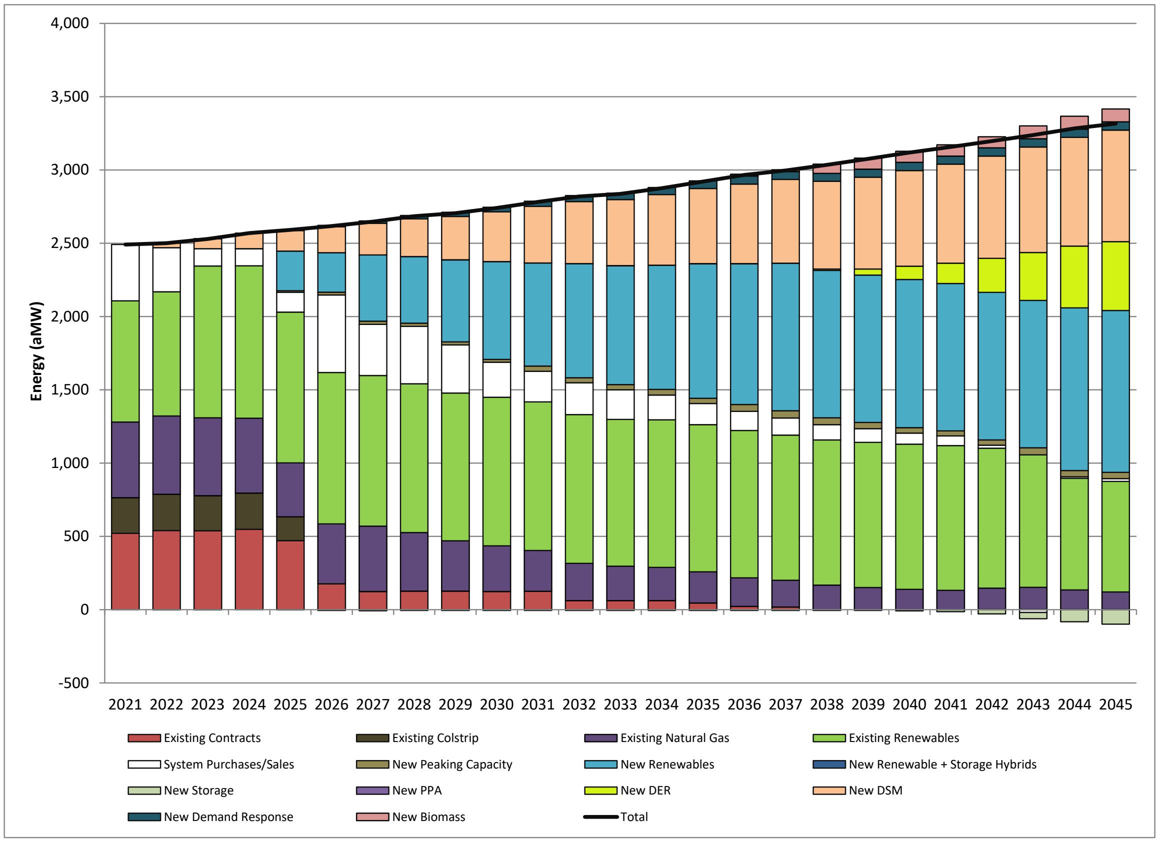
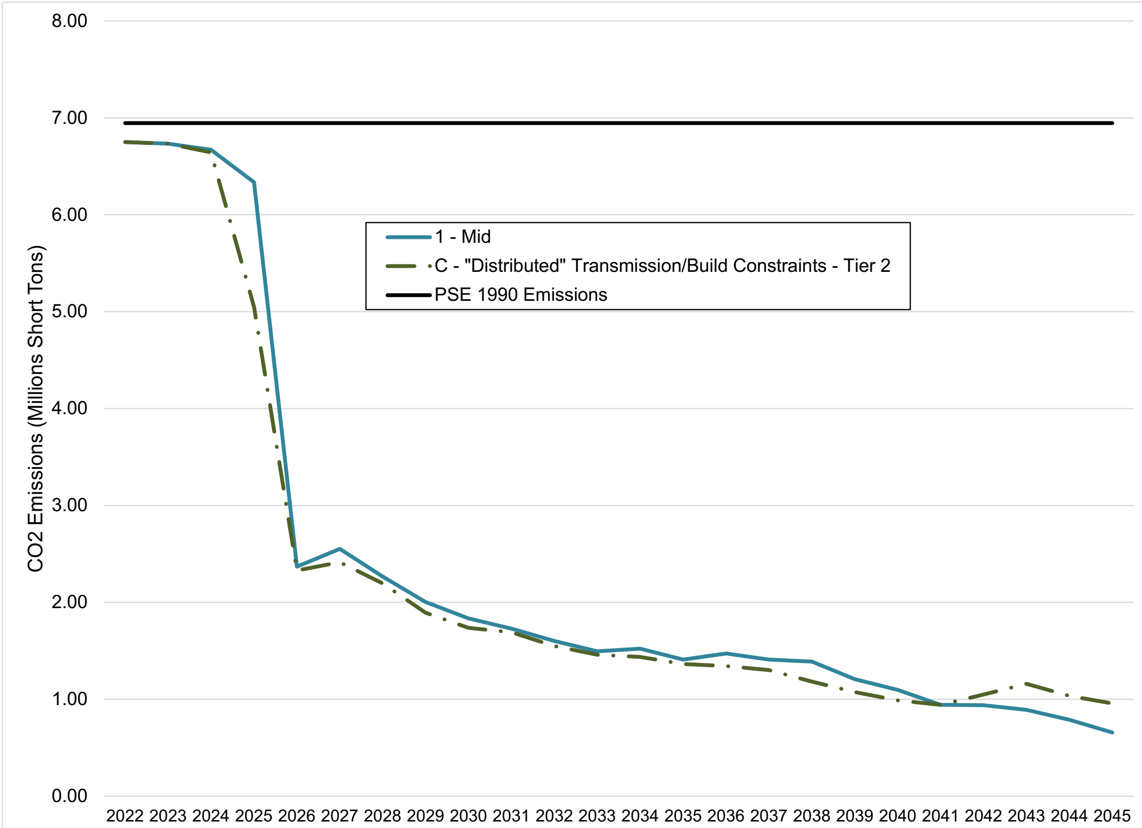


Figure 8-29: Portfolio Emissions – Mid Scenario and Sensitivity C



E. Firm Transmission as a Percentage of Resource Nameplate

What would be the impact on portfolio costs when the capacity of firm transmission purchased with new resources was less than the nameplate capacity of the generating resource?

Baseline: New Resources are acquired with transmission capacity equal to their nameplate capacity.
Sensitivity: New resources are acquired with less transmission capacity than nameplate capacity.

Key Findings

In general, cost savings from reduced firm transmission sensitivities are marginal and likely not a viable method to reduce portfolio costs. Wind resources show the least cost benefit in transmission reduction sensitivities due to the significant portion of time wind resource generate power at or near nameplate capacity (i.e., rated power). Solar resources, which typically spend less time at rated power, show increased cost benefit relative to wind resources, but the cost benefit is still unlikely to prove valuable in resource portfolios.

Assumptions

This sensitivity examines the trade-off in the cost of firm transmission against the replacement cost of power lost to transmission curtailment. The trade-off was calculated for the following generic resource alternatives: Washington wind, Montana wind east, Montana wind central, Wyoming wind east, Wyoming wind west, Idaho wind, utility-scale Washington solar east, utility-scale Wyoming solar east, utility-scale Wyoming solar west and utility-scale Idaho solar. The annual transmission cost for each resource was calculated from the fixed transmission cost (provided in Figure 5-25 in Chapter 5) times the nameplate capacity of the resource. The transmission-curtailed energy was calculated as the sum of all hours where the resource production exceeded the reduced transmission limit. For example, a 100 MW wind farm operating at rated power with 10 percent reduced transmission will curtail 10 MWh for a one-hour period (100 MW x 1 h – 100 MW x (1-0.10) x 1 h = 10 MWh). The replacement cost of transmission-curtailed energy was assumed to be equal to the levelized cost of power for the given resource. PSE acknowledges that these assumptions present a “worst-case scenario” analysis, where it is assumed that all power produced can be used (i.e. production equals demand) and that no short-term transmission may be purchased to supplement long-term firm transmission. While not a comprehensive analysis, this assessment provides a reasonable estimate of potential costs and benefits attributable to reduced transmission sensitivities.

Wind Results

Figure 8-30 shows the trade-off for 200 MW, generic wind resources modeled in the 2021 IRP at various degrees of transmission under-build. Points greater than zero on this plot indicate reduced transmission scenarios which provide a benefit to the project, while negative values indicate a cost. All transmission reduction scenarios are presented relative to firm transmission capacity equal to resource nameplate capacity (i.e., 100 percent), therefore at 100 percent, there is no benefit or cost. All wind resources indicate a maximum benefit at transmission capacity equal to 97.5 percent of resource nameplate. This is because wind farms typically produce 0 to 3 percent less power than nameplate due to internal electrical line losses. After this point, the trade-off quickly drops below zero, representing a cost. This is because wind resources often produce rated power. Figure 8-31 shows a typical histogram for a wind resource, where the plurality of the generation time is at or above 95 percent net capacity factor. Therefore, most often, when the wind farm is generating power, it is likely to be using all available transmission.

Figure 8-30: Trade-off as a Function of Transmission Under-build Degree for 200 MW Wind Resources

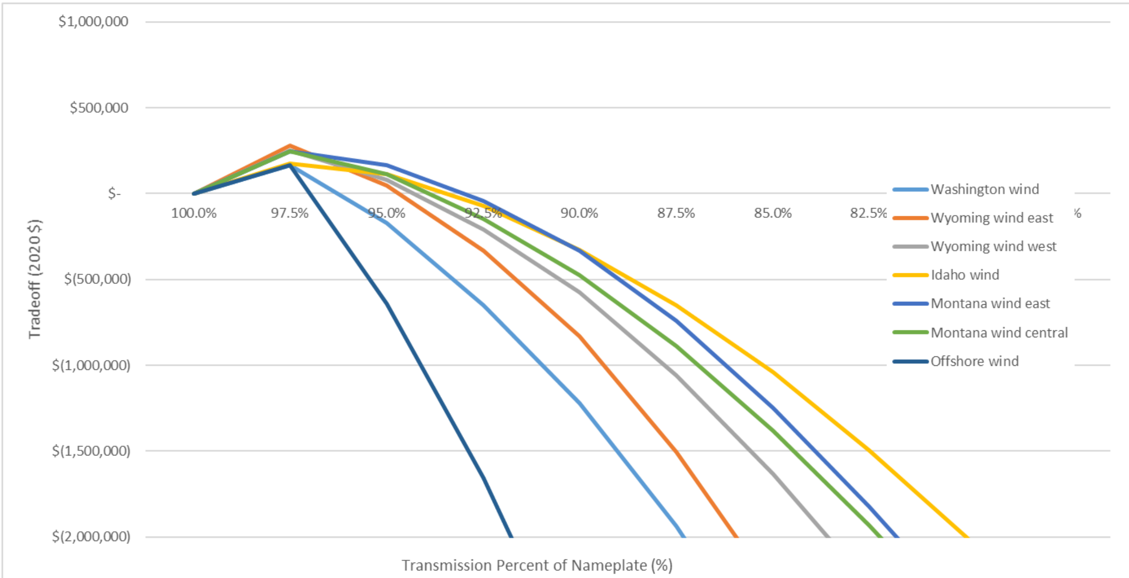
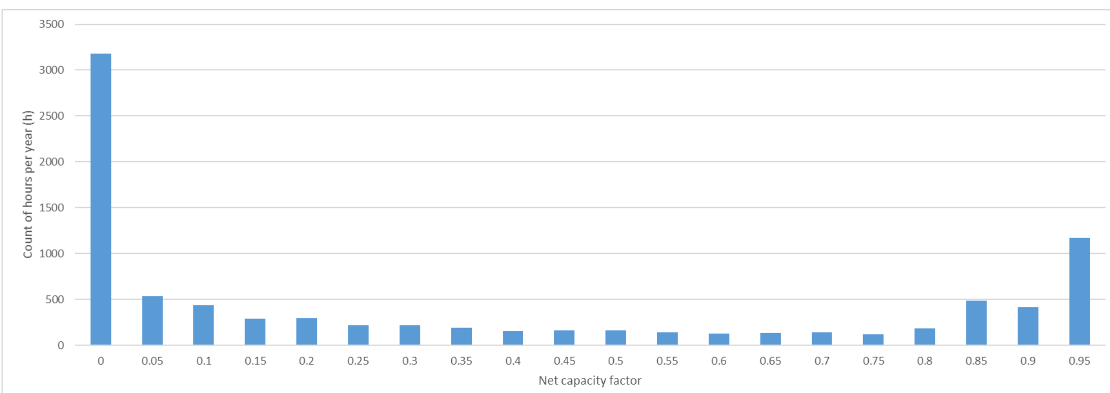


Figure 8-31: Net Capacity Factor Distribution of a Typical Wind Resource



For a 200 MW wind facility, the maximum cost benefit ranges from $165,000 to $281,000 per year depending on the resource location. While these are potentially material cost savings, PSE does not believe incorporation of a 97.5 percent transmission under-build would result in material changes in the portfolio assessment. These costs are relatively small compared to overall capital and transmission costs and all wind resources would gain roughly the same cost benefit.

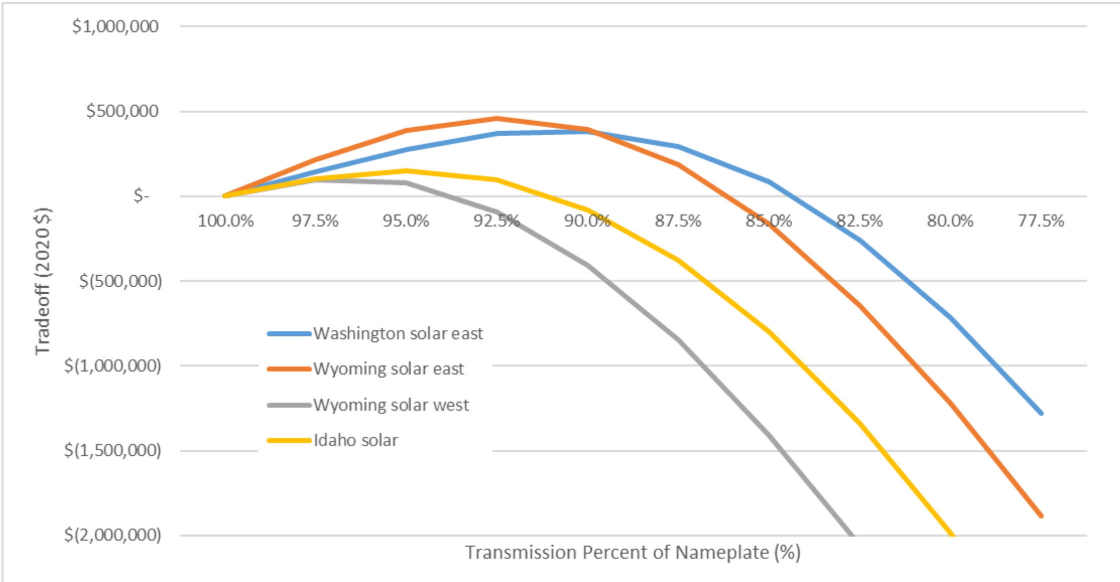
Decisions to purchase less firm transmission than nameplate capacity are more appropriate during the resource acquisition process, as opposed to the IRP planning process.

Furthermore, limiting output capacity from a resource would also reduce the effective load carrying capacity of the resource. Peaking capacity is a key consideration for PSE's portfolio and firm transmission under-build would only increase the amount of resources added to meet peak need.

Solar Results

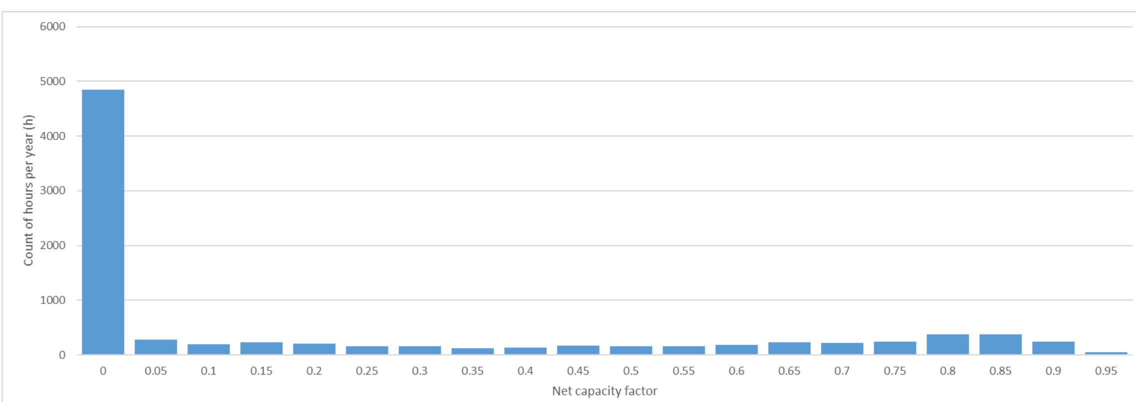
Figure 8:32 shows the trade-off for 200 MW of generic solar resources modeled in the 2021 IRP at various degrees of transmission reduction. Points greater than zero on this plot indicate transmission reduction scenarios which provide a benefit to the project, while negative values indicate a cost. All transmission reduction scenarios are presented relative to firm transmission capacity equal to resource nameplate capacity (i.e., 100 percent), therefore at 100 percent, there is no benefit or cost. Solar resources indicate a maximum benefit at transmission capacity between 97.5 percent and 90.0 percent of resource nameplate. This is because solar farms have a more variable distribution of power production at high capacity factors, giving each solar resource a unique trade-off cost profile. However, as discussed in the wind results above, solar farms also produce most power at higher hourly capacity factors Figure 8-33 shows a typical histogram for a solar resource, where the plurality of the generation time is at or above 80 percent hourly capacity factor.

Figure 8-32: Trade-off as a Function of Transmission Under-build Degree for 200 MW Solar Resources



For a 200 MW solar facility, the maximum benefit ranges from $97,000 to $460,000 per year depending on the resource location. Similar to the wind farm results presented above, solar resources do show some benefit, however, PSE does not feel these benefits would add materially to the IRP portfolio development process. This assessment may provide more benefit in resource acquisition decisions.

Figure 8-33: Net Capacity Factor Distribution of a Typical Solar Resource

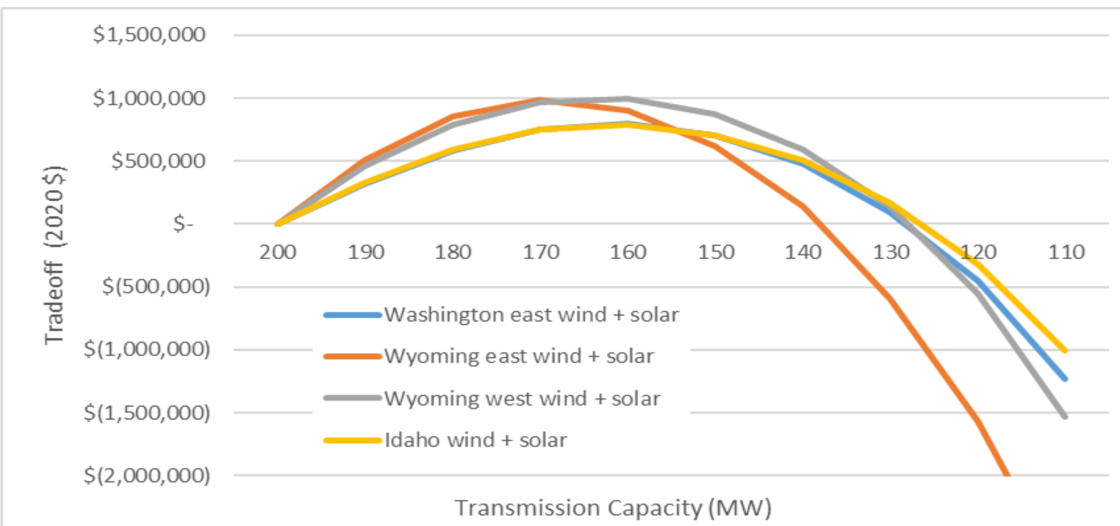


Next Steps

In addition to the reduced transmission sensitivities described above, PSE also took an initial look at co-locating a wind and solar resource with shared, limited transmission capacity. A complementary relationship appears to exist between the resource pairs assessed. First, wind resources with higher winter time production may benefit from co-location with solar resources which have greater production in the summer months. Second, wind resources with higher overnight production may benefit from co-location with solar resources which, by nature, only produce power during the day. Cost savings may be realized by optimizing the amount of transmission to better match the average seasonal and diurnal production of the co-located resources, as opposed to securing firm transmission for both resources individually.

Figure 8-34 shows the possible trade-off of co-locating a 100 MW wind farm with a 100 MW solar farm at various locations. The maximum cost benefit ranges from $784,000 to $999,000 per year depending on resource location. PSE intends to examine co-located resources in more detail in future IRP cycles.

Figure 8-34: Trade-off as a Function of Transmission Capacity for Co-located 100 MW Wind and 100 MW Solar Resources



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

How would the LTCE model build if SCGHG was implemented as an externality cost instead of a planning adder?

> **Baseline:** SCGHG is implemented as a planning adder in the Long-term Capacity Expansion Model (LTCE), and not used in the hourly dispatch.
> **Sensitivity:** SCGHG is implemented as an externality cost in the LTCE model, and not used in the hourly dispatch.

Key Findings

The changes brought on by changing SCGHG to an externality cost are minor. The model optimizes the dispatch of existing gas plants to minimize costs, while newly acquired peaking capacity is largely unused. The sensitivity resulted in more peaking capacity being built than in the Mid Scenario portfolio, but the average capacity factors of the newly built plants averages to 0.3 percent by 2045.

Assumptions

In the Mid Scenario portfolio, SCGHG is included as a planning adder (fixed cost) to emitting resources in the LTCE model. In this sensitivity, the SCGHG is applied as an externality cost (variable cost) in the LTCE model. The SCGHG is not applied in the hourly dispatch model for either portfolio. Both portfolio use the mid electric price forecast with the SCGHG as an adder for market purchases.

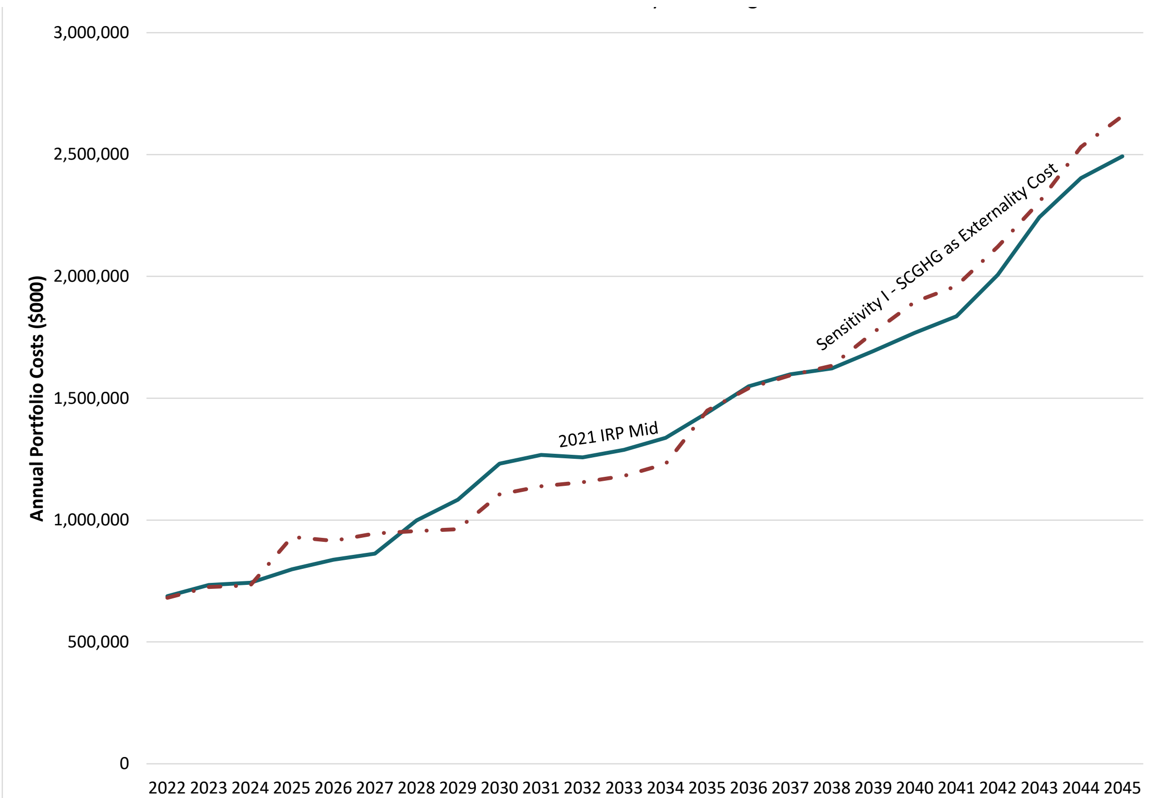
Portfolio Costs

Figure 8-35 and 8-36 illustrate the breakdown of costs between the Mid Scenario and Sensitivity I portfolios. The costs of the portfolio remain similar throughout the time horizon of the model, with Sensitivity I reaching a higher annual cost in 2045 as a result of increased biomass builds that begin to enter the portfolio in 2036. Overall, the cost differences between these portfolios are minor, with Sensitivity I purchasing slightly more expensive resources in the later years.

Figure 8-35: 24-year Levelized Costs – Mid and Sensitivity I portfolios

		24-Yr Levelized Costs			
	Portfolio	Revenue Requirement	SCGHG Costs	Total	Change from Mid
1	Mid Scenario	$13.63	$5.04	$18.68	
I	SCGHG as Externality Cost	$13.65	$4.78	$18.42	($0.25)

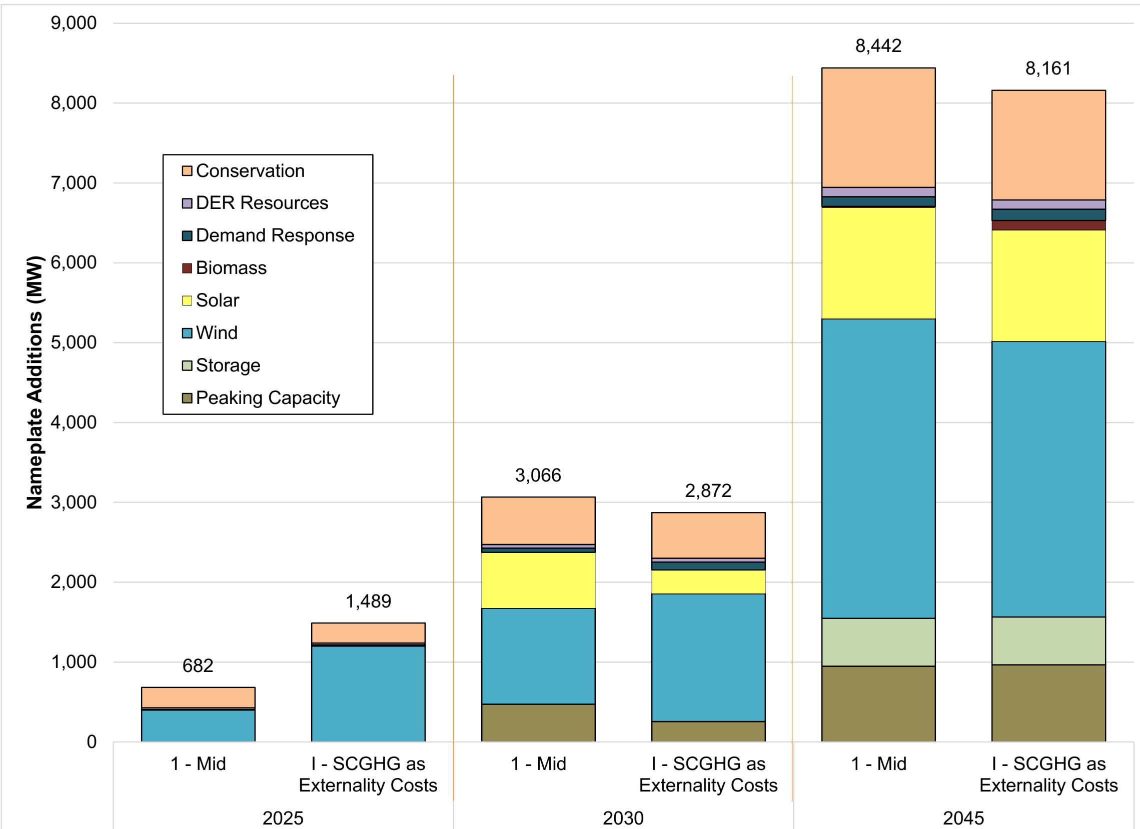
Figure 8-36: Annual Portfolio Costs – Mid Scenario and Sensitivity I



Resource Additions

Figure 8-37 compares the nameplate capacity additions of the Sensitivity I and Mid Scenario portfolios. The model in Sensitivity I builds a large amount of Washington wind capacity in 2025 as the retirements of Colstrip and Centralia take place. However, the total Washington wind resources added to the Sensitivity I is lower by 300 MW nameplate capacity compared to the Mid Scenario. Unique to Sensitivity I is the addition of 250 MW of Wind + Battery capacity by 2045. Beyond this change in wind resource selection, by 2045 the amount of intermittent renewable resources is roughly equivalent in nameplate capacity to the Mid Scenario portfolio. Biomass is gradually added to the Sensitivity I portfolio between the years 2036 and 2045 as the model strives to reach CETA and capacity requirements without burning natural gas. Battery builds reach the same total capacity but with a different mix of resources, with 70 percent of the capacity coming from 6-hour flow batteries and the other 30 percent comprised of 4-hour flow, 4-hour lithium-ion and 2-hour lithium-ion batteries. In the Mid Scenario, the portfolio builds 50 percent of 6-hour flow batteries and 50 percent of 4-hour lithium-ion batteries.

Figure 8-37: Portfolio Additions, Sensitivity I – SCGHG as Externality Cost



Other Findings

Peaking capacity is gradually added to the portfolio starting in the year 2026 in order to meet peak need after the retirements of Colstrip and Centralia. Peaking resource additions track with the increases of peak need, as shown in Figure 8-38. In the Sensitivity I portfolio, the new additions of peaking capacity are dispatching less than in the Mid Scenario portfolio by the year 2045, but existing plants are dispatching more. New peaking capacity averages a capacity factor of 0.3 percent in Sensitivity I while new peaking capacity in the Mid Scenario has an average capacity factor of 3.19 percent. Existing gas plants see an increase from an average capacity factor of 3.2 percent to 4.2 percent. The model has optimized around existing natural gas plants, but still requires additional peaking capacity.

The reduced usage of new peaking capacity leads to an overall decrease in the emissions from resources in the portfolio. Figure 8-39 shows the emissions of the Sensitivity I portfolio, where PSE is producing below two million short tons of emissions in the year 2045. The portfolio does begin to lean more on market purchases, which have a CETA-specified emission rate of 0.437 metric tons of CO_2 per MWh.

Figure 8-39: Sensitivity I – Portfolio Peak Capacity Needs

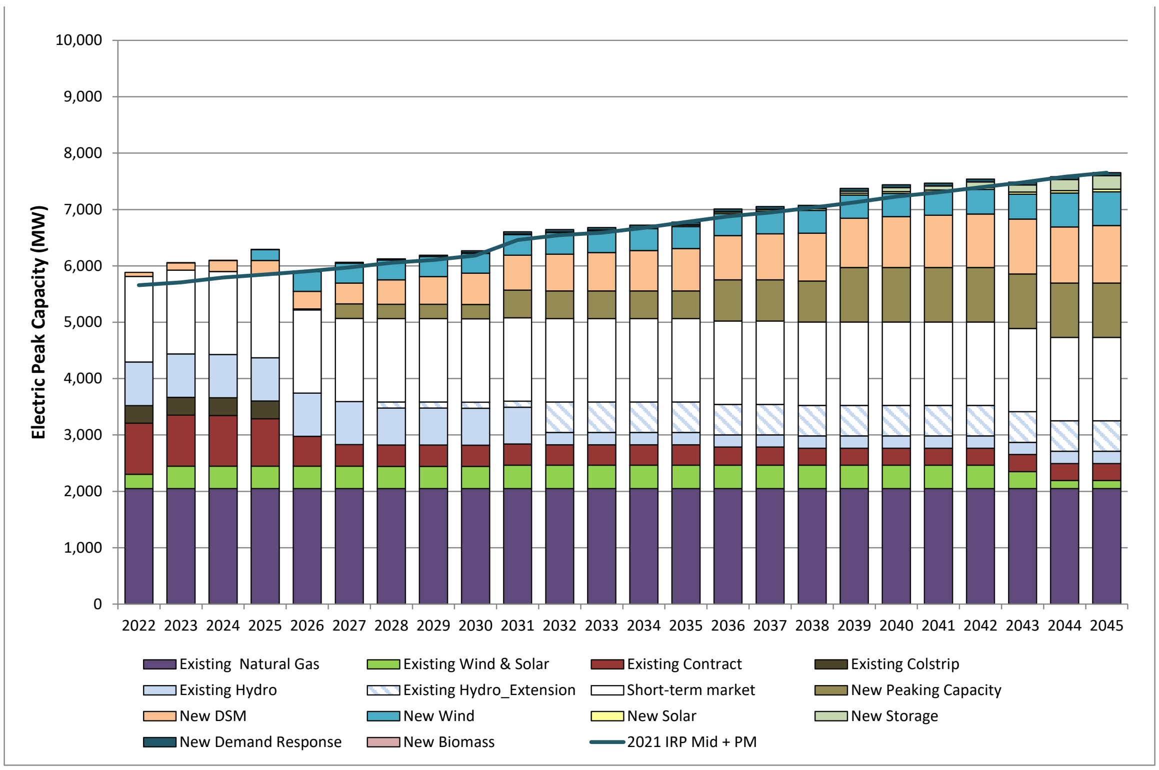


Figure 8-39: Sensitivity I – Emissions

N: 100% Renewable by 2030

What is the cost difference between the mid portfolio and a portfolio with an alternate CETA target of 100% renewable by 2030?

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

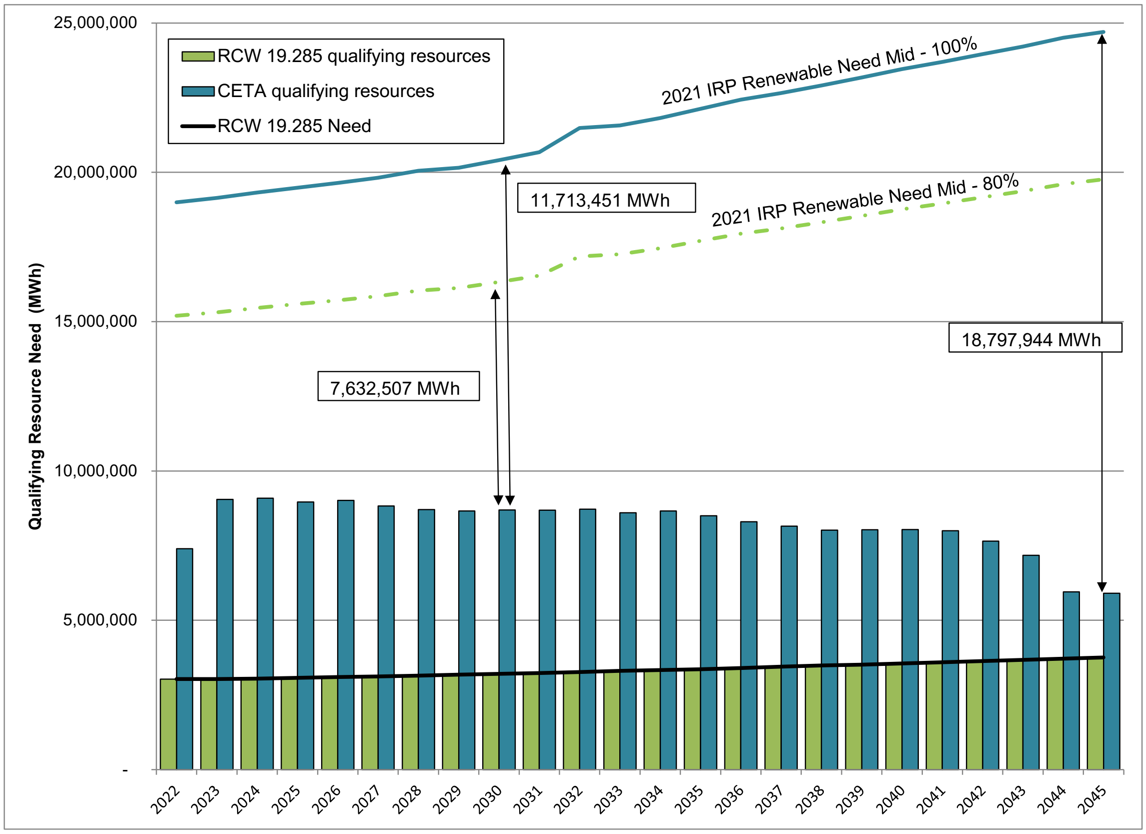
Key Findings

In this sensitivity, the 24-year levelized portfolio costs increased by 128 percent for a total of $31.1 billion dollars in revenue requirement. With no access to thermal resources by 2030, a significant amount of batteries totaling 26,100 nameplate MW were built to keep the portfolio balanced. Market access remains important in this sensitivity as purchases became a resource for meeting energy and peak capacity needs, in addition to being a source for charging the batteries.

Assumptions

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

Figure 8-40: Renewable Targets in the Mid Scenario and Sensitivity N Portfolio



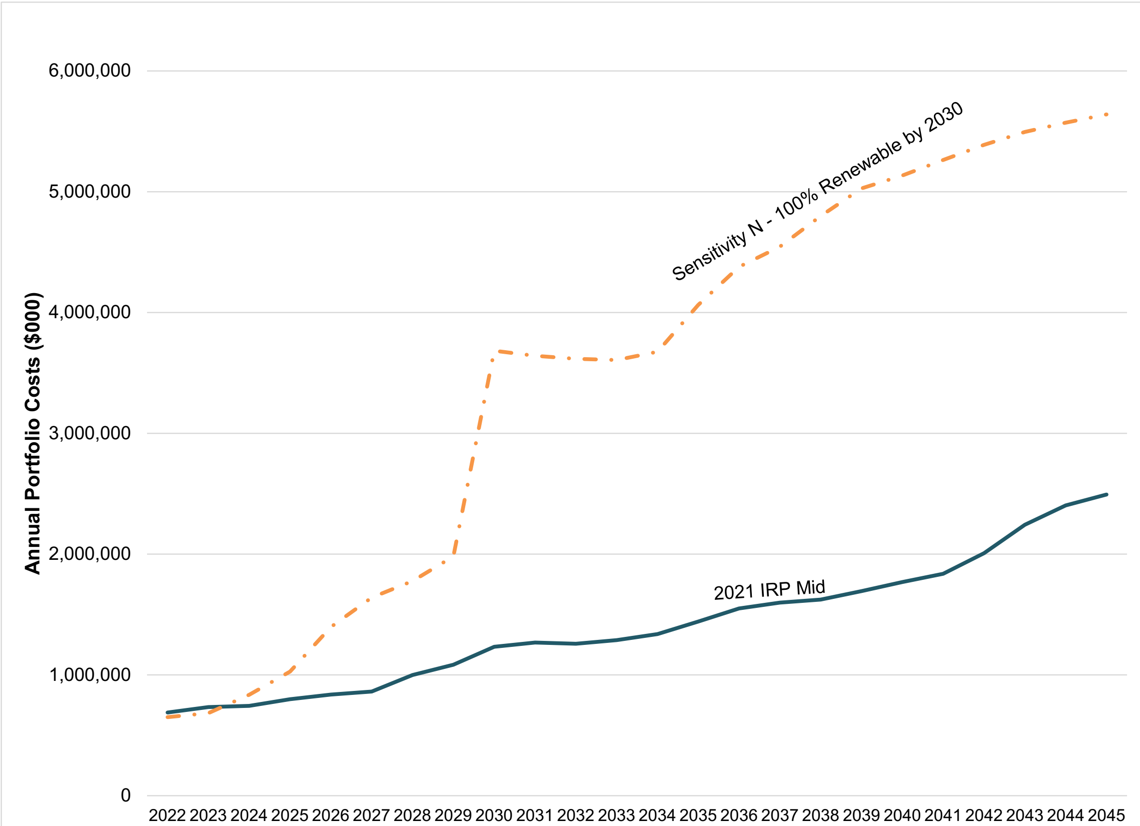
Portfolio Costs

Figures 8-41 and 8-42 illustrate the breakdown of costs between the Mid Scenario and Sensitivity N portfolios. The increase in costs for Sensitivity N is attributed to the increase in the overall resource builds, particularly for storage resources.

Figure 8-41: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity N

		24-Yr Levelized Costs			
	Portfolio	Revenue Requirement	SCGHG Costs	Total	Change from Mid
1	Mid Scenario	$13.63	$5.04	$18.68	
N	100% Renewable by 2030	$31.14	$3.42	$34.56	$15.89

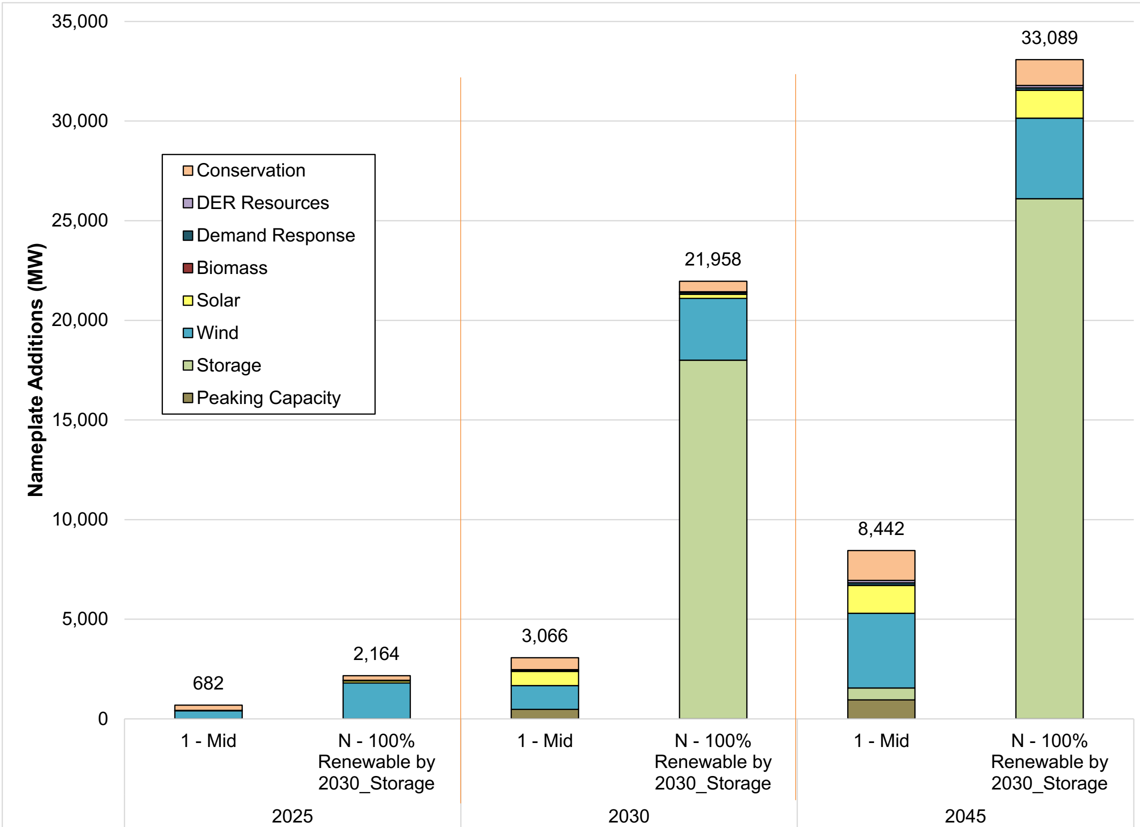
Figure 8-42: Annual Portfolio Costs – Mid Scenario and Sensitivity N



Resource Additions

Figure 8-43 compares the nameplate capacity additions of the Sensitivity N and Mid Scenario portfolios. The model in Sensitivity N builds a large amount of wind capacity in 2025 as the retirements of Colstrip and Centralia take place, but also to meet the higher CETA renewable need. By 2030, a total of 3,100 MW nameplate capacity of wind has been added in this sensitivity compared to 1,200 nameplate capacity of wind in the Mid Scenario portfolio. A total of 18,000 MW of 2-hour lithium-ion battery storage is also added to the portfolio by 2030, replacing the entire fleet of PSE's existing thermal resources. At the end of the planning period, we continue to see an increase in 2-hour lithium-ion battery storage with a total of 26,100 MW nameplate capacity.

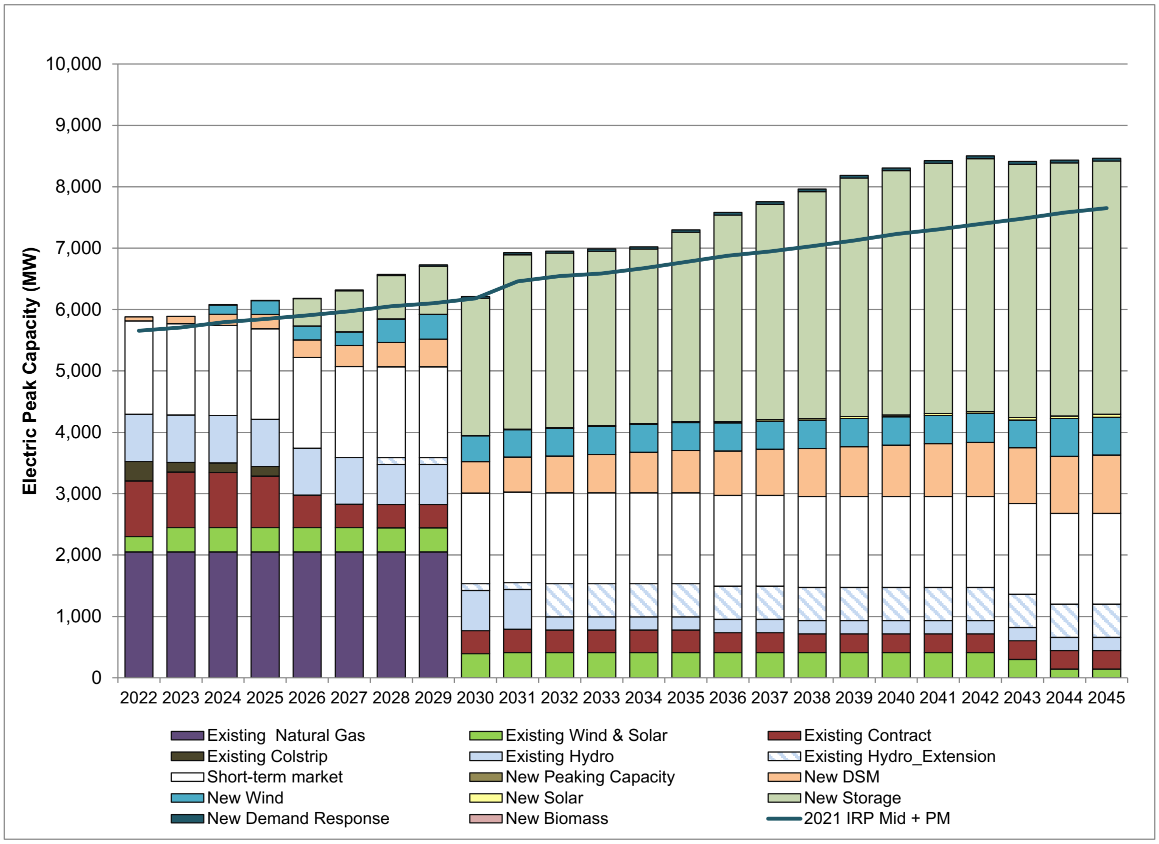
Figure 8-43: Portfolio Additions, Sensitivity N – 100% Renewable by 2030



Other Findings

PEAK CAPACITY. Peak capacity contribution from PSE's existing thermal resources is approximately 2,000 MW. For Sensitivity N, the replacement peak capacity contribution is made up of a mix of new 2-hour lithium-ion batteries, wind and solar resources. Figure 8-44 shows an overbuild of new resources compared to the peak capacity need except for year 2030, when existing thermal resources are removed from the portfolio.

