ELECTRIC ANALYSIS

Contents

The electric analysis in the 2015 IRP explores long-range planning issues related to supply-side resources, conservation, carbon reduction, emerging resources and wholesale market risk. In this IRP, we update our planning standard. We also include wholesale market risk in the analysis for the first time. Wholesale market purchases have been a significant component of PSE's least cost portfolios for the past decade, but now that the region is forecasted to shift from capacity surplus to deficit in the coming decade unless new resources are added,[1] that strategy needs to be reevaluated. Continuing the current level of reliance on wholesale market purchases could expose PSE and its customers to unreasonable levels of physical and financial risk.

1 / Refer to Appendix F for the regional resource adequacy studies produced by NPCC, BPC and PNUCC.

ANALYSIS OVERVIEW

The electric analysis in the 2015 IRP followed the seven-step process outlined below. Steps 1, 3, 4 and 5 are described in detail in this chapter. Other steps are treated in more detail elsewhere in the IRP.

1. Analyze Resource Need

- PSE updated its electric planning standard based on the benefits and costs of reliability from our customers' perspective.
- The peak capacity value of wholesale market purchases was reassessed to incorporate wholesale market reliability risk.

2. Determine Planning Assumptions and Identify Resource Alternatives

- Chapter 4 discusses the scenarios and sensitivities developed for this analysis.
- Chapter 5 presents the 2015 IRP demand forecasts.
- Appendix D describes existing electric resources and alternatives in detail.

3. Deterministic Analysis of Scenarios and Sensitivities

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.
- In some scenarios, CCCT plants were more cost effective than CT's with a combination of firm pipeline capacity and oil backup, but in other scenarios, the CT's were lower cost. Therefore, we developed six candidate resource portfolios based on different strategies, to examine in the stochastic risk analysis.

4. Stochastic Risk Analysis of Candidate Resource Strategies

Stochastic risk analysis deliberately varies the static inputs to the deterministic analysis, to test how the different candidate strategies perform with regard to cost and risk across a wide range of potential future power prices, gas prices, hydro generation, wind generation, loads, plant forced outages and CO_2 prices.

- PSE analyzed six candidate resource strategies against 250 combinations of variables in the stochastic risk analysis.

5. Analyze Results

Results of the quantitative analysis – both deterministic and stochastic – are studied to understand the key findings that lead to decisions about the resource plan.

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

6. Make Decisions

Chapter 2 describes the reasoning behind the strategy chosen for this resource plan forecast.

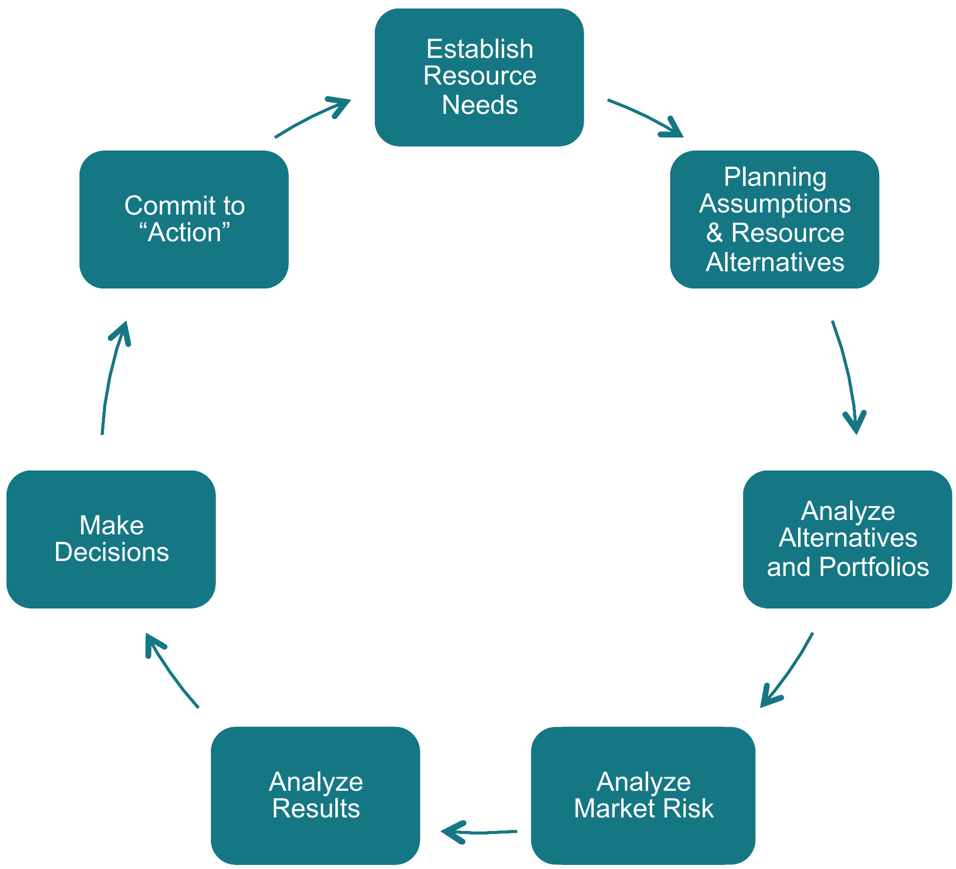
7. Commit to Action

Resource decisions are not made in the IRP. What we learn from this forecasting exercise determines the Action Plan; this is "the plan" that PSE will execute against.

- The Action Plan is presented in the Executive Summary, Chapter 1.

Figure 6-1 illustrates this process.

Figure 6-1: 2015 IRP Process



RESOURCE NEED

PSE expanded its analysis of resource need in two areas for this IRP. First, we examined updating PSE's planning standard to better reflect the value of reliability to customers; and second, we reassessed the peak capacity value of PSE's wholesale market purchases in order to reflect the reliability risk created by the changing load/resource balance in the Pacific Northwest. These adjustments are discussed first, since both impact the determination of peak capacity need.

Updating the Planning Standard

Basing the Planning Standard on Benefit/Cost Analysis
This IRP adopts an optimal planning standard that reflects a benefit/cost analysis designed to minimize the net cost of reliability to customers. The analysis also incorporates wholesale market risk in its peak capacity assessment of wholesale market purchases, consistent with regional resource adequacy assessments. The updated standard and incorporation of market risk reduces the expected value of lost load to customers by $130 million per year. The cost to achieve that expected savings is $63 million per year, for a net benefit to customers of $67 million per year. Risk reduction is dramatic. The $63 million per year cost reduces the risk to customers by $1.3 billion per year.

Incorporating Wholesale Market Purchase Risk
Since regional resource adequacy studies forecast a shift from surplus to deficit in the region's load/resource balance, this a particularly appropriate time for PSE to incorporate wholesale market risk into its IRP analysis. Prior IRPs also assumed wholesale market purchases were 100 percent reliable, but this is no longer a reasonable assumption now that the capacity surplus in the region is shrinking. Therefore, PSE incorporates wholesale market risk into its updated capacity planning standard.

Summary of Planning Standard Changes. Figure 6-2, Summary of Planning Standard Changes, provides information that will be used in the discussion below. Additional detail is included in Appendix G, Wholesale Market Risk, and Appendix N.

Figure 6-2: Summary of Planning Standard Changes

		Reliability Metric		2021 Peaker Capacity Added after DSR (MW)	Customer Value of Lost Load	
		LOLP	EUE (MWh)		Expected ($mill/yr)	TVar90 ($mill/yr)
1	2013 Planning Standard with No Market Risk	5%	26	(150)	86*	858*
2	2013 Planning Standard with Market Risk	5%	50	(117)	169	1,691
3	2015 Optimal Planning Standard (Includes Market Risk)	1%	10.9	234	39	385

** Inaccurate estimate because it ignores reliability impact of wholesale market risk.*

2015 Optimal Planning Standard versus 2013 Planning Standard.

To understand the impact of the change to PSE's capacity planning standard in this IRP, it is helpful to understand what the reliability metrics in the table in Figure 6-2 represent. Loss of load probability (LOLP) is a measure of the likelihood of a load curtailment occurring; expected unserved energy (EUE) is a measure of the magnitude of potential load curtailments, in other words, how much load and how many customers are likely to be impacted.

The 2013 Planning Standard called for maintaining enough peak capacity to achieve a 5 percent loss of load probability (LOLP). This is a reasonable, industry-standard approach, adopted by the Northwest Power and Conservation Council (NPCC) for its regional resource adequacy assessment and adopted by PSE in 2009, but it is not tied to the value of reliability to customers. That is, the 5 percent LOLP does not explicitly consider the value of reliability to customers or the cost to provide that reliability. This IRP focuses on those tradeoffs, so that we can be sure we are providing the optimal balance of cost and risk to our customers. In addition, the 2013 Planning Standard did not incorporate PSE's wholesale market purchase risk.

2015 Optimal Planning Standard

- Determined by benefit/cost analysis focused on the value of reliability to customers
- Includes wholesale market purchase risk

2013 Planning Standard

- Focused on a 5 percent LOLP target
- Does not incorporate wholesale market purchase risk.

In line one of Figure 6-2, the 2013 Planning Standard – which is focused on a 5 percent LOLP and ignores market risk – indicates that PSE would be surplus 150 MW in 2021. In line two, when the 2013 standard includes market risk, the surplus diminishes to 117 MW. From this perspective, recognizing market risk would require PSE to add 33 MW to maintain the 5 percent LOLP. However, the real impact of ignoring risk can be seen in the EUE and customer value of lost load sections on these two lines. Recognizing market risk nearly doubles EUE, the customer value of lost load and risk. EUE increases from 26 MWh to 50 MWh; the expected customer value of lost load increases from $86 million to $169 million; and risk increases from $858 million to $1,691 million.

These results highlight the need for a new planning standard. Focusing only on LOLP misses the fact that customer curtailment volumes would be almost twice as high. In addition, achieving a specified LOLP target (by adding new generating capacity) does not ensure that the additional cost of increasing system reliability is balanced against the additional value gained by customers. Clearly, a more comprehensive approach to defining the planning standard is needed.

In developing the 2015 Optimal Planning Standard, we focused on the benefits and costs to customers of improving reliability. Translating MWh of lost load into a dollar metric based on its value to customers facilitated performing a benefit/cost analysis to define the optimal planning standard. The word "optimal" is used here in an economic context. The analysis compared the cost to customers of potential outages with the cost of adding generating resources to increase service reliability to find the "optimal" level of reliability – the point at which the benefit to customers of increased reliability (marginal benefit) is equal to the cost of providing that level of reliability (marginal cost).

Again, Figure 6-2 shows that moving to the 2015 Optimal Planning Standard reduces the expected value of lost load to customers by $130 million per year.[2] The cost to achieve that expected savings is $63 million per year,[3] for a net benefit to customers of $67 million per year. Risk reduction (as measured by the TailVar90 metric) to customers is dramatic. That $63 million per year in new resource costs reduces the risk to customers by $1.3 billion per year.[4]

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2 / From Figure 2-1. This is calculated by comparing the Expected VOLL in line 2 (2013 Planning Standard Including Market Risk) with the Expected VOLL in line 3 (2015 Optimal Planning Standard): $169 million - $39 million = $130.
*3 / This value is derived by first calculating the difference between the surplus of 117 MW in line 2 (2013 Planning Standard Including Market Risk) and the need (deficit) of 234 MW in line 3 (2015 Optimal Planning Standard). This value is then multiplied by the levelized cost of a peaker, estimated from the portfolio model at $0.18 million per MW per year. So: 234 MW – (-117 MW) = 351 MW. Then: 351 MW * $0.18 million per MW per year = $63 million per year.*
4 / $1,691 million - $385 million = $1,306 million

Incorporating Wholesale Market Reliability Risk

In this IRP, PSE incorporates wholesale market risk for the first time. This change is directly related to the pending retirement of two regional coal plants and the shifting load/resource balance in the Pacific Northwest.

Time for a Change. PSE has essentially ignored market risk in prior IRP analyses, because we have been able to rely on wholesale market purchases as a least-cost way of meeting physical need with a high degree of confidence that wholesale power would be available for purchase in the future whenever it was needed. Although studies demonstrated that technically regional capacity wouldn't be sufficient in all circumstances, PSE assumed wholesale markets were 100 percent reliable due to ongoing regional capacity surpluses. We understood that such an optimistic assumption was not sustainable indefinitely, but as long as the region was meeting regional resource adequacy metrics, this strategy made sense for our customers. Refining that assumption becomes a high priority now that studies indicate the region will fail to meet acceptable resource adequacy metrics by 2021.[5]

This is important, because short-term wholesale market purchases are the single largest category in PSE's current resource portfolio. They account for up to 1,666 MW, or approximately 28 percent, of the resources we use to meet our peak capacity need. And, since PSE is one of the largest purchasers of winter capacity in the region, our customers would be especially exposed during regional curtailment events, because large portions of the capacity that PSE has counted on to purchase may simply not be available as surpluses shrink.

5 / The regional studies on load/resource balance conducted by NPCC, PNUCC and BPA (or links to them) appear in Appendix F. Appendix G explains how these studies were used in PSE's wholesale market risk analysis.

Assumptions Regarding Regional Resource Configurations.

Incorporating wholesale market risk into the 2015 IRP analysis required us to make certain assumptions regarding regional resource configurations. We began with the assumptions incorporated into the May 2015 NPCC regional resource adequacy study, and made three key adjustments.

Southwest imports were increased by 475 MW.

The NPCC's base analysis assumes 3,400 MW of transmission capacity is available from California, but only 2,925 MW of winter season on-peak resources were included in the NPCC's analysis (2,500 MW of spot market purchases plus 425 MW of long-term contracts). We added the spot market import amounts necessary such that total imports from California equal 3,400 MW on all hours. It seemed reasonable to assume that this additional capacity would be available during the region's peak need season.

Regional generation was increased by 440 MW.

Portland General Electric (PGE) has plans to acquire 440 MW of firm generation by 2021, when their Boardman coal plant retires. Information from PGE demonstrates a strong preference for that generation to be a non-intermittent renewable resource. PGE is, however, prepared to build Carty 2, which would be a 440 MW gas CCCT plant if adequate renewable resources are not available. This plant did not meet the criteria to include in the NPCC's regional adequacy analysis, but it seems reasonable to assume that it will be built, and we did not want to overstate our resource needs.

Regional generation was reduced by 650 MW.

This adjustment assumes the 650 MW Grays Harbor CCCT is not available to operate during PNW load curtailment events. This gas-fired generating plant appears to rely solely on wholesale market purchases of interruptible fuel supply. It has neither firm pipeline capacity for natural gas fuel supply nor oil backup, which means that under extreme cold weather conditions – when the region is most likely to have a capacity deficit – the plant may not be able to operate until weather conditions improve and wholesale market gas supplies are available again. The NPCC assumed firm fuel supply in its regional adequacy analysis because of the difficulty of determining when the plant might be unable to obtain supplies, but it would be inconsistent for PSE to include it in our regional resource configuration since we would not be able to consider it firm for our customers if it were in our portfolio.

Benefit/Cost Analysis. The benefit cost analysis establishes the optimal capacity addition to meet the optimal customer reliability level.

Figure 6-3 compares the results of the benefit/cost analysis for four different capacity addition amounts ranging in size from 0 MW to 300 MW. This table also illustrates that the optimal 2021 planning margin is achieved with a capacity addition of 234 MW (i.e., the point at which the benefit/cost ratio is 1.0).

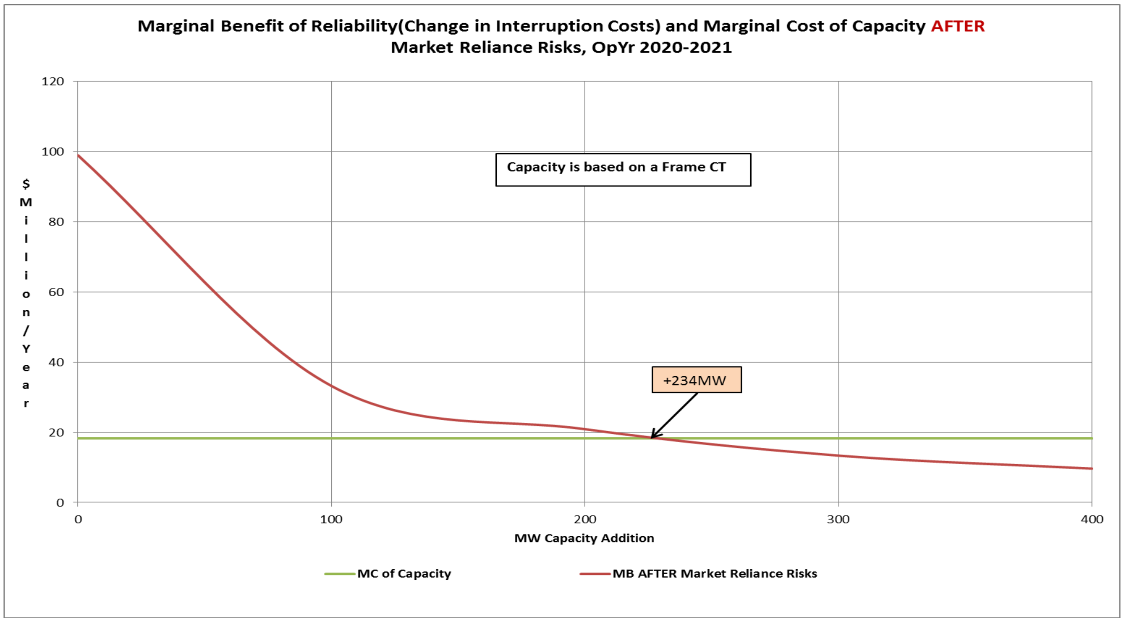
Figure 6-3: Benefit/Cost Comparison, 2015 Optimal Planning Standard Highlighted

Added CT Capacity (MW)	Cost of Reliability ($mill/yr)		Expected Benefit of Improving Reliability ($mill/yr)		B/C Test	Risk Benefit ($mill/yr)	
	Added Resource Cost	Incremental Cost	Expected VOLL	VOLL Reduction Incremental Benefit	Benefit/ cost Ratio	Reliability Risk TVar90 of VOLL	Reduction in VOLL risk
0	0		98			989	
100	18	18	64	33	1.8	641	348
234*	43	25	39	25	1.0	385	257
300	55	12	30	9	0.7	299	86

** 2015 Optimal Planning Standard*

Figure 6-4 illustrates where the marginal benefit and marginal cost of reliability to customers intersects using the 2015 Optimal Planning Standard. This chart shows that as generation increases, the incremental benefit created by that addition falls. This is because fewer and fewer outages are avoided by the increased generation. The incremental cost is constant (shown here as the incremental cost of adding 100 MW blocks of generation). The chart shows that if we stopped adding generation before 234 MW, we would be leaving value on the table for customers, because the benefits exceed costs up to that point. On the other hand, adding generation beyond 234 MW would cost customers more than it saves, reducing the net benefit to customers to below the $67 million per year.

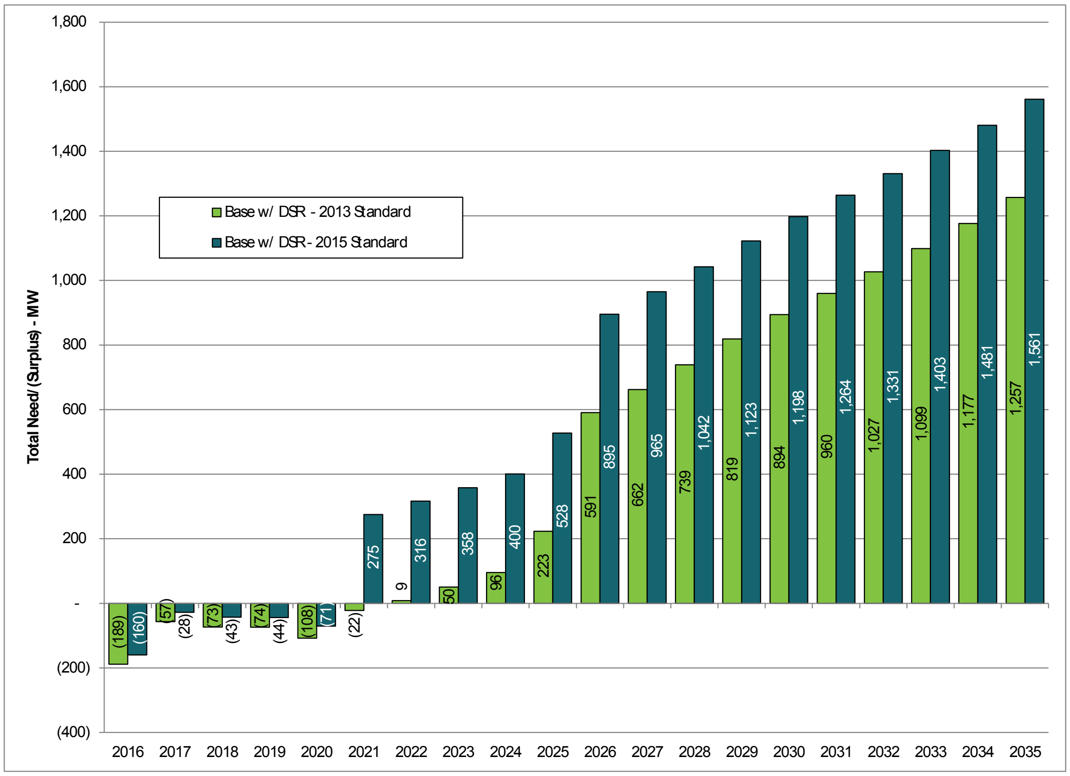
Figure 6-4: Marginal Benefit of Reliability, 2015 Optimal Planning Standard



Using this cost/benefit approach will enable us to continue to identify the optimal planning margin even as conditions in the region and PSE's service territory change over time.

Figure 6-5 compares the winter peak resource need under the 2013 Planning Standard to the winter peak need under the 2015 Optimal Planning Standard.

Figure 6-5: December Peak Capacity Need after Demand-side Resources, 2015 and 2013 Planning Standards



The benefit/cost analysis in Figures 6-3 and 6-4 show a capacity addition of 234 MW, while the peak capacity need chart in Figure 6-5 shows a 275 MW resource need in 2021 after DSM. There are three reasons these numbers are slightly different:

1. **Estimated Conservation vs Forecast Conservation**. The RAM analysis used to calculate the 234 MW capacity addition included conservation assumptions from the 2013 IRP, since 2015 IRP conservation savings cannot be determined until after the updated resource need has been established.
2. **Operating Reserves.** PSE's operating reserve obligations vary as a function of the estimated and forecasted 2021 conservation-related peak load reductions.
3. **Mid-C Wholesale Purchases.** The amounts of wholesale purchases that PSE can import from the Mid-C using its firm transmission rights is a function of the operating reserves being maintained at PSE's Mid-C hydro plants.

Incremental Capacity Equivalents (ICE). The incremental capacity credits assigned to PSE's existing and prospective resources were developed by applying the incremental capacity equivalent (ICE) approach[6] in the RAM. In essence, the ICE approach identifies the equivalent capacity of a gas-fired peaking plant that would yield the same customer optimal EUE level as the capacity of a different resource such as a wind farm, energy storage facility, Colstrip or wholesale market purchases using PSE's available firm Mid-C transmission import rights. The ratio of the equivalent gas peaker capacity to the alternative resource capacity is the incremental capacity equivalent (ICE); this value represents the capacity credit assigned to the alternative resource. For the 2015 IRP, ICE was calculated for existing and new wind projects, the Colstrip plant, and for wholesale market purchases.[7]

Assessing the Capacity Contribution of Wholesale Market Purchases. To include wholesale market reliability risk in the analysis, we applied ICE analysis to wholesale market purchases – the same approach we use to assess the peak capacity value of other variable energy resources like wind, solar and batteries. ICE analysis is an important part of PSE's Resource Adequacy Model (RAM) because it allows us to assess the capacity value of resources with very different characteristics. ICE is defined and calculated as the change in capacity of a generic natural gas peaking plant that results from adding to the system a different type of resource with any given set of energy production characteristics, while keeping the resource adequacy metric constant.

Before performing the ICE analysis, we had to do two things: 1) determine what planning standards would be used in the ICE analysis (as discussed earlier), and 2) identify the impact that the regional resource adequacy forecasts would have on PSE's system and customers.

TRANSLATING REGIONAL FORECASTS TO PSE IMPACTS

Determining the impact of regional deficit forecasts on PSE was accomplished as part of a study performed by Lloyd Reed of Reed Consulting for PSE. That study is reported in detail in Appendix G, Wholesale Market Risk. Most relevant to this discussion is that the study:

a. identified forecasted regional shortages, beginning with data from the NPCC and BPA's regional adequacy analyses,[8]
b. allocated those market shortages to PSE's portfolio, and
c. modeled this allocation against 7 potential resource configuration cases for the region.

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6 / The ICE approach is similar to the equivalent load carrying capability (ELCC) approach.
7 / Additional details regarding the ICE computations are contained in Appendix N.
8 / Refer to Appendix F, Regional Resource Adequacy Studies.

For the input to the ICE analyses, PSE chose the regional resource configuration it judged most likely to be in place at 2021. This configuration (Wholesale Market Reliance Scenario 7) made adjustments to the base assumptions about regional imports, resource additions and resource refinements used in the NPCC's May 2015 Resource Adequacy Advisory Committee analysis, as was discussed in the previous section.

ANALYSIS RESULTS

Once the 2015 Optimal Planning Standard and associated reliability metrics were established and we determined which regional resource configuration to model, we could perform the ICE analysis to assess the peak capacity value of wholesale market purchases.

Figure 6-6 summarizes the ICE analysis results for all capacity resources using both the 2013 Planning Standard and the 2015 Optimal Planning Standard.

Figure 6-6: Incremental Capacity Equivalent (ICE) Values/Capacity Credits for Winter 2020-2021

Incremental Capacity Equivalent for Winter 2020-2021		
Resource Type	2013 Standard	2015 Standard
Baseline: Natural Gas Peaker	**100%**	**100%**
1) Existing Wind (Cumulative = 822MW)	12%	9%
2) New Wind (SE Washington = 100MW)*	8%	8%
3) Batteries (4 hour discharge + min 4 hour recharge)	100%	100%
4) Colstrip	92%	90%
5) Available Mid-C Transmission (Wholesale Market Purchases)	100%	84%

**A southeast Washington wind location was chosen as the generic wind for this IRP. Good historical wind data exists for the area, PSE already owns development rights at the Lower Snake River site, and transmission to the grid already exists in this location. Comparison of improvements in the incremental capacity equivalents for other wind sites must account for the incremental transmission costs required to connect the site to the regional grid. (PSE examined the incremental capacity if a central Washington wind project in the 2011 IRP.)*

Components of Physical (Peak) Need

Physical need refers to the resources required to ensure reliable operation of the system. It is an operational requirement that includes three components: customer demand, planning margins and operating reserves. The word "load" – as in "PSE must meet load obligations" – specifically refers to customer demand plus planning margins plus operating reserve obligations. The planning margin and operating reserves are amounts over and above customer demand that ensure the system has enough flexibility to handle balancing needs and unexpected events such as variations in temperature, hydro and wind generation; equipment failure; or transmission interruption with minimal interruption of service.

