2

2017 PSE Integrated Resource Plan

Resource Plan Decisions

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

Contents

1. OVERVIEW

The resource plan forecast 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."[1]

The resource plan forecast described here is not simply the output of a deterministic portfolio optimization model. It incorporates what we learned from the deterministic analysis of how different long-term economic conditions and other factors affect risk across scenarios, from a stochastic portfolio analysis that includes consideration of how short-term variability impacts risk, and from the application of judgment given a qualitative assessment of the market in which we operate, which is more complex than can be simplified to a mathematical model. First, this chapter summarizes resource additions in the resource plan forecast. Then we present a high-level summary of the findings from the deterministic optimization analysis and stochastic portfolio risk analysis. Finally, after establishing context from the analysis, we step through each element of the resource plan to explain how judgment was applied.

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.

---

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

2. ELECTRIC RESOURCE PLAN

Resource Additions Summary

Figure 2-1 summarizes the forecast of resource additions to the company's electric portfolio that resulted from the 2017 IRP analysis. Most notably, this resource plan postpones the need for new thermal peaking plants out to 2025. We accomplish this by accelerating conservation investments, acquiring demand response, redirecting transmission to market, and using energy storage in the first seven years of the study period. This pushes fossil fuel peaking plant additions out into the realm of hypothetical resources. The further into the future that the need for such plants can be pushed, the better the chances are that technological innