



# RESOURCE PLAN DECISIONS

## Contents:

### **2-2. ELECTRIC RESOURCE PLAN**

- Capacity Planning Standard Update
- Regional Resource Configuration Assumptions
- Resource Additions Summary
- Electric Results across Scenarios
- Demand-side Resource Additions
- Renewable Resource Additions
- Supply-side Resource Additions
- Resources Not Selected

### **2-20. GAS SALES RESOURCE PLAN**

- Resource Additions Summary
- Gas Sales Results across Scenarios
- Demand-side Resource Additions
- Supply-side Resource Additions

*The resource plan in this IRP represents "...the mix of energy supply and conservation that will meet current and future needs at the lowest reasonable cost to the utility and its ratepayers."<sup>1</sup> It is the culmination of comprehensive quantitative and qualitative analyses, including extensive risk analysis, reported throughout the document.*

*The electric and gas resource plans included in the IRP are best understood as long-term forecasts of what will be cost effective in the future, given what we know about the future today. The IRP is not a plan for acquiring specific demand-side or supply-side resources. Resource decisions can be informed by the foresight developed in the IRP, but ultimately they will be made when it best serves the interest of our customers, and they will depend upon actual market opportunities and updated assessments of market conditions. This chapter summarizes the reasoning for the additions to the electric and gas resource plans.*

<sup>1</sup> / WAC 480-100-238 (2) (a) Definitions, Integrated Resource Plan.



# ELECTRIC RESOURCE PLAN

This discussion assumes the reader is familiar with the key assumptions described in Chapter 4. Further information on the analyses discussed here can be found in Chapters 4, 5, 6, 7 and the Appendices.

## Capacity Planning Standard Update

**DECISION.** 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.

**SUMMARY.** 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.

**FACTORS THAT COULD AFFECT DECISION.** Changes to the region's resource adequacy assessment and/or changes to PSE's load forecast could impact the amount of capacity PSE needs to acquire, but this would not change the approach. We will continue to base our planning standard on the value of reliability to customers unless the Commission expresses significant concerns about the approach in its letter on the 2015 IRP.

**DISCUSSION.** Since regional resource adequacy studies forecast a shift from surplus to deficit in the region's load/resource balance, this a particularly appropriate time to focus PSE's electric planning standard on the value of reliability to customers and to incorporate wholesale market risk in the analysis.

The old 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 based on 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.



Prior IRPs also assumed wholesale market purchases were 100 percent reliable, but this is no longer a reasonable assumption now that surplus capacity in the region is shrinking. Therefore, PSE incorporates wholesale market risk into the analysis to support its capacity planning standard. Figure 2-2, Summary of Planning Standard Changes, provides information that will be used in the discussion below. Additional detail is included in Chapter 6, Electric Analysis, Appendix G, Wholesale Market Risk, and Appendix N.

Figure 2-1, Summary of Planning Standard Changes

		Reliability Metric		2021 Peaker Capacity	Customer Value of Lost Load	
		LOLP	EUE (MWh)	Added after DSR (MW)	Expected (\$mill/yr)	TVar90 (\$mill/yr)
1	2013 Planning Standard 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.

To understand the impact of the change, it is helpful to understand what the reliability metrics in the table in Figure 2-1 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.

In line one of Figure 2-1, 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 curtailments would be almost twice as high. Clearly, a more comprehensive approach to defining the planning standard is needed.



**The 2015 Optimal Planning Standard.** To develop 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) equals the cost of providing that level of reliability (marginal cost).

Again, Figure 2-1 shows that moving to the 2015 Optimal Planning Standard reduces the expected value of lost load to customers by \$130 million per year.<sup>2</sup> The cost to achieve that expected savings is \$63 million per year,<sup>3</sup> for a net benefit to customers of \$67 million per year. Risk reduction to customers is dramatic. That \$67 million per year cost reduces the risk to customers by \$1.3 billion per year.<sup>4</sup>

Figure 2-2 illustrates where the marginal benefit and marginal cost of reliability to customers intersects at the 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.

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.

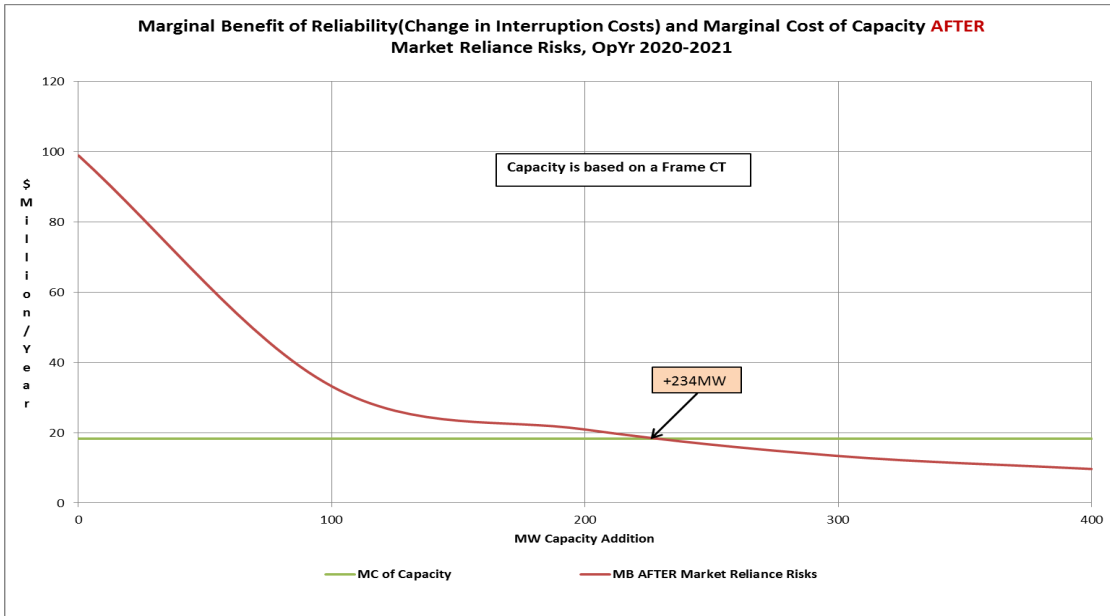
3 / This value is derived by first calculating the difference between the surplus of 117 MW in line 2 (2013 Planning Standard Including Market Risk) and the need (deficit) of 234 MW in line 3 (2015 Optimal Planning Standard). This value is then multiplied by the levelized cost of a peaker, estimated from the portfolio model at \$0.18 million per MW per year. So:  $234 \text{ MW} - (-117 \text{ MW}) = 351 \text{ MW}$ . Then:  $351 \text{ MW} * \$0.18 \text{ million per MW per year} = \$63 \text{ million per year}$ .

4 / \$1,691 million - \$385 million = \$1,306 million



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

Figure 2-2: Marginal Benefit and Marginal Cost of Reliability to Customers



## Regional Resource Configuration Assumptions

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

### 1. 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 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.



### **2. 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 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.

### **3. 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 the plant in our regional resource configuration since we would not be able to consider it firm for our customers if it were in our portfolio. Removing Grays Harbor from the regional adequacy study ends up increasing PSE's resource need by approximately 64 MW.<sup>5</sup>

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<sup>5</sup> / See Appendix G, Wholesale Market Risk, for additional detail.



## Resource Additions Summary

Figure 2-3 summarizes the forecast of resource additions to the company's electric portfolio that resulted from the 2015 IRP analysis. The plan forecasts accelerated acquisition of conservation and demand-response in the early years, the addition of a natural gas-fueled peaking plant in 2021-22, and the addition of renewable resources by 2023 to meet RCW 19.285 (Northwest wind). Further out, CCCT plants are added starting in 2026 as the coal plant retirements begin to impact need. Additional renewables before 2023 were not included, because the stochastic portfolio analysis demonstrated that additional wind (the least cost renewable) did not reduce cost or reduce risk. The discussion below summarizes key decisions for the resource plan.

*Figure 2-3: Electric Resource Plan Forecast,  
Cumulative Nameplate Capacity of Resource Additions*

	2021	2026	2030	2035
Conservation (MW)	411	669	770	906
Demand Response (MW)	121	130	138	148
Wind (MW)	-	206	337	337
Combined Cycle Gas (MW)	-	577	577	805
Peaker/ CT Dual Fuel (MW)	277	403	609	609

## Electric Results across Scenarios

Figure 2-4 summarizes the demand- and supply-side resource additions to PSE's existing resource portfolio across scenarios; this picture is the product of the deterministic portfolio optimization analysis. For each scenario, the analysis considered supply- and demand-side resources on an equal footing. All were required to meet three objectives: physical capacity need (peak demand), energy need (customer demand across all hours), and renewable energy need (to meet RCW 19.285 targets). The portfolios in Figure 2-4 minimize long-term revenue requirements (costs as customers will experience them in rates), given the market conditions and resource costs assumed for each scenario.

Least-cost portfolio builds are similar across most scenarios, with respect to renewables and demand-side resources, though the choice of gas resources differs. This consistency is a powerful finding. It means that the wide variety of external market factors modeled in these scenarios will have little impact on the selection of renewables and demand-side resources.



Figure 2-4: Resource Builds by Scenario, Cumulative Additions by Nameplate (MW), 2015 Optimal Planning Standard

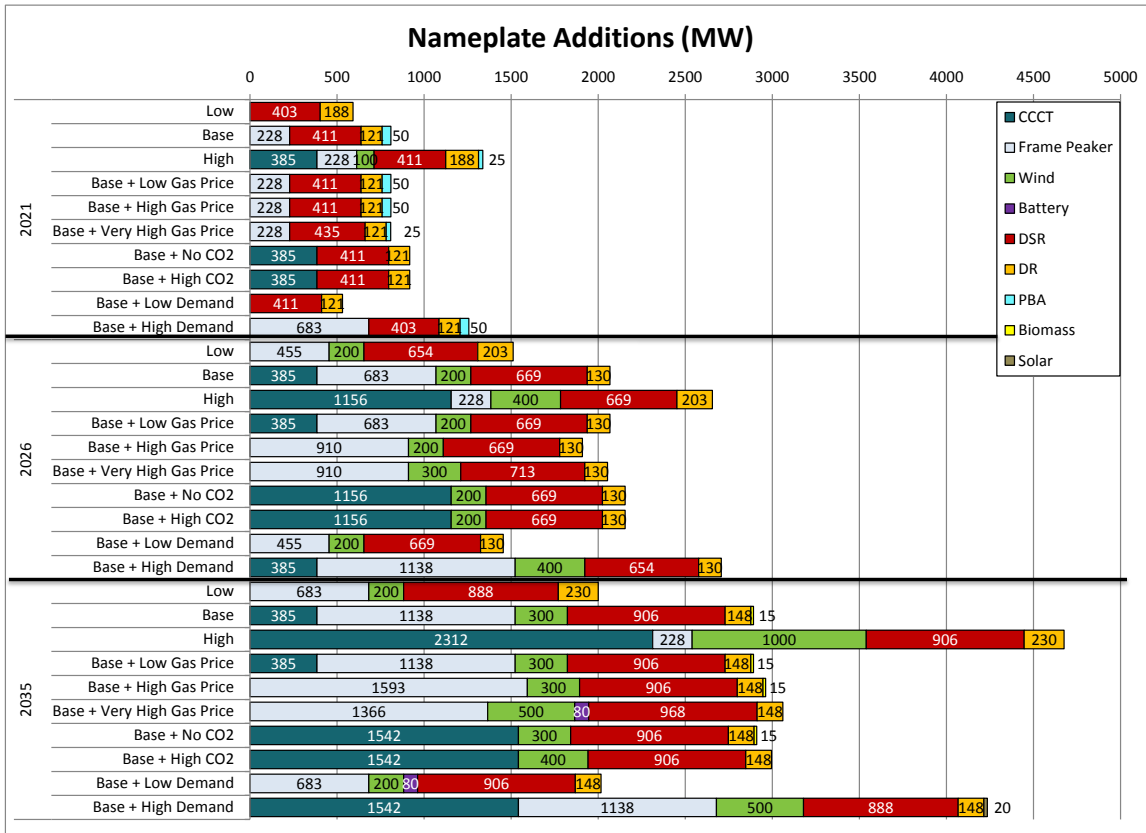


Figure 2-4, above, highlights that gas plant additions differed across the scenarios. To further explore gas resource choices, we developed a set of six candidate resource strategies for the stochastic phase of the analysis, to test how different combinations of gas plants would perform across all futures. We also included a strategy that added more wind than the minimum required under RCW 19.285. These strategies, developed as a result of the deterministic analysis, are summarized as follows:

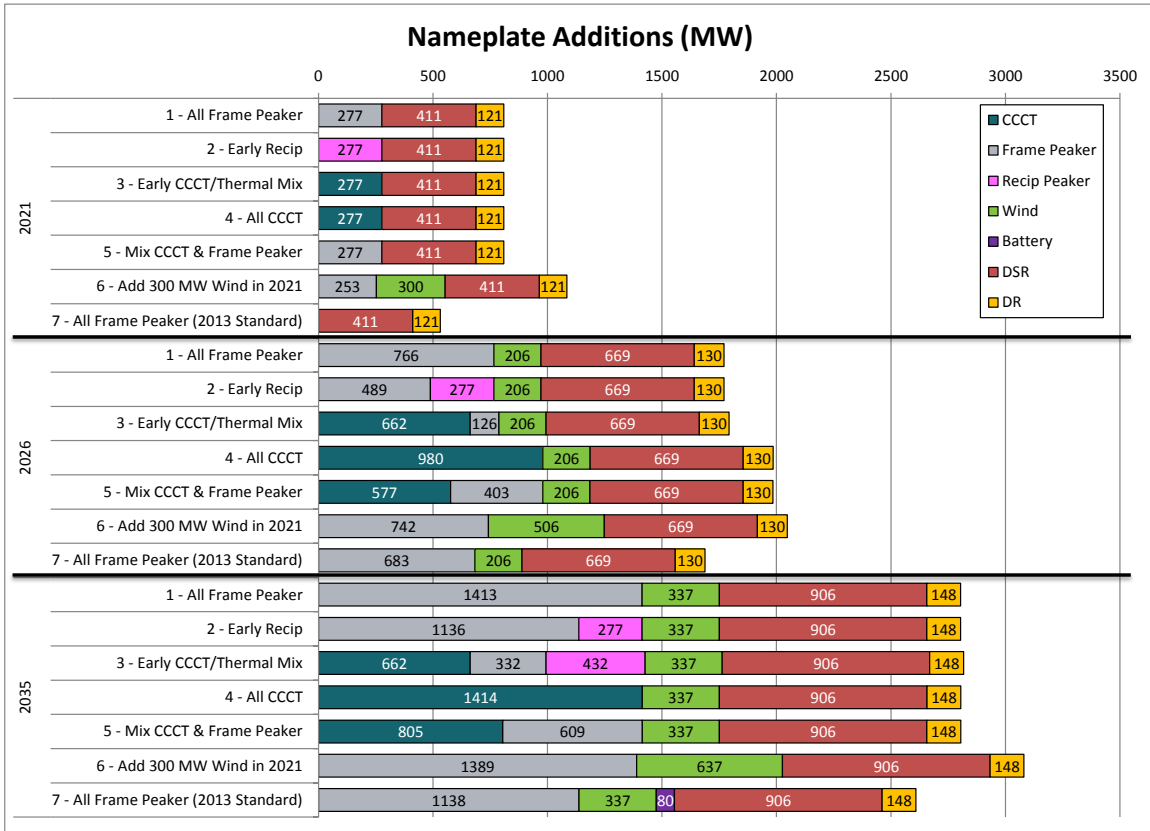
1. All frame peakers.
2. Early reciprocating engine peaker, with frame peakers for remaining thermal plants.
3. Early CCCT plants, with a mix of CCCT and frame peakers.
4. All CCCT plants.
5. Mix of frame peakers and CCCT plants, with frame peaker first
6. Add 300 MW of wind beyond RPS requirements.





Figure 2-5 illustrates the additions produced by stochastic analysis of the six strategies.

Figure 2-5: Stochastic Analysis Results for Six Candidate Resource Strategies



In the end, strategy five, a combination of peakers and CCCT plants, appeared to provide the best combination of cost-effectiveness, flexibility and risk management

A detailed discussion of each element of the resource plan follows.



# Demand-side Resource Additions

## Energy Efficiency

**DECISION.** Energy efficiency measures are forecast to total 411 MW by 2021 and increase to 906 MW by 2035. This includes both PSE-implemented programs and the effect of new codes and standards.

**SUMMARY.** Least-cost energy efficiency levels were consistent across the wide range of scenarios and sensitivities examined. The level chosen is consistent with results from the seven of the ten scenarios tested including the Base Scenario.

**FACTORS THAT COULD AFFECT DECISION.** Little change is expected in the near term, since PSE works with the CRAG to develop conservation targets based on these IRP results. Longer-term, changes in technology or policies could impact future conservation targets in the IRP.

**DISCUSSION.** Least cost portfolios in 7 of the 10 scenarios (including the Base Scenario) included the same level of conservation, shown in Figure 2-4, above. By the end of the planning horizon, the lowest conservation result was only 18 MW lower than the Base Scenario result, and the highest was 62 MW higher by 2035. By 2021, the difference between highest and lowest levels was only 32 MW.



### Demand-response

**DECISION.** The plan forecasts acquiring 121 MW of demand-response by 2021.

**SUMMARY.** Cost-effective levels of demand-response were found to be consistent across nearly all scenarios. In the Action Plan for the 2015 IRP, PSE commits to developing and executing an acquisition process focused on demand-response separate from other resources.

**FACTORS THAT COULD AFFECT DECISION.** The acquisition process may reveal costs or attributes different from those assumed in the IRP, and this could lead to adjusting the amount of demand-response acquired up or down. Changes to resource need are driven by updates to the long-term load forecast and revisions to the regional resource adequacy analysis may also affect the quantity of demand-response.

**DISCUSSION.** The level of cost-effective demand-response across scenarios was even more consistent than conservation results. By 2021, 121 MW of demand-response was found cost effective in all but two cases. (An additional 66 MW was found cost effective in the High and Low Scenarios.) Evaluation of demand-response will continue in future IRPs, so that we can adjust amounts appropriately as market conditions change.



# Renewable Resource Additions

**DECISION.** The plan forecasts the addition of 206 MW of southeast Washington wind to the portfolio by 2023, followed by another 131 MW by 2028.

**SUMMARY.** Southeast Washington wind is forecast to be the most cost-effective renewable resource for compliance with RCW 19.285. Additional wind beyond the law's requirements was not cost-competitive with non-renewable resources, nor did it mitigate risk. Therefore, the resource plan includes additional resources to meet compliance obligations only.

**FACTORS THAT COULD AFFECT DECISION.** Three key factors could affect the amount or mix of renewables added in the future: changes to the load forecast, to public policy or to renewable technologies.

1. RCW 19.285 is a load-based requirement, so changes that affect the load forecast will also impact renewable needs.
2. Public policy changes could alter renewable requirements in the future either directly or indirectly. A direct example would be changing the energy requirements in RCW 19.285. An indirect example would be using an emission rate approach to state implementation of EPA's Clean Power Plan rule 111(d).
3. Technological innovation could result in renewable resources becoming cost competitive with non-renewable resources,<sup>6</sup> or in changes to the mix of renewables. For example, utility scale solar may become more cost effective than southeast Washington wind in the future.

**DISCUSSION.** The addition of wind beyond requirements was found to be cost effective only in the High Scenario, which models both high gas prices and high carbon costs. In candidate resource strategy 6, we also examined whether additional wind could reduce portfolio risk enough to justify its inclusion in the portfolio. The analysis indicated that this would slightly reduce risk of the portfolio, as can be seen in Figure 2-6 where (TailVar90 falls by \$13 million NPV. This is the first time PSE has found wind to reduce portfolio risk, but the cost was high; it would cost \$239 million to protect against a \$252 million loss. Adding capacity for reliability purposes, as described in the planning standard discussion, would reduce risk at a far smaller cost.

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<sup>6</sup> / To reduce renewable resource costs to the point where they can compete with market energy in this part of the country will require significant advances, because of the amount of low variable cost hydro generation available in the Pacific Northwest.



Figure 2-6: 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	<b>12,531</b>		<b>11,343</b>		<b>14,589</b>	
6 - Add 300 MW Wind in 2021	12,798	267	11,582	239	14,576	(13)

Having established the level of renewables, the last step in this portion of developing the resource plan was to determine the timing and exact amounts of wind to include in the resource plan. To make those decisions, we aggregated up renewable builds at key periods, to reflect the lumpiness of renewable investments while reflecting the ability to scale those resources.

Based on the current load forecast, and the ability to bank renewable energy credits (RECs), additional wind is not needed until 2023. 203 MW of wind would meet regulatory requirements until 2028, when a combination of slight load growth and expiration of a long-term, 50 MW contract for output from the Klondike wind farm expires. At 2028, an additional 131 MW of wind would be sufficient to meet requirements through 2035. It is possible that other resources and different strategies will emerge by 2028, based on evolving market conditions and changing energy policies. We will complete 5 more IRPs by 2025, so will be able to adjust strategies and decisions as the future unfolds.

This IRP also examined the possibility of acquiring wind from Montana. The challenge is that Montana wind does not generally qualify as a renewable resource under RCW 19.285 because it is outside the Pacific Northwest footprint. Therefore, Montana wind would have to be cost-competitive with other supply alternatives. This would be difficult because of the transmission costs involved. Chapter 6 describes the analysis of potential transmission options and costs PSE conducted for this IRP. Results indicated the capacity contribution of Montana wind would have to be greater than 50% to be cost effective. Under certain sets of assumptions, the results estimated a capacity value of 55%, so it is possible that Montana wind could appear cost effective under some future market conditions. PSE will continue to refine its assumptions for this resource in future IRP analyses.



Biomass and solar were also included in the optimization analysis. Minor amounts of biomass, 15 MW, appear least cost in a few scenarios. One scenario also included 20 MW of utility-scale solar in the last few years of the planning horizon. Biomass and utility scale solar appeared cost effective in those scenarios primarily because they satisfied a small renewable need toward the very end of the planning horizon, so they were the “right size” compared to larger scale wind resources. Ultimately, the analysis found that adding 131 MW of wind in 2028 instead of 100 MW, would cover that small renewable need at a lower cost than either biomass or solar. Market conditions, energy policies, and load forecasts will most like change significantly by 2030, and this analysis highlights that PSE should continue examining feasibility of biomass and utility scale solar resources.

### Supply-side Resource Additions

**DECISION.** Forecast additions include a mix of frame peakers and CCCT plants; the first addition will most likely be a frame peaker with backup fuel that does not require firm interstate gas pipeline capacity. CCCT plants are included to meet larger needs, including the expiration of PSE’s contract with Centralia in 2026.

**SUMMARY.** Forecasting a combination of frame CTs and CCCT plants for the resource plan is reasonable, based on consideration of the quantitative and qualitative analyses. While deterministic scenario analysis shows CCCT plants would be more cost effective than frame peakers in some scenarios, and stochastic analysis also shows CCCT plants would be more cost effective than frame peakers, the qualitative consideration of several factors tips the balance toward including frame peakers. These include assumptions about firm gas pipeline capacity requirements for frame peakers, the ability of frame peakers to meet smaller increases in capacity need more cost-effectively than CCCTs, and uncertainty about the direction of future market conditions.

**FACTORS THAT COULD AFFECT DECISIONS.** It is important to emphasize again that the resource plan is a forecast of resource additions that appear to be cost effective given what we know about the future today. Four key factors will impact how the future acquisition of gas plants will unfold.



1. **Resource Need and Optimal Sizing of Plants.** Changes in the size of our capacity resource needs will impact the choice of technology. Large increases in capacity need tilt the portfolio toward CCCT plants, while smaller capacity need increases could be more cost-effectively met with peaking plants. So, when PSE's contract with the Centralia coal plant expires, when a portion of Colstrip needs to be replaced, or when there is significant load growth, CCCT plants will fit PSE's needs well. Smaller increases in capacity need will tend to tilt the portfolio toward frame peakers.
2. **Fuel Assumptions for Frame Peakers.** Changes in the availability of non-firm gas supply may also impact technology choices. In this IRP, frame peakers are assumed to need sufficient firm pipeline capacity to run for 12 on-peak hours, with backup fuel being used for any remaining reliability need. However, when frame peakers can avoid the cost of firm pipeline capacity by operating with a combination of non-firm gas and backup fuel oil, peakers look more cost effective even in the stochastic analysis.

An extensive analysis of sufficiency of back-up fuel inventories applied to our existing peaker fleet is reported in Chapter 6, Electric Analysis. We are confident that at least one more frame CT can be added without needing firm pipeline capacity for reliability, even taking into account very conservative assumptions about the availability of non-firm gas supply and air permit limitations. Beyond the next peaking plant, the ability to construct a backup fuel tank and obtain adequate air permits will depend on its location and the applicable emission regulations.

3. **Future Energy Policies.** Changes in the direction of energy policy could also impact technology choices. Some policies designed to reduce carbon emissions tip the economics toward frame peakers, while others favor CCCTs. This uncertainty suggests minimizing long-term fixed cost commitments to plants that may end up being uneconomic; that is, it favors smaller frame peakers with backup fuel, because they do not require long-term gas pipeline commitments. But, different carbon reduction policies will have different impacts. Marketwide policies that seek to reduce coal generation across the WECC on a consistent basis increase the relative value of CCCT plants, making them more cost effective; however, when similar policies are applied on a state-by-state basis, things become complicated. For example, a hard carbon cap in Washington could limit the run hours for CCCT plants, increasing costs and reducing the cost effectiveness of CCCT. On the other hand, if other states impose similar caps, less energy will be available across the entire WECC, which could driving up market prices and the value of CCCT plants. Policies that include carbon caps tied to an undefined or unclear carbon market for offsets do little to alleviate this uncertainty. Changes in



renewable portfolio standards can also impact the relative value between types of gas plants.

4. **Value of Sub-Hourly Flexibility and Technology.** Changes in the relative flexibility values of 4. different resources could change technology decisions. Analysis in this IRP incorporated initial estimates of sub-hourly flexibility value of different resources, including CCCT, batteries, frame and other peakers, and reciprocating engines. Including flexibility value improved the value of reciprocating engines to the degree that they supplanted CCCT and other peakers in terms of cost effectiveness. However, while the reciprocating engines examined in this IRP appear to be cost effective from the perspective of flexibility benefits, their particulate emissions may exceed recent EPA standards. We plan to upgrade our sub-hourly flexibility modeling, and will continue to study possible particulate emission concerns. Should there be a solution for those concerns, reciprocating engines may become a least-cost resource.

**DISCUSSION.** The results for gas plants in the deterministic portfolio analysis is shown in Figure 2-4. In 6 of the 10 scenarios, some level of CCCT plants would be cost effective, and in two only CCCT plants are least cost. This is partially due to “lumpiness,” i.e., the larger size required for CCCT plants to be cost effective. If we reasonably adjust generic plant sizes to better match the timing of resource needs, for example, frame peakers with firm gas pipeline capacity would be chosen as cost effective in the Base Scenario. CCCT plants performed better in scenarios where the margin (market price minus variable operating cost) from operating CCCT plants is higher, which effectively reduces the cost of the plants. For example, in the Base + High CO<sub>2</sub> Scenario, coal plants are pushed out of the dispatch, driving up power prices relative to natural gas prices so the additional margin from CCCT plants offsets their higher capital cost relative to CTs. In the Base + No CO<sub>2</sub> Scenario, the margin from operating CCCT is again higher, this time because the lack of a CO<sub>2</sub> tax reduces the variable operating cost of CCCT plants enough for the margin to again offset its higher capital cost relative to a CT.





The stochastic analysis demonstrated that including CCCT plants in the mix reduced both cost and risk, and the more other gas resources were displaced, the lower the cost and risk. In fact, the stochastic analysis showed that candidate strategy 4, which added only CCCT plants, would be expected to be about 1.3 percent lower cost over the planning horizon than the chosen resource plan forecast.

*Figure 2-7: Stochastic Analysis Resource Addition Results*

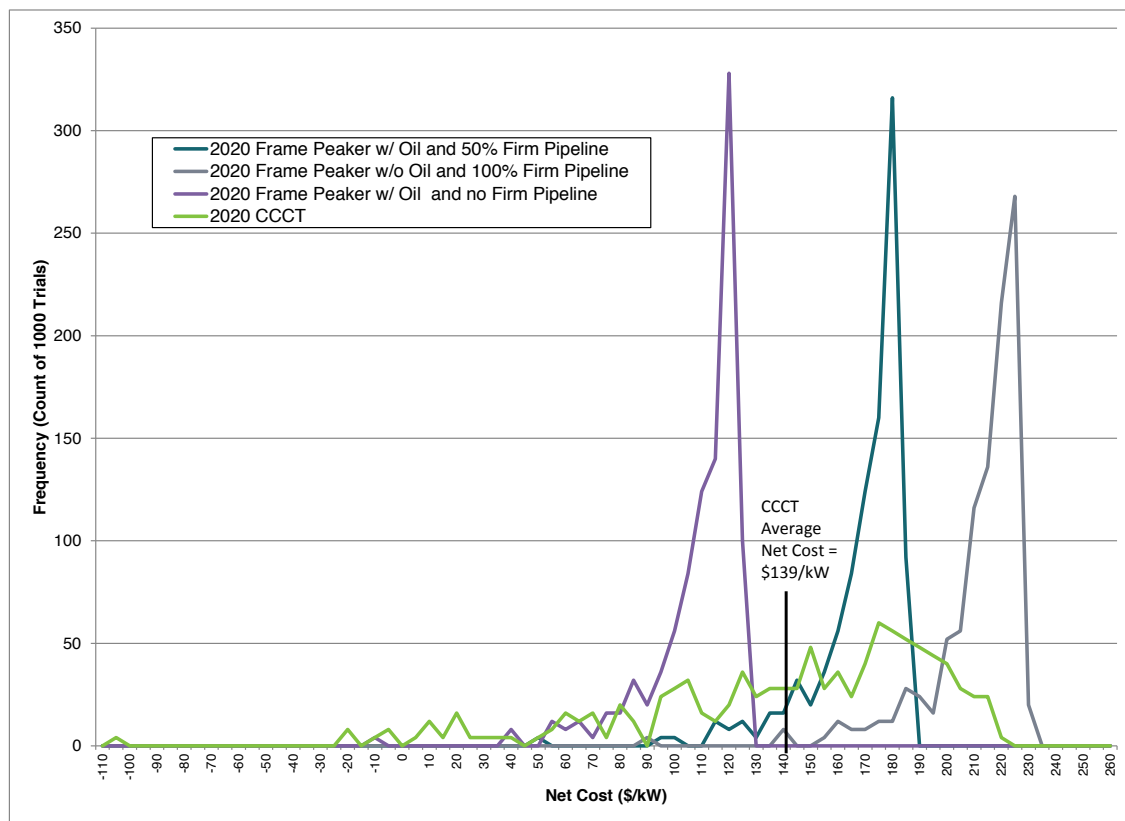
NPV (\$Millions)	Base Deterministic Portfolio Cost	Difference from Base	Mean	Difference from Base	TVar90	Difference from Base
1 - All Frame Peaker	<b>12,531</b>		<b>11,343</b>		<b>14,589</b>	
2 - Early Recip Peaker	12,620	89	11,782	439	15,014	426
3 - Early CCCT/Thermal Mix	12,729	198	11,392	49	14,412	(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)

**Why Include Frame Peakers in Resource Plan?** There were two compelling reasons for adding frame peakers to the resource plan, one quantitative, the other qualitative. Qualitative concerns relate to the impact of technology changes, especially with respect to reciprocating engines, and energy policy uncertainty.



Quantitatively, analysis demonstrated that the net cost for frame peakers was lower than CCCTs if firm pipeline capacity is not needed, and since we are confident that at least one or two additional frame CTs could be sited and permitted with backup fuel and adequate air permits, the resource plan should reflect addition of these resources.<sup>7</sup> Figure 2-8, below, compares the distribution of net generation costs<sup>8</sup> of CCCT plants with three sets of assumptions for frame CTs. The middle distribution that resembles a spike represents the frame peakers with firm pipeline capacity to cover 12 run-hours (50% firm pipeline). The CCCT distribution is much more spread out, and its mean is clearly to the left of the frame peaker distribution. This shows that if sizing were irrelevant, CCCT would be lower cost, consistent with the results for candidate strategies 4 and 5. However, when firm pipeline capacity is not needed, the net cost for frame peakers shifts significantly to the left and is clearly less than the expected value for CCCT.

*Figure 2-9: CCCT and Peakers with Oil Backup, Comparison of Net Cost Distribution in the Base Scenario (in 2016 dollars per kW)*



7 / Chapter 6 presents a comprehensive analysis demonstrating that back-up fuel for existing dual-fuel units is sufficient—firm pipeline capacity does not appear to be needed.

8 / Net generation cost is calculated by subtracting the operating margin (electric price minus variable operating cost) calculated hourly, in each simulation from the fixed cost of the plant.



## Resources Not Selected

The following summarizes expectations for some alternative resources that were not selected for the electric resource plan.

**Energy Storage.** This is a very broad category, that can include smaller scale resources like batteries, up to 1000 MW pumped hydro storage. Continuing to improve our analytical capability to economically value flexibility will help better value those aspects of these resources. However, even the very high relative flexibility value assigned to batteries in our flexibility sensitivity analysis did not show those resources being cost effective. This may change in the future as technology continues to reduce cost of utility scale batteries. Pumped hydro did not appear cost effective on a generic basis, but it is possible that developers will participate in PSE's anticipated all-source RFP, so we will be able analyze these resources on a specific basis, which may show they are more cost effective than we found in the IRP.

**Montana Wind.** Montana wind generally has high capacity factors and higher peak capacity value than Northwest wind, but generally does not meet the legal requirements under RCW 19.285 as a qualifying renewable resource, because they are outside the defined geographical boundaries. This IRP demonstrated that if the capacity contribution of Montana wind is high enough, it may be able to overcome the transmission cost to bring Montana wind to PSE. It is possible that developers may have specific transmission solutions that are less costly than our generic assumptions in the IRP. If specific Montana wind resource alternatives are bid into the all-source RFP process, they will be rigorously analyzed along with the other resource alternatives.

**Utility Scale Solar.** The cost of solar continues to decline. It is possible that utility scale solar will become more cost effective than wind in the Northwest. Our need for renewables to comply with RCW 19.285 is still 8 years away. We will continue to monitor trends as technology drives down the cost of all resources.

**Reciprocating Engines.** These resources provide significantly faster response than other types of thermal resources. In the flexibility sensitivity, the value of that flexibility appeared to compensate for the higher upfront cost of these resources. The challenge with these resources, however, is that they may have a difficult time meeting particulate emission limits – the requirements are site specific. Engineering innovations may overcome this challenge in the future – we will continue to monitor those developments.



## GAS SALES RESOURCE PLAN

### Resource Additions Summary

The gas sales resource plan is summarized in Figure 2-9, followed by a discussion of the reasoning that led to the plan. (Information on the analysis of gas for generation fuel can be found in Chapter 6.)