When we compare physical need with the peak capacity value of existing resources, the resulting gap identifies resource need. Each of these four components – customer demand, planning margins, operating reserves and existing resources – is reviewed below.

Customer Demand. PSE develops a range of demand forecasts for the 20-year IRP planning horizon using national, regional and local economic and population data.[9] Chapter 5 presents the 2015 IRP Base, Low and High Demand Forecasts, and Appendix E delivers a detailed discussion of the econometric models used to develop them.

PSE is a winter-peaking utility, so we experience the highest end-use demand for electricity when the weather is coldest. Projecting peak energy demand begins with a forecast of how much power will be used at a temperature of 23 degrees Fahrenheit at SeaTac. This is considered a normal winter peak for PSE's service territory. We also experience sustained strong demand during the summer air-conditioning season, although these highs do not reach winter peaks.

Planning Margin.[10] Planning margins represent the amount of resources needed to achieve a specific planning standard reliability target. As discussed earlier in this chapter, this analysis tested two planning standards. We performed significant amounts of portfolio analysis using each of the planning standards, because we were simultaneously analyzing resource needs and portfolio analysis. The planning standard made no difference in the mix of resources, only in the quantity of resources and the timing of their addition.

9 / The demand forecasts developed for the IRP are a snapshot in time, since the full IRP analysis takes more than a year to complete and this input is required at the outset. Forecasts are updated continually during the business year, which is why those used in acquisitions planning or rate cases may differ from the IRP.

10 / A detailed, technical explanation of how planning margins were calculated can be found in Appendix N, Electric Analysis.

The 2015 Optimal Planning Standard (shown in Figure 6-3 above) resulted in a 2021 planning margin of 20.0 percent, in part because incorporating wholesale market risk in the capacity value of short-term market purchases via ICE analysis reduced their peak capacity value by 269 MW. Using the 20.0 percent planning margin would have implicitly increased this 269 MW adjustment at the same rate as load growth, which would overstate resource need going forward. In order to avoid this, we pulled out the 269 MW and treated it separately. We adjusted the single 20.0 percent value to 13.7 percent plus a fixed 269 MW capacity adjustment to reflect the wholesale market purchase risk component. This two-stage adjusted planning margin yields the same 1,059 MW capacity margin value for 2021, as shown in Figure 6-7. We expect this planning margin to change as we regional resource adequacy assumptions are updated in the future and as changes to PSE's existing portfolio are made.

Figure 6-7: Calculation of PSE's 2021 Planning Margin

	Option A	Option B
Planning Margin (% of Normal Peak Load)	20%	13.7%
Wholesale Market Purchase Risk Adjustment	0 MW	269 MW
Total Capacity above Normal Peaker	1,059 MW	1,059 MW

Operating Reserves. North American Electric Reliability Council (NERC) standards require that utilities maintain capacity "reserves" in excess of end-use demand as a contingency in order to ensure continuous, reliable operation of the regional electric grid. PSE's operating agreements with the Northwest Power Pool, therefore, require the company to maintain two kinds of operating reserves: contingency reserves and balancing reserves.

CONTINGENCY RESERVES

In the event of an unplanned outage, NWPP members can call on the contingency reserves of other members to cover the resource loss during the 60 minutes following the outage event.

The Federal Energy Regulatory Commission (FERC) approved a new rule that affects the amount of contingency reserves PSE must carry – Bal-002-WECC-1 – which took effect on October 1, 2014. The new rule requires PSE to carry reserve amounts equal to 3 percent of on-line generating resources (hydro, wind and thermal) plus 3 percent of load to meet contingency obligations. The terms "load" and "generation" in the new rule refer to the total net load and all generation in PSE's Balancing Authority (BA). This increases PSE's reserve requirement, because the rule now requires PSE to carry reserves for third-party loads and generation in addition to our own. The previous rule applied higher percentages (5 percent of hydro and wind and 7 percent of thermal resources) but to a smaller set of generating resources – only those owned and operated by PSE.

BALANCING RESERVES

Utilities must also have sufficient reserves available to maintain system reliability within the operating hour; this includes frequency support, managing load and variable resource forecast error, and actual load and generation deviations. Balancing reserves do not provide the same kind of short-term, forced-outage reliability benefit as contingency reserves, which are triggered only when certain criteria are met. Balancing reserves must be resources with the ability to ramp up and down instantaneously as loads and resources fluctuate each hour.[11]

For PSE, the amount of balancing reserves is 123 MW. This amount is based on a 95 percent confidence interval, or the amount of reserves that would capture 95 percent of the within-hour load and resource deviations. This confidence interval is derived from historical data during the months of December and January, to coincide with the period used for PSE's winter-peak planning. A full description of how this number was calculated can be found in Appendix H, Operational Flexibility.

Existing Resources. In examining the peak capacity value of existing resources PSE performed two sets of ICE analysis, one for each of the planning standards being examined. As mentioned earlier, ICE enables us to assess the capacity value of resources with very different characteristics. This value changes depending upon the planning standard applied, since ICE is defined and calculated as the change in capacity of a generic natural gas peaking plant that results from adding to the system a different type of resource with any given set of energy production characteristics, *while keeping the resource adequacy metric constant*. (Existing resources are described in detail in Appendix D.)

11 / *System flexibility needs are discussed in more detail in Appendix H, Operational Flexibility.*

SUMMARY OF EXISTING RESOURCES ASSESSMENT

Figure 6-8 summarizes the winter peak capacity values for PSE's existing supply-side resources.

Figure 6-8: Existing Supply-side Resources
Nameplate Capacity and Winter Peak Capacity for December 2016

Type of Generation	Nameplate Capacity (MW)	Winter Peak Capacity (MW) 2015 Standard
Hydro	996	897
Colstrip	677	592
Natural Gas	1,888[1]	2,008
Wind	823[2]	74
Contracts	805[3]	765
Available Mid-C Transmission	2,331	1,686
Total Supply-side Resources	**7,520**	**6,022**

NOTES
1 The nameplate capacity for the natural gas units is based on the net maximum capacity that a unit can sustain over a 60 minutes when not restricted to ambient conditions. Natural gas plants are more efficient in colder weather, so the winter peak capacity at 23 degrees F is higher than the nameplate capacity.
2 Includes Klondike III as a wind resource (50 MW)
3 Includes Centralia contract at 380 MW in December 2016

For the winter months of 2016, PSE is currently forecast to have a total of 1,881 MW of BPA transmission capacity and 450 MW of owned transmission capacity, for a total of 2,331 MW. A portion of the capacity, 645 MW, is allocated to long-term contracts and existing resources such as PSE's portion of the Mid-C hydro projects. This leaves 1,686 MW of capacity available for short-term market purchases. The specific allocation of that capacity as of December 2016 is listed below in Figure 6-9. The capacities and contract periods for the various BPA contracts are reported in Appendix D, and PSE's forecast Mid-C peak transmission capacities are included as part of the resource stack in Figure 6-10, Electric Peak Capacity Need.

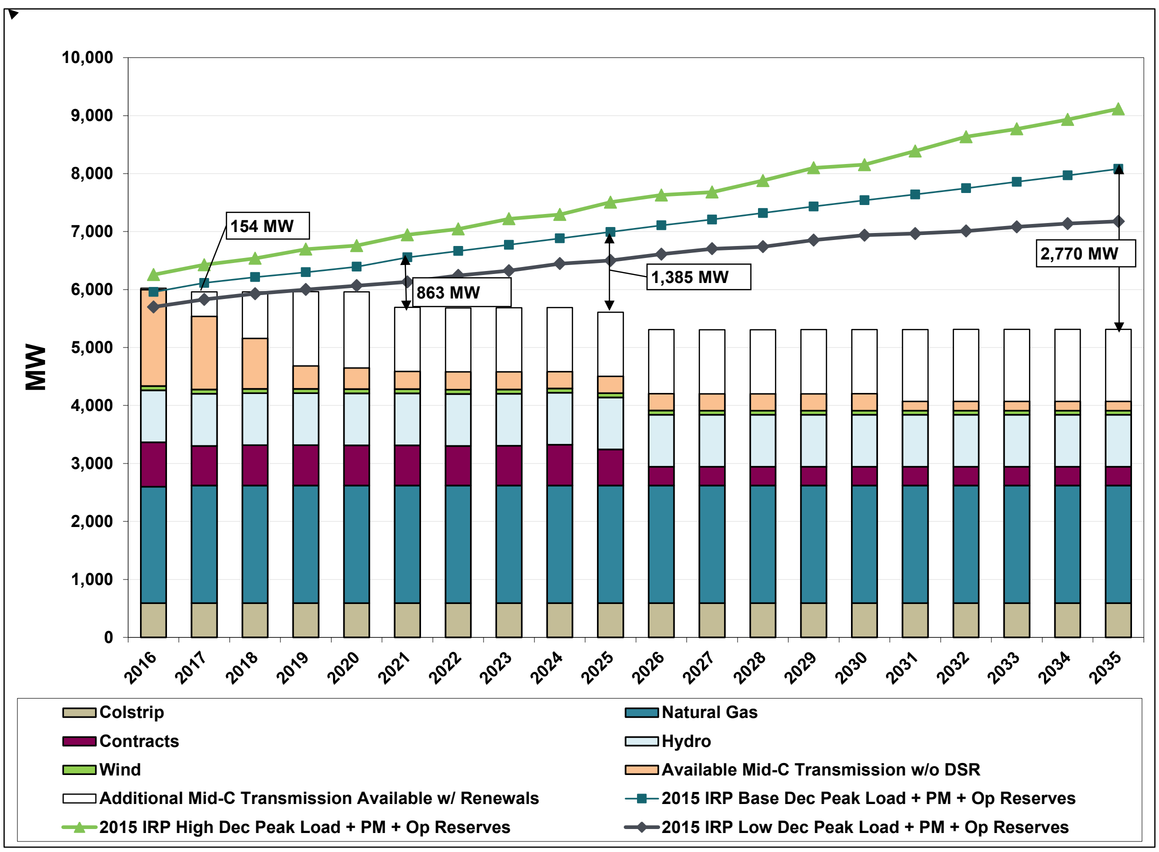
Figure 6-9: PSE Mid-C Transmission Capacity as of December 2016

	Winter Peak Capacity (MW)
Total Mid-C Transmission	2,331
Allocated to Long-term Resources & Contracts	(645)
Available for short-term wholesale market purchases	1,686

Peak Capacity Need

Figure 6-10 shows the physical reliability need for the three demand scenarios modeled in this IRP. This picture applies the optimal planning standard (2015), and it incorporates the ICE adjustment to wholesale market purchases discussed above. Before any additional demand-side resources, peak capacity need in the base case is almost 900 MW by 2021 and over 2,700 MW by the end of the planning period. This picture differs from Figure 6-5 above, because it includes no demand-side resources past the study period's start date. One of the major tasks of the IRP analysis is to identify the most cost-effective amount of conservation to include in the resource plan, and to accomplish this it is necessary to start with peak need forecasts that do not include forward projections of conservation savings.

*Figure 6-10: Electric Peak Capacity Need**
(Physical Reliability Need, Peak Hour Need Compared with Existing Resources)



** See note next page.*

NOTE: 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.

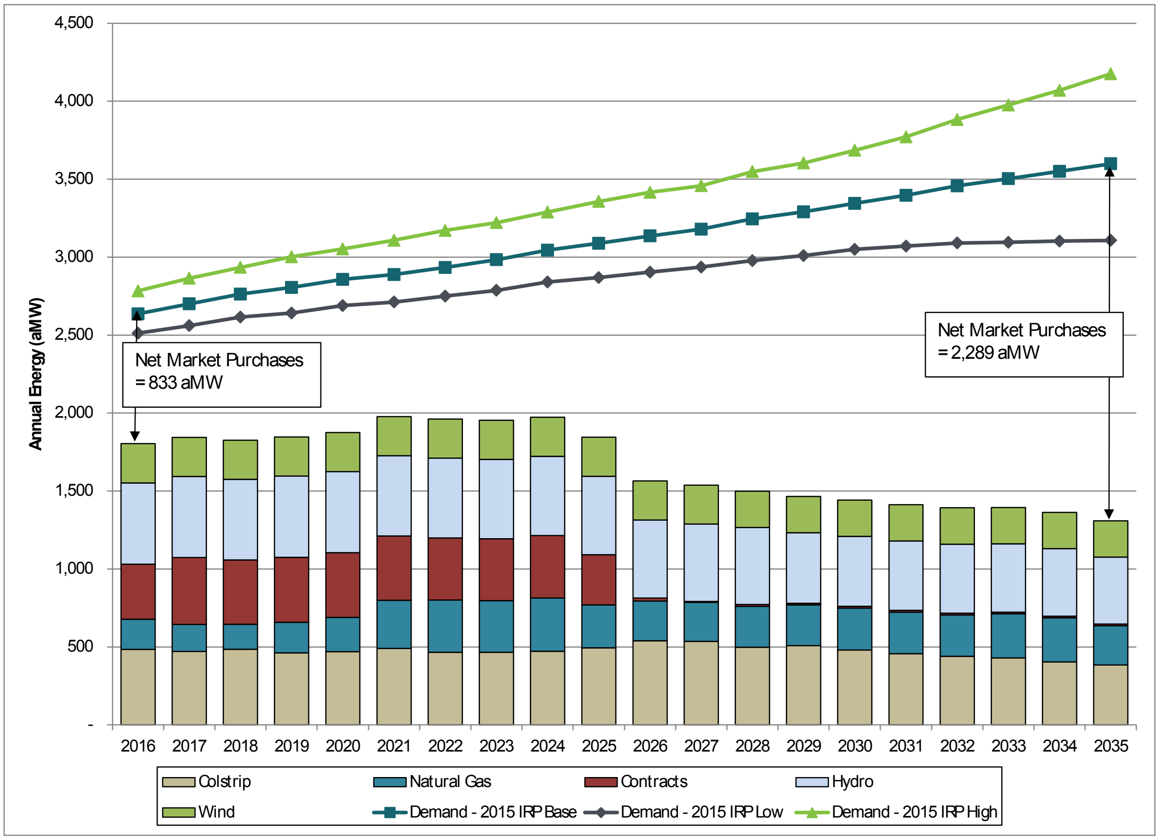
Energy Need

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 6-11 illustrates the company's energy position across the planning horizon, based on the energy load forecasts and economic dispatches of the 2015 IRP Base Scenario presented in Chapter 4, Key Analytical Assumptions.

Figure 6-11: Annual Energy Position
Resource Economic Dispatch from Base Scenario



Renewable Need

Washington State's renewable portfolio standard (RPS) requires PSE to meet specific percentages of our load with renewable resources or renewable energy credits (RECs) by specific dates. The main provisions of the statute (RCW 19.285) are summarized below.

Washington State RPS Targets
Renewable resources must comprise:
3 percent of supply-side resources by 2012
9 percent of supply-side resources by 2016
15 percent of supply-side resources by 2020

PSE has sufficient qualifying renewable resources to meet RPS requirements through 2022, including the ability to bank RECs. For all practical purposes, wind remains the main resource available to fulfill RPS requirements for PSE. Existing hydroelectric resources may not be counted towards RPS goals except under certain circumstances for new run of river and efficiency upgrades, and other renewable technologies are not yet capable of producing power on a large enough scale to make substantial contributions to meeting the targets.

EMERGING RESOURCES STUDIES

PSE continues to monitor emerging resources that may develop effective utility applications. This IRP tests portfolio sensitivities that incorporate renewable resources such as battery storage and distributed solar generation. The results of these sensitivity analyses are discussed later in this chapter and in more detail in Appendix L, Electric Energy Storage, and Appendix M, Distributed Solar.

RENEWABLE RESOURCES INFLUENCE SUPPLY-SIDE RESOURCE DECISIONS

Adding wind to the portfolio increases the need for stand-by backup generation that can be turned on and off or adjusted up or down quickly. The amount of electricity supplied to the system by wind drops off when the wind stops, but customer need does not, therefore, as the amount of wind in the portfolio increases, so does the need for reliable backup generation.

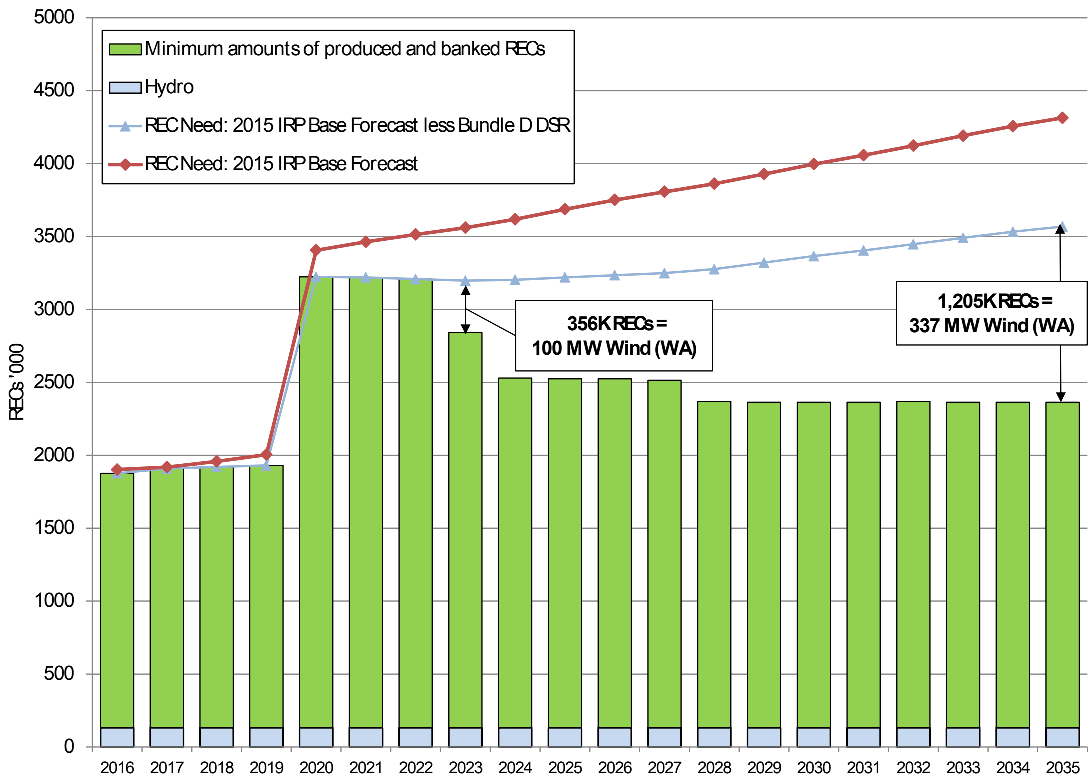
DEMAND-SIDE ACHIEVEMENTS AFFECT RENEWABLE AMOUNTS

Washington's renewable portfolio standard calculates the required amount of renewable resources as a percentage of megawatt hour (MWh) sales; therefore, if MWh sales decrease, so does the amount of renewables we need. Achieving demand-side resources (DSR) targets has precisely this effect: DSR decreases sales volumes, which then decreases the amount of renewable resources needed.

REC Banking Provision. Washington's renewable portfolio standard allows for REC banking. Unused RECs can be banked forward one year or can be borrowed from one year in the future. In this IRP, PSE assumes that the company would employ a REC banking strategy that would push the need for additional RECs further into the future.

Figure 6-12 illustrates the need for renewable energy – namely wind – after accounting for REC banking and the savings from demand-side resources that were found cost effective for the 2015 IRP.

Figure 6-12: REC Need Based on Achievement of All Cost-effective DSR



ASSUMPTIONS AND ALTERNATIVES

The scenarios, sensitivities and resource alternatives used in the electric analysis are summarized here for convenience.[12]

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 Base Scenario assumptions and change one variable. They allow us to isolate the effect of an individual variable on the portfolio, so that we can consider how different combinations of resources would affect costs, cost risks and emissions.

Figure 6-13: 2015 IRP Scenarios

	Scenario Name	Gas Price	CO_2 Price	Demand
1	Low Scenario	Low	None	Low
2	Base Scenario	Mid	Mid	Mid
3	High Scenario	High	High	High
4	Base + Low Gas Price	Low	Mid	Mid
5	Base + High Gas Price	High	Mid	Mid
6	Base + Very High Gas Price	Very High	Mid	Mid
7	Base + No CO_2	Mid	None	Mid
8	Base + High CO_2	Mid	High	Mid
9	Base + Low Demand	Mid	Mid	Low
10	Base + High Demand	Mid	Mid	High

12 / Chapter 4 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 (CO2) 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 6-14: 2015 IRP Portfolio Sensitivities

	Sensitivities	Alternatives Analyzed
	Electric Analysis	
A	Colstrip If Colstrip units are retired, what's the most cost-effective way to replace those resources?	*Baseline – All 4 Colstrip units remain in service* 1. Retire Units 1 & 2 in 2026. 2. Retire all 4 units in 2026.
B	Demand-side Resources (DSR) How much does DSR reduce cost, risk and emissions?	*Baseline – All cost-effective DSR per RCW 19.285 requirements* 1. No DSR. All needs are met with supply-side resources.
C	Thermal Mix How does changing the mix of resources affect portfolio cost and risk?	*Baseline – All peakers selected as lowest cost in the Base Scenario deterministic portfolio.* 1. All CCCT 2. Mix CCCT and frame peaker
D	Gas Plant Location What if the gas plants were built in eastern Washington instead of PSE service territory?	*Baseline – Gas plants located in PSE Service territory* 1. Model gas plants with gas transport costs and transmission costs from eastern Washington.
E	Gas Transport/Oil Backup for Peakers What if peakers cannot rely on oil for backup fuel and must have firm gas supply instead?	*Baseline – 50% firm pipeline capacity with 48 hours of oil backup* 1. 100% firm pipeline capacity with no oil backup
F	Energy Storage/Flexibility What is the cost difference between a portfolio with and without energy storage? How do energy storage resources impact system flexibility?	*Baseline – Batteries and pumped hydro included only when chosen economically* 1. Add 80 MW battery in 2023 instead of economically chosen peaker. 2. Add 80 MW pumped hydro storage in 2023 instead of economically chosen peaker. 3. Add 200 MW of pumped hydro storage in 2023 instead of economically chosen peaker.
G	Reciprocating Engine/Flexibility How do reciprocating peakers affect system flexibility?	*Baseline – Reciprocating peakers modeled at 220 MW with an all-in cost of $1,599 per kW* 1. Model lower capital cost for 75 MW recip peaker. 2. Add 75 MW recip peaker with lower capital cost in 2023. 3. Add 75 MW recip peaker with lower capital cost and flexibility credit in 2023.
H	Montana Wind Update transmission cost for Montana wind to be more optimistic if Colstrip continues to operate. Will MT wind be chosen in lowest cost portfolio?	*Baseline – PSE cost estimate for transmission upgrades to Montana* 1. Lower transmission cost estimate
I	Solar Penetration What if customers install significantly more rooftop solar than expected?	*Baseline – Rooftop solar growth based on current growth forecast trend* 1. Maximum potential capture of rooftop solar
J	Carbon Reduction How does increasing renewable resources and DSR beyond requirements affect carbon reduction and portfolio costs?	*Baseline – Renewable resources and DSR per RCW 19.285 requirements* 1. Add 300 MW of wind beyond renewable requirements. 2. Add 300 MW of utility-scale solar beyond renewable requirements. 3. Increase DSR beyond requirements.

Available Resource Alternatives

Existing resources and resource alternatives are described in detail in Appendix D.

Supply-side Resources

Short-term Wholesale Market Purchases. PSE relies on short-term wholesale market purchases for both peak capacity and energy. The short-term market purchases use the transmission contracts with Bonneville Power Administration to carry electricity from contracted wholesale market purchases to PSE's service territory. A more detailed discussion of the wholesale market is included in Appendix G.

Combined-cycle Combustion Turbines (CCCTs). F-type, 1x1 engines with wet cooling towers are assumed to generate 335 MW plus 50 MW of duct firing and be located in PSE's service territory.

Simple-cycle Combustion Turbines (Frame Peakers). F-type, wet-cooled turbines are assumed to generate 228 MW and located in PSE's service territory. Those modeled without 48 hours of oil backup were required to have firm gas pipeline capacity to cover 12 hours of operation and gas storage.

Aeroderivative Combustion Turbines (Aero Peakers). The 2-turbine design with wet cooling is assumed to generate a total of 203 MW and to be located in PSE's service territory. Those modeled without 48 hours of oil backup were required to have firm gas pipeline capacity to cover 12 hours of operation and gas storage.

Reciprocating Engines (Recip Peakers). This 12-engine design (18.3 MW each) with wet cooling is assumed to generate a total of 220 MW and to be located in PSE's service territory.

Wind. Wind was modeled in southeast Washington and central Montana. Washington wind is assumed to have a capacity factor of 34 percent. Montana wind is assumed to be located east of the continental divide and have a capacity factor of 41 percent.

Energy Storage. Two energy storage technologies are modeled: batteries and pumped hydro. The generic battery resource is lithium-ion technology. Pumped hydro resources are generally large, on the order of 400 MW to 3,000 MW. This analysis assumes PSE would split the output of a pumped hydro storage project with other interested parties.

Solar. Utility-scale solar PV is assumed to be located in central to southern Washington, use a fixed tilt system, and have a capacity factor of 20 percent.

Demand-side Resources

Energy Efficiency Measures. This label is used for a wide variety of measures that result in less energy being used to accomplish the same amount of work. These measures often focus on retrofitting programs and new construction codes and standards and include measures like appliance upgrades, building envelope upgrades, heating and cooling systems and lighting changes.

Demand-response. Demand-response resources are flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost.

Distributed Generation. Distributed generation refers to small-scale electricity generators (like rooftop solar panels) located close to the source of the customer's load.

Distributed Efficiency (Voltage Reduction and Phase Balancing). Voltage reduction is the practice of reducing the voltage on distribution circuits to reduce energy consumption. Phase balancing eliminates total current flow losses that can reduce energy loss.

Generation Efficiency. Energy efficiency improvements at PSE generating plant facilities.

Codes and Standards. No-cost energy efficiency measures that work their way to the market via new efficiency standards that originate from federal and state codes/standards.