Figure 8-44: Sensitivity N – Portfolio Peak Capacity Needs



STORAGE OPTIONS. PSE ran four portfolios for Sensitivity N, adjusting the size of the storage options in order to get insight into the impact on portfolio costs and to improve model run time. The results and discussion for Sensitivity N are based on N2 in Figure 8-45 below.

Figure 8-45: Sensitivity N – Storage Options

		24-yr Levelized Cost ($ Billions)
Storage Option	**Results**	**Revenue Requirement**
N1. 25 MW Batteries, 25 Pump Hydro Storage	Peak capacity need not met	N/A
N2. 300 MW Batteries, 500 MW Pump Hydro Storage	26,100 MW of 2hr Li-Ion	$31.14
N3. 500 MW Pump Hydro Storage Only	19,500 MW of PHES	$53.81
N4. 100 MW Batteries, 100 MW Pump Hydro Storage	22,000 MW of 2-hr Li-Ion; 4,300 MW of 4-hr Li-Ion	$34.89

O: Gas Generation Out by 2045

What is the cost difference between the mid portfolio and a portfolio that has no gas fired generation resources by 2045?

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

Key Findings

In this sensitivity, the 24-year levelized revenue requirement is $33.9 billion dollars, an increase of $20.3 billion dollars or 149 percent compared to the Mid Scenario portfolio. With the retirement of all existing gas-fired and new peaking capacity resources happening in one year, the portfolio model fails to meet the peak capacity need in 2045. There is a huge spike in annual portfolio costs between 2044 and 2045 due to penalties related to violation of model constraints. This sensitivity requires further work for the final 2021 IRP.

Assumptions

In the Mid Scenario portfolio, existing gas-fired generation resources remain in operation unless economically retired by the model. Generic peaking capacity resources are available as a new resource and have an operating life of 30 years. In this sensitivity, all existing gas-fired generation resources are retired by 2045 regardless of economic viability. Generic peaking capacity resources are available as a new resource but are expected to retire by 2045.

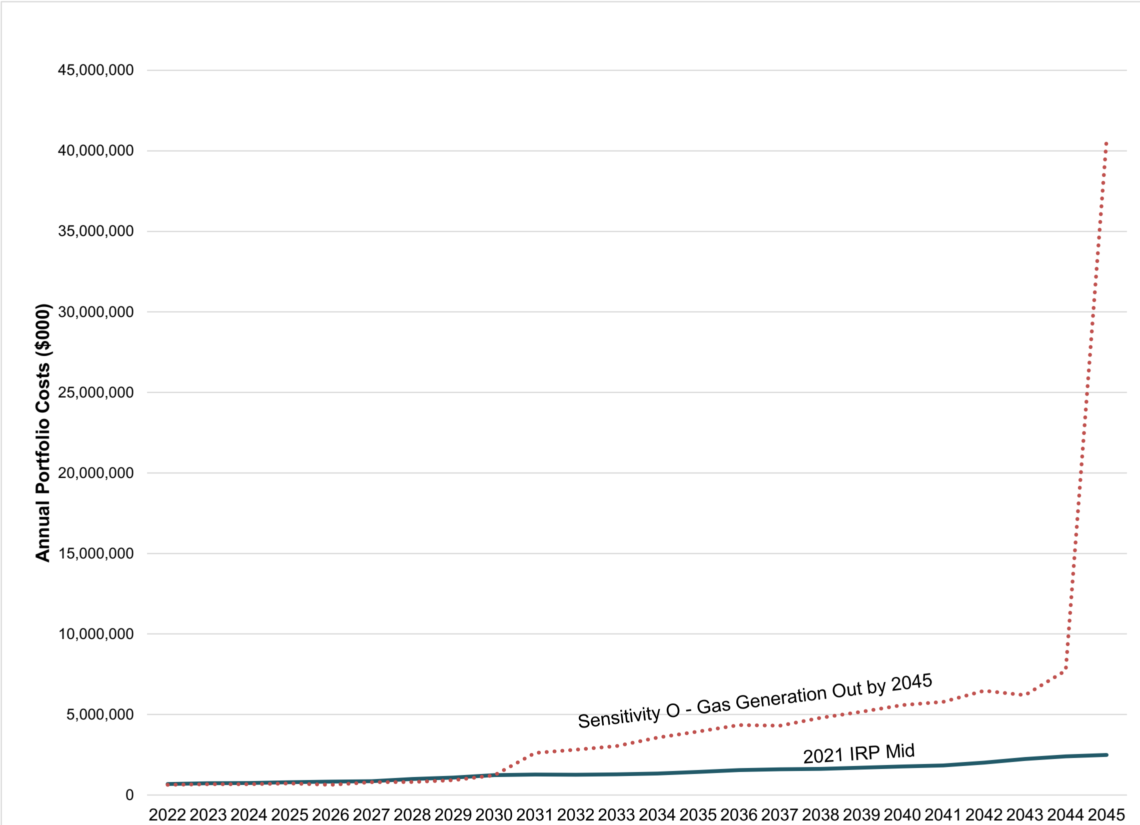
Portfolio Costs

Figures 8-46 and 8-47 illustrate the breakdown of costs between the Mid Scenario and Sensitivity N portfolios. The increase in costs for Sensitivity O is attributed to the increase in the overall resource builds and violations related to the peak capacity requirements for 2045.

Figure 8-46: 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivity O

		24-Yr Levelized Costs			
	Portfolio	Revenue Requirement	SCGHG Costs	Total	Change from Mid
1	Mid Scenario	$13.63	$5.04	$18.68	
O	Gas Generation out by 2045	$33.90	$6.24	$40.14	$21.46

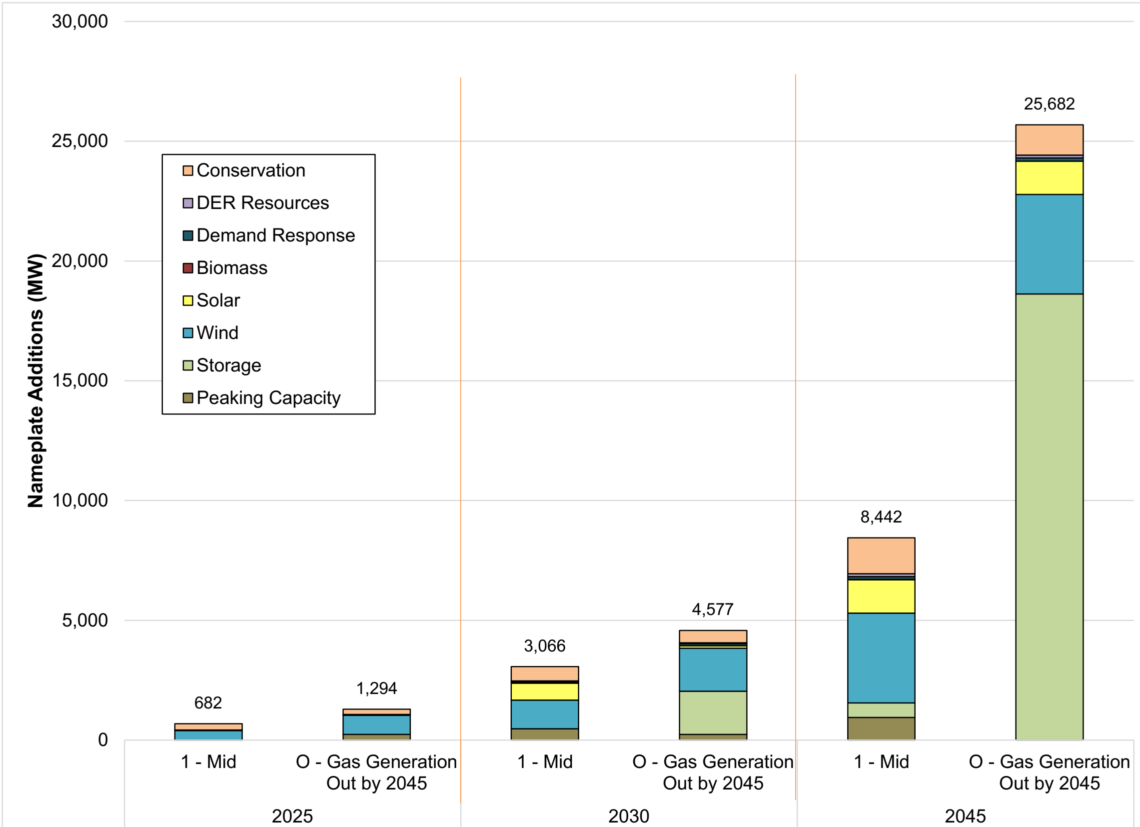
Figure 8-47: Annual Portfolio Costs – Mid Scenario and Sensitivity O



Resource Additions

Figure 8-48 shows a comparison between the nameplate capacity additions of Sensitivity O and the Mid Scenario portfolios. The model in Sensitivity O builds 237 MW of peaking capacity resources as the retirements of Colstrip and Centralia take place, but do not build anymore beyond that. Between 2026 and 2030, 1,800 MW of storage resources are added to the portfolio, and an additional 16,825 MW by 2045. However, there are still not enough resource additions available to meet the peak capacity need for 2045.

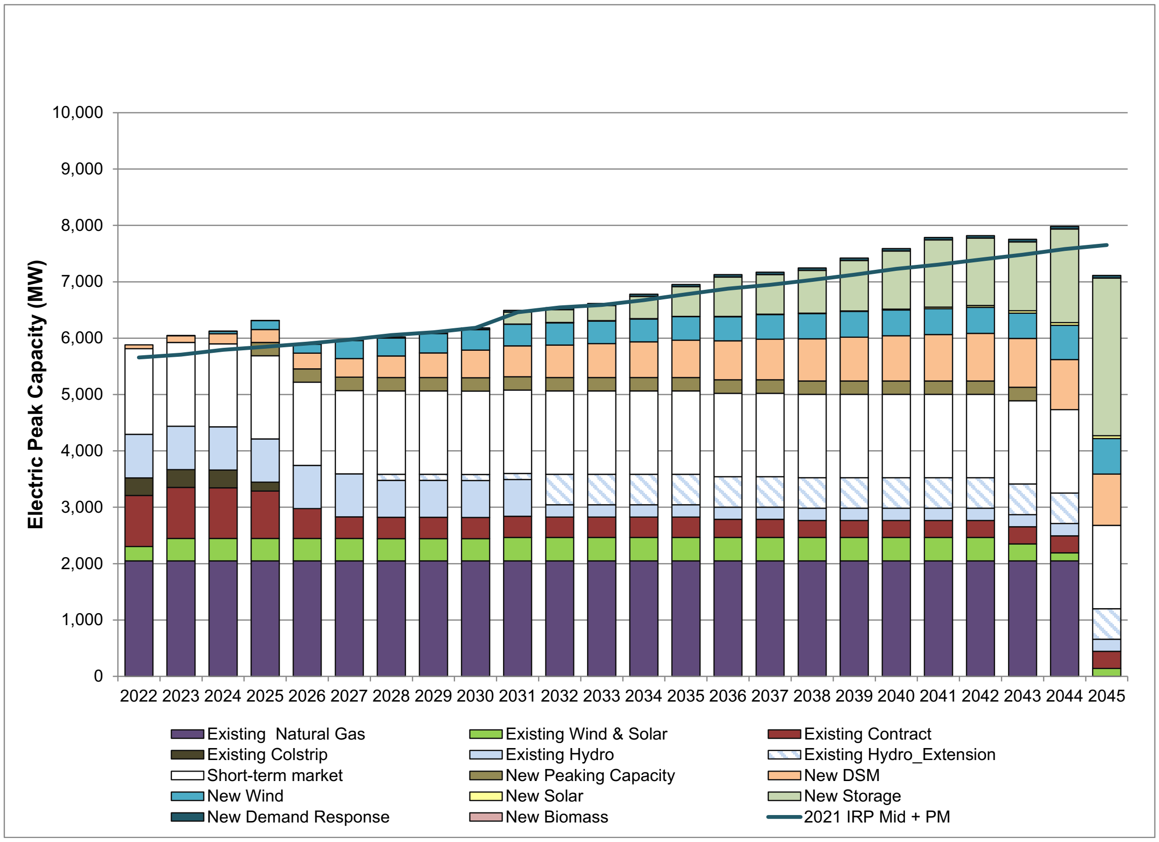
Figure 8-48: Portfolio Additions – Mid Scenario and Sensitivity O



Other Findings

PEAK CAPACITY. Absent of gas-fired generation by 2045, the portfolio fails to meet the peak capacity need at the end of the planning horizon and requires further work for the final IRP. Figure 8-49 shows the peak capacity contribution of existing and new resources compared to the peak capacity need.