Figure 2-9: Gas Sales Resource Plan – Cumulative Capacity Additions (MDth/day)

Base Scenario MDth/day	2018-19	2022-23	2026-27	2030-31	2034-35
<b>Demand-side Resources</b>	12	29	46	58	69
<b>PSE LNG Peaking Project</b>	69	85	85	85	85
<b>Swarr Upgrade</b>	30	30	30	30	30
<b>NWP/Westcoast Expansion</b>	-	34	49	102	102
<b>Mist Storage Expansion</b>	-	-	50	50	50
<b>Cross Cascades to AECO Expansion</b>	-	-	10	10	10
<b>Cross Cascades to Malin Expansion</b>	-	-	-	99	99
<b>NWP/KORP Expansion</b>	-	-	-	-	-
<b>Total</b>	111	178	270	434	445

The gas sales resource plan integrates demand-side and supply-side resources to arrive at the lowest reasonable cost portfolio capable of meeting customer needs over the 20-year planning period. The additions identified above are consistent with the optimal portfolio additions produced for the Base Scenario by the SENDOUT gas portfolio model analysis tool. SENDOUT is a helpful tool, but results must be reviewed based on judgment, since real world market conditions and limitations on resource additions are not reflected in the model.



## Gas Sales Results across Scenarios

As with the electric analysis, the gas sales analysis examined the lowest reasonable cost mix of resources across a range of ten scenarios. Figure 2-10 illustrates the lowest reasonable cost portfolio of resources across those potential future conditions.

Figure 2-10: Gas Sales Portfolios by Scenario (MDth/day)

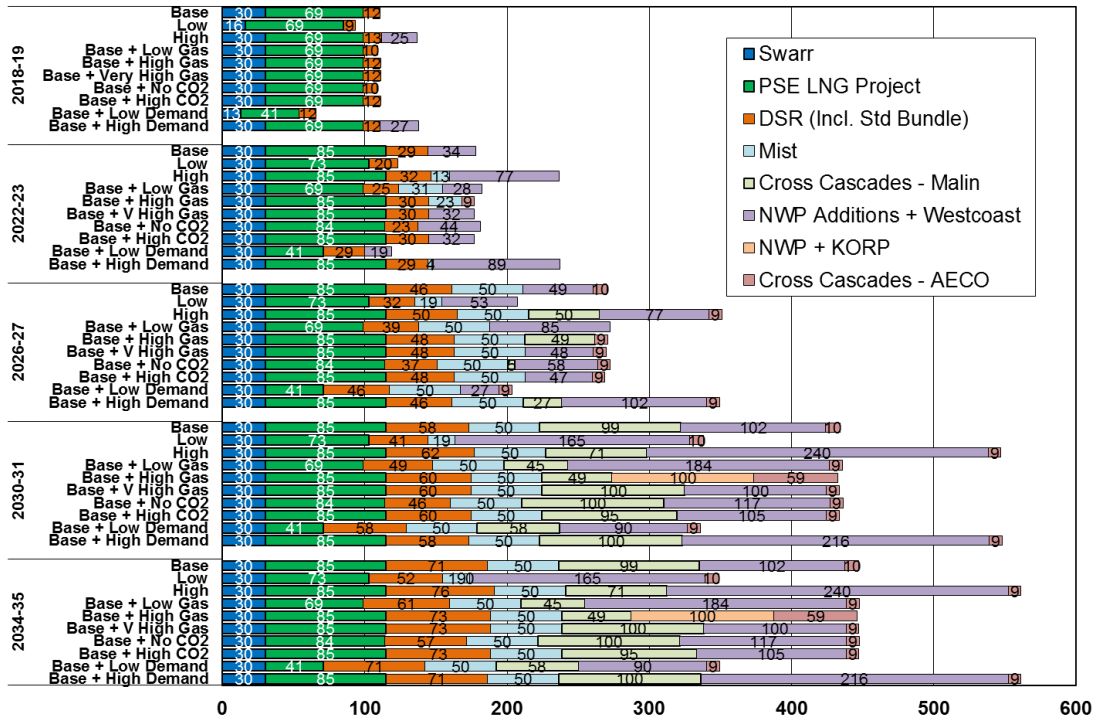


Figure 2-12, above, shows that results across scenarios are consistent. The full Swarr upgrade is cost effective in all scenarios by the 2022-23 winter period and a similar level of DSR is cost effective across all scenarios. In 6 out of 10 scenario/sensitivities, 100% of the PSE LNG Project was found to be cost effective—at least some of that resource was cost effective in all 10 scenario/sensitivities. The peak day capacity of the PSE LNG Project chosen varies in four of the scenarios, but this is a function of the SENDOUT model's limitations, since the capacity of the LNG project is not flexible, as discussed in more detail in Chapter 7, Gas Analysis. Also, the Mist storage with prospective pipeline capacity on Northwest pipeline (NWP) from Portland to Seattle is selected in most scenarios beginning in 2026, though this resource availability is dependent on expansion of the NWP. The remaining gas sales resource need is filled with varying amounts of pipeline volumes to either the Station 2 hub on the Westcoast pipeline or to the Malin hub via the possible Cross-Cascades pipeline. Later in the planning horizon, results vary mostly because of long-term load growth projections. Different elements of the resource plan are discussed below.



### Demand-side Resource Additions

**DECISION.** PSE will include gas DSR consistent with results from the Sendout model for the Base Scenario results.

**SUMMARY.** Cost-effective DSR levels vary slightly across scenarios. By the 2022-23 heating season, the difference between the High Scenario<sup>9</sup> (at 32 MDth per day) and the Low Scenario<sup>10</sup> (at 20 MDth per day) is only 12 MDth per day. Even the addition of a carbon tax in the Base Scenario had an impact of only 7 MDth per day by the 2022-23 heating season since it still selected 29 MDth of DSR and the Base + No CO<sub>2</sub> Scenario selected 23 MDth per day. Given the small range, it is reasonable to adopt the level of conservation from the Base Scenario of 29 MDth per day by 2022-23 growing to 69 MDth per day by 2034-35 or the resource plan.

**FACTORS THAT COULD AFFECT DECISION.** There should be little impact in the near term level of planned DSR, since PSE works with the CRAG to develop conservation targets based on these IRP results. Longer-term, technology changes or policies could impact conservation targets in future IRPs.

### Supply-side Resource Additions

#### Swarr Upgrade

**DECISION.** Preliminary work necessary to upgrade the facility's environmental safety and reliability systems and increase production capacity to 30,000 Dth per day should proceed with the goal to ready this resource for availability for the 2016-2017 winter.