TWO TYPES OF ANALYSIS

PSE uses two types of analysis to develop its resource plan: deterministic optimization analysis and stochastic risk analysis.[13]

DETERMINISTIC PORTFOLIO OPTIMIZATION ANALYSIS

All scenarios and sensitivities are subjected to deterministic portfolio analysis. This is the first stage of the resource plan analysis. It identifies least-cost portfolio – that is, the 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.

CANDIDATE RESOURCE STRATEGIES

Using what we learned from the deterministic analysis, we created a set of candidate resource strategies to test different resource strategies. For example, how does the addition of a mix of thermal resources perform compared to the addition of a single type of thermal resource?

STOCHASTIC RISK ANALYSIS

In this stage of the resource plan analysis, we examine how the candidate 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 candidate resource strategies again. This allows us to learn how the candidate resource strategies perform with regard to cost and risk across a wide range power prices, gas prices, hydro generation, wind generation, loads, plant forced outages and CO_2 prices.

13 / 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.

Deterministic Portfolio Optimization Analysis

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.

Three analytical tools are used during this stage of the analysis: Aurora, the Portfolio Screening Model III (PSM III) and Frontline System's Risk Solver Platform.

The initial Aurora input price run produces:

1. **Annual Energy Estimates (MWh).** This is the sum of the total energy produced by each resource for the entire year.
2. **Annual Variable Cost Estimates ($000).** This includes fuel price plus variable pipeline charges, fuel use, and taxes; variable operations and maintenance (O&M) cost; variable transmission cost; start-up costs; any emissions cost where applicable; and PPA costs.
3. **Annual Revenue ($000) Estimates.** This is the revenue that a resource produces when its excess energy production is sold into the market.
4. **CO_2 Emissions Estimates (tons).** For tracking total emissions in the portfolio.

The Portfolio Screening Model III (PSM III) is a spreadsheet-based capacity expansion model that the company developed to evaluate incremental costs and risks of a wide variety of resource alternatives and portfolio strategies. This model produces the least-cost mix of resources using a linear programming, dual-simplex method that minimizes the present value of portfolio costs subject to planning margin and renewable portfolio standard constraints.

The solver used for the linear programming optimization is Frontline System's Risk Solver Platform. This is an excel add-in that works with PSM III. Incremental cost includes: i) the variable fuel cost and emissions for PSE's existing fleet, ii) the variable cost of fuel emissions and operations and maintenance for new resources, iii) the fixed depreciation and capital cost of investments in new resources, iv) the booked cost and offsetting market benefit remaining at the end of the 20-year model horizon (called the "end effects"), and v) the market purchases or sales in hours when resource-dispatched outputs are deficient or surplus to meet PSE's need.

The primary input assumptions to the PSM III are:

- PSE's peak and energy demand forecasts,
- PSE's existing and generic resources, their capacities and outage rates,
- expected dispatched energy (MWh), variable cost ($000) and revenue ($000) from AURORAxmp for existing contracts and existing and generic resources,
- capital and fixed-cost assumptions of generic resources,
- financial assumptions such as cost of capital, taxes, depreciation and escalation rates,
- capacity contributions and planning margin constraints, and
- renewable portfolio targets.

A mathematical representation of PSM III can be found in Appendix N, Electric Analysis.

Candidate Resource Strategies

Candidate resource strategies were originally created in the portfolio model. The parameters of the model were relaxed to allow the resources to be 100 MW short of need, and the integer constraint was removed to allow fractions of plants to be added. DSR bundle D was chosen in the majority of the portfolios in the deterministic portfolio analysis, so all the candidate resource strategies include DSR bundle D, the codes and standards bundle, distribution efficiency, distributed solar PV, and demand-response programs 1 and 5. Also, based on the results of the deterministic portfolio analysis, wind is added to meet the RPS, so wind was sized exactly to meet the RPS for the 2015 IRP Base load forecast. After the wind and DSR were added to the candidate resource strategies, thermal plants were added to meet capacity need. Six candidate resource strategies were created using the Base Scenario. The first option, all frame peakers, is the lowest cost portfolio in the deterministic analysis of the Base Scenario.

The six candidate resource strategies tested were:

1. All frame peakers.
2. Early recip peaker added in 2021 and the remainder of the thermal units are frame peakers.
3. Early CCCT added in 2021 and then the remainder is a mix of CCCT, frame peaker and recip peaker.
4. All CCCT.
5. Mix CCCT and frame peaker. This portfolio has a frame in 2021 and 2025 and a CCCT in 2026.
6. Additional 300 MW of wind in 2021.

Stochastic Risk Analysis

With stochastic risk analysis, we test the robustness of the candidate portfolios. In other words, we want to know how well the portfolio might perform under 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 candidate portfolio.

For this purpose, we take the portfolio candidates (drawn from a subset of the lowest cost portfolios produced in the deterministic analysis) and run them through 250 draws[14] that model varying power prices, gas prices, hydro generation, wind generation, load forecasts (energy and peak), plant forced outages and CO_2 prices. From this analysis, we can observe how risky the portfolio may be and where significant differences occur when risk is analyzed. For example, in the deterministic analysis for this IRP, the frame peaker was lowest cost resource addition in the Base Scenario portfolio, but many other scenarios included the CCCT in the lowest cost portfolio. When we perform the stochastic analysis, we find that the CCCT reduces the portfolio's risk, because it provides a benefit to the portfolio in many of the draws; by running the stochastic analysis, we learn that balancing the portfolio with both peakers and CCCT plants is the better option. The goal of the process is to find the set of resources with the lowest cost and the lowest risk.

ANALYSIS TOOLS

A Monte Carlo approach is used to develop the stochastic inputs. Monte Carlo draws of inputs are used to generate a distribution of resource outputs (dispatched to prices and must-take power), costs and revenues from AURORAxmp. These distributions of outputs, costs and revenues are then used to perform risk simulations in the PSM III model where risk metrics for portfolio costs and revenue requirements are computed to evaluate candidate portfolios. Appendix N, Electric Analysis, includes a full description of how PSE developed the stochastic inputs.

14 / *Each of the 250 simulations is for the twenty-year IRP forecasting period, 2016 through 2035.*

KEY FINDINGS

The quantitative results produced by this extensive analytical and statistical evaluation led to the following key findings. These are summarized below and discussed in more detail in the following pages.

Incorporating wholesale market risk into the planning standard and resource capacity values was such a complex and lengthy process that it was necessary to begin the IRP analysis before that process was finished. That is why some analyses were performed using the 2013 Planning Standard. Where the results were sensitive to the change, we performed the analysis again using the 2015 Optimal Planning Standard.

Scenarios

1. **Portfolio Builds.** Portfolio additions across scenarios are very similar. The most common difference was which type of gas-fired generation was selected, peakers or CCCT plants.
    a. 2013 Planning Standard
    b. 2015 Optimal Planning Standard
2. **Emissions.** Emissions results vary across portfolios, with the economic dispatch of coal generation as the primary factor that differentiates results.
    a. 2013 Planning Standard
    b. 2015 Optimal Planning Standard
3. **Cost of Peakers vs. CCCT Plants.** Market conditions affect the net cost of peakers vs. CCCT plants, not the resource needs.
4. **Renewables.** RPS requirements and load forecasts drive renewable builds.
5. **Wind vs. Solar.** Wind remains more cost-effective than utility-scale solar.

Sensitivities (using 2013 Planning Standard)

A. **Colstrip.** If Colstrip units 1 & 2 had to be replaced in 2026, resource additions would be consistent across the Low, Base and High scenarios. That is, Colstrip being in or out of the portfolio does not impact the mix of resource additions. If all four units were out of operation, new combined-cycle plants would be part of the least-cost mix, since market heat rates would be impacted enough to drive down the net cost of CCCT making it cost effective.

B. **Demand-side Resources:** Energy efficiency and other demand-side resources are consistently cost effective and reduce risk. The level of cost effective DSR varies little across scenarios.

C. **Thermal Mix:** A mix of gas-fired thermal resources reduces expected cost and reduces risk, relative to selecting only one type of gas-fired thermal plant.

D. **Gas Plant Location:** The location of resources (east vs. west of the Cascades) is a very close call. Qualitative considerations of BPA transmission policy risk and sub-hourly value being connected to our BA tips the balance in favor of resources on our system for the IRP.

E. **Gas Transport/Oil Backup for Peakers:** Non-firm pipeline capacity may be significantly limited for extended winter periods in the future. For the near future, existing dual-fuel units do not appear to require firm pipeline capacity – current oil tanks can supply sufficient backup fuel. Further out in the planning horizon, however, it is not clear whether enough oil storage could be permitted to avoid the need for additional firm pipeline capacity and ensure peakers can run during on-peak hours.

F. **Energy Storage and Flexibility:** Batteries and pumped hydro storage are higher cost than traditional peaking plants, although energy storage can provide valuable flexibility. Even including this value, however, battery technology needs to come down in price before they will look cost effective as an energy supply resource. At present, the flexibility value of batteries would have to be 50 percent greater than our current estimates for batteries to be cost effective. We will continue to improve our analytical capabilities with respect to flexibility and energy storage.

G. **Flexibility and Reciprocating Engines:** Adjusting the relative cost of CCCTs, CTs, reciprocating engines and batteries for our initial estimates of flexibility value changed the optimal mix of resource additions. Reciprocating engines became the dominant new resource – though there may be challenges with air permits, given updated EPA standards on particulate emissions.

H. **Montana Wind:** Based on current assumptions, Montana wind is not expected to be cost effective because of transmission cost. Even in the sensitivity where Colstrip was retired and wind from Montana could rely on the existing transmission system at embedded cost rates, the capacity contribution of the wind would have to be greater than 50 percent to be cost effective – which is clearly a very high hurdle. We will study additional hourly wind data from Montana wind projects in the next IRP, if we can acquire the data.

I. **Solar Penetration:** Assuming customers own their own distributed solar generation systems (typically rooftop solar panels), the primary energy-supply-related impact of high solar penetration would be to reduce the need for RPS compliant resource additions since load would be lower. Otherwise the resource mix is not affected. High penetration of distributed solar in PSE's service territory may create different kinds of engineering challenges to solve on different kinds circuits. In the future, distributed solar could create synergies between energy supply planning and distribution system planning, if energy storage or other energy supply resources are a cost effective part of the solution to those challenges on the distribution system.

J. **Carbon Abatement:** DSR and wind resources affect emission rates, but to a much smaller extent than Colstrip or the Coal Transition PPA.

Candidate Resource Strategies (using 2015 Optimal Planning Standard)

Deterministic analysis was used to develop several candidate resource strategies to test in the stochastic portfolio risk analysis. Combinations of resources were tested based on deterministic results, to test individual thermal resources, such as an all CCCT portfolio, a mix of thermal resources, and additional wind.

1. **All Frame Peakers.** This portfolio is the lowest cost in the Base Scenario, but in the stochastic analysis, it had higher average cost and risk than the portfolios with CCCT.
2. **Early Recip Peaker.** This portfolio had a higher expected cost and risk than the all-frame-peaker portfolio.
3. **Early CCCT with Thermal Mix.** This portfolio had a higher expected cost because of the Recip Peakers, but the risk was lower than the all frame peaker portfolio because of the CCCT plants.
4. **All CCCT.** This portfolio has the highest cost in the expected base scenario, but the lowest average cost and risk in the stochastic simulations.
5. **Mix CCCT and Frame Peaker.** This portfolio has a higher cost in the expected base scenario than the all frame peaker, but has a lower average cost and risk in the stochastic simulations.
6. **Additional 300 MW of Wind.** This portfolio is higher cost and higher risk than the all frame peaker portfolio.

SCENARIO ANALYSIS RESULTS

1. Portfolio Builds

The portfolio builds for all scenarios look very much alike since resource alternatives are so limited. Small variations occurred due to load variations in the high and low load forecasts, but the similarities are striking. The main difference was the type of gas-fired generation chosen. CCCTs were selected as lower cost in some scenarios, while frame peakers were selected as lower cost in others. Also, in the High Scenario, wind was cheaper than market due to such high gas and carbon prices, so in this scenario, it was necessary to constrain wind to 1,000 MW. If wind did become cheaper than market, independent power producers would rush to build resources, driving up costs in many segments of the supply chain and causing wind costs to go up – a key assumption that was not reflected in our modeling. Additionally, as PSE's resources could greatly exceed load, PSE would have to adopt an energy planning standard to ensure the company operates as a utility rather than a wholesale power marketer. That is, that we add resources to meet the needs of customers, rather than taking a speculative position in the energy market. Figure 6-15 summarizes resource additions and net present value of portfolio costs across the 10 scenarios.

Figure 6-15: Relative Optimal Portfolio Builds and Costs by Scenario by 2035, 2013 Planning Standard
(Energy in total MW. Dollars in billions. NPV includes end effects.)

		NPV	DR	DSR	CCCT	Peaker	Wind	Biomass	Battery
1	Low	$7.20	174	888	-	455	200	-	-
2	Base	$12.28	172	906	-	1,138	300	15	80
3	High	$17.59	174	906	2,312	-	1,000	-	-
4	Base + Low Gas Price	$11.57	172	906	771	455	300	15	-
5	Base + High Gas Price	$12.90	172	906	-	1,138	300	15	80
6	Base + Very High Gas PrIce	$13.66	172	968	-	1,138	600	-	-
7	Base + No CO2	$9.92	172	906	771	455	300	15	-
8	Base + High CO2	$13.50	172	956	1,156	-	400	-	-
9	Base + Low Demand	$9.76	174	888	-	455	200	-	-
10	Base + High Demand	$15.55	254	956	1,542	683	500	-	-

The portfolio builds for all scenarios look similar to the portfolio builds for the 2013 planning standard with the exception of more resources added to meet the higher need.

Figure 6-16: Relative Optimal Portfolio Builds and Costs by Scenario by 2035, 2015 Optimal Planning Standard (Energy in total MW. Dollars in billions. NPV includes end effects.)

		NPV	DR	DSR	CCCT	Peaker	Wind	Biomass/ Solar*	Battery
1	Low	$7.67	230	888	-	683	200	-	-
2	Base	$12.79	148	906	385	1,138	300	15	-
3	High	$17.99	230	906	2,312	228	1,000	-	-
4	Base + Low Gas Price	$12.04	148	906	385	1,138	300	15	-
5	Base + High Gas Price	$13.41	148	906	-	1,593	300	15	-
6	Base + Very High Gas Price	$14.18	148	968	-	1,366	500	-	80
7	Base + No CO2	$10.38	148	906	1,542	-	300	15	-
8	Base + High CO2	$13.95	148	906	1,542	-	400	-	-
9	Base + Low Demand	$10.20	148	906	-	683	200	-	80
10	Base + High Demand	$16.09	148	888	1,542	1,138	500	20	-

** 20 MW refers to a solar addition, and 15 MW is a biomass addition.*

Summary of Deterministic Optimization Analysis. Figure 6-17 below displays the megawatt additions for the deterministic analysis optimal portfolios for all scenarios in 2021, 2026 and 2035 using the 2013 Planning Standard. Under the 2013 standard, no new resources are added until 2023 except in the High and Base + High Demand scenarios; both use the high demand forecast.

Figure 6-18 is the same chart for the portfolios using the 2015 Optimal Planning Standard. Under the 2015 standard, new resources are added in 2021 to meet needs except in the Low and Base + Low Demand scenarios. See Appendix N, Electric Analysis, for more detailed information.

Figure 6-17: Resource Builds by Scenario, Cumulative Additions by Nameplate (MW), 2013 Planning Standard

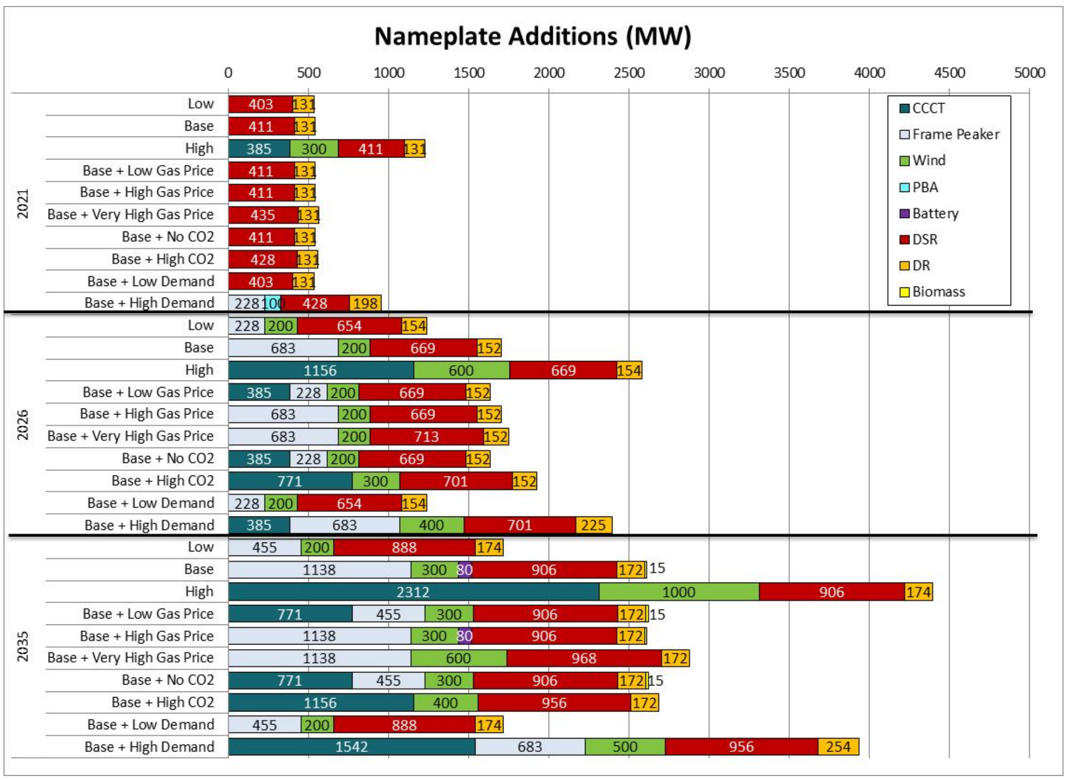
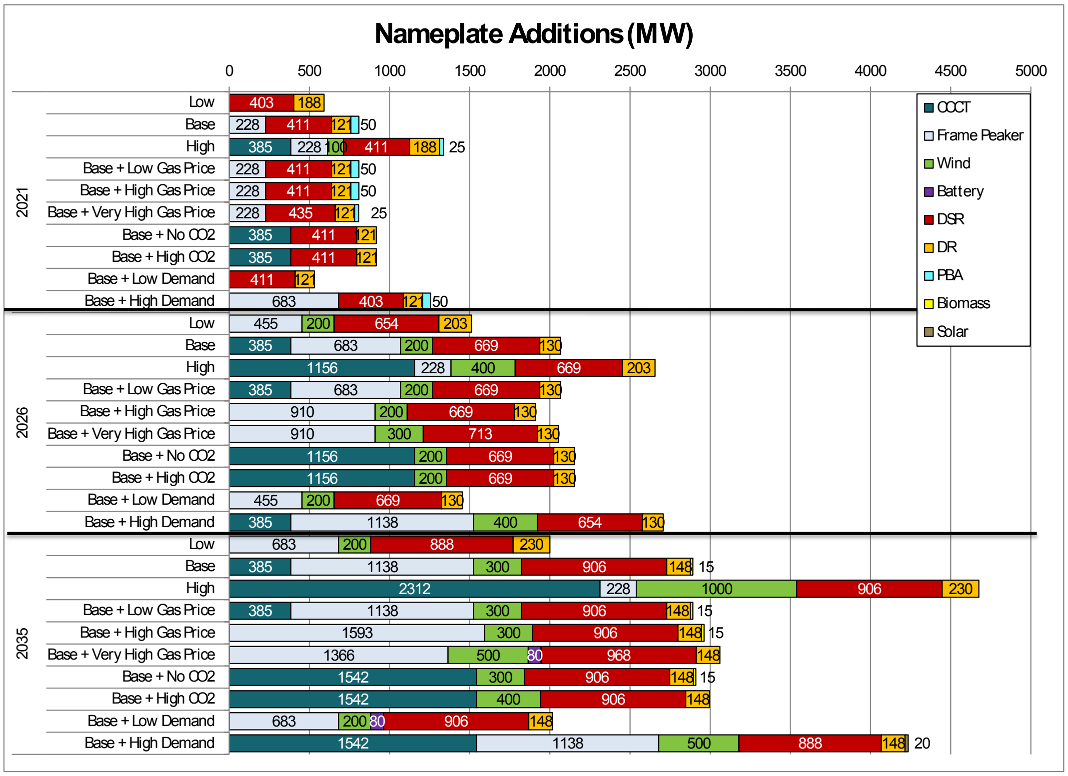


Figure 6-18: Resource Builds by Scenario, Cumulative Additions by Nameplate (MW), 2015 Optimal Planning Standard



2. Emissions

PSE examined how different carbon mitigation strategies affect portfolio builds, costs and emissions. Figure 6-19 shows CO_2 emissions for the least-cost portfolio in each scenario using the 2013 Planning Standard; Figure 6-20 shows CO_2 emissions using the 2015 Optimal Planning Standard. Many of the portfolios show a drop in emissions in 2026 corresponding to the expiration of the Coal Transition PPA on December 31, 2025. As the charts illustrate, only four portfolios/scenarios reduce emissions below 1990 levels. In two of those scenarios, High and Base + High CO_2, the CO_2 price is high enough to reduce the dispatch of Colstrip.

Figure 6-19: CO_2 Emissions by Portfolio – 2013 Planning Standard

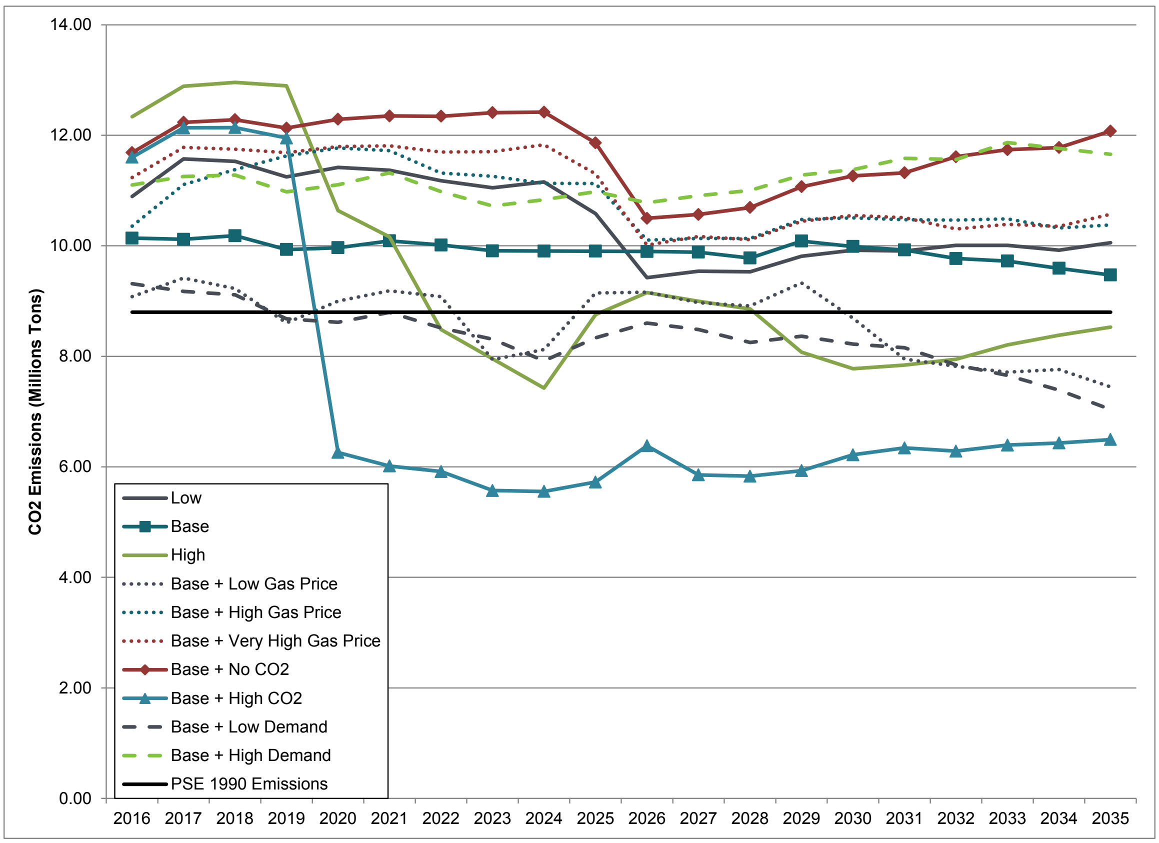
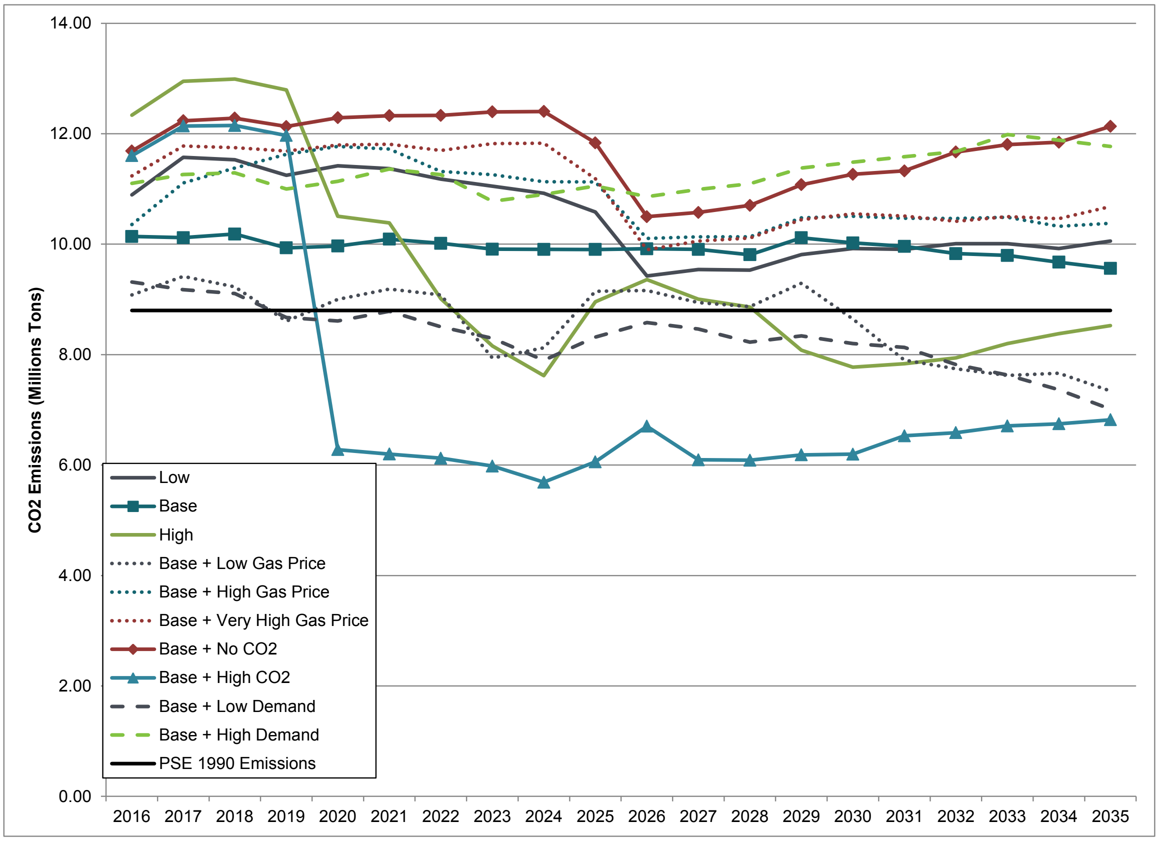
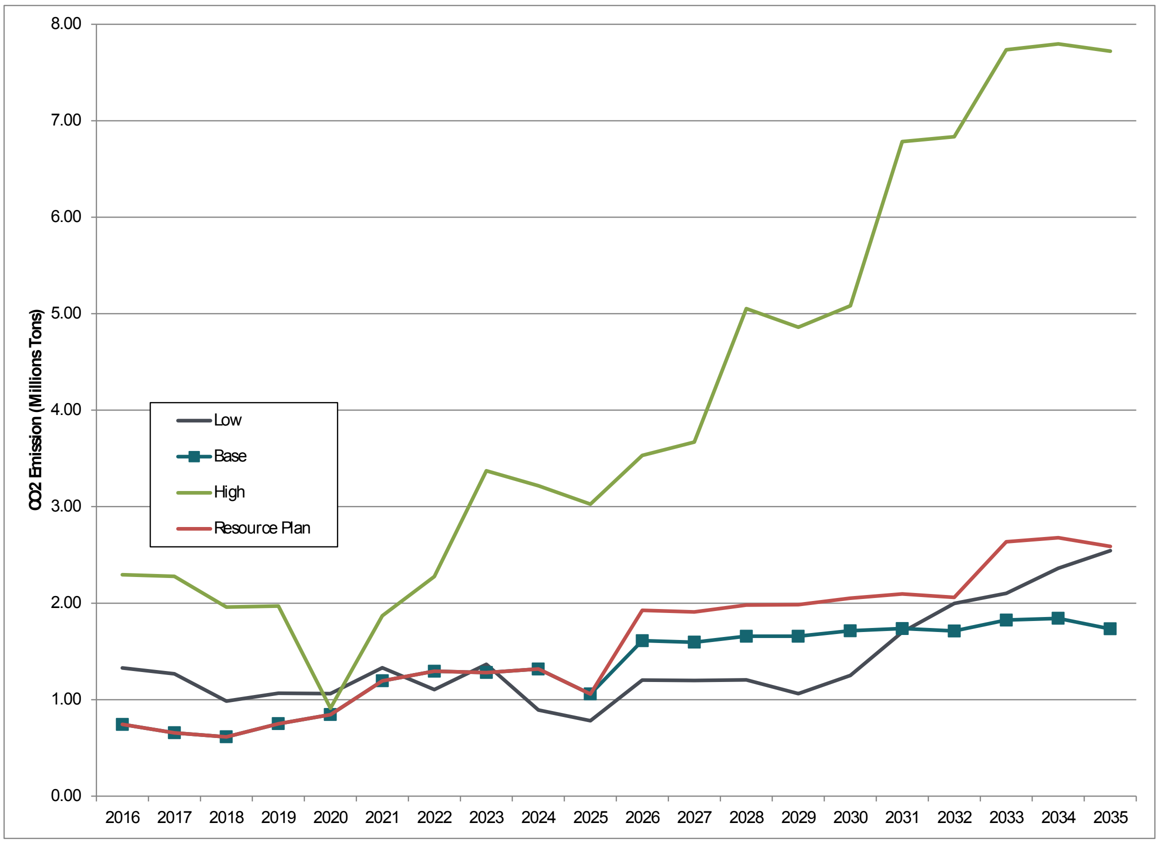


Figure 6-20: Projected CO_2 Emissions by Portfolio – 2015 Optimal Planning Standard



A portfolio view of carbon emissions does not reflect emissions occurring specifically in Washington state. Figure 6-21, below, shows a range of emissions from PSE's owned power plants that are located in Washington state, for the Base, High, and Low Scenarios. The chart illustrates that PSE's emissions in Washington are driven by dispatch of CCCTs. In the Base scenario, there is only one additional CCCT plant, but in the other two, all new additions are CCCT plants. A final line, showing the resource plan, is in the middle because it is a combination of CCCT and CT plants.

Figure 6-21: PSE's Projected Washington CO_2 Emissions – 2015 Optimal Planning Standard



3. Cost of Peakers vs. CCCT Plants

Peakers and CCCTs traded off being the lower cost resource, depending on the scenario. Figure 6-22 compares the cost of peakers and combined-cycle plants across scenarios. Net revenue requirements were calculated by taking all capital and fixed costs of a plant and then subtracting the margin (market revenue less variable costs). This calculation lets one quickly compare how the model evaluated these resources.

- Peaking units were modeled with and without oil backup. For peakers with oil backup, we included 50 percent firm pipeline transportation costs, plus the cost of 48 hours of oil. Those without oil backup were assigned higher-priced firm fuel transportation and storage costs similar to those that CCCTs are burdened with.
- Plants are assumed to be located on the west side of the Cascades. (How location affects resource costs is discussed in sensitivity results.)
- The levelized cost for both the frame peaker and CCCT plant was calculated over the 35-year life of the plant from 2020-2054.

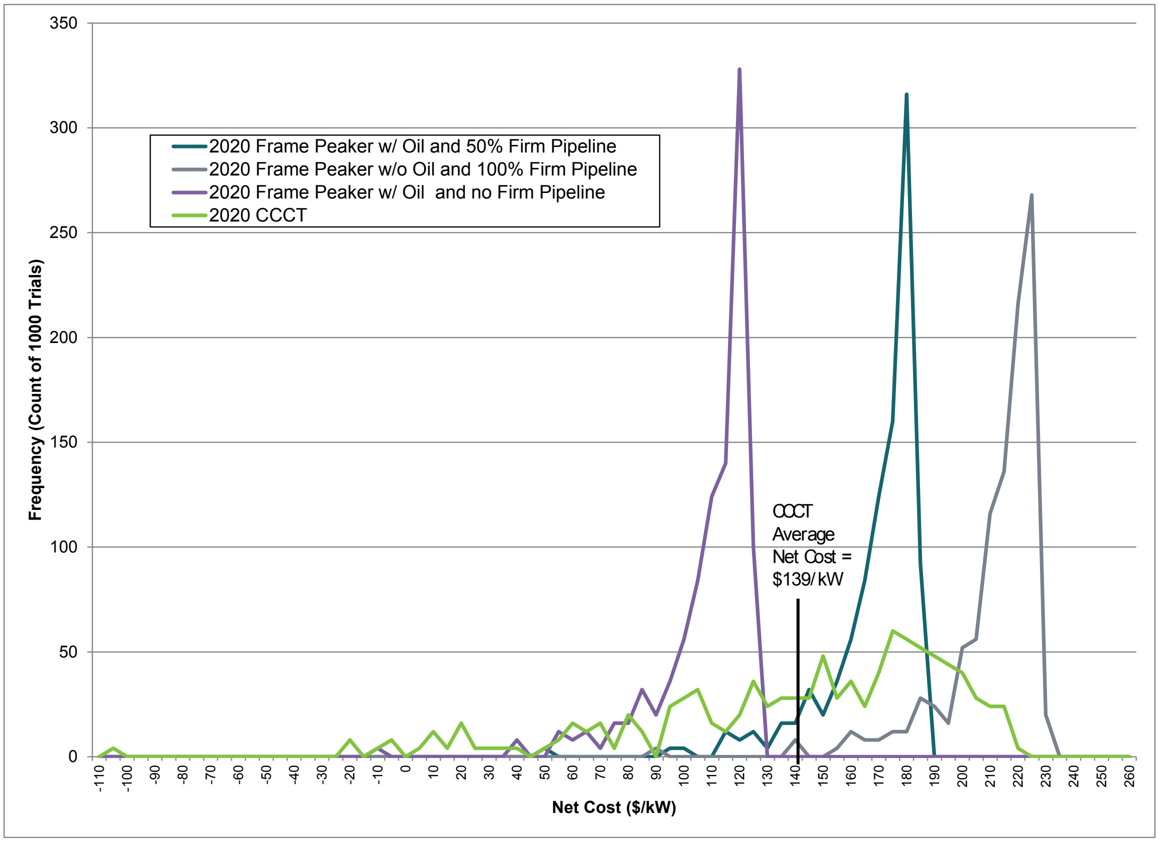
In the scenarios where the CCCT looks more cost effective, the dispatch of the CCCT plants is high, so the plant produces a lot of excess power to sell into the market; this creates revenue that lowers the net cost of the plant to customers, resulting in CCCTs being chosen in the lowest cost portfolio. The frame peaker costs are constant across all scenarios since there is no dispatch of the plant, so there are no variable O&M costs and no revenue on the plants, and the fixed costs remain constant across all scenarios. An exception is the Low Scenario, where there is a very small dispatch.

Figure 6-22: Peaker and CCCT Net Costs Compared

	Levelized Net Cost (2016 $/kW)	2020 Frame peaker w/ oil and no firm pipeline	2020 Frame peaker w/ oil and 50% Firm pipeline	2020 Frame peaker w/o oil and 100% Firm pipeline	2020 CCCT
1	Low	$115.94	$166.23	$193.96	$184.10
2	Base	$115.97	$165.34	$193.99	$183.15
3	High	$115.97	$165.34	$193.99	$149.04
4	Base + Low Gas Price	$115.97	$165.34	$193.99	$170.09
5	Base + High Gas Price	$115.97	$165.34	$193.99	$184.00
6	Base + Very High Gas Price	$115.97	$165.34	$193.99	$186.15
7	Base + No CO2	$115.97	$165.34	$193.99	$159.90
8	Base + High CO2	$115.97	$165.34	$193.99	$155.04
9	Base + Low Demand	$115.97	$165.34	$193.99	$194.23
10	Base + High Demand	$115.97	$165.34	$193.99	$169.90

Figure 6-22 illustrates how the net cost of a CCCT plant is significantly affected by the margin it generates. A 250-simulation Monte Carlo analysis for a 2020 vintage plant shows how the net cost per kW of peakers and CCCT plants are distributed under different market conditions. The peakers show a very tight probability distribution of cost, because they do not dispatch or create much margin in many draws. In contrast, the CCCT plant margins are widely dispersed; this spreads out the CCCT probability distribution more broadly than the peaker distribution. Net cost is not specifically used as part of the cost minimization function; however, showing net cost may provide useful insights. Figure 6-23 illustrates that if sufficient backup fuel can be permitted and constructed so as to avoid needing any firm pipeline capacity, peakers with oil backup may be lower cost and lower risk than CCCT plants. The ability to permit sufficient backup fuel is a resource-specific-level decision, but it is difficult to believe the company could permit such resources in the future, as the natural gas system becomes more constrained and emissions regulations continue to get more stringent.

Figure 6-23: Comparison of Net Cost Distribution in the Base Scenario, CCCT and Peakers with Oil Backup (in 2016 dollars per kW)



4. Renewable Builds

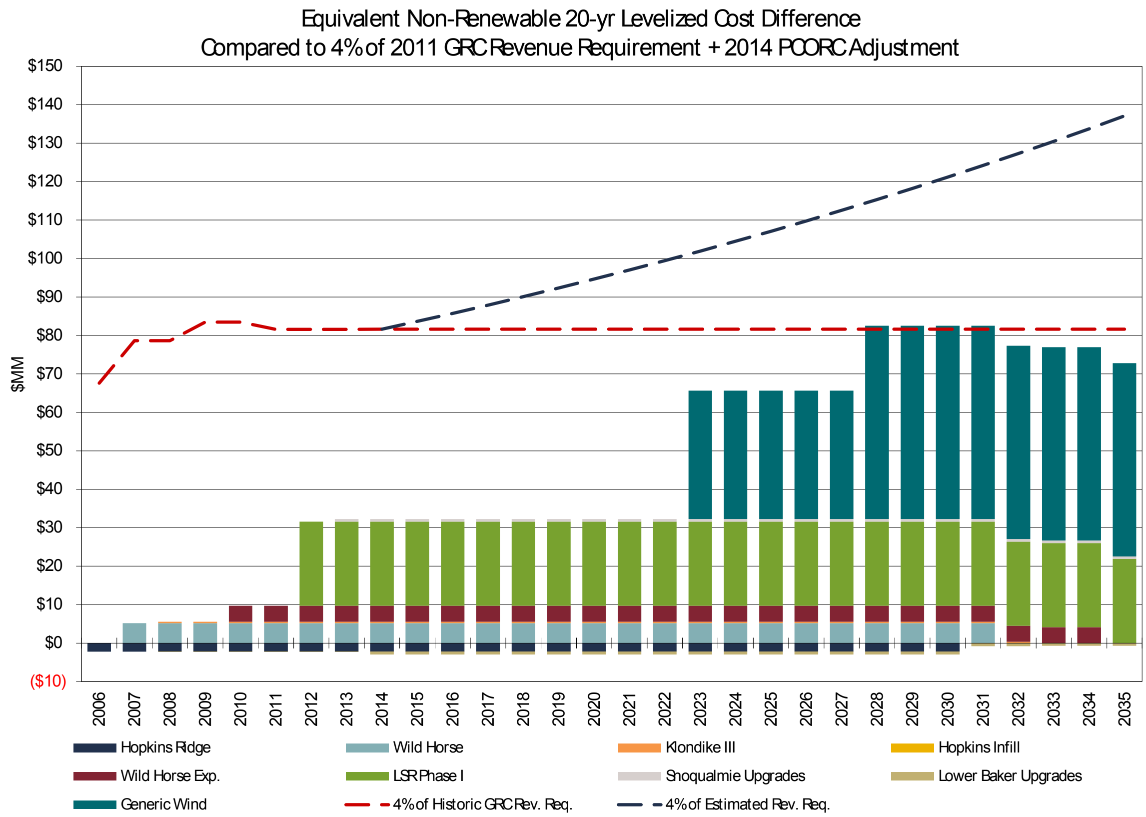
The amount of renewable resources included in portfolios is driven by RPS requirements. In all scenarios but High and Base + Very High Gas Price, wind resources are only added to meet the minimum requirements of RCW 19.285, not because they are least cost. See Figure 6-19 and 6-20 above for total wind builds by scenario.

RPS Incremental Cost Cap Analysis. As part of RCW 19.285, if the incremental cost of the renewable resources compared to an equivalent non-renewable is greater than 4 percent of its revenue requirement, then the utility will be considered in compliance with the annual renewable energy target.[15]

Each renewable resource that counts towards meeting the renewable energy target was compared to an equivalent non-renewable resource starting in the same year and levelized over the book life of the plant: 25 years for wind power and 40 years for hydroelectric power. Figure 6-24 presents results of this analysis for existing resources and projected resources. This demonstrates that PSE expects to meet the physical targets under RCW 19.285 without being constrained by the cost cap. A negative cost difference means that the renewable was lower cost than the equivalent non-renewable, while a positive cost means that the renewable was a higher cost.

15 / RCW 19.285.050 (1) (a) (b) "The incremental cost of an eligible renewable resource is calculated as the difference between the levelized delivered cost of the eligible renewable resource, regardless of ownership, compared to the levelized delivered cost of an equivalent amount of reasonably available substitute resource that does not qualify as eligible renewable resources."

Figure 6-24: Equivalent Non-renewable 20-year Levelized Cost Difference Compared to 4% of 2011 GRC Revenue Requirement + 2014 PCORC adjustment



5. Wind vs. Solar

The Puget Sound Region is on the lower end of solar potential in the United States,[16] and Washington state currently generates less than 1 MW of utility solar. PSE's Wild Horse solar facility (0.5 MW) has historically experienced an 18 percent capacity factor. Capacity factor has a significant impact on the economics of solar projects. Solar projects would provide no contribution to PSE's winter peak capacity since those peaks occur when it's dark and cold during the winter months. Even if solar could be imported from areas with higher solar potential, it would still make only limited contribution to peak capacity.

Photovoltaic technology costs have declined over the last decade, but there is uncertainty about the degree and pace of future price declines. Figure 6-25 shows the price curve, and the gray bar indicates the range of costs. The U.S. Energy Information Administration's 2014 Energy Outlook estimated the all-in capital cost for utility solar at $3,564 per kW (in 2012 dollars) or $4,000 per kW (in 2016 dollars). The levelized costs range from $101 to $200 per MWh with capacity factors ranging from 22 to 32 percent. Solar in the Puget Sound Region would fall into the upper end of the cost per MWh range or even higher due to the poor solar profile of the area.

16 / A map that shows solar potential across the entire United States is included in Appendix M, Distributed Solar.

Figure 6-25: Utility-scale Solar PV Capital Cost Estimates

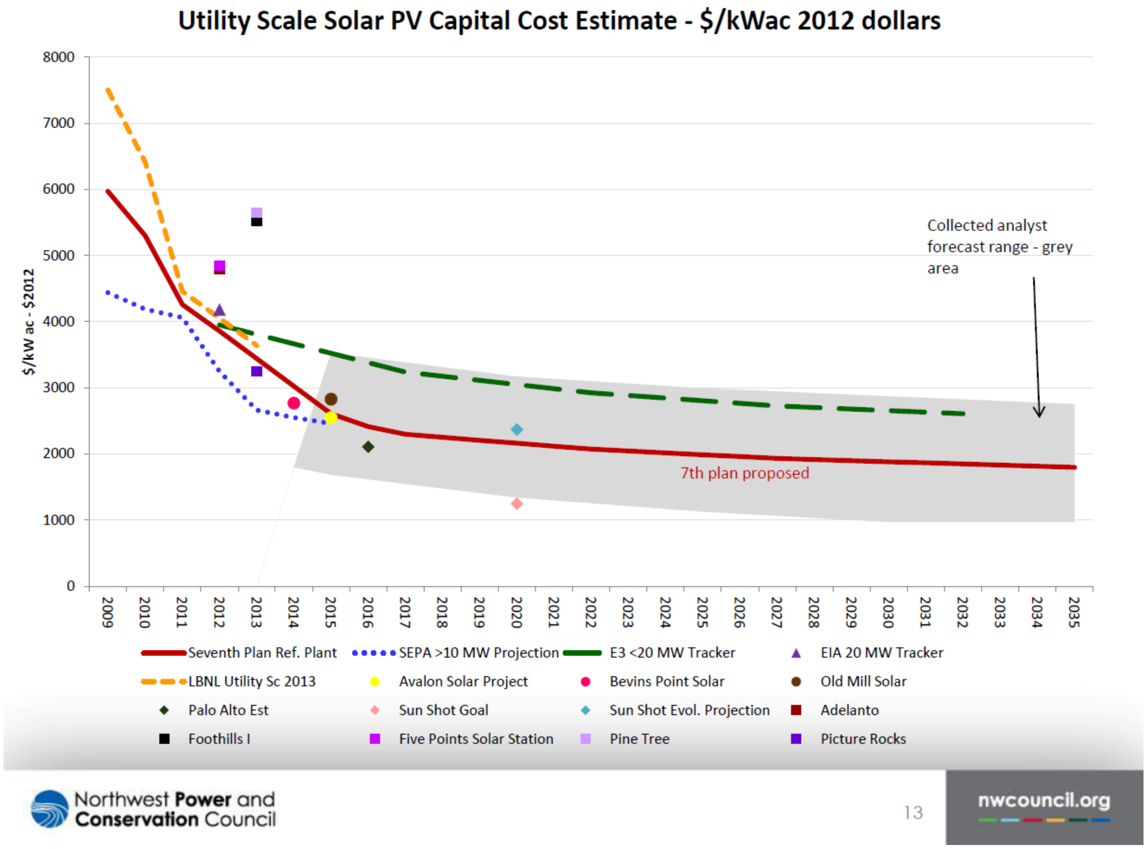


Figure 6-26 shows the impact of capital cost on solar levelized costs at a 20 percent capacity factor, and how this compares to wind and market. Based on the current projection of 2016 capital costs at $2,664 per kW, costs would have to decrease by over 50 percent to $1,283 per kW to be competitive with wind. In areas with higher solar potential the curve would shift down proportionally based on the capacity factor.

Figure 6-26: Solar PV Levelized Revenue Requirements

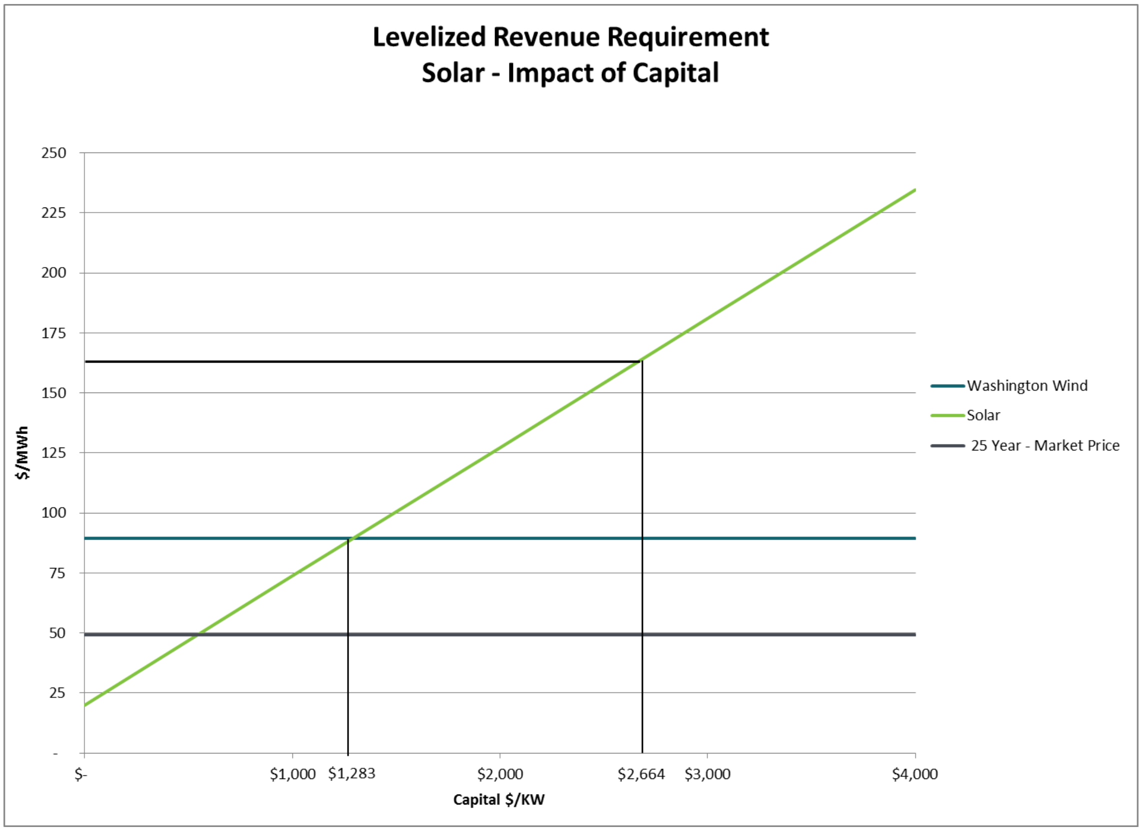
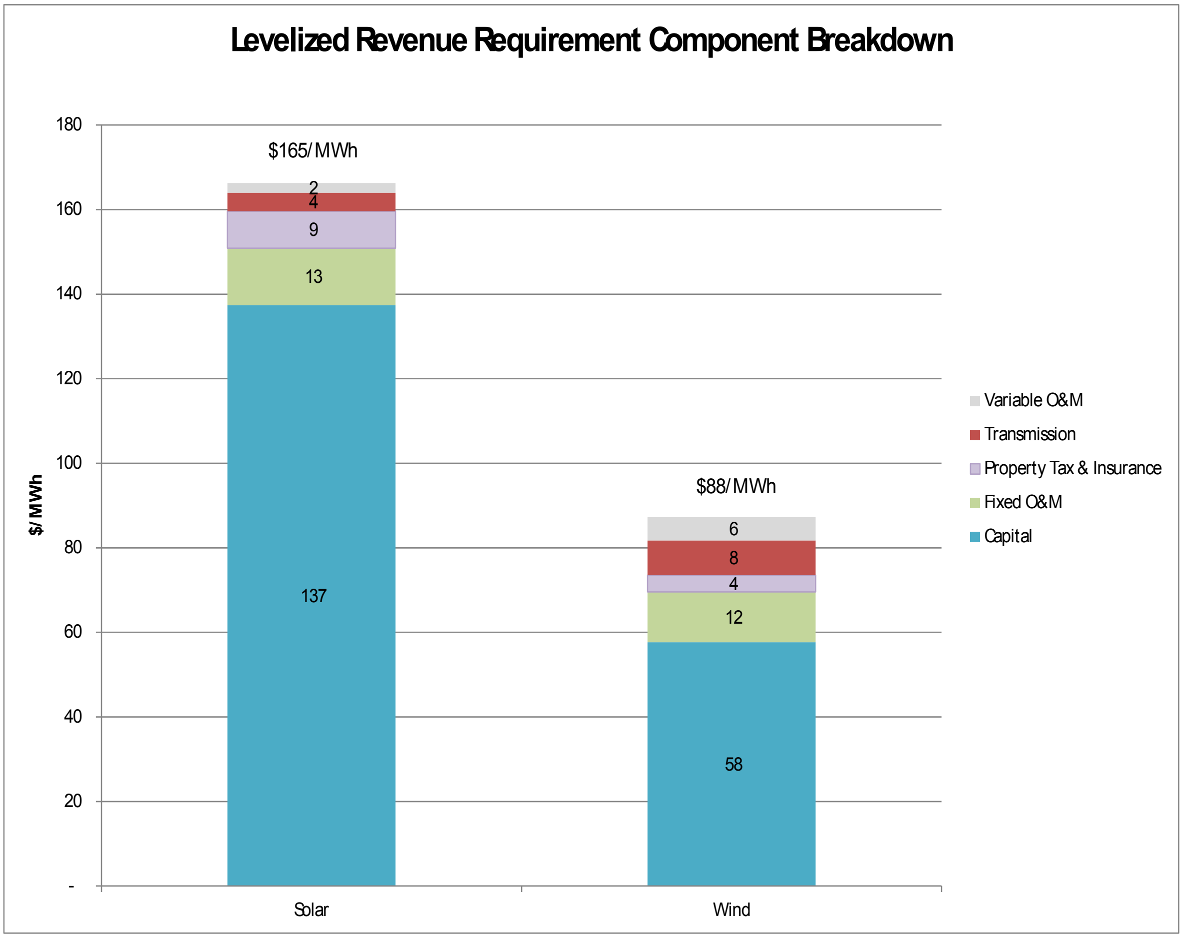


Figure 6-27 compares wind and solar cost components. Solar resources clearly have higher capital costs and lower capacity factors than wind resources, which makes it difficult for solar to compete with wind resources as a renewable alternative in Washington.

Figure 6-27: Wind and Solar Cost Components



SENSITIVITY ANALYSIS RESULTS USING 2013 PLANNING STANDARD

A. Colstrip

If Colstrip units are retired, what is the most cost-effective way to replace those resources?

Baseline: All four Colstrip units remain in service.

Sensitivity 1: Units 1 & 2 retire in 2026 (PSE owns 307 MW total capacity).

Sensitivity 2: All four units retire in 2026 (PSE owns 677 MW total capacity).

This sensitivity tested a "replacement power" portfolio analysis that took Colstrip out of PSE's portfolio across three scenarios (Low, Base and High), so that we could compare the different portfolio builds. As part of the assumptions for Colstrip retirement, we also assumed that the Colstrip transmission capacity was available for wind resources in Montana, so the generic Montana wind costs were reduced to reflect this assumption. (See Scenario A in the Montana Wind sensitivity section of this chapter).

Baseline Result. When all four Colstrip units remain in service, frame peakers are chosen as the lowest cost resource addition in the Base Scenario.

Base Scenario Results. In the baseline portfolio, two frame peakers are added in 2026 to replace the Centralia contract and meet growing demand.

- When Colstrip Units 1 & 2 are retired in 2026, one additional frame peaker is added to replace the lost capacity (228 MW). Also, 300 MW of wind in Montana is added on top of the 300 MW of Washington wind for the RPS. The Montana wind plants become cost effective with the lower capital cost for transmission upgrades and the 55 percent capacity credit. If the capacity credit of MT wind is lower than 55 percent, then it is no longer cost effective.
- When all 4 units are retired in 2026, two CCCT units (385 MW each) and one frame peaker are added to replace capacity and meet growing demand instead of two frame peakers, along with an additional 300 MW of Montana wind. The CCCT plants become cost effective when retirements increase market prices, especially the spread between gas prices and power prices.

Low Scenario Results. In the Low Scenario portfolio, one frame peaker is added in 2026 to replace Centralia.

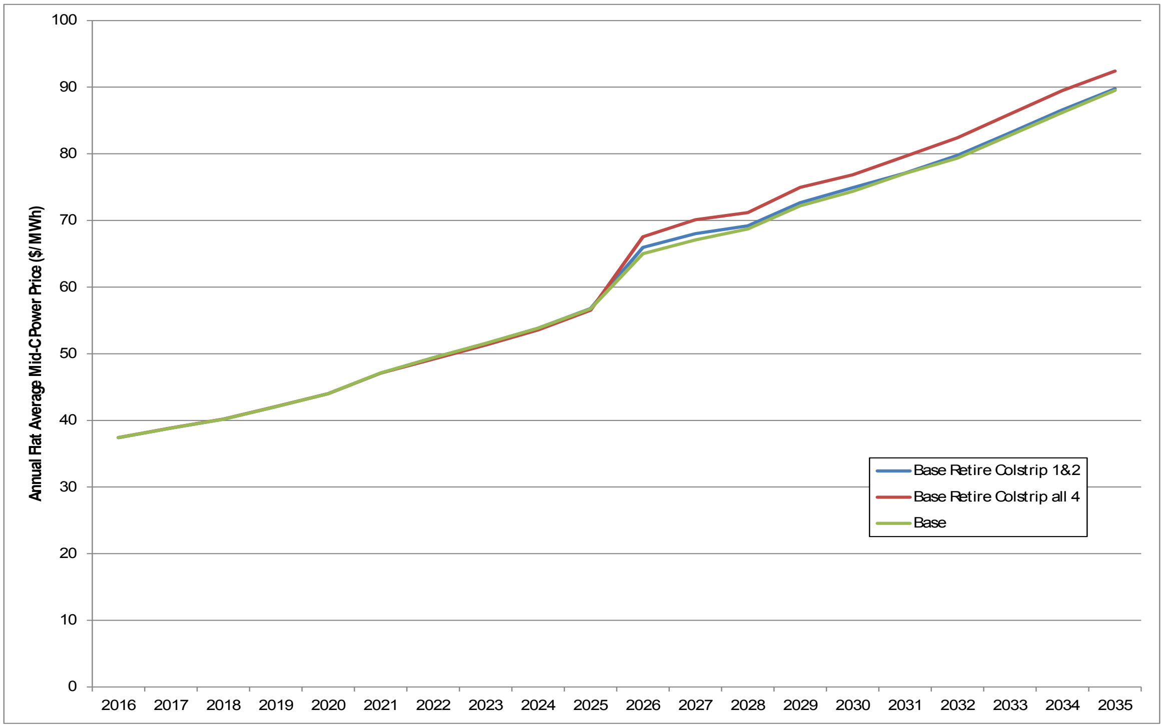
- When Colstrip Units 1 & 2 retire in 2026, two additional frame peakers are added to replace capacity, for a total of three frame peakers in 2026.
- When all four units retire in 2026, three additional frame peakers are added, for a total of four frame peakers in 2026.

High Scenario Results. In the High Scenario portfolio, one CCCT is added in 2026 to replace Centralia and meet growing demand.

- When Colstrip Units 1 & 2 retire in 2026, 500 MW of Montana wind is added (275 MW capacity), and additional DSR bundles are added to replace capacity.
- When all four units retire in 2026, the same DSR selected in the baseline case is retained (Bundle D), one CCCT plant is added to replace capacity, and 500 MW of Montana wind is added.

Figure 6-28 illustrates the significantly greater impact that removing all four Colstrip units has on wholesale market prices compared to removing Units 1 & 2 alone, as the effects ripple across the WECC. Tables of annual portfolio additions are located in Appendix N, Electric Analysis.

Figure 6-28: Forecast Mid-C Electric Prices with and without Colstrip Operating



B. Demand-side Resources (DSR)

How much does DSR reduce cost, risk and emissions?

Baseline: All cost-effective DSR per RCW 19.285 requirements.

Sensitivity: No DSR. All needs met with supply-side resources.

Demand-side resources were found to reduce both cost and market risk in portfolios.

Figure 6-29 shows the optimal DSR bundle in each scenario. The avoided cost of capacity (this includes energy, capacity and renewable resources) plays a big role in the selection of the optimal bundle. The avoided cost of energy, in particular, varies depending on the power price included in the scenario. Analysis of ramp rates continues to show that the sooner DSR is acquired, the more cost effective it is. In the 2011 IRP, a 10-year ramp rate was identified as the better option over the 20 year ramp rate used by the Council. (Detailed results by scenario, including avoided cost calculations, are presented in Appendix N, Electric Analysis.)

Demand-side resources must be cost effective to be included in the plan, so by definition they are also least-cost resources. The Base Scenario deterministic least-cost portfolio includes 1,078 MW of DSR by 2035.

Figure 6-29: Optimal DSR Results across Scenarios for 2013 Planning Standard

	MW Additions by 2035	Bundle		Demand-response		DE	EISA	Total
1	Low	C	664	1,3,4,5	174	27	197	1,062
2	Base	D	683	1,3,5	172	27	197	1,078
3	High	D	683	1,3,4,5	174	27	197	1,081
4	Base + Low Gas Price	D	683	1,3,5	172	27	197	1,078
5	Base + High Gas Price	D	683	1,3,5	172	27	197	1,078
6	Base + Very High Gas Price	F	744	1,3,5	172	27	197	1,139
7	Base + No CO2	D	683	1,3,5	172	27	197	1,078
8	Base + High CO2	E	732	1,3,5	172	27	197	1,127
9	Base + Low Demand	C	664	1,3,4,5	174	27	197	1,062
10	Base + High Demand	E	732	1,2,3,5	254	27	197	1,209

Demand response is a subset of DSR and is considered as part of determining the least-cost resources. Demand-response programs were broken down into 5 categories:

1. Residential Direct Load Control (DLC) Space Heating
2. Residential DLC Water Heating
3. Residential Critical Peak Pricing (CPP)
4. Commercial and Industrial Critical Peak Pricing
5. Curtailment

Figure 6-30 compares expected costs and cost ranges to illustrate how DSR reduces cost and risk in the portfolio. The amount of cost-effective conservation acquired varies across scenarios, but by 2035, the range is very tight, 1,062 MW to 1,209 MW. Compared to the Base Scenario portfolio with no DSR, the Base Scenario portfolio with DSR is lower cost and has a lower TVar90, which measures the risk of how costly a portfolio can get.

Figure 6-30: Effect of DSR on Costs and Risks

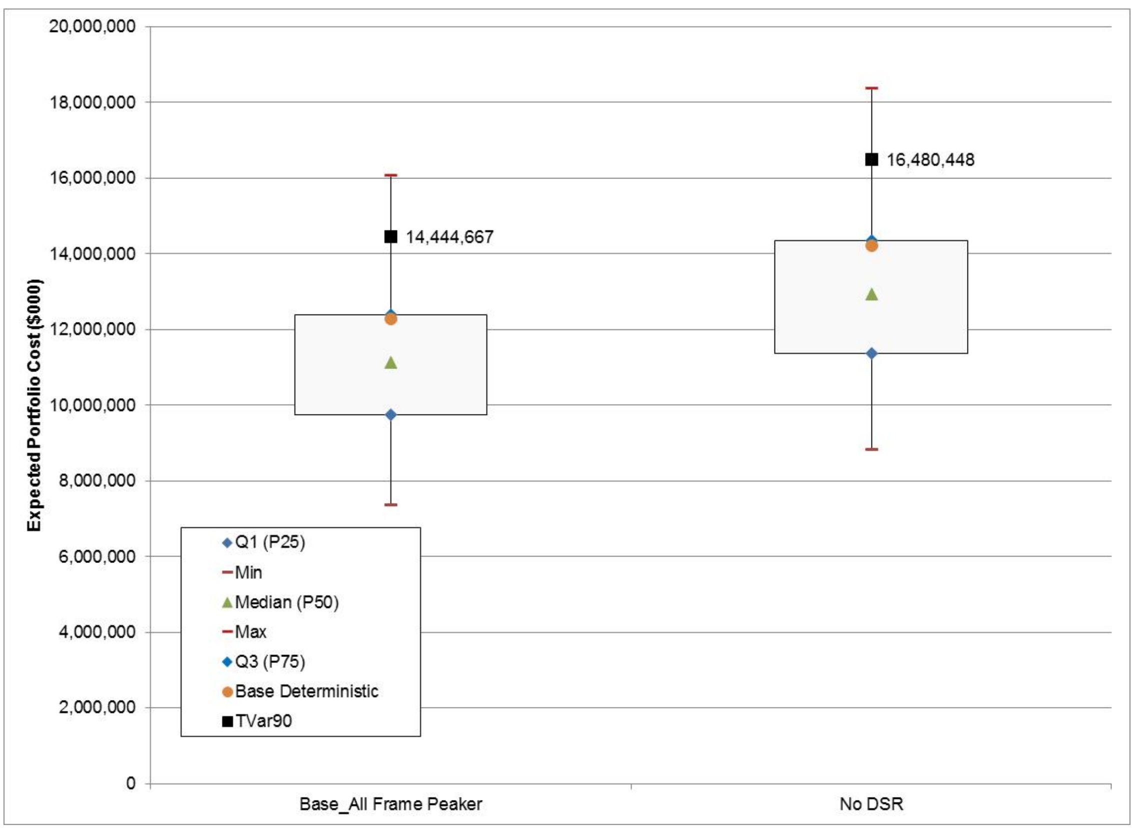


Figure 6-31 shows that DSR reduces power cost risk relative to no DSR. The Tail Var 90 of variable costs for the No DSR portfolio would be a little over $2.04 billion higher than the Base Scenario optimal portfolio with DSR. It also illustrates that the No DSR portfolio revenue requirement is $1.93 billion more than the Base Scenario optimal portfolio, which reflects the higher costs of adding peakers instead of DSR. This is clearly a reasonable cost/risk tradeoff. Adding DSR to the portfolio reduces cost and risk at the same time.

Figure 6-31: Comparison of Expected Costs and Cost Ranges for No-DSR and Optimal Base Scenario Portfolios 20-yr NPV Portfolio Cost (dollars in billions)

No CO2 Price	Base + DSR	Base + No DSR	Difference
Expected Cost	12.28	14.21	1.93
TVar90	14.45	16.48	2.04

C. Thermal Mix

How does changing the mix of thermal resources affect portfolio cost and risk?

Baseline: All peakers are selected in the Base Scenario portfolio.

Sensitivity 1: What happens when all CCCT plants are modeled?

Sensitivity 2: What happens when a mix of CCCT and frame peakers are modeled?

In this IRP, the lowest cost thermal resource varied between the frame peaker and the CCCT depending on the scenario. The all-peaker portfolio is the least-cost portfolio from the Base Scenario, the CCCT builds are based on the Base + High CO_2 least-cost portfolio and the mix of frame and CCCT portfolio is the least-cost portfolio from the Base + No CO_2 scenario.

Figure 6-32 compares the differences among portfolio costs compared to the tail value at risk (TVar90). TVar90[17] represents the downside financial risk associated with a portfolio; it is calculated as the average value of the worst 10 percent of outcomes.

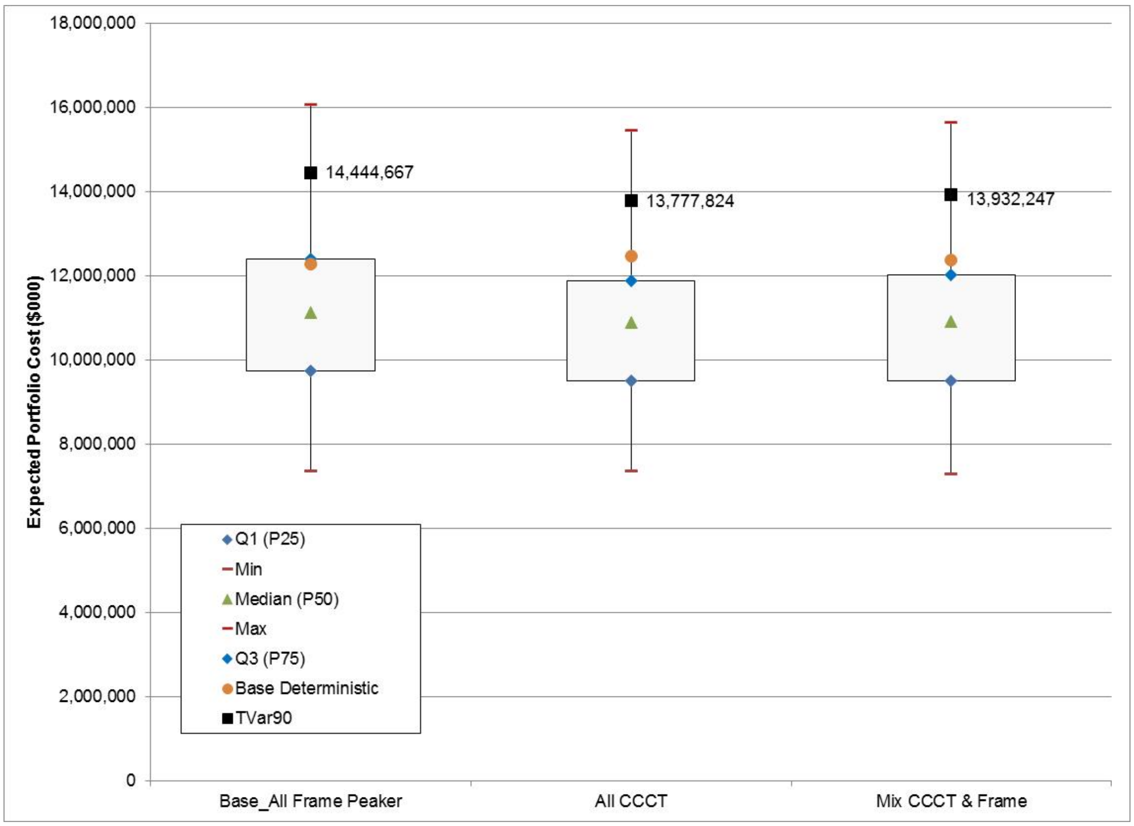
Figure 6-32: Thermal Mix – Total Portfolio Cost and TVar90

NPV ($ millions)	Base Deterministic Portfolio Cost	Difference from Base	TVar90	Difference from Base
Base (all Frame Peaker)	12,277	-	14,445	-
All CCCT	12,471	194	13,778	(667)
Mix CCCT & Frame	12,363	86	13,932	(512)

17 / Tail value at risk (TVaR) is also known as tail conditional expectation (TCE) or conditional tail expectation (CTE), is a risk measure associated with the more general value at risk. It quantifies the expected value of the loss given that an event outside a given probability level has occurred.

The all-CCCT portfolio adds $194 million to the deterministic portfolio cost, but saves $667 million in risk to the TVar90. The mixed portfolio adds $86 million to total portfolio cost, but saves $512 million in risk. In this analysis, the all-CCCT portfolio appears to be less risky because the benefit associated with the cost increase is greater than for the mixed portfolio. The box plots in Figure 6-33 chart the distribution of the three different portfolio costs.

Figure 6-33: Thermal Mix – Range of Portfolio Costs across 1,000 Trials



D. Gas Plant Location

What if gas plants are built in eastern Washington instead of PSE service territory?

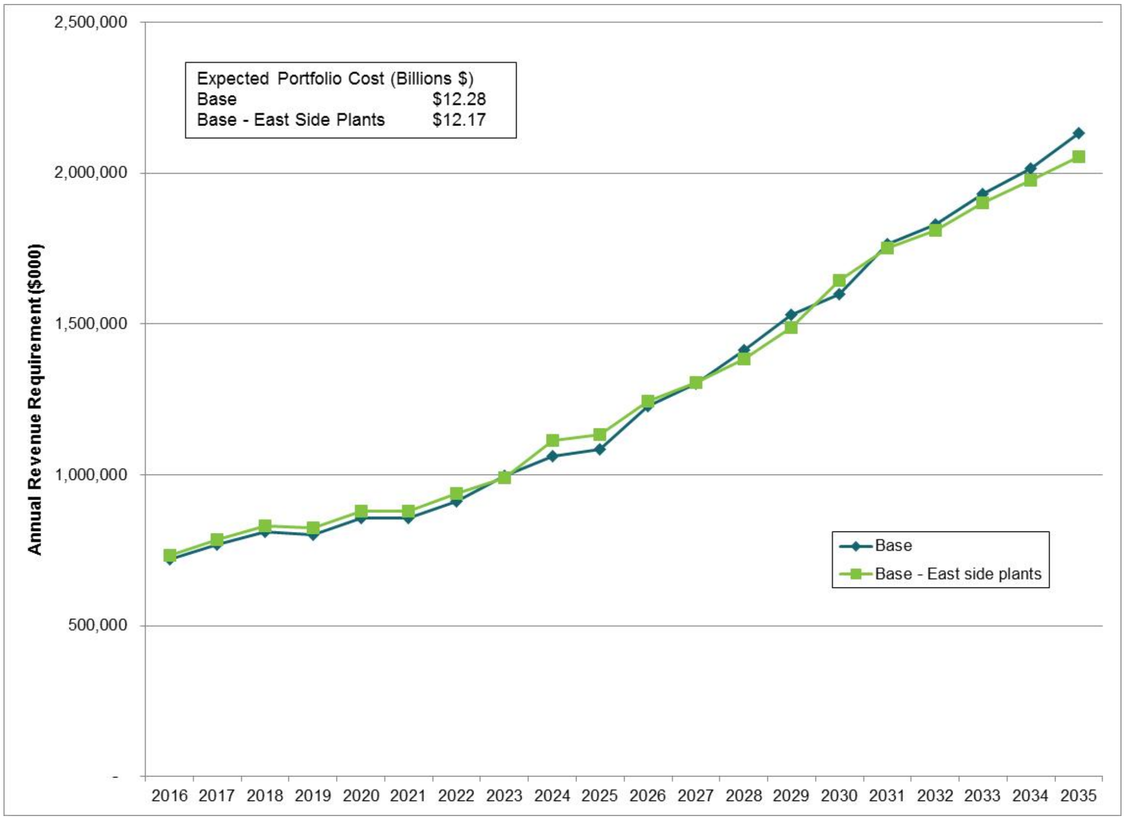
Baseline: Gas plants are located in PSE service territory.

Sensitivity: Model with gas transport and transmission costs from eastern Washington.

Resources located within PSE's balancing authority west of the Cascade mountains have higher fuel costs but would carry lower transmission costs than resources located on the east side of the mountains. East side resources incur lower fuel costs, but higher transmission costs since they require the purchase of transmission contracts from BPA to bring the power to our system. As a result, the Base Scenario portfolio with west side plants selects frame peakers as lower cost, but when the Base Scenario is modeled with east side plants, CCCT plants are lower cost and therefore selected in the portfolio.

Figure 6-34, below, indicates that overall costs over the 20-years are very close between these two scenarios. Resources built in eastern Washington would be located within BPA's balancing authority and subject to the risk of BPA transmission tariff pricing and policy changes. West side plants, on the other hand, give PSE access to all of the short-term operational benefits that thermal resources can provide (minute-to-minute up to sub-hourly). Access to these same benefits from east side plants would depend upon BPA transmission policies. Given these considerations, and the small difference in cost between the two, PSE chose to include west side peakers in the resource plan.

Figure 6-34: Annual Revenue Requirements and Total Portfolio Costs for Gas Plants Located East and West of the Cascades



E. Gas Transport/Oil Backup for Peaking Plants

What if peakers cannot rely on oil for backup fuel and must have firm gas supply instead?

> **Baseline: Peakers are modeled assuming they have 50 percent firm pipeline capacity with 48 hours of oil backup fuel.**
> **Sensitivity: Model plants with 100 percent firm pipeline capacity and no oil backup capability.**

PSE has been reviewing its simple cycle combustion turbines (SCCT) (aka: “peakers”) that have the capability to generate with natural gas or distillate fuel oil to determine if oil generation would be adequate to keep these plants operating to meet extreme winter peak demand in winter months. Several components were involved in the review:

1. Supply of Backup Fuel: Current use practices, policies and oil generation capacity from peaker oil storage tanks,
2. Supply of Non-firm Gas Supply: Review of any excess existing firm gas pipeline capacity in the gas sales portfolio that could be available to serve the SCCT peaking plants, and
3. Demand/Need for Non-firm Gas Supply: Review of 2021 peaker generation modeled to meet gas sales demand during peak winter months.

CURRENT USE PRACTICES, POLICIES AND OIL GENERATION CAPACITY

PSE's run time on distillate fuel for winter months is limited to the capacity of the fuel oil tanks at each site because we have limited ability to quickly refill the tanks via tanker trucks during the inclement weather of winter months. The current policy is to keep 53 hours of oil in the tanks (48 hours for generation plus five hours for testing) - even though they have capacity to hold several more days. Based on the current air permits for the peaking plants, there are no constraints with running the plants on oil to meet peaking needs during the winter months as noted below.

See Figure 6-35 for more generation information for the peaking plants.

Figure 6-35: Peaking Plants, Summary Information

Simple Cycle Combustion Turbine (Peaker)	No. of Oil Tanks[1]	Oil Tank Capacity (gallons)	Oil use per Day (gallons)	Oil Gener-ation (days)	Peak Capacity (MW)	Oil gener-ation for 48 hours (MWh)	Generation per Tank of Oil (MWh)[2]
Whitehorn 2 & 3	1	5,914,971	340,938	17	168	8,064	69,952
Frederickson 1 & 2	1	4,070,766	340,935	12	168	8,064	48,142
Fredonia 1 & 2	1	5,914,971	455,832	6	234	11,232	36,364
Fredonia 3 & 4			207,720	6	126	6,048	19,581
Total		**14,282,295**	**1,345,428**		**696**	**33,408**	**174,038**

NOTES
Fredonia 1 & 2 and 3 & 4 share one oil tank.
Estimated generation at peak demand temperatures of 23 degrees.

REVIEW OF ANY EXCESS EXISTING FIRM GAS PIPELINE CAPACITY IN THE GAS SALES PORTFOLIO

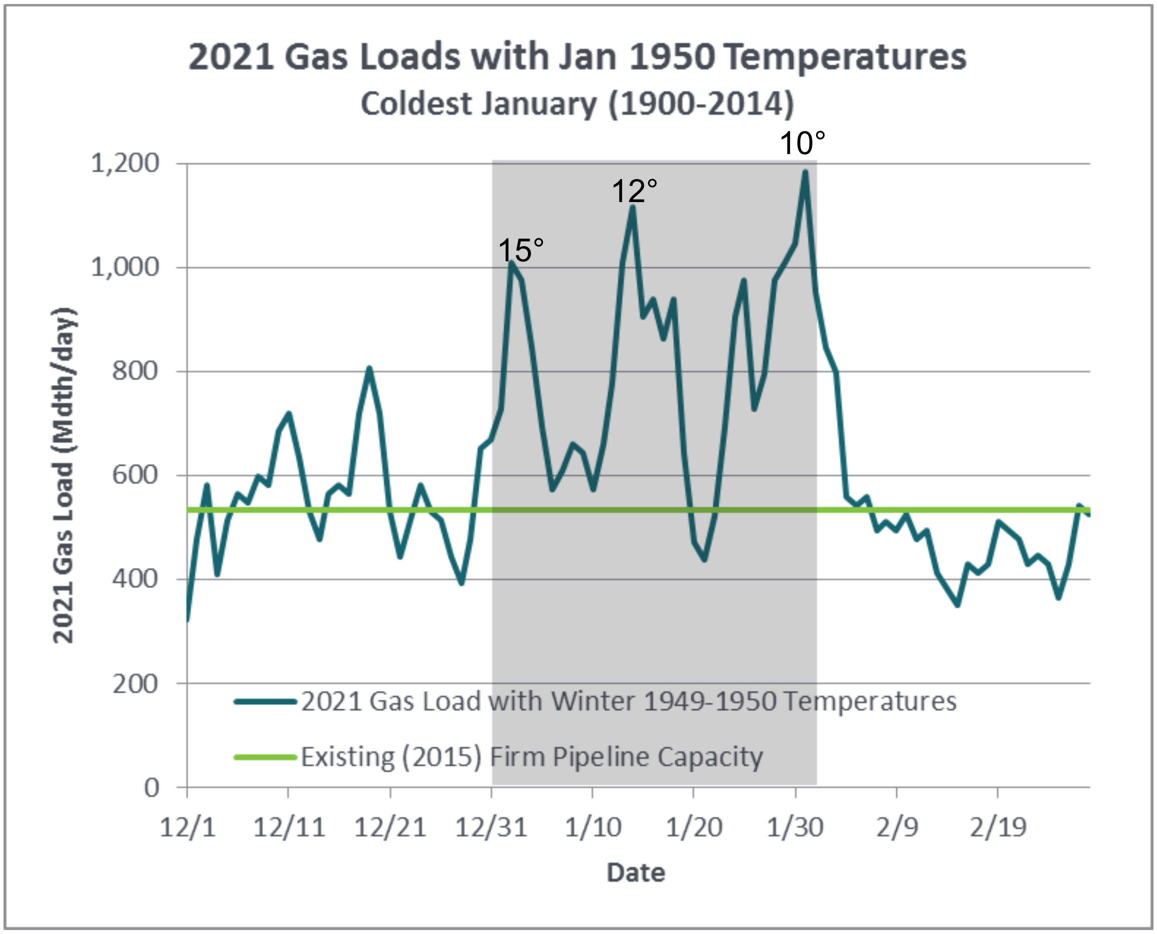
Will non-firm gas supply be available from Northwest Pipeline when the peakers need it, after consuming the fuel in their oil tanks? There is no gas industry organization that studies these kinds of questions, the way the NPCC's Resource Adequacy Advisory Committee studies regional electric supply. We can, however, study our own gas utility loads and resources in order to draw conclusions about the availability of non-firm fuel supply. Here we examine whether excess firm gas is available from the gas utility during peak days. Peak need was determined using the gas portfolio model (Sendout) and historical temperature data sets.

A historical temperature data set (1900-2014) for the region was obtained from the National Oceanic and Atmospheric Administration (NOAA). To create a long term data set we combined daily weather data from the Portage Bay Weather Station from 1900-1948 and from SeaTac International Airport from 1949-2014 to create a 114 year temperature record. Average daily temperatures were calculated as the average of the minimum temperature and maximum temperature.

Using the 114 years of daily historical temperature data, 114 gas load profiles were created with 2021 loads using the Gas Portfolio Model (GPM). Months with high gas loads (December and January) were examined further and compared to our existing daily firm gas pipeline supply (533 Mdth/day) to determine if the gas utility could meet the gas load using the firm pipeline supply.

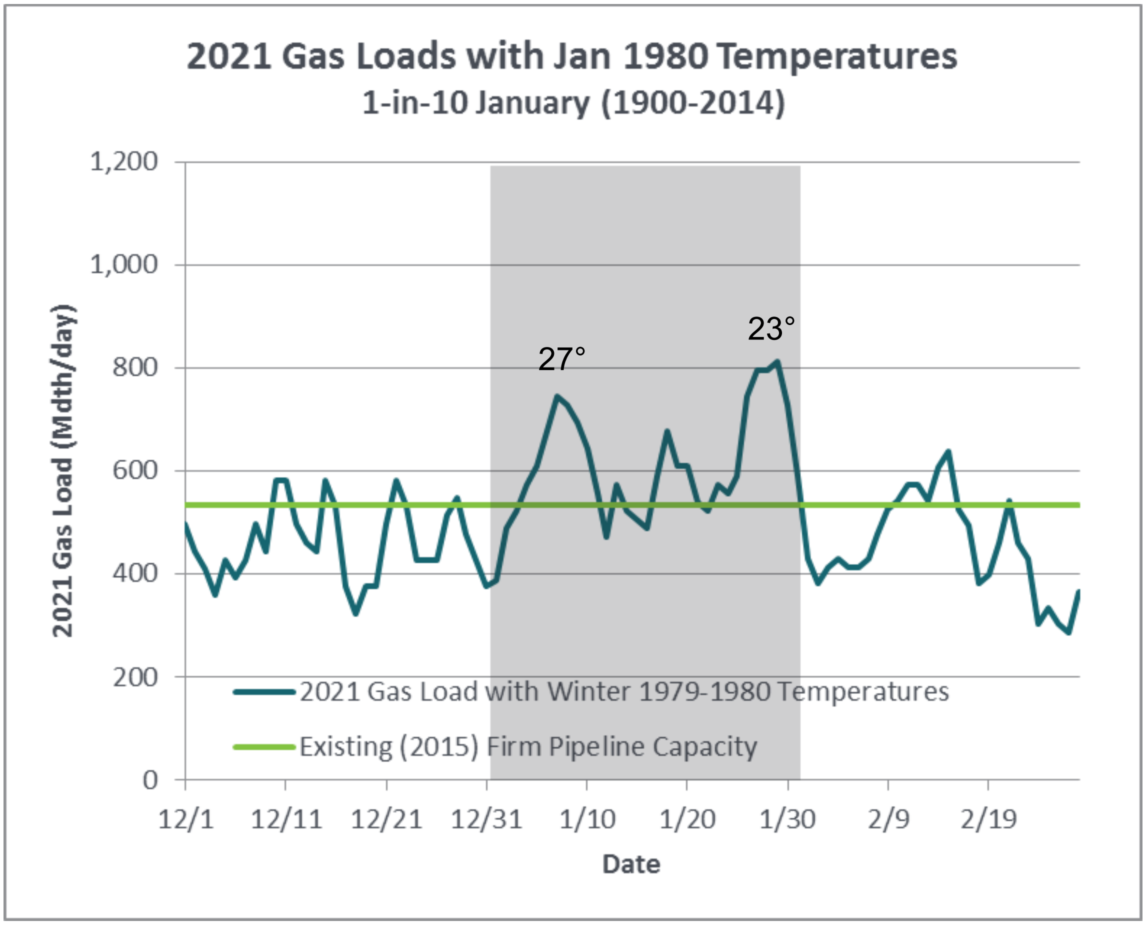
Below are three charts showing different possible 2021 gas loads using three different years of historical temperatures. Figure 6-36 shows December 1949 to February 1950 with January 1950 highlighted in grey. January 1950 was the coldest month in the 114 year dataset, with extreme cold spells occurring three times throughout the month. With 2021 gas loads and this temperature pattern, the demand is greater than the existing firm pipeline capacity for most of the month, only dropping below 533 Mdth/day for 3 days. In addition to the firm pipeline supply, fuel from Jackson Prairie storage can be used to meet gas and electric loads. Gas storage at Jackson Prairie can be withdrawn to meet loads, but is also refilled throughout the winter on lower load days. Therefore, even if the load was below 533 Mdth for the 3 days during this example, the fuel would likely go toward refilling Jackson Prairie storage and would not be available for running the peaking units to generate electricity.

Figure 6-36: 2021 Gas Sales Utility Loads with Winter 1949-1950 Weather



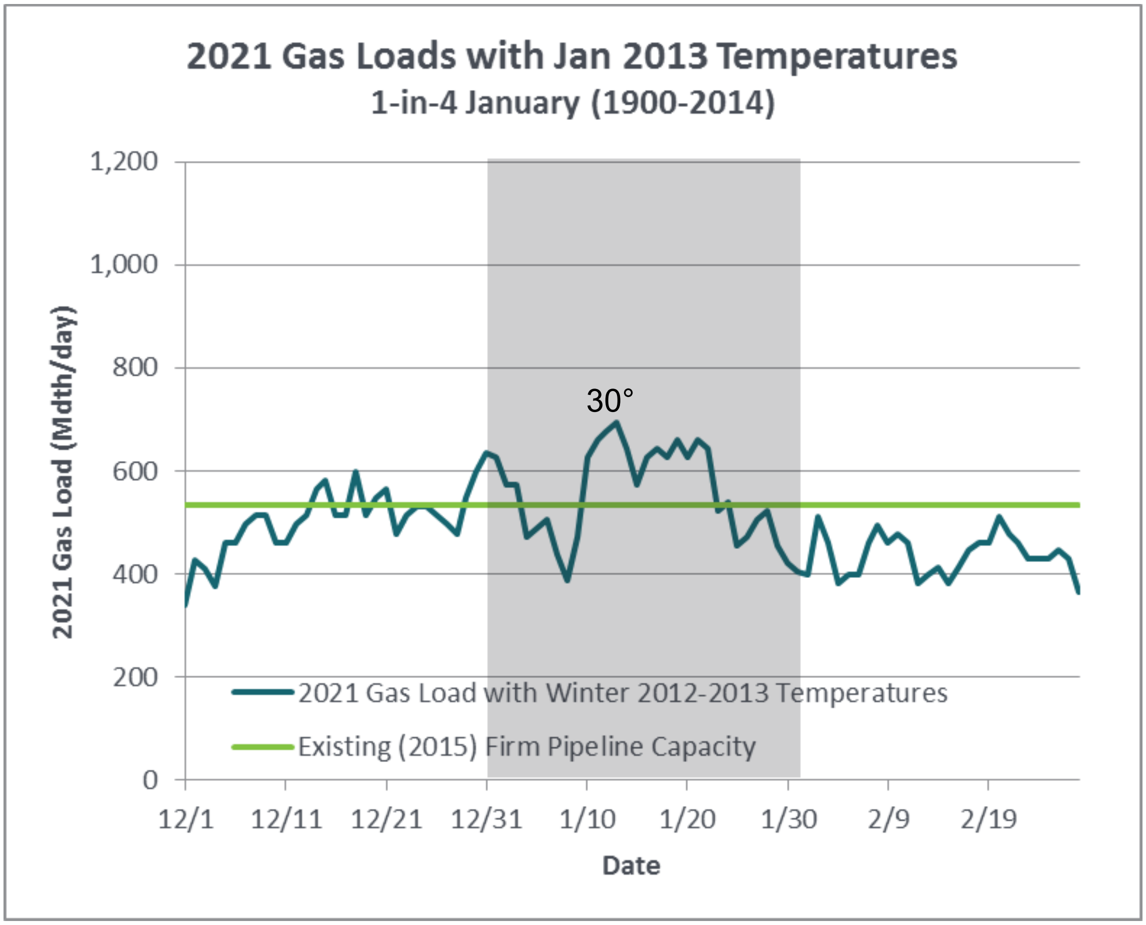
January 1950 was the most extreme month in the data set. January 1980 (Figure 6-37) represents a 1-in-10 January, meaning that 1-in-10 Januaries in the data set were as cold or colder than 1980. The January 1980 peak temperatures are higher than the January 1950, but the load is still above the firm pipeline capacity for much of the month, and therefore not available to run peakers during that time. In this example, 8 days had loads below 533 Mdth/day, however some or all of that excess volume would still go to refill storage and therefore, on those days, the fuel would not be available for running the peakers.

Figure 6-37: 2021 Gas Sales Utility Loads with Winter 1979-1980 Weather



A more recent and less extreme data set is January 2013 (Figure 6-38). In this data set, 17 days in January were above the existing firm pipeline capacity, so on those days there would be no excess pipeline capacity for peakers, and gas from storage would be used to meet gas utility loads.

Figure 6-38: 2021 Gas Sales Utility Loads with Winter 2012-2013 Weather



When loads are above the existing firm pipeline capacity (533 Mdth per day) there is no excess pipeline capacity for peakers and some or all of storage capacity is used to meet gas utility loads. When loads are below 533 Mdth per day in the winter some or all of the excess volume is being used to refill storage, depending on how storage volume that has been used, the monthly ending target for storage volume, and the short term weather forecast is. In more mild years some or all of this volume may be available to fuel the peaking units.

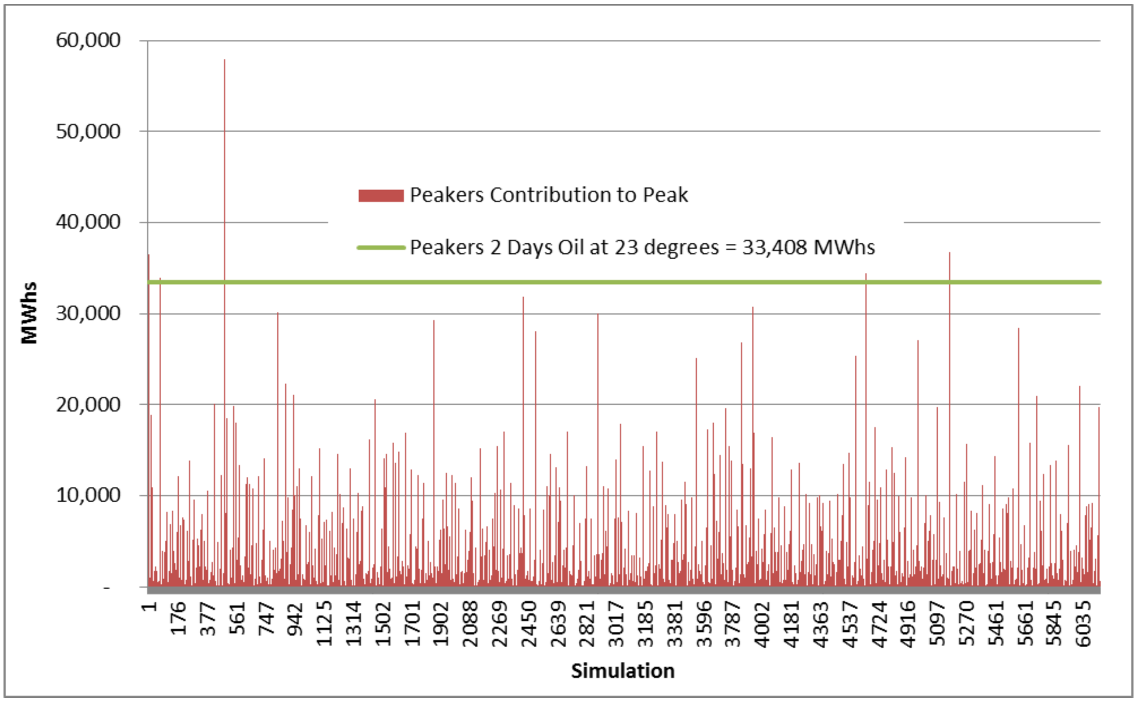
Therefore, there are times that the electric utility cannot rely on surplus gas supply for fuel for generation. These times are typically during cold weather events in the winter when the gas supply is peaking. Peakers are likely needed on cold days when there are peaks in the gas need.

REVIEW OF 2021 PEAKER GENERATION MODELED TO MEET GAS SALES DURING PEAK WINTER MONTHS

Having established that PSE's electric utility should not rely on non-firm fuel supply for extended periods in the winter, we turned our attention to whether existing oil inventories were sufficient. To examine this question, we used PSE's RAM to do a comparative sensitivity analysis. We started with a baseline case that included the peakers in the RAM, subject to the base forced outage rates and all other assumptions. The winter unserved energy in MWh was calculated in each of 6,160 simulations. We then performed another case, where all the dual-fueled peakers were excluded, and again calculated the MWh of unserved energy in each of 6,160 simulations. The additional MWh of unserved energy represents the number of MWh, by simulation, the peakers are needed to meet load across the entire winter. In this analysis, the only difference is inclusion of the dual-fuel peakers. Therefore, we can compare the MWh needed with the MWh that could be generated with 48-hours of oil supply in the tanks.

Figure 6-39 illustrates that the peakers are needed for reliability purposes in many simulations. However, the chart also illustrates 48-hours of oil inventory is sufficient to cover all but five of the 6,160 simulations. This analysis is conservative, in that it does not provide for the ability to refill the oil tanks at any time throughout the winter – the inventory is assumed to be fixed. Results of this analysis demonstrate that backup fuel for the existing units is sufficient. This analysis is not directly applicable to new peakers, but does provide important insights. That conclusion will be driven by whether backup fuel can be permitted at a specific location and by the maximum run hours allowed. We now have a framework for analyzing whether new peakers with backup fuel will need firm pipeline capacity.

Figure 6-39: Back-up Fuel for Existing Dual Fuel Units



F. Energy Storage and Flexibility

What is the cost difference between a portfolio with and without energy storage. How do energy storage resources impact system flexibility?

Baseline: Batteries chosen only if analysis selects them as lowest economic cost.
Sensitivity 1: Add 80 MW battery in 2023 instead of economically chosen peaker.
Sensitivity 2: Add 80 MW pumped hydro storage in 2023 instead of economically chosen peaker.
Sensitivity 3: Add 200 MW of pumped hydro storage in 2023 instead of economically chosen peaker.

The optimal portfolio in the 2015 IRP Base Scenario added an 80 MW battery in 2035, the final year of the study period, primarily because it was the right size needed for the price; when additional resources are first needed starting in 2021, most scenarios we analyzed added frame peakers in that year. This sensitivity analysis explores two energy storage alternatives to that selection, batteries and pumped hydro. The first year additional resources are needed according to the 2015 IRP Base Scenario demand forecast and 2013 planning standard is in 2023.

Pumped Storage. Pumped hydro is a proven storage technology: however, the facilities are very expensive to build and may have controversial environmental impacts. They also have extensive permitting processes and require sites with specific topologic and/or geologic characteristics.

The assumed overnight cost to construct pumped storage is $2,400 per kW in 2014 dollars as compared to $896 per kW for a frame peaker. The analysis assumes no benefit for ancillary services. Pumped storage projects are usually very large, so realistically PSE would have to partner with other owners for a share of the project. For example, the proposed JD Pool pumped storage hydro project in southern Washington is estimated to be 1,500 MW. The analysis tested two sizes of pumped storage, 80 MW and 200 MW, adding them in 2023. As shown in Figure 6-40, 80 MW of pumped storage would increase portfolio cost by $200 million, and 200 MW of pumped storage would increase it by $638 million.

Batteries. Historically, electricity is consumed immediately after it is created. The emergence of a new generation of advanced batteries which allow for storage on the grid has led to the first instances of large-scale energy storage for the electric distribution network. Batteries can also provide ancillary services such as spinning reserves and frequency regulation, along with peak capacity.

Batteries were chosen in the deterministic portfolio for the Base Scenario in 2035 due to how they fit into the portfolio in the very last year of the peak capacity calculation. This sensitivity forces a battery into the portfolio build in 2023 that could provide 2 hours of maximum capacity at 80 MW. For purposes of the analysis, batteries are assumed to provide 100 percent peak capacity credit. Forcing the 80 MW battery into the portfolio build at 2023 increased the portfolio cost by $97 million. Batteries would have to provide $150 per kW in flexibility to match the optimal portfolio in the Base Scenario, which is above what would be deemed reasonable. As part of the operational flexibility analysis, batteries have a benefit of $99.52 per kw per year.

Figure 6-40: Battery and Pumped Storage Portfolio Cost

	NPV Portfolio Cost ($Millions)	Difference from Base
Base Portfolio[1]	12,277	
80 MW Pumped Storage in 2023	12,478	201
200 MW Pumped Storage in 2023	12,915	638
80 MW Batteries in 2023	12,374	97
80 MW Batteries in 2023 with $150/kw-yr Flexibility Value[2]	12,277	-

NOTES
1 Includes 80 MW of batteries in 2035
2 Represents the tipping point for the flexibility value to bring batteries in line with the base portfolio.

G. Reciprocating Engines and Flexibility

How do reciprocating engines affect system flexibility?

Baseline: Reciprocating engines chosen for portfolio only if deterministic analysis selects them as lowest economic cost.

Sensitivity 1: Add 75 MW reciprocating engine in 2023.

Sensitivity 2: Analyze lower costs for additional 75 MW reciprocating engine in 2023

Reciprocating engines could provide valuable operational flexibility benefits to the portfolio. Since they are able to start up relatively quickly and are able to quickly ramp up and down, they can be used for load balancing purposes and other ancillary services.

The 2013 IRP flexibility analysis was used as the basis for this sensitivity examination. The stochastic analysis developed over 50 simulations to model the 2013 IRP Base Scenario portfolio with an incremental reciprocating engine, a combined cycle plant and a frame peaker to calculate the expected annual savings in balancing costs as compared to the Base Scenario portfolio. Figure 6-41 summarizes the results..

Figure 6-41: Summary Results from 2013 IRP Stochastic Flexibility Analysis, 50 Simulations

Portfolio	Capacity (MW)	Expected Annual Balancing Savings ($)	Expected Annual Balancing Savings ($/kW Capacity)
Base Portfolio + CCCT	343	$800,000	$2.33
Base Portfolio + Frame CT	220	$1,037,000	$4.69
Base Portfolio + Recip	18	$328,000	$18.23

For the 2015 IRP, the fixed operations and maintenance (O&M) costs were adjusted for each type of generic resource based on the expected annual savings from the 2013 IRP analysis. In addition, capital cost estimates for reciprocating engines were also updated based on alternative pricing estimates from a secondary source. Finally, the analysis included a smaller 75 MW reciprocating engine option as a resource alternative in the portfolio optimization, since the Base Scenario analysis included only a 220 MW option. These capital costs and fixed O&M assumptions are shown in Figure 6-42.

Figure 6-42: 2015 Flexibility Analysis, Capital Cost and O&M Cost Assumptions

2015 IRP- Reciprocating Engines Resources

2014 $	Units	Original Recip Engine (Base)	Updated Recip Engine (Small Size)	Updated Recip Engine (Large Size)	Updated Recip Engine w/ Flexibilty (Small Size)	Updated Recip Engine w/ Flexibilty (Large Size)
ISO Capacity Primary	MW	220	75	224	75	224
Winter Capacity Primary	MW	220	75	224	75	224
Capacity DF	MW					
Capital Cost	$/KW	$1,599	$1,404	$1,175	$1,404	$1,175
O&M Fixed	$/KW-yr	$5.31	$5.31	$5.31	($12.92)	($12.92)

This sensitivity analysis shows the difference in portfolio cost between the Base Scenario least-cost portfolio, which selected no reciprocating engines, and an alternative portfolio optimized around a reciprocating engine that was forced into the portfolio in 2023, the first year additional resources are needed. The analysis was broken down into 3 cases, based on the degree of flexibility benefit used in the evaluation:

1. no flexibility benefit is included,
2. full flexibility benefit for all technologies is included, and
3. a 50 percent flexibility benefit is assigned to reciprocating engines, and full flexibility benefit is assigned to the other technologies.

Each analysis included 3 portfolio alternatives for comparison to the Base Scenario least-cost portfolio:

1. a portfolio in which the screening model was allowed to choose a 75 MW reciprocating engine option,
2. a portfolio which optimized around a 75 MW reciprocating engine option built in 2023, and
3. a portfolio which optimized around a 224 MW reciprocating engine option built in 2023.

The results are shown in Figure 6-43 on the next page.

Figure 6-43: Portfolio Sensitivity Analysis, Reciprocating Engines ($Millions)

NPV ($Millions)	No Flexibility Benefit		With Flexibility Benefit			With Flexibility Benefits at 50% for Recip Peakers		
	Portfolio Cost (a)	Difference from Base (b)	Portfolio Cost (c)	Difference from Base (d)	Value of Flexibility to Portfolio (e) = (a)-(c)	Portfolio Cost (f)	Difference from Base (g)	Value of Flexibility to Portfolio (h) = (a)-(f)
Base Portfolio	12,277		12,221		56	12,221		56
Recip Peaker 75 MW*	12,263	14	12,202	19	61	12,208	14	56
Recip Peaker 75 MW in 2023	12,282	(5)	12,212	10	70	12,221	1	61
Recip Peaker 224 MW in 2023	12,354	(77)	12,235	(13)	120	12,260	(40)	93

** Replaces battery in 2035 as cheaper alternative*

In all three cases, the analysis selects a 75 MW reciprocating engine build in 2035 rather than the battery selected in the Base Scenario optimal portfolio. The portfolio benefit ranges from $13.6 million to $19.5 million.

Forcing a 75 MW reciprocating engine into the 2023 portfolio build would result in a $5.0 million portfolio cost in the no flexibility case as compared to the Base Scenario optimal portfolio, a $9.5 million benefit in the full flexibility case, and $0.7 million benefit for the 50 percent flexibility case.

The benefit derived from the flexibility cases is really a comparison between a 75 MW reciprocating engine and a battery. The optimal portfolios in the flexibility cases indicate that building the 75 MW reciprocating engine in 2035 instead of 2023 provides a portfolio benefit of over $10 million. The larger build for reciprocating engines (224 MW in 2023) results in a higher portfolio cost that ranges between $13.4 million and $77.4 million, depending on the flexibility case.

On a dollars per kW basis, reciprocating engines are more expensive than frame peakers. The current results do not indicate a compelling need for reciprocating engines in the near term, but they have certain advantages that merit consideration. They can be installed in 18 MW increments that could provide a right-sizing approach, and they can provide added value through flexibility benefits. The flexibility of each type of technology needs to be further examined since the market is moving towards addressing the industry’s flexibility needs.

H. Montana Wind

Update transmission cost for Montana wind to be more optimistic if Colstrip continues to operate. Will Montana wind be chosen in the lowest cost portfolio?

Baseline: Assume PSE cost estimate for transmission upgrades to Montana.

Sensitivity: Assume lower transmission cost estimate.

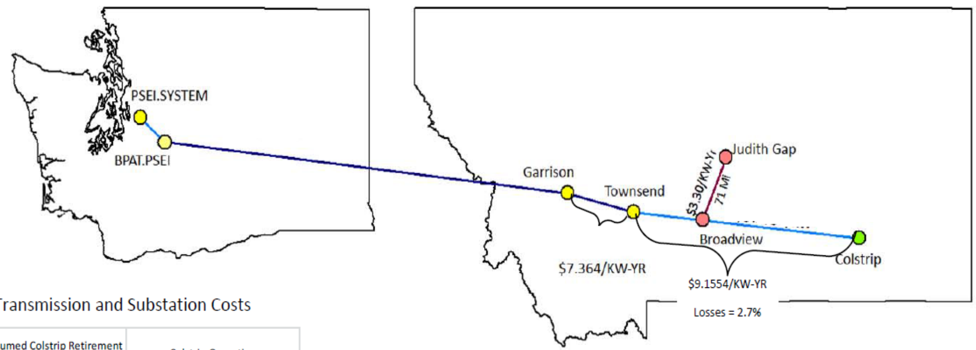
Montana wind has the benefit of higher capacity factors than Washington wind (41 percent versus 31 percent), but it also has the added costs of transmission to move the power to PSE's system. In addition, whether Montana wind qualifies as a qualifying renewable resource under RCW 19.285 depends on the location of the facility—most of the prime wind resources in Montana are outside the footprint defined in the law. Montana wind is viewed as a capacity resource that is compared to dispatchable resources used to meet peak capacity need in the analysis.