Figure 8-49: Sensitivity O – Portfolio Peak Capacity Needs



P: Must-take Battery and P2 Must-take Pumped Hydro Energy Storage

What is the cost difference between the Mid Scenario portfolio and a portfolio where storage resources and demand response programs are selected prior to any peaking capacity resources?

Baseline: Peaking capacity resources are available as early as 2025**.**

Sensitivity P: First eligible year for peaking capacity resources is 2030.

Sensitivity P2: Same as P; Pump hydro energy storage resources are available as early as 2023. First year availability of batteries is moved to 2030 from 2023.

Key Findings

Sensitivity P: Delaying the availability of peaking capacity resources resulted in much earlier addition of battery storage resources, for a total of 3,775 MW nameplate capacity by 2030. We also see an additional 7 MW nameplate capacity of demand response by 2045 compared to the Mid Scenario portfolio. Peaking capacity resources were still added to the portfolio for a total of 711 MW nameplate capacity compared to 948 MW nameplate capacity in the Mid Scenario portfolio. In Sensitivity P, the 24-year levelized revenue requirement is $29.1 billion dollars, an increase of $15.5 billion dollars or 113 percent over the Mid Scenario.

Sensitivity P2: Without peaking capacity resources and batteries available until 2030, 2,800 MW nameplate capacity of pump hydro energy storage resources were added to the portfolio by 2028 in order to fill the peak capacity needed after the removal of Centralia and Colstrip 3&4. Interestingly, 711 MW nameplate of peaking capacity resources and 1,225 MW nameplate of 2-hr Lithium Ion batteries were added to the portfolio by 2045. For Sensitivity P2, the 24-year levelized revenue requirement is $22.4 billion dollars, an increase of $8.72 billion dollars over the Mid Scenario.

Assumptions

In the Mid Scenario portfolio, peaking capacity resources are available as early as 2025. In this sensitivities P and P2, peaking capacity resources are available much later, in 2030. This forces the model to optimize its resource selection between batteries and demand response to keep the portfolio balanced prior to the availability of peaking capacity resources. To better understand the impact of limited storage options, only pump hydro energy storage resources are available for selection in Sensitivity P2 starting in 2023. Lithium Ion and Flow batteries are not available until 2030 in Sensitivity P2.

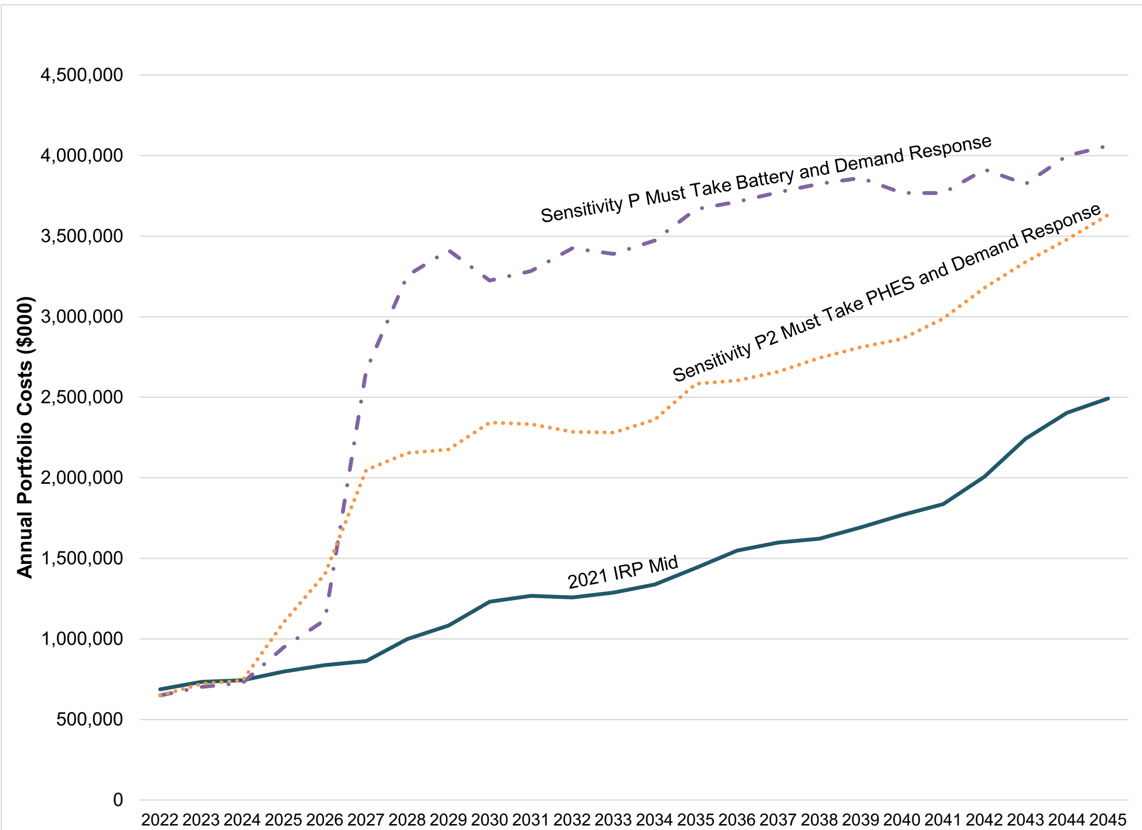
Portfolio Costs

Figures 8-50 and 8-51 illustrate the breakdown of costs between the Mid Scenario and Sensitivity P and P2 portfolios. The annual portfolio costs are significantly higher for both Sensitivities P and P2 compared to the Mid Scenario. Storage resources and Demand Response programs are more expensive options compared to peaking capacity resources. Both sensitivities added over 3,000 MW more nameplate capacity of new resources compared to the Mid Scenario, resulting in higher portfolio costs. A significant amount of batteries and pump hydro energy storage was added to both portfolios between 2025 and 2030 and resulted in the spike in the annual portfolio costs.

Figure 8-50: 20 and 24-year Levelized Portfolio Costs – Mid Scenario and Sensitivities P and P2

		24-Yr Levelized Costs			
	Portfolio	Revenue Requirement	SCGHG Costs	Total	Change from Mid
1	Mid Scenario	$13.63	$5.04	$18.68	
P	Must-take Battery	$29.09	$6.06	$35.15	$16.47
P2	Must-take Pumped Hydro Storage	$22.35	$4.36	$26.71	$8.04

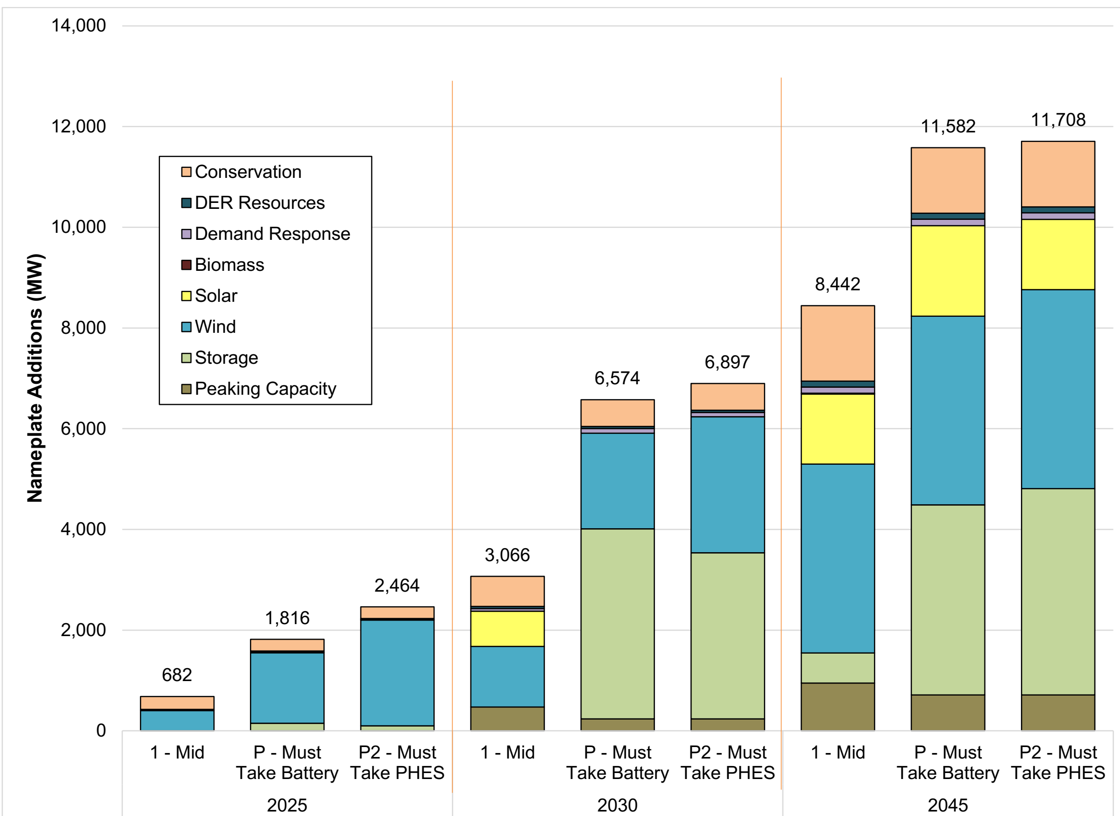
Figure 8-51: Annual Portfolio Costs – Mid Scenario and Sensitivities P and P2



Resource Additions

Figure 8-52 compares the nameplate capacity additions of Sensitivity P and P2 and the Mid Scenario portfolios. In the Mid Scenario portfolio, 474 MW of peaking capacity resources were added in 2026 as the retirements of Colstrip and Centralia take place. In Sensitivity P, batteries are selected to meet that peak need. With 2-hour lithium-ion batteries having a 12.4 percent ELCC, it will take about 3,800 MW nameplate capacity of batteries to replace those peaking capacity resources. In this sensitivity, the model selected 3,775 MW of 2-hour lithium-ion batteries to make up for the difference left unserved by new peaking capacity resources. We see similar resource additions for Sensitivity P2 with the only difference being the addition of pumped hydro energy storage instead of batteries.

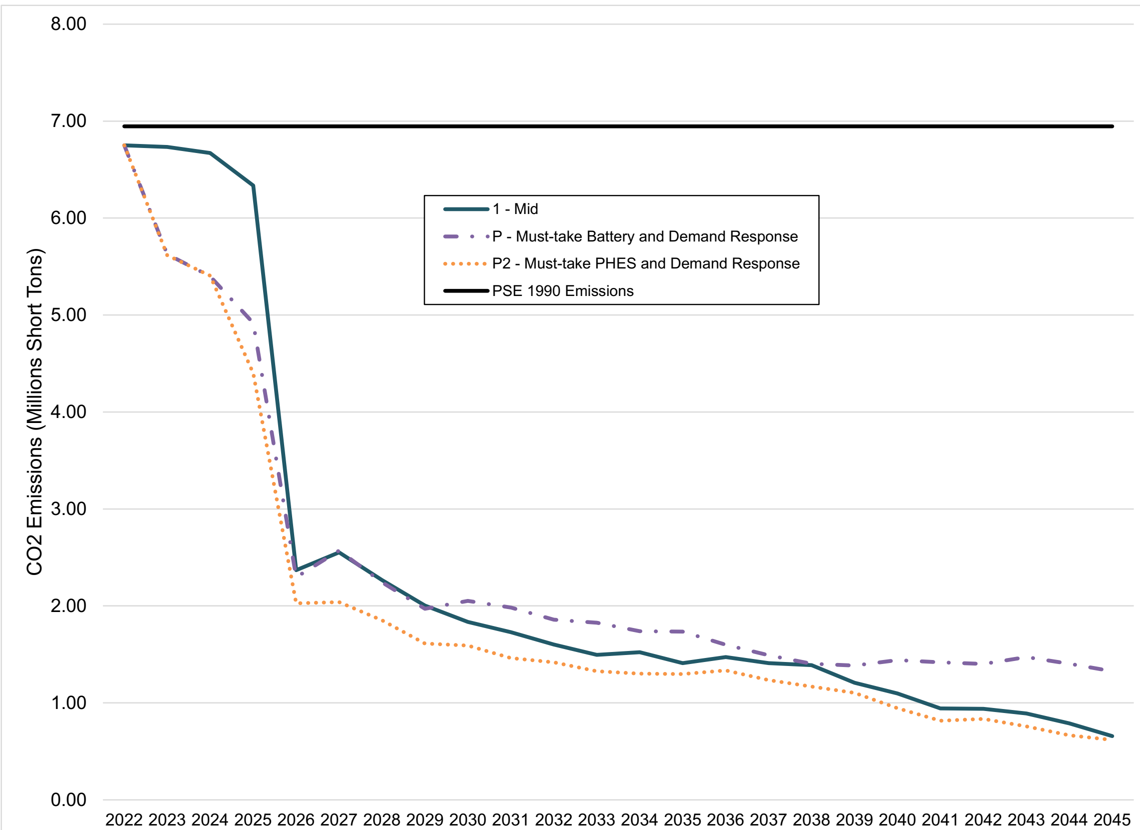
Figure 8-52: Portfolio Additions – Mid Scenario and Sensitivities P and P2



Other Findings

EMISSIONS. Delaying the addition of peaking capacity resources results in slightly higher dispatch of existing thermal plants as seen Sensitivity P. Slightly lower direct emissions from existing and new thermal plants are seen in Sensitivity P2 compared to the Mid Scenario. Figure 8-53 compares the emissions from the Mid Scenario and Sensitivities P and P2 portfolios in millions short tons.

Figure 8-53: Portfolio Emissions – Mid Scenario and Sensitivities P and P2



S. SCGHG Cost Included, No CETA, and

T. No CETA

What is the cost difference between the mid portfolio and a portfolio with the CETA requirement and Social Cost of Greenhouse gas?

Baseline: SCGHG for thermal resources as a fixed cost adder and the CETA requirement is included in the model.
Sensitivity S: There is no CETA renewable requirement. SCGHG costs as a fixed cost adder is included for thermal plants.
Sensitivity T: There is no CETA renewable requirement and SCGHG costs are not included in the model.

Key Findings

Without the CETA renewable requirement and SCGHG as a fixed cost adder, the 24-year levelized revenue requirement for Sensitivity T is $9.4 billion dollars, $4.2 billion dollars less than the Mid Scenario portfolio. Compared to Sensitivity S, the 24-year levelized revenue requirement for Sensitivity T is lower by $0.7 billion dollars. Similar to Sensitivity S, there are no renewable resource additions to the portfolio except for 350 MW of wind in 2044 needed to maintain compliance with the RPS requirement. There are less conservation resources selected in both Sensitivities S and T compared to the Mid Scenario.

Assumptions

In the Mid Scenario portfolio, 80 percent of sales must be met by non-emitting/renewable resources by 2030; the remaining 20 percent is met through alternative compliance. The Social Cost of Greenhouse Gases is included as a fixed O&M cost for thermal resources during resource selection. In Sensitivity T, there is no CETA renewable requirement and SCGHG costs are not included in the model. Absent the CETA renewable requirement, the 15 percent of sales RPS requirement under RCW 19.285 is applied in this sensitivity. For Sensitivity S, only the SCGHG costs are included in the mode.l

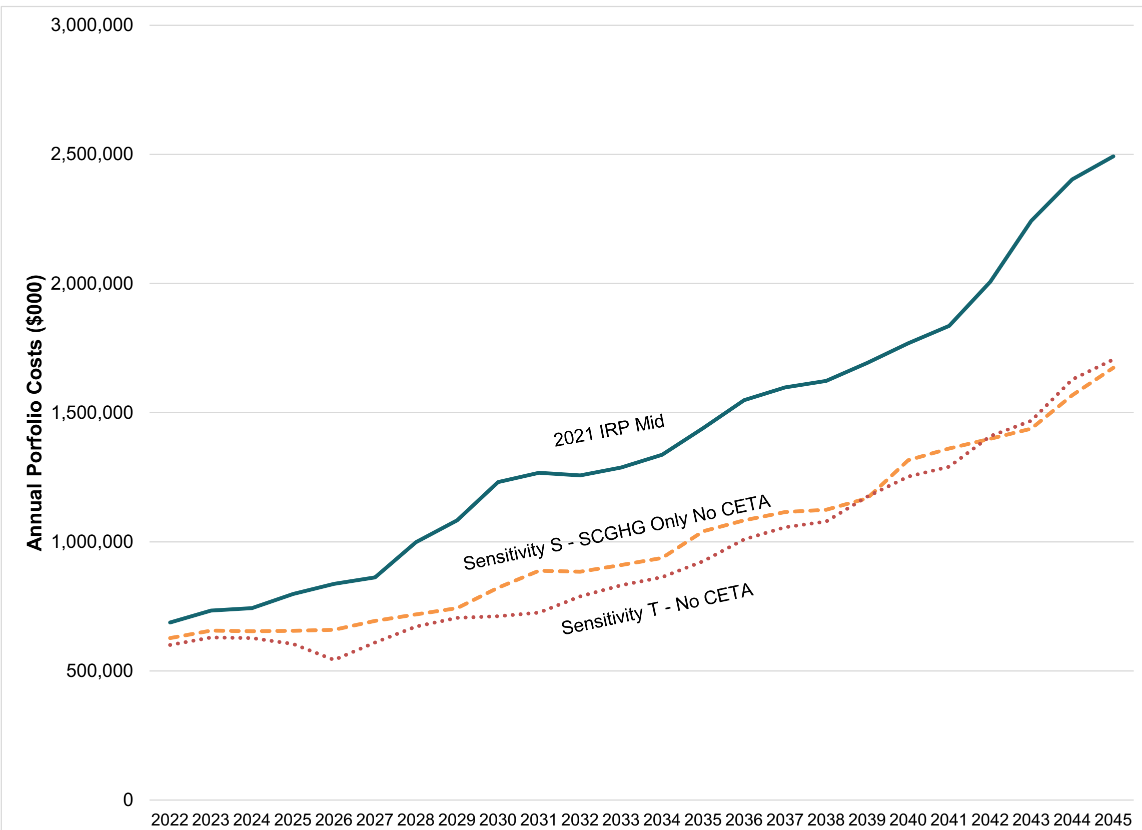
Portfolio Costs

Figures 8-54 and 8-55 illustrate the breakdown of costs between the Mid Scenario, Sensitivity S and Sensitivity T portfolios. The reduction in conservation resources drives the costs even lower for Sensitivity T compared to Sensitivity S.

Figure 8-54: 24-year Levelized Portfolio Costs – Mid Scenario, Sensitivity S and Sensitivity T

		24-Yr Levelized Costs			
	Portfolio	Revenue Requirement	SCGHG Costs	Total	Change from Mid
1	Mid Scenario	$13.63	$5.04	$18.68	
S	SCGHG Included, No CETA	$10.06	$9.01	$19.08	$0.40
T	No CETA	$9.40	-	$9.40	($9.28)

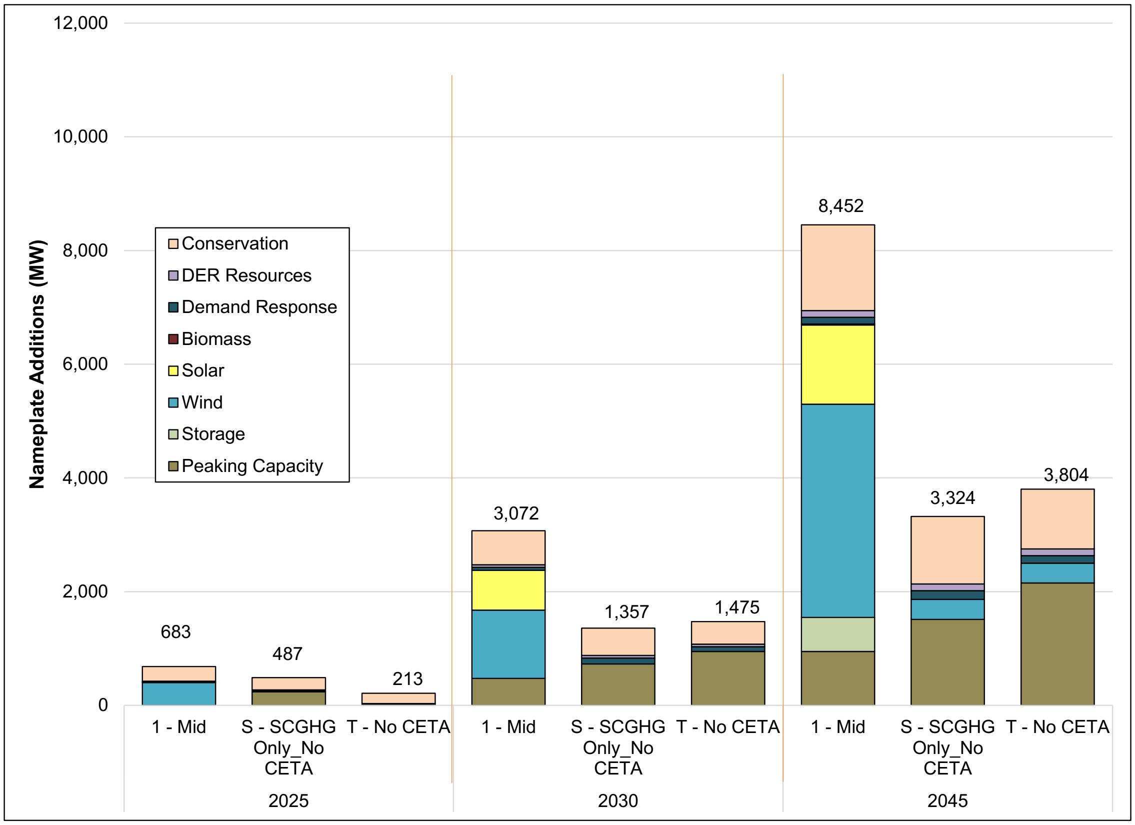
Figure 8-55: Annual Portfolio Costs – Mid Scenario, Sensitivity S and Sensitivity T



Resource Additions

Figure 8-56 compares the nameplate capacity additions of the Sensitivity S, T and Mid Scenario portfolios. Similar to Sensitivity S, there is no incentive to add renewable resources to the portfolio except for compliance to RCW 19.285. Without SCGHG as a fixed cost adder, even more peaking capacity resources are added for a total 2,151 MW of nameplate capacity by 2045.

Figure 8-56: Portfolio Additions – Mid Scenario, Sensitivity S and Sensitivity T



V. Balanced Portfolio, and

W. Balanced Portfolio with Alternative Fuel

These sensitivities are performed in order to compare the Mid Scenario with a portfolio that gives increased consideration to distributed energy resources. The portfolio was developed from analysis of sensitivity results and lessons were applied in developing the inputs for this sensitivity. The electric capacity expansion model is set to optimize the total portfolio cost and as we notice, delaying new builds till the end does lower cost. This is because all the resources have a declining cost curve over time, so it is more beneficial to wait till the last minute in order to optimize the resource costs. This is not always possible to wait till end to add a lot of resources. When looking at sensitivity C, transmission build constraints, the model waits till the end to add a significant amount of distributed resources. This portfolio takes those distributed resources and ramps them over time starting in 2025 instead of waiting till the last 5-10 years of the portfolio along with adding more customer programs to meet CETA requirements.

Baseline: New resources are acquired when cost effective and needed, conservation and DR measures are acquired when cost-effective.

Sensitivity V: Increased distributed energy resources and customer programs are ramped in over time as follows:

- Distributed ground-mounted solar: 50 MW in 2025
- Distributed rooftop solar: 30 MW/year from the year 2025 to 2045 for a total of 630 MW
- Demand response programs under $300/kw-yr
- Battery energy storage: 25 MW/year 2025-2031 for a total of 175 MW by 2031
- Increased customer-owned rooftop solar
- Green Direct: additional 300 MW by 2030

Sensitivity W: Same as Sensitivity V above, with the addition of biodiesel as fuel source for new frame peaker resources.

Key Findings

Sensitivity V: Ramping in forced resource additions versus economic resource model selection resulted in higher portfolio costs in Sensitivity V compared to the Mid Scenario. Distributed solar resources are higher cost than Washington wind and Washington solar east resources, which were found to be the optimal renewable resources following Montana and Wyoming wind resources in the Mid Scenario. In Sensitivity V, the 24-year levelized revenue requirement is $14.37 billion dollars, an increase of $0.74 billion dollars or 5 percent over the Mid Scenario.

Sensitivity W: Extending the assumptions from Sensitivity V to include biodiesel as fuel source for new frame peakers resulted in an increase of $0.8 billion dollars in the 24-year levelized revenue requirement for Sensitivity W compared to the Mid Scenario. The 24-year levelized revenue requirement is $14.43 billion dollars, an increase of $0.06 billion dollars from Sensitivity V. Even with the premium on biodiesel fuel prices compared to natural gas price, the model selected the same amount of frame peaker resources in Sensitivity W compared to the Mid Scenario.

Assumptions

Sensitivity V assumes greater investment in distributed energy resources, load reducing resources (i.e. Green Direct) and conservation measures to create a portfolio with greater balance between large, central power plants and small, distributed resources. Investments in these resources are modeled as forced acquisitions. These forced acquisitions include:

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

PSE has ramped in resource additions in this sensitivity to spread out the acquisition of new resources. Often resource selections made by the optimization model will be grouped together late in the modeling horizon to take advantage of lower costs projected by the cost curves (also known as learning curves). All generic resource options are still available for economic selection by the optimization model.

Building off the assumptions made in Sensitivity V, Sensitivity W also explores the use of alternative fuel for some peaking capacity resources. The sensitivity assumes new frame peakers are fueled with biodiesel instead of natural gas. Existing thermal resources, new CCCT+DF and new recip peakers will continue to be fueled with natural gas throughout the modeling horizon. The market price for biodiesel was estimated from PSE experience and informed by the U.S. Department of Energy Clean Cities Alternative Fuel Price Report, October 2020. PSE has assumed a fixed biodiesel price of $30.53 per million British Thermal Units (MM BTU) over the entire study period.

Portfolio Costs

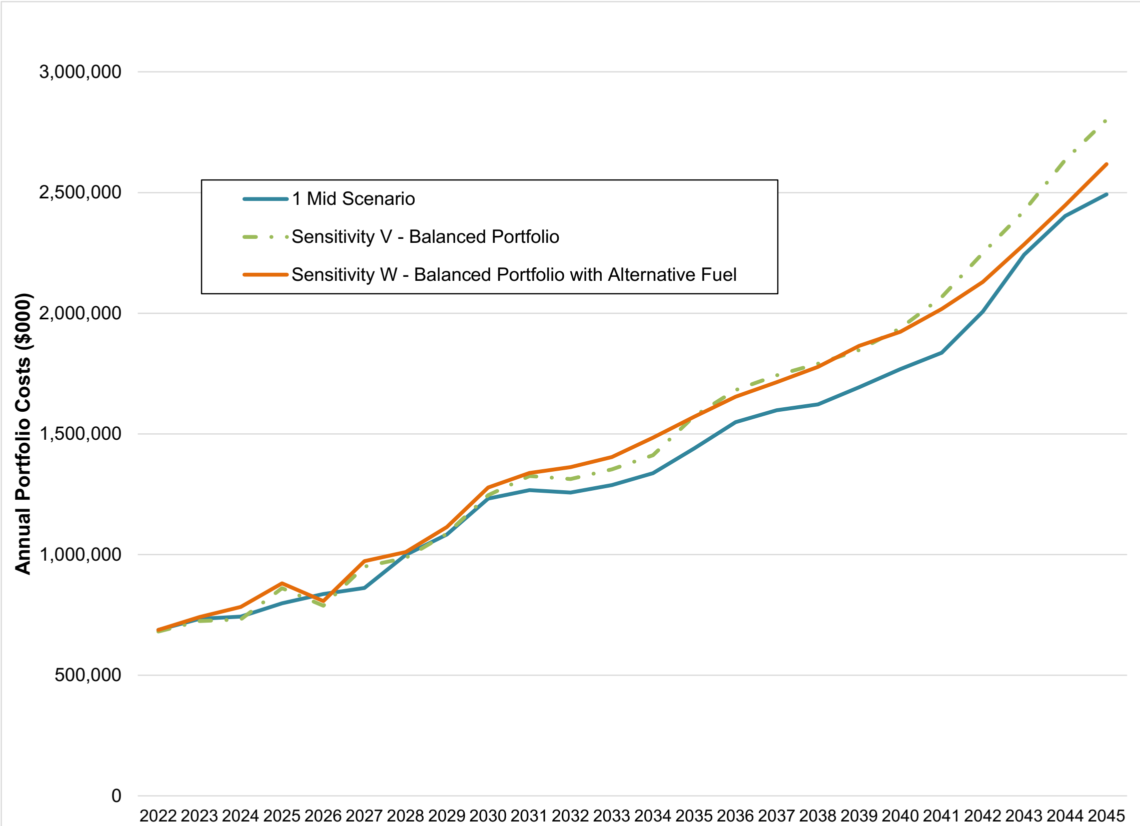
Early investments in high cost resources such as distributed solar and storage result in higher portfolio costs for Sensitivities V and W, as compared to the Mid Scenario. The increased portfolio costs for Sensitivities V and W are driven by the increased revenue requirements of the portfolios as shown in Figure 8-57. SCGHG costs are on par with the Mid Scenario, with Sensitivity V having slightly higher SCGHG costs because of more market purchases and Sensitivity W having slightly lower SCGHG costs because new peaking resources are using an alternative fuel.

Figure 8-57: Portfolio Cost Comparison – Mid Scenario and Sensitivities V and W

		24-Yr Levelized Costs			
	Portfolio	Revenue Requirement	SCGHG Costs	Total	Change from Mid
1	Mid Scenario	$13.63	$5.04	$18.68	
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 for the Mid Scenario and Sensitivities V and W are provided in Figure 8-58. Sensitivities V and W ramped in resources throughout the early years of the modeling horizon in an effort to smooth revenue requirement costs. However, these ramped acquisitions had very little impact on the year-to-year portfolio cost.

Figure 8-58: Annual Portfolio Costs – Mid Scenario and Sensitivities V and W



Resource Additions

Resource additions over time for the Mid Scenario and Sensitivities V and W are provided in Figure 8-59. Portfolio builds between the two sensitivities and the Mid Scenario are relatively similar, with a few subtle differences. The capacity of wind resources and peak capacity remains the same between the Mid Scenario and Sensitivities V and W. Wind is a low cost, CETA eligible resource so it is expected that all three portfolios selected the same quantity of wind capacity. Peaking capacity resources are among the lowest cost methods to meet peak demand hours. Therefore it is expected that most portfolios will include some peaking capacity. The same quantity of peaking capacity was selected between Sensitivities V and W. In Sensitivity W, new peaking capacity resources are fueled with biodiesel instead of natural gas. Biodiesel, a renewable resource, and does not have SCGHG cost for that resource. However, biodiesel is also much more expensive than natural gas. It appears, at the current cost projections for biodiesel, the price and the SCGHG of the fuel are offsetting, resulting in similar peaking resource decisions in Sensitivities V and W.

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

More storage is built in both Sensitivities V and W as compared to the Mid Scenario. Both sensitivities ramp in 2hr Lithium Ion battery storage from 2025 to 2031. This storage is useful, particularly paired with the increased DER solar builds in both sensitivities. However, the storage in the Mid Scenario is composed of 4hr Lithium Ion and 6hr Flow battery storage, which is built after year 2040. Sensitivities V and W show similar late year additions of longer duration storage, despite the abundance of 2hr storage added early in the modeling horizon. This shows that longer duration storage is an important component of these portfolios.

Figure 8-59: Portfolio Additions – Mid Scenario and Sensitivities V and W

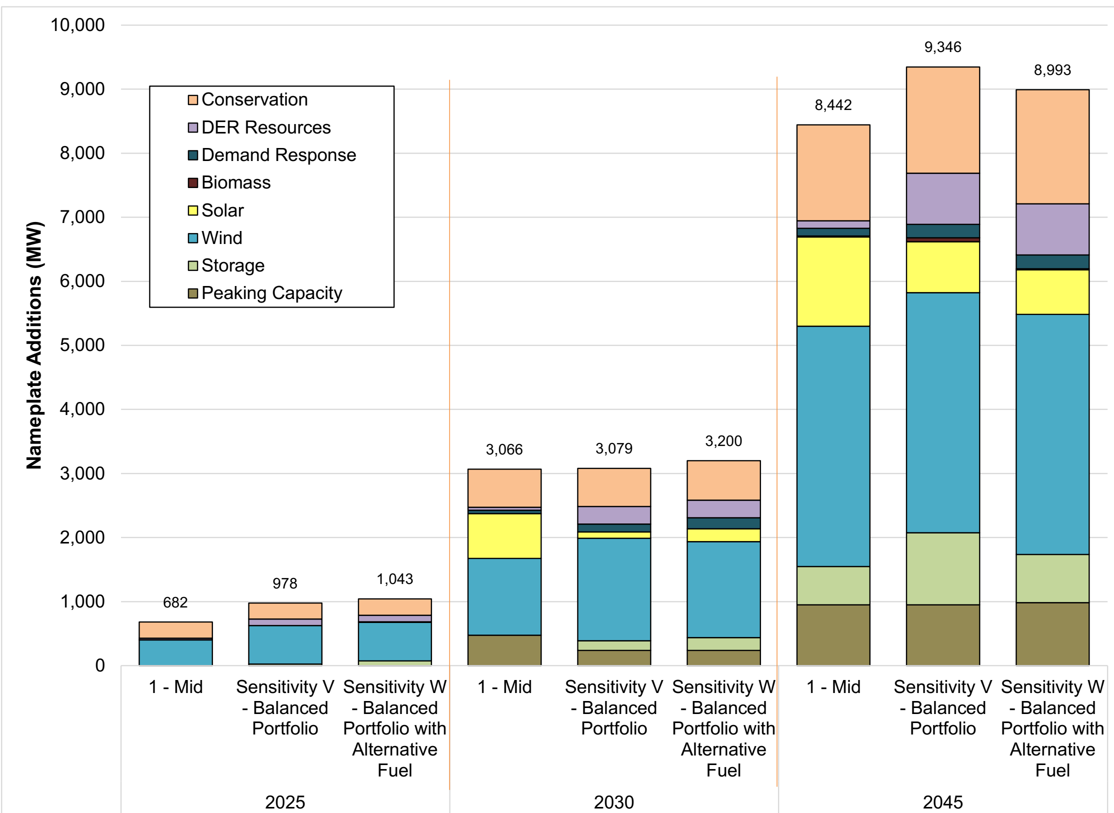


Figure 8-60 provides the final resource builds for Sensitivities V and W as they compare to the Mid Scenario in the year 2045.

Figure 8-60: Portfolio Additions by 2045 – Sensitivities V and W

Resource Additions by 2045	Mid	Sensitivity V - Balanced Portfolio	Sensitivity W - Balanced Portfolio with Alternative Fuel
Conservation	1497 MW	1658 MW	1784 MW
DER Resources	118 MW	798 MW	798 MW
Demand Response	121 MW	211 MW	215 MW
Renewable Resources	5158 MW	4606 MW	4462 MW
Biomass	15 MW	60 MW	15 MW
Solar	1393 MW	796 MW	697 MW
Wind	3750 MW	3750 MW	3750 MW
Energy Storage	600 MW	1125 MW	750 MW
Peaking Capacity	948 MW	948 MW	984 MW

8. SUMMARY OF STOCHASTIC PORTFOLIO ANALYSIS

To be provided in the final IRP.