**SUMMARY.** All of the scenarios selected the Swarr upgrade project early in the study period (by 2018). Upgrades to increase deliverability to the 30 MDth per day design level are low cost relative to other resource alternatives. The Swarr upgrade has been selected consistently in PSE IRP analyses, and the company will begin implementing this upgrade, as reflected in the Action Plan.

**FACTORS THAT COULD AFFECT DECISION.** This is a very near-term action item. PSE is ready to begin construction. Aside from unexpected issues in implementing the upgrades, little will impact this decision.

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<sup>9</sup> / The High Scenario had High CO<sub>2</sub> prices.

<sup>10</sup> / The Low Scenario had zero CO<sub>2</sub> prices.



### PSE LNG Peaking Project

**DECISION.** Include the PSE LNG Peaking Project facility in the resource plan, starting at 69 MDth per day and ramping up to 85 MDth per day as PSE's distribution system is built out to accept the full withdrawal capacity.

**SUMMARY.** PSE's planned PSE LNG Project, located in Tacoma, will provide peaking supplies for our gas sales customers as well as LNG as a transportation fuel. SENDOUT optimization analysis illustrated in Figure 2-10, shows the PSE LNG Project is a cost-effective peaking supply across all scenarios. The small variation in optimal plant sizes is primarily related to SENDOUT modeling limitations because in optimization mode, SENDOUT assumes resources can be scaled linearly, meaning 75% of the plant would only cost 75% of the full cost. That logic does not apply to an asset-based resource like the PSE LNG Project. Additional analysis of the portfolio benefits of the PSE LNG Project discussed in Chapter 7 demonstrates the PSE LNG Project would be cost effective in every scenario.

**FACTORS THAT COULD AFFECT DECISION.** PSE is in the late development stage of the LNG peaking project in Tacoma. Our final decision will be based on the receipt of all major project permits, and take into account regulatory and other business considerations, taken as a whole.

**DISCUSSION.** Some level of capacity from the PSE LNG Project appears cost effective in every scenario. In four cases, the SENDOUT optimization analysis showed less than the full 85 MDth per day would be cost effective, but additional analysis demonstrated that the full capacity would be cost effective in all scenarios. In optimization mode, the SENDOUT model uses a simplifying assumption that optimal sizing is possible and that the relationship between capacity and cost is linear. Since the costs of the LNG project do not vary linearly with capacity, additional analysis was necessary to understand the tradeoffs of including or excluding LNG across the different scenarios.

For each scenario, we ran another set of analyses. In one, the LNG Peaking Project was included in the portfolio at 85 MDth per day, and in the other the project was excluded. The results quantify the net benefit (or cost) to customers in each scenario. Figure 2-11, below, demonstrates that the NPV benefits to customers of the LNG Peaking Project range from \$8.4 million to \$103 million, with the Base Scenario showing a savings to customers of almost \$98 million. Given the 85 MDth per day LNG Peaking plant is a least cost resource in every scenario, it was included in the resource additions forecast.



Figure 2-11: Portfolio Benefits From PSE LNG Peaker

SCENARIO	Gas Portfolio Costs Net Present Value (\$000s)		
	FULL LNG	NO LNG	(Benefit) / Cost of LNG
BASE	\$ 9,366,925	\$ 9,464,726	\$ (97,801)
LOW	\$ 6,257,998	\$ 6,294,659	\$ (36,661)
HIGH	\$ 12,963,307	\$ 13,052,452	\$ (89,146)
BASE + LOW GAS	\$ 8,212,622	\$ 8,263,903	\$ (51,281)
BASE + HIGH GAS	\$ 10,719,839	\$ 10,823,632	\$ (103,794)
BASE+VERY HIGH GAS	\$ 11,906,047	\$ 11,994,805	\$ (88,758)
BASE+NO CO2	\$ 7,775,728	\$ 7,846,172	\$ (70,444)
BASE+HIGH CO2	\$ 10,465,655	\$ 10,565,404	\$ (99,748)
BASE+LOW DEMAND	\$ 9,031,721	\$ 9,040,101	\$ (8,379)
BASE+HIGH DEMAND	\$ 10,450,532	\$ 10,550,911	\$ (100,379)

## Mist Storage and Pipeline Expansions

**DECISION.** Continue to consider resource additions from the Base Scenario for expanded NWP pipeline capacity and Mist storage that occur later in the planning horizon. Improve the analytical process to better reflect variability in prices between gas market hubs.

**SUMMARY.** These further-out decisions do not need to be made at this time, allowing PSE time to further refine our risk analysis. There is an important relative risk to consider when acquiring long-term pipeline capacity versus market area storage. Acquiring pipeline capacity generally locks in supply pricing to a specific basin, whether it may be in Northern British Columbia at Station 2, in Alberta at AECO or in the Rockies at Malin. Prices between these basins have changed over time for a variety of reasons, some of which may or may not be present in the future. Market area storage, such as Mist, avoids the risk of locking in price levels to any specific basin – gas conservation programs have the same benefit. In PSE’s 2017 IRP, we will focus on improving this risk analysis to better support specific resource decisions.





**FACTORS THAT CAN AFFECT DECISIONS.** Two sets of factors could affect these decisions.

1. ***New Market Entrants.*** Utilities could find themselves taking a back seat in future pipeline expansion decisions if methanol plants or LNG export facilities enter the market because the gas infrastructure needs of those industries are so significant. That is, if a large methanol manufacturing facility on the I-5 corridor contracts with Northwest Pipeline and Westcoast to go to Station 2, gas utilities will only have a choice of whether or not to join; there will not be enough market share to build an expansion in another direction. Such new players could also create opportunities to acquire peaking resources if their production processes do not require the same degree of firm physical deliveries as the utility industry.
2. ***Relative Prices Between Basins.*** Sometimes the spread in market gas prices between different basins can be large enough to cover the fixed cost of a pipeline expansion. For example, if market gas prices in the Rockies relative to Station 2 fall by \$2.00 per MMBtu, that may be sufficient to cover a higher pipeline cost to the Rockies. Market area storage, like Mist, helps to avoid some of that risk because there may be sufficient flexibility to fill the storage resource during off-peak seasons. This is a risk where PSE will focus during the next IRP process.