Additional analysis was done to examine Montana wind more closely. We assumed that the Montana wind project is located at Judith Gap, and did the analysis assuming Colstrip continues to operate and assuming there is excess transmission capacity with retirement of Colstrip. As shown below, this would require four transmission paths to deliver the power to PSE's system:

1. Wind facility (Judith Gap) to Broadview
2. Broadview to Townsend
3. Townsend to Garrison
4. Garrison to PSE's system

Broadview to Garrison is fully committed for Colstrip operations, therefore there is no excess capacity to accommodate additional wind capacity unless the transmission lines are upgraded or some of Colstrip is retired. With additional transmission losses of 6.7 percent as shown in Figure 6-44 below, the 41 percent capacity factor at the source is effectively 38 percent when delivered to PSE's system. The capacity factor for Washington wind is 34 percent. Montana wind also incurs the added annual cost of transmission for each of the transmission segments. See the transmission map in Figure 6-46 for the transmission path from Montana.

Figure 6-44: Montana Wind Transmission Paths



Transmission and Substation Costs

Assumed Colstrip Retirement Colstrip Operating	Colstrip Operating
A) $32.4 Million- Upgrade JG-Broadview Line	C) $662 Million- Upgrade JG-Broadview Line + Expand Broadview Sub + New Broadview-Garrison Line + Expand Garrison Sub
B) $94.2 Million- New JG-Broadview Line + Broadview Sub. Upgrade	D) $724 Million- New JG-Broadview Line + Expand Broadview Sub + New Broadview-Garrison Line + Expand Garrison Sub

*Right Of Way costs are not included in estimate of new transmission lines
*Assuming plant size of 265 MWs
*Costs only reflect additional substation/transmission equipment does not include transmission wheeling or cost to build wind facility
*Overheads not included

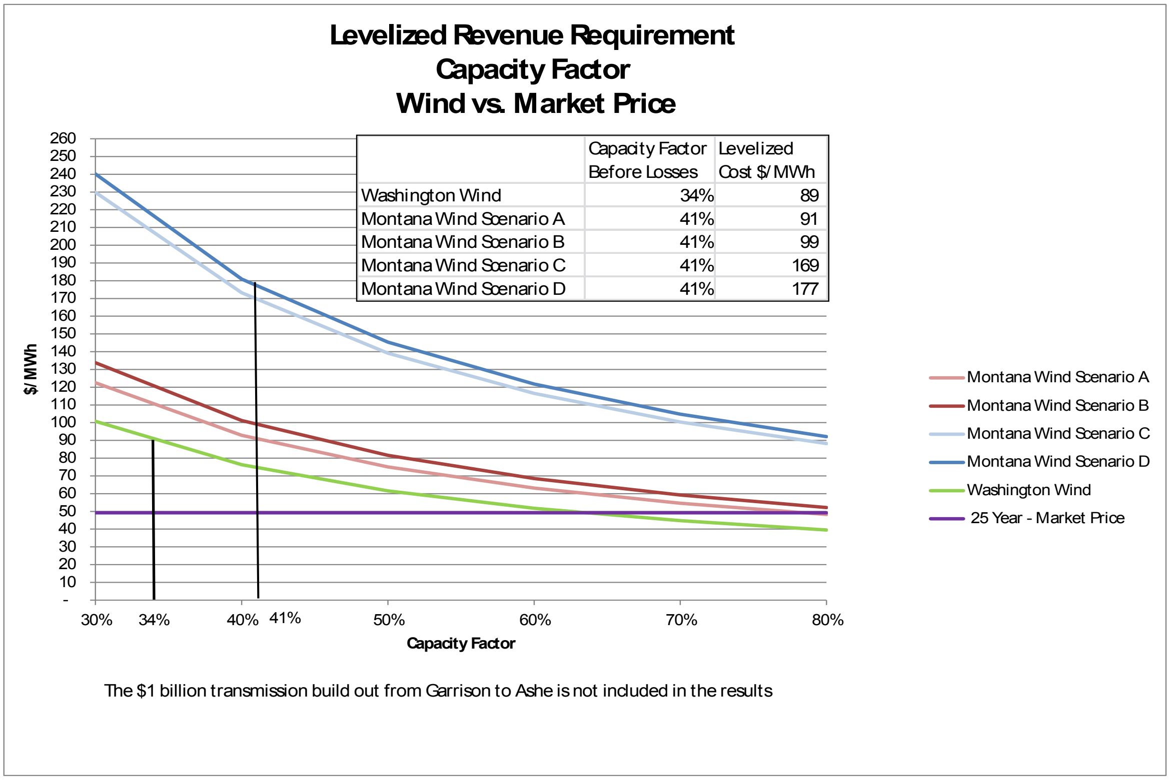
Wind Capacity	Percentage
MT Wind Capacity Factor	41.00%
Loss Factor	6.70%
Wind Capacity Net of Losses	38.30%
Transmission Costs	**$/KW-Year**
Judith Gap to Broadview	$ 3.3000
Broadview to Townsend	$ 9.1550
Townsend to Garrison	$ 7.3640
Total	**$ 19.8190**
$/MWh	**$ 5.5200**

The sensitivity analyses and incremental transmission costs are as follows. The costs in the following scenarios include three substations at the wind facility.

A. Colstrip Retired
   - Upgrade current NorthWestern line from wind facility to Broadview
   - $32.4 million - $122 per kW
B. Colstrip Retired
   - Build new line from wind facility to Broadview
   - $94.2 million - $355 per kW
C. With Colstrip Operations
   - Upgrade current NorthWestern line from wind facility to Broadview
   - Upgrade Colstrip line to Garrison
   - $662 million - $2,489 per kW
D. With Colstrip Operations
   - Builds new line from wind facility to Broadview
   - Upgrade Colstrip line to Garrison
   - $723 million - $2,728 per kW

Figure 6-45 shows the impact of the levelized costs versus capacity factor of wind as compared to market price.

Figure 6-45: Levelized Costs and Capacity Factors Compared, Montana Wind, Washington Wind and Market Price



	Capacity Factor Before Losses	Levelized Cost $/MWh
Washington Wind	34%	89
Montana Wind Scenario A	41%	91
Montana Wind Scenario B	41%	99
Montana Wind Scenario C	41%	169
Montana Wind Scenario D	41%	177

The results are as follows:

- Washington wind is comparable to market purchases at about a 65 percent capacity factor.
- Montana wind is $2 to $10 per MWh higher than Washington wind in the Colstrip Retired-Low Cost Scenario A.
- Montana wind is $80 to $88 per MWh higher than Washington wind in the Continued Colstrip-High Cost Scenario D.
- Montana wind is not selected as a resource in the optimization model.

Wind Scenarios. PSE analyzed an additional Montana wind scenario that included lower cost estimates in response to requests by interested parties. The assumptions for that analysis are listed below, followed by the results of the analysis in Figure 6-46.

1. Capital costs were reduced from $4,913 to $2,381 per kW,
2. Montana transmission line losses were reduced from 6.7 percent to 5.4 percent, and
3. Transmission costs were reduced from $55.05 to $51.75 per kW per yr.

Figure 6-46: Reduced Cost Montana Wind Analysis

Wind Costs

2014 $	WA Wind	MT Wind Base	MT Wind Update
Capital Cost Facility ($/kW)	$1,703	$1,703	$1,703
Sales Tax ($/kW)	$123		
Transmission/Substations ($/kW)		$2,813	$507
AFUDC ($/kW)	$141	$396	$171
Total Capital Cost ($/kW)	$1,968	$4,913	$2,381
Northwestern Line Losses		4.0%	2.7%
PSEI Colstrip Line Losses		2.7%	2.7%
Montana Losses		6.7%	5.4%
BPA Line Losses	1.9%	1.9%	1.9%
Total line losses	1.9%	8.6%	7.3%
Capacity Factor	34%	41%	41%
O&M Variable ($/MWh)	$3.15	$3.15	$3.15
Variable Transmission ($/MWh)	$1.84	$1.84	$1.84
Northwestern to Broadview		$3.30	$0.00
PSE tariff - Broadview to Townsend		$9.16	$9.16
BPA tariff - Townsend to Garrison		$7.36	$7.36
BPA tariff - Garrison to PSE	$35.23	$35.23	$35.23
Total Fixed Transmssion Cost ($/kW-yr)	$35.23	$55.05	$51.75
O&M Fixed ($/kw-yr)	$27.12	$27.12	$27.12

An important factor for comparing Montana wind to a dispatchable capacity resource is the capacity credit to meet peak loads. That is, what is the ICE for Montana wind? Hourly data is necessary to develop capacity credits, and though information over a number of years exists for the annual capacity factor, the hourly data is limited. However, PSE was provided with hourly Montana wind data for a 2-year period. This data indicated a peak capacity credit for a site at Judith Gap of 55 percent with an annual capacity factor of only 41 percent. Comparatively, Washington wind, for which we have 9 years of hourly data, provides only an 8 percent peak capacity credit. The validity of the peak capacity credit for Montana wind needs to be verified over a longer time period. Also, the capacity contribution of Montana wind was based on a 5% LOLP method for calculating the ICE—it was not updated to use 10.9 MWh EUE. We will shift to the EUE approach in future IRPs. .

See Figure 6-47 for the Montana wind results assuming continued operations at Colstrip. The base case did not select Montana wind given the prohibitively high capital costs of $4,913 per kW. The analysis below assumes a 300 MW Montana Wind build in 2023 at the reduced capital cost of $2,381/kW; but this is still high relative to Washington wind at $1,968 per kW. The analysis assumes the Montana wind does not qualify for the renewable portfolio standard given its location in Montana near Judith Gap; therefore it is viewed only as a peak capacity resource. The peak capacity credit was varied from 55 percent to 40 percent for Montana wind to test how high the capacity credit would need to be for Montana wind to be cost effective. This resulted in an increase in portfolio costs ranging from $184 to $226 million.

Figure 6-47: 300 MW Montana Wind added in 2023, tested at four different Capacity Credits

NPV (Millions $)	Portfolio Cost	Difference from Base Benefit/(Cost)
Base Portfolio (no MT Wind)	$12,277	
Add 300 MW MT Wind with 55% capacity credit	$12,462	($184)
Add 300 MW MT Wind with 50% capacity credit	$12,474	($197)
Add 300 MW MT Wind with 45% capacity credit	$12,483	($206)
Add 300 MW MT Wind with 40% capacity credit	$12,503	($226)

I. Solar Penetration

What if customers install significantly more rooftop solar than expected?

Baseline: Rooftop solar growth based on forecast of current growth trends.

Sensitivity: Assume maximum capture of rooftop solar.

Distributed solar generation has never been selected in the portfolio analysis as a cost-effective resource for the PSE system, but federal tax credits and state production incentives have made it cost-effective for customers. Already, PSE has 2,800 net-metered customers who have installed rooftop solar panels totaling 17.4 megawatts of capacity and 17,360 megawatt hours of annual energy, and we expect many more customers will install solar panels in the future.

For this IRP, the Cadmus Group prepared a system-wide study that explored the maximum potential for rooftop solar within the PSE system. It asked how much distributed solar might be added to the system in two scenarios:

1. if federal and state incentives are renewed, and
2. if incentives are allowed to sunset.

The Baseline assumption for portfolio modeling allowed the incentives to expire. This resulted in an additional 3 MW nameplate capacity or 0.18 aMW by 2035 that was added to the portfolio as a no-cost resource that reduced demand.

The sensitivity analysis assumed that all federal and state incentives were renewed; this resulted in a total of 309 MW nameplate capacity or 36.7 aMW of additional rooftop solar. The additional solar PV will reduce the total energy needed for the portfolio, but will not change the amount of capacity needed, since PSE's system peak occurs during December before sunrise or after sunset, it does not contribute towards peak. So the sensitivity with the additional 36.7 aMW of solar has a lower total expected portfolio NPV than the Base Scenario portfolio by $65.59 million due to the lower market purchases needed, but the portfolio builds are exactly the same.

J. Carbon Reduction

How does increasing renewable resources and DSR beyond requirements affect carbon reduction and portfolio costs?

Baseline: Renewable resources and DSR per RCW 19.285 requirements.
Sensitivity 1: Add 300 MW of wind beyond renewable requirements.
Sensitivity 2: Add 300 MW of utility-scale solar beyond renewable requirements
Sensitivity 3: Increase DSR beyond requirements.

Wind. In this analysis, 300 MW of wind was added to the portfolio in 2021 and the changes in portfolio costs and emissions relative to the least-cost portfolio in the Base Scenario were used to calculate the incremental cost per ton over the 25-year period 2021-2045. The 25-year analysis period was chosen as it represents the depreciable life of the wind plant.

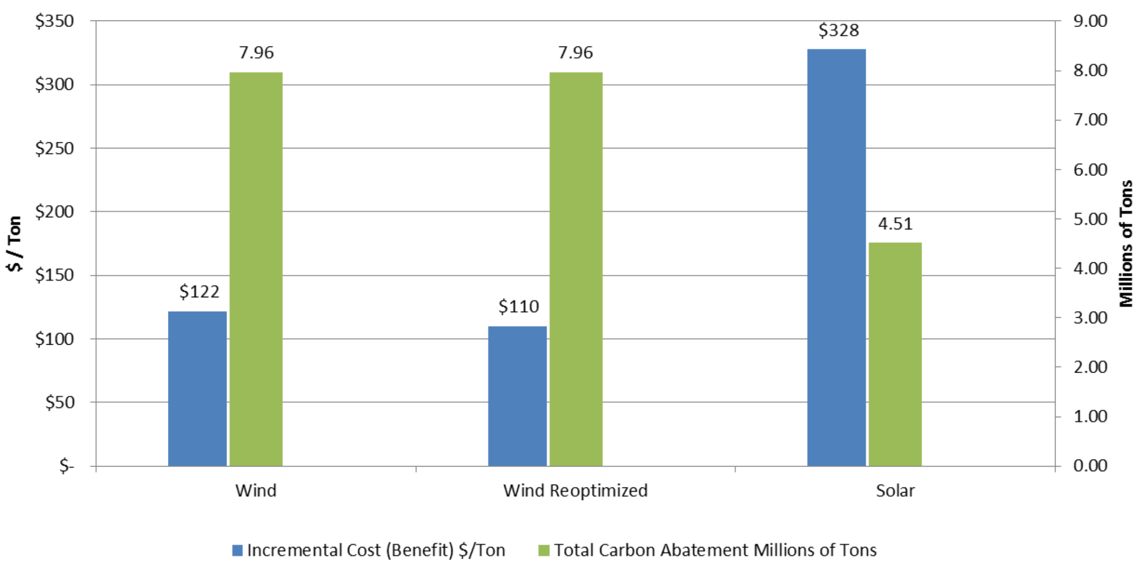
For the first case, the wind was added without re-optimizing the portfolio in order to determine its impact as a stand-alone resource. In a second case, the portfolio model was re-optimized to determine the additional wind's impact on the portfolio. In this case, demand-side resources were fixed at the levels selected in the optimal Base Scenario portfolio to isolate the impact on supply-side resources. The addition of wind resulted in one-year delays in the acquisition of two peakers during the 20-year planning horizon relative to the Base Scenario optimal portfolio.

In addition to examining Montana wind, this IRP also includes an analysis of adding an additional 300 MW of wind in 2021, above and beyond the amount required by the RPS. When modeling wind for the RPS, we include the cost of replacing the plant at the end of its useful life as part of the end effects, but for examining the cost of this extra wind, we did not, so that the results would focus on only the impact of this wind on PSE portfolio costs.

Solar. For the solar analysis, 300 MW of utility-scale solar was added to the optimal Base Scenario portfolio in 2021. Because solar does not contribute to the peak capacity need, it was not necessary to re-optimize the portfolio model.

Wind and Solar Results. For the wind and solar analyses, the purpose was to estimate the changes in portfolio cost and emissions that resulted from these additions, and to estimate the incremental cost of reducing emissions on a dollar-per-ton basis. In this analysis, all the changes in portfolio cost are included in the unit cost of carbon abatement, whereas in reality, the addition of a resource brings other benefits as well. Total incremental carbon abatement and the incremental cost per ton that resulted are presented in Figure 6-48.

Figure 6-48: Additional 300 MW Wind or Solar,
Incremental Revenue Requirement and Total Carbon Abatement, 2021-2045



Incremental revenue requirement per ton of emissions relative to base scenario, levelized over 25 years. Sum of carbon abatement over 25 years relative to base scenario.

In all three analyses, adding a renewable resource increases portfolio cost and reduces emissions. The incremental cost of carbon abatement is estimated at $122 per ton when wind is added without re-optimizing the portfolio, $110 per ton when adding wind and re-optimizing, and $328 per ton when solar is added. These results are presented in Figure 6-49.

Figure 6-49: Additional 300 MW of Wind or Solar, Incremental Cost per Ton of Carbon Abatement, 2021-2045

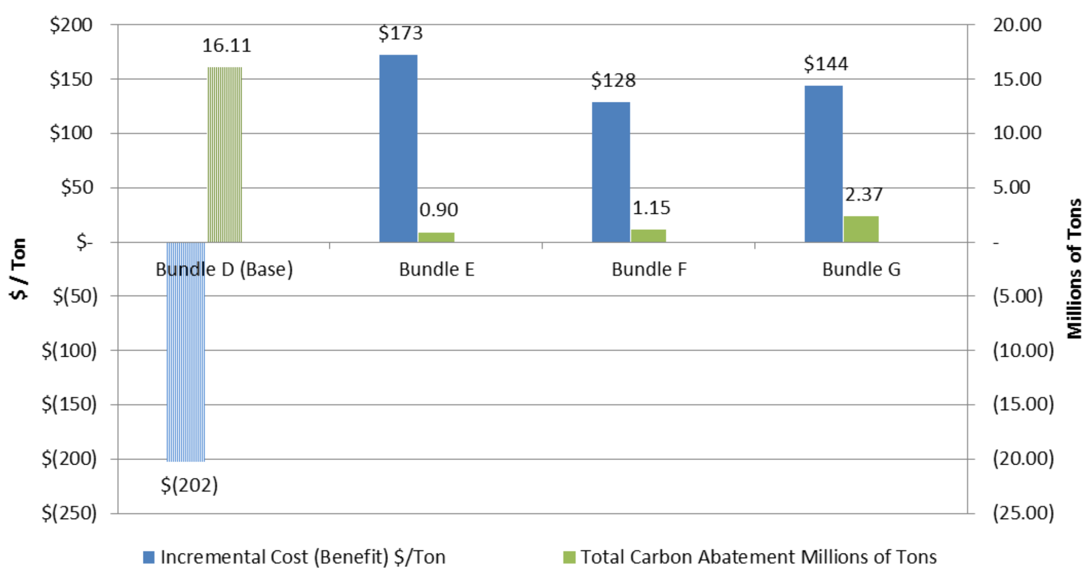
(Thousands $)	Wind	Wind Re-optimized	Solar
Base Scenario NPV Expected Cost	$12,008,998	$12,008,998	$12,008,998
NPV Expected Cost	$12,431,986	$12,391,240	$12,653,231
NPV Incremental Cost	$422,989	$382,242	$644,233
Levelized Cost ($Thousands / Year)	$38,849	$35,107	$59,170
Avg. Incremental Emissions (Millions Tons/Year)	(0.32)	(0.32)	(0.18)
Incremental Cost ($ / Ton)	$122	$110	$328

Demand-side Resources. Analysis of additional DSR bundles began with the optimal portfolio for the Base Scenario, which includes DSR bundles A through D; this was compared to the Base Scenario with no DSR. Then, bundle E was added to the optimal portfolio with DSR and the portfolio was re-optimized; these results were compared to the scenario with bundle D. Bundles F and G were also added incrementally and compared to the optimal portfolio with bundle D.

When bundles A through D are added to the portfolio without DSR, there is a $1.3 billion reduction in portfolio cost and a 16 million ton reduction in emissions over the 20-year planning horizon (2016-2035). This results in an incremental benefit of $202 per ton. Including this amount of DSR reduces the number of thermal resources built because it reduces the peak capacity need. It also reduces the number of renewable resources built because it reduces the overall energy need that determines the RPS requirement. When additional DSR bundles are added, the incremental emissions abatement is relatively small and occurs at a cost. The addition of bundle E delays some supply-side resources by one year, but the cost savings from the delays do not offset the cost of the additional DSR and the incremental cost is $173 per ton. With the addition of bundle F, portfolio cost declines a marginal amount relative to portfolio with bundle E; this is the result of other changes in the model when the portfolio is re-optimized, including a change in demand-response bundles. Adding Bundle G results in additional delays of supply-side resources, but the reduced costs do not offset the increased cost of demand-side resources.

Incremental cost per ton for each DSR configuration relative to the Base Scenario, along with total incremental carbon abatement, is presented in Figure 6-50.

Figure 6-50: Additional DSR, Incremental Revenue Requirement and Total Carbon Abatement by Bundle, 2016-2035



Bundle D is relative to base scenario without demand side resources; subsequent bundles are relative to base scenario with bundle D. Costs are levelized over 2016-2035. Abatement is 2016-2035 total relative to reference scenario.

Overall, supply-side resources are delayed but not eliminated in these sensitivity analyses. Demand-response programs change with the addition of DSR bundles, and carbon emissions are achieved – but at an incremental cost that is not economic. These results support the Base Scenario optimal portfolio finding in which bundle D was chosen as the most cost effective DSR bundle.

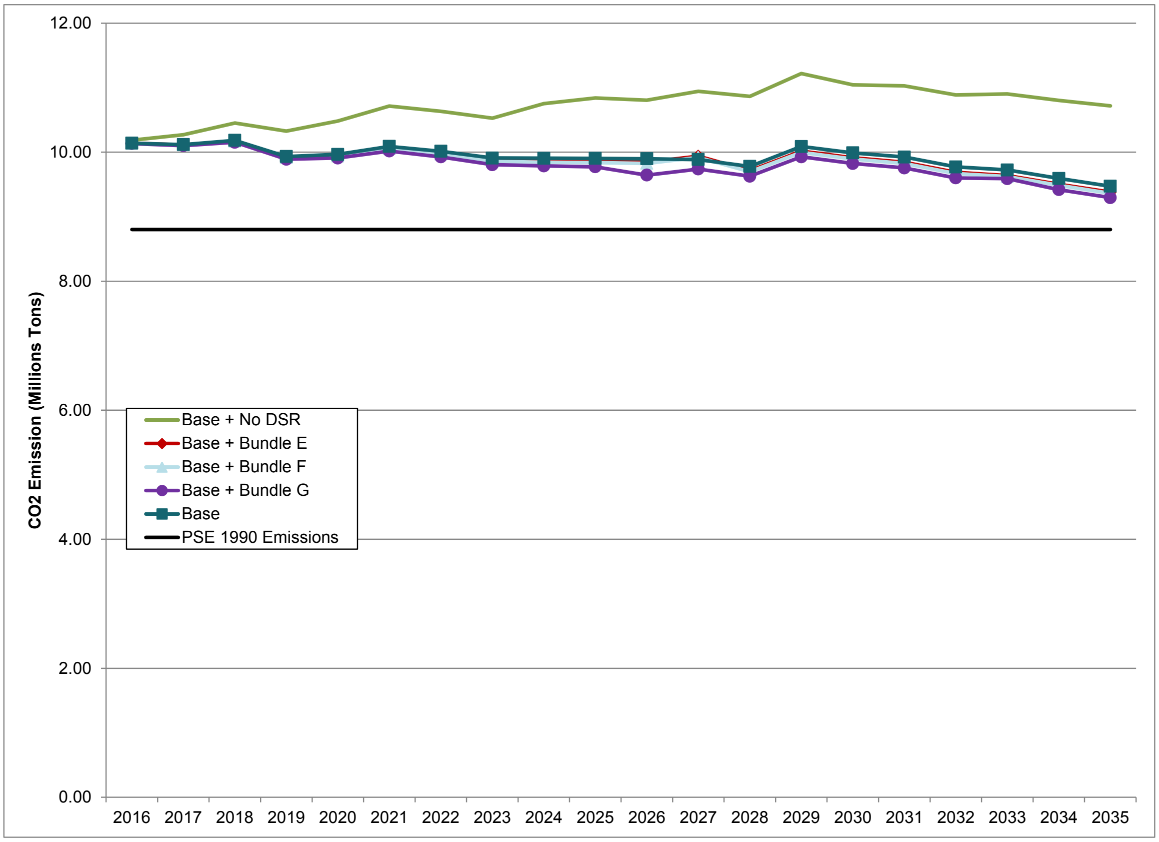
Figure 6-51: Incremental Cost per Ton of Carbon Abatement by DSR Bundle, 2016-2035

Thousands $	Bundle D (Base)	Bundle E	Bundle F	Bundle G
Base w/o DSR NPV Expected Cost	$12,339,055	$12,339,055	$12,339,055	$12,339,055
NPV Expected Cost	$11,019,322	$11,077,321	$11,075,068	$11,155,377
NPV Incremental Cost (Benefit)[1]	($1,319,733)	$58,000	$55,747	$136,055
NPV Incremental Emissions (Millions of Tons)[1]	-6.52	-0.34	-0.43	-0.95
Incremental Cost (Benefit) ($ / Ton)[1]	($202)	$173	$128	$144

NOTE: Bundle D is relative to Base Scenario without DSR; others are relative to Base Scenario with bundle D.

DSR and wind resources affect emission rates, but to a much smaller extent than Colstrip or the Coal Transition PPA. Figure 6-52 illustrates the effect that additional DSR has on portfolio emission rates for the Base Scenario. By 2035, the DSR in the Base Scenario least-cost deterministic portfolio, which includes Bundle D, reduces CO_2 emissions by 1.25 million tons annually, but this does not get the portfolio to 1990 levels.

Figure 6-52: Emissions by Portfolio (Base refers to the least-cost, deterministic portfolio in the Base Scenario which includes Bundle D)



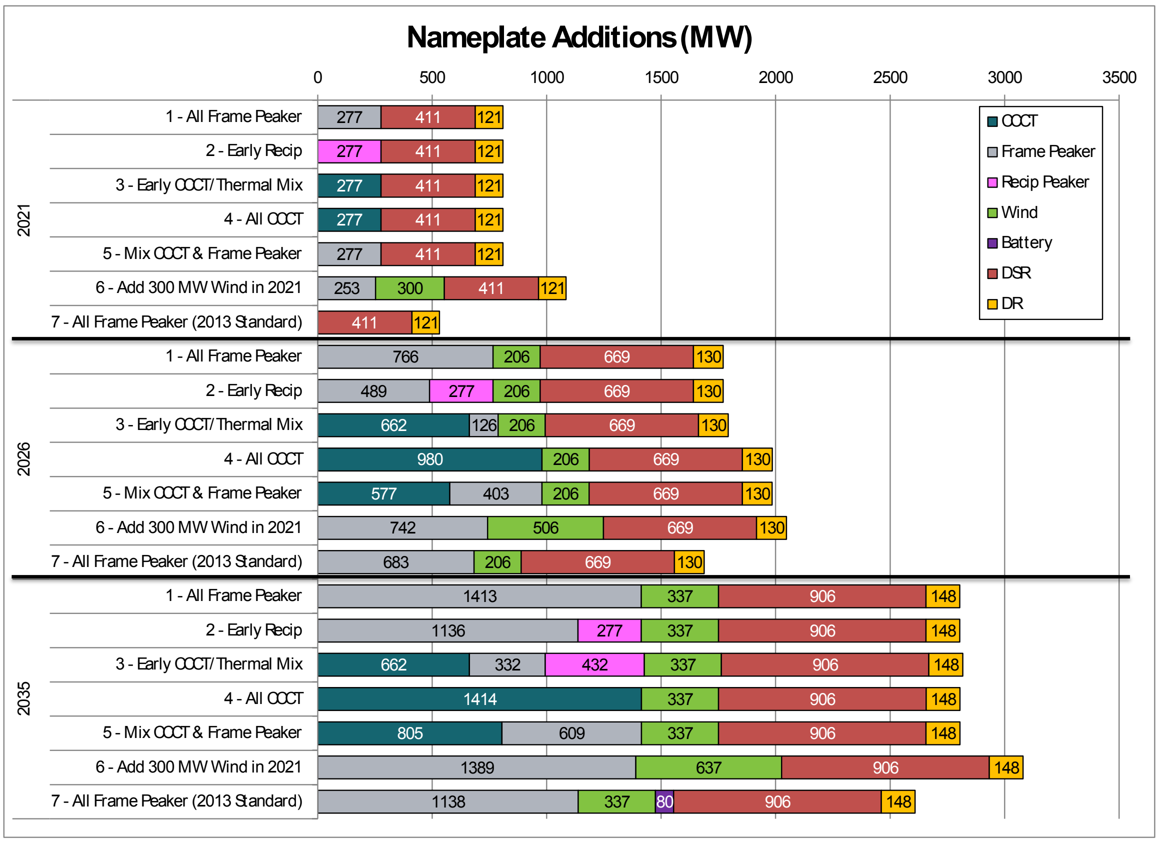
CANDIDATE RESOURCE STRATEGY RESULTS (2015 PLANNING STANDARD)

As part of the 2015 IRP, we developed candidate resource strategies to test different configurations of gas-fired resources and wind.

Summary of Deterministic Analysis

Figure 6-53 below displays the megawatt additions for the deterministic analysis least-cost portfolios for all of the candidate strategies in 2021, 2026 and 2035. See Appendix N, Electric Analysis, for more detailed information.

Figure 6-53: Resource Builds by Scenario, Cumulative Additions by Nameplate (MW)



Summary of Stochastic Analysis

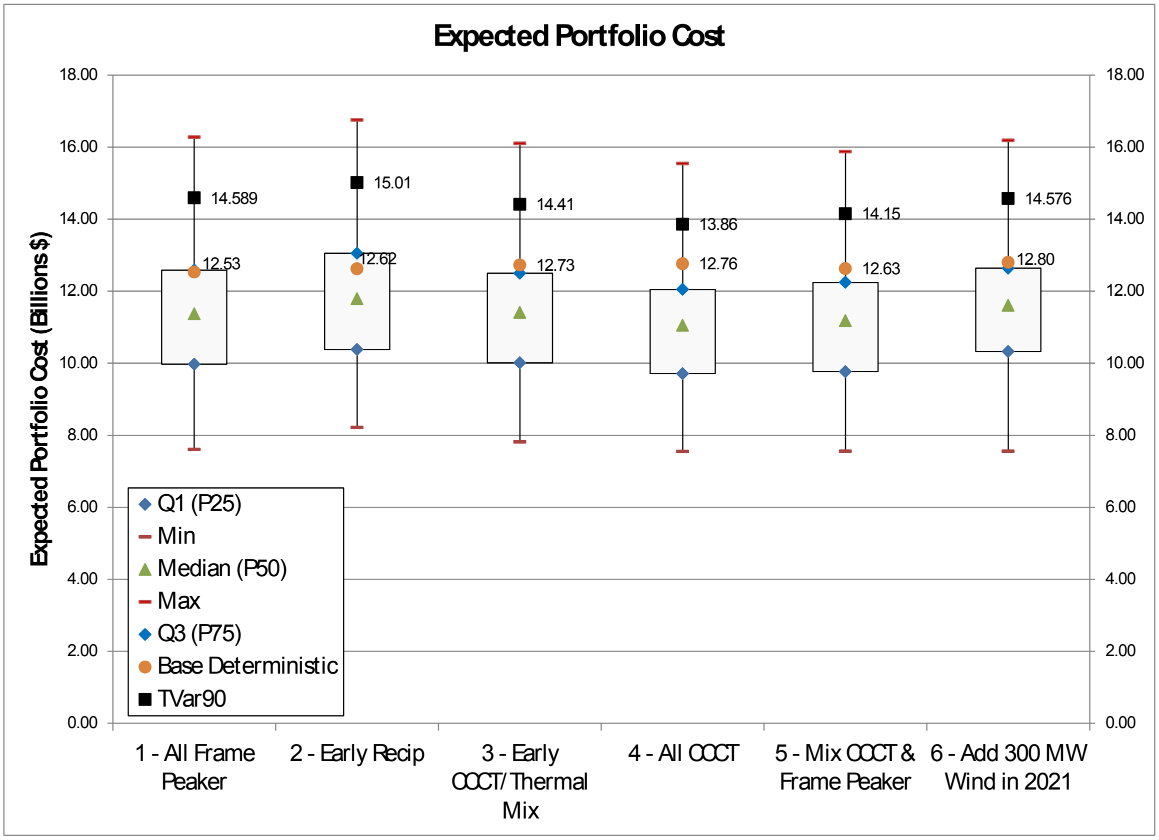
All six candidate portfolio options were tested in the stochastic analysis. In Figure 6-54 below, the all frame peaker is the lowest-cost portfolio in the Base Scenario, but since the stochastic analysis takes into account many different futures we see that the mean of frame peaker portfolio is actually higher cost than the all CCCT and mix of CCCT and frame peaker portfolio.

Figure 6-54: Results of Stochastic Analysis

NPV ($Millions)	Base Deterministic Portfolio Cost	Difference from Base	Mean	Difference from Base	TVar90	Difference from Base
1 - All Frame Peaker	12,531		11,343		14,589	
2 - Early Recip Peaker	12,620	89	11,782	439	15,014	426
3 - Early CCCT/Thermal Mix	12,729	198	11,392	49	14,412	(177)
4 - All CCCT	12,761	230	10,993	(350)	13,856	(733)
5 - Mix CCCT & Frame Peaker	12,627	96	11,138	(205)	14,147	(442)
6 - Add 300 MW Wind in 2021	12,798	267	11,582	239	14,576	(13)

In this IRP, the lowest cost thermal resource varied between the frame peaker and the CCCT depending on the scenario. But the stochastic analysis indicates that a combination of CCCT and frame peakers reduced the cost and risk of the portfolio.

Figure 6-55: Range of Portfolio Costs across 1,000 Trials



GAS-FOR-POWER PORTFOLIO ANALYSIS

Natural gas fuel for power generation is vital to the electric utility's ability to meet customer peak demand reliably. In fact, every IRP since 2007 has identified natural gas-fired generation as the most cost-effective supply-side addition for PSE portfolios. This IRP is no different: All of the electric portfolios produced by the analysis include the addition of substantial amounts of gas-fired generation as part of the solution to meeting future electricity demand.

Determining the resources necessary to ensure that natural gas fuel is available when needed is not a straightforward exercise. Although both CCCTs and peakers are needed to meet peak demand, they require different types of fuel resources. CCCTs are assumed to need 100 percent firm gas transportation since their higher efficiency means they are dispatched more frequently than peakers. Peakers, on the other hand, generally operate with temporary, non-firm pipeline capacity purchased from either the gas sales book, the pipeline, or through the capacity release market, because they are expected to run fewer hours than CCCTs due to their higher, less efficient heat rates.

PSE's owned peakers have dual-fuel capability; that is, they can use either natural gas or distillate fuel (oil) to generate power. Under existing emissions limitations, these plants are allowed to use both forms of fuel. We also have the necessary permits for one additional dual-fuel peaker. Beyond the first additional peaking plant, we assumed the facility would require 50 percent firm gas pipeline transportation. Currently, the future of environmental constraints on CO_2 emissions is uncertain, so it was reasonable to assume new peakers may not receive the permits necessary to generate with oil in all the hours necessary for meeting peak demand. Therefore, peakers beyond the first addition are assumed to be able to generate with distillate fuel oil for some – but not all – of the hours needed to meet peak; hence the addition of 50 percent firm pipeline capacity. We will adjust this expectation according to conditions as they develop in the future.

Gas-for-power Resource Need

Figure 6-56 describes gas-for-power needs for the Base Scenario electric portfolio forecast. This portfolio added 2 new CCCTs, a 577 MW plant in 2026 and a 228 MW plant in 2033; it also added peakers with oil backup in 2021, 2025 and 2030. The peaker added in 2021 is already permitted with the capacity to meet peak winter demand with distillate fuel oil, so additional pipeline capacity isn't needed until the winter of 2026 when the second peaker and first CCCT additions are made. The pipeline capacity requirements shown below include the gas-for-power need for both CCCTs. The green line assumes the peakers added in 2025 and 2030 require 50 percent firm pipeline capacity; the purple line assumes the peakers require no additional firm pipeline capacity because they can use oil for backup fuel. These needs are shown in Figure 6-56.

Figure 6-56: Two Views of Gas-for-power Resource Need
(Existing gas-for-power gas transportation resources compared to peak day demand)

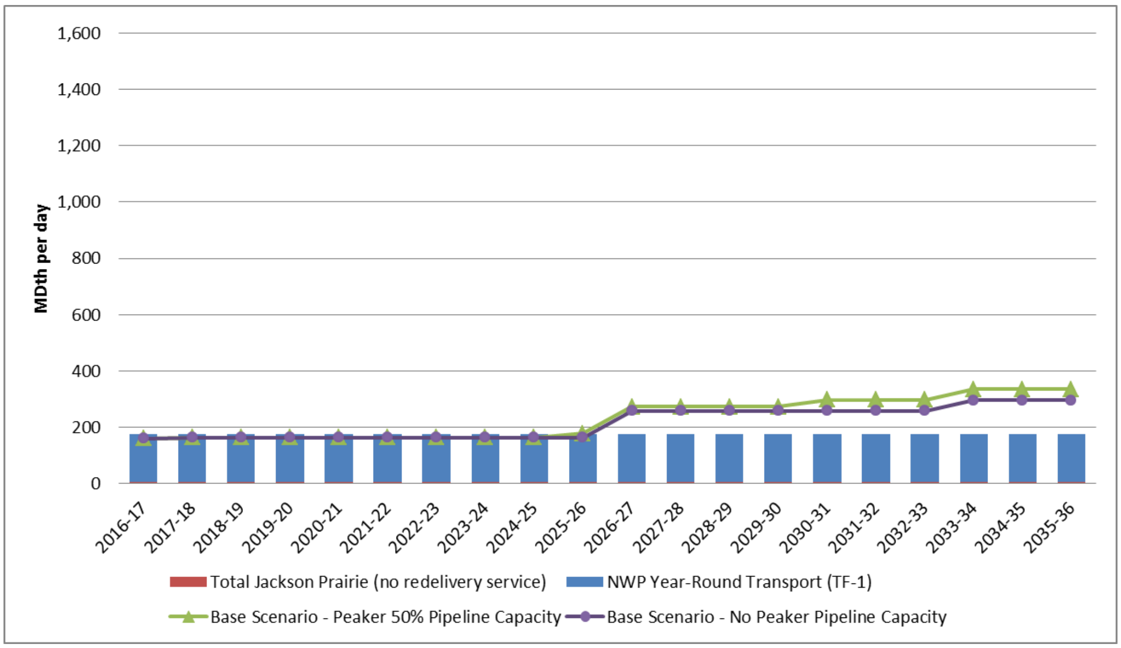


Figure 6-57: Forecast Gas-for-power Pipeline Capacity Need

Forecast Pipeline Need (MDth/day)	2018-19	2026-27	2030-31	2033-34
Peaker 50% Pipeline	11	106	130	167
Peaker No Pipeline	-	91	91	129

Existing Supply-Side Resources

Figure 6-58 summarizes the firm pipeline transportation capacity for delivery of fuel to PSE's gas-fired generation plants.

Figure 6-58: Gas-for-power Generation Gas Pipeline Capacity (Dth/day)

Direct-connect Capacity						
Plant	Transporter	Service	Capacity (Dth/day)	Primary Path	Year of Expiration	Renewal Right
Whitehorn	Cascade Natural Gas	Firm	(1)	Westcoast (Sumas) to Plant	2017	Yr. to Yr.
Ferndale	Cascade Natural Gas	Firm	(2)	Westcoast (Sumas) to Plant	2037	Yr. to Yr.
Encogen	Cascade Natural Gas	Firm	(2)	NWP (Bellingham) to Plant	2017	Yr. to Yr.
Fredonia	Cascade Natural Gas	Firm	(2)	NWP (Sedro-Woolley) to Plant	2021	Yr. to Yr.
Mint Farm	Cascade Natural Gas	Firm	(2)	NWP (Longview) to Plant (6)	2018	Yr. to Yr.

Upstream Capacity						
Plant	Transporter	Service	Capacity (Dth/day)	Primary Path	Year of Expiration	Renewal Right
Various	Westcoast	Firm	51,345 (3)	Station 2 to Sumas	2018	Yes
Various	Westcoast	Firm	33,313 (3)	Station 2 to Sumas or Kingsgate	2017	Yes
Various	NWP	Firm	28,928	Stanfield to Bellingham, Jackson Prairie and Deer Island	2025	Assumed (7)
Freddy 1	NWP	Firm	21,747	Westcoast (Sumas) to Plant	2018	Yr. to Yr.
Goldendale	NWP	Firm	45,000	Westcoast (Sumas) to Everett (4)	2018	Yr. to Yr
Various	NWP	Firm	50,000	Stanfield to SIPI	2035	Yes
Various	NWP	Firm	2,000	Sumas to Tacoma	2023	Yes
Various	NWP	Firm	21,747	Westcoast (Sumas) to Plant	2018	Yr. to Yr
Various	NWP	Firm	45,000	Westcoast (Sumas) to Everett (4)	2018	Yr. to Yr
Various	NWP	Firm	10,710	Sumas to Stanfield	2044	Yes
Various	NWP	Firm	500	Sumas to Longview	2044	Yes

Storage Capacity						
Plant	Transporter	Service	Deliverability (Dth/day)	Storage Capacity (Dth)	Year of Expiration	Renewal Right
Jackson Prairie	NWP	Firm	6,704	140,622	2026	Yes
Jackson Prairie (5)	PSE	Firm	50,000	500,000	2016	No

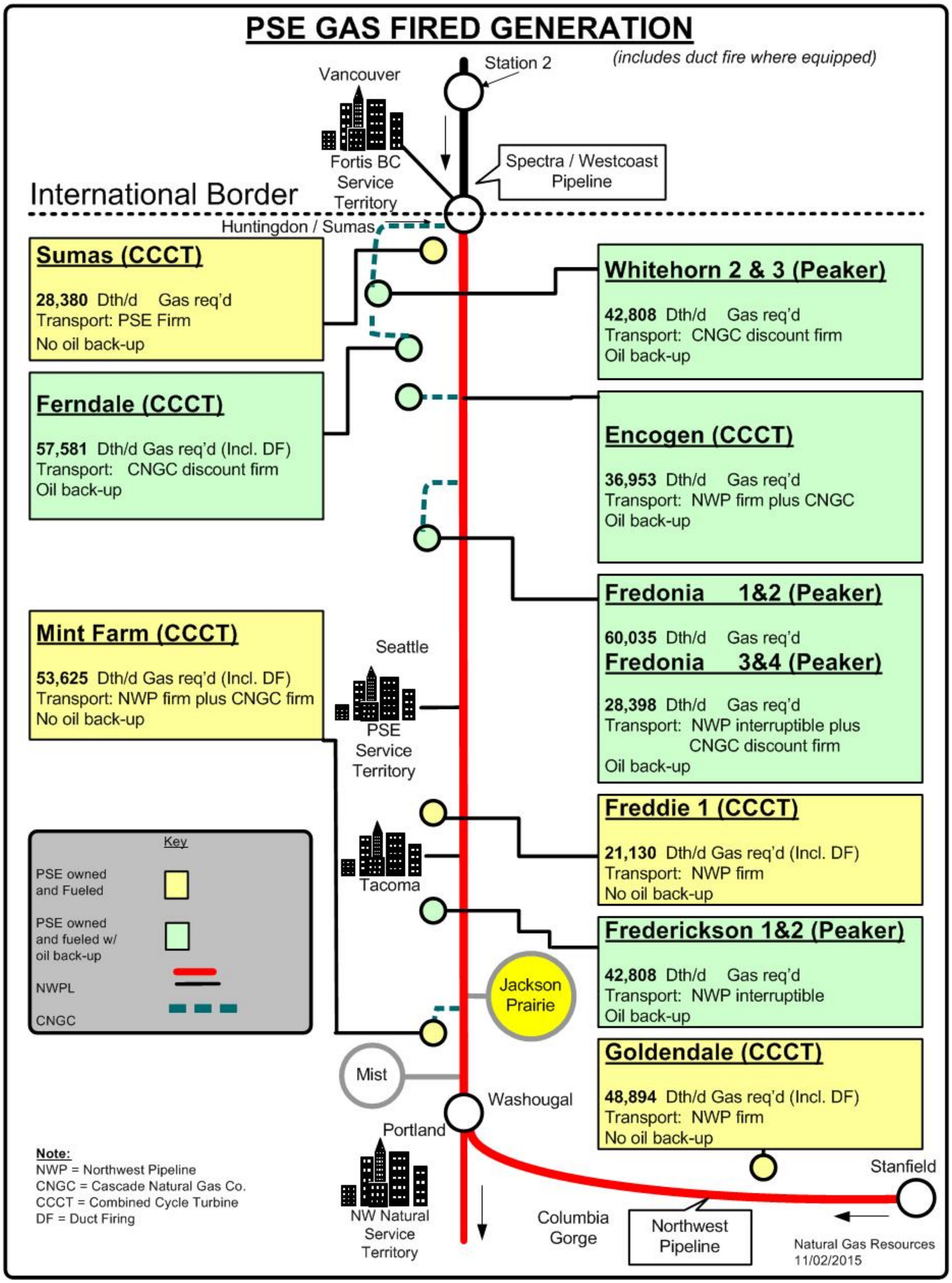
NOTES
1 50% of plant requirements.
2 Full plant requirements.
3 Converted to approximate Dth/day from contract stated in cubic meters/day.
4 Gas transported to points south of Everett under NWP flex rights, when conditions allow..
5 Storage capacity made available (at market-based price) from PSE gas sales portfolio. Renewal may be possible, depending on gas sales portfolio needs. The gas sales portfolio may recall 15,000, 35,000 and 50,000 Dth per day of firm withdrawal rights for up to 4 days in each winter 2013/14, 2014/15 and 2015/16, respectively.
6 30,000 Dth/day is year to year; 22,000 terminates in 2018, but can be renewed.
7 PSE does not have guaranteed renewal rights on this segmented capacity; however, the releasing shipper has indicated willingness to renew the agreement, subject to approval by the pipeline. Renewal may be possible.

PSE has firm NWP pipeline capacity to serve its CCCTs that require NWP service (Encogen, Freddy 1, Goldendale, and Mint Farm); Sumas is directly connected to Westcoast. Ferndale is connected to Sumas via firm capacity on Cascade Natural Gas. All of our simple-cycle combustion turbine generation units (Whitehorn, Fredonia, and Frederickson) have fuel oil back-up capability and thus do not require firm pipeline capacity on NWP.

Gas supply contracts tend to have a shorter duration than pipeline transportation contracts, with terms to ensure supplier performance. We meet forecast gas for power generation needs with a mix of long-term (more than two years) and short-term (two years or less) physical gas supply contracts. Longer-term contracts typically supply base-load needs and are delivered at a constant daily rate over the contract period. We estimate average gas for power generation requirements for upcoming months and enter into transactions to balance forecast load. PSE balances daily and intra-day positions using storage (from Jackson Prairie), day-ahead purchases, and off-system sales transactions. PSE will continue to monitor gas markets to identify trends and opportunities to fine-tune our contracting strategies.

PSE's existing gas-fired generating plants are generally located along the I-5 corridor in western Washington, as the map in Figure 6-59 shows. The exception is Goldendale, which is located near Goldendale, Washington. The peak gas requirement and the type of gas pipeline delivery are also listed. The capacity and operating assumptions for the plants are described in detail in Appendix D, Electric Resources and Alternatives.

Figure 6-59: PSE's Existing Gas-fired Generating Plants



Gas-for-power Resource Alternatives

The complete list of resource alternatives evaluated for the gas-for-power portfolio is detailed in Chapter 7, Gas Analysis. Most relevant to this analysis were the following.

- **CROSS CASCADES TO AECO OR MALIN HUBS**. The prospective Cross Cascades pipeline bringing gas supply from Alberta (AECO hub) via existing or new upstream pipeline capacity on the TC-AB (NOVA), TC-BC (Foothills) and TC-GTN pipelines to Stanfield; or from the Rockies hub on the Ruby pipeline to Malin (or directly from Malin) and with backhaul on the TC-GTN pipeline to Stanfield. Final delivery from Stanfield to PSE would be via the proposed Cross Cascades pipeline.
- **MIST EXPANSION**. This option provides for PSE to lease storage capacity from NW Natural after an expansion of the Mist storage facility. Delivery of gas would require expansion of pipeline capacity from Mist to PSE's service territory for Mist storage redelivery service. The expansion of pipeline capacity from Mist to PSE will be dependent on an expansion on NWP from Sumas to Portland.
- **NWP + WESTCOAST**. Expansion of NWP and Westcoast pipeline to Sumas and Station 2, located in northern BC.

Gas-for-power Analytic Methodology

For this IRP, PSE developed a separate gas portfolio model (SENDOUT) database to evaluate the resource needs of the gas-for-power portfolio. The model inputs include: 1) the costs and capacities for the existing pipeline, storage and gas supply markets as well as for the alternative supply resources, and 2) forecasts of the loads of for existing and future gas-fired plants. The existing and alternative supply resources are described earlier in this chapter and in Chapter 7. The AURORA model develops forecasts of the gas required for the gas-fired plants when performing the analyses of the electric portfolio scenarios; AURORA also dispatches the resources and calculates the electric generation.

While the methodology for the gas-for-power portfolio is very similar to the SENDOUT modeling methodology discussed in Chapter 7, Gas Analysis, the approach to developing gas-for-power needs is different from gas sales loads. In general, gas-fired plants are economically dispatched based on the relationship of the power and gas prices in the market, which is known as the market heat rate. The market heat rate is compared to the plant's heat rate (plus variable dispatch costs) to determine whether it is less expensive to generate power or to purchase it in the market (or sell it into the market when generation is not needed to serve load).

Because electric and gas prices vary based on regional factors such as loads, generation outages, transmission constraints, wind and hydro generation and demand for electricity from adjoining regions, the dispatch of gas-fired plants varies greatly depending on market and weather conditions. The AURORA model incorporates these conditions within the Base Scenario. The daily plant gas use from the AURORA model plus the gas-for-power need calculated during a winter peak event was input to the SENDOUT model to model the Base Scenario's 20-year study period for each of the gas-fired generators. The results are shown in the next section.

Gas-for-power Portfolio Analysis Results

The results discussed in this section are for the electric Base Scenario, which calls for the addition of two CCCTs and three additional gas-fired peakers over the next 20 years, located along the I-5 corridor.

Key Findings. The key findings provide guidance for development of PSE's long-term gas-for-power resource strategy.

1. **Ten MDth per day of the proposed Cross Cascades pipeline providing access to the Stanfield natural gas hub is cost-effective beginning in 2022, filling the gap between existing pipeline capacity to Stanfield and Stanfield supply. Procurement increases in 2026, to 61 MDth per day.**

2. **41 MDth per day of the Mist storage expansion alternative appears cost-effective for the gas-for-power portfolio beginning in 2026.**

3. **The proposed Westcoast to NWP pipeline expansion to access natural gas at the Station 2 hub in British Columbia is a low cost resource choice beginning in 2030.**

Figure 6-60 shows the amount of these resources selected in the electric Base Scenario. The acquisition of the proposed Cross Cascades pipeline capacity, providing access to the Stanfield gas hub is clearly the least-cost resource. Over 80 percent of the Mist storage expansion is chosen as cost effective beginning in 2026. Finally, proposed Westcoast to Northwest pipeline expansion with access to the lower priced Station 2 hub in British Columbia, is a resource choice beginning in 2026.

As discussed earlier and illustrated in Figure 6-58, the gas-fired plants added in the electric Base Scenario are CCCTs, and two of the three additional peakers with oil backup require 50 percent firm pipeline capacity. However, additional gas pipeline capacity may be required to supply the volumes needed to support the combined gas sales and gas-for-power loads and maintain sufficient storage to ensure reliable service.

Figure 6-60: Resource Capacities Selected for the Base Gas-for-power Portfolio (MDth/day)

Base Scenario MDth/day	2018-19	2022-23	2026-27	2030-31	2034-35
Cross Cascades	-	10	64	64	64
Mist Storage Expansion	-	-	41	41	41
NPW/Westcoast Expansion	-	-	-	62	62
Total	**-**	**46**	**105**	**167**	**167**

The electric Base Scenario portfolio adds a 577MW CCCT in 2026 and a 228 MW CCCT in 2033; they require approximately 95,100 and 37,600 Dth per day of natural gas per day, respectively, to run at capacity. Three peakers with a total capacity of 605 MW are added to the portfolio by 2030. As discussed, the first 277 MW peaker is assumed to require no firm pipeline capacity. The second and third peakers add 124 MW in 2025 and 204 MW in 2030 with 50 percent firm pipeline capacity of approximately 14,500 and 23,900 Dth per day, respectively. While the total peak gas need of these CCCT and peaker plants is approximately 275 MDth per day by 2035, after considering a 50 percent pipeline need for the second and third peaker and current gas-for-power transportation contracts, the peak gas-for-power need is 167 MDth per day by 2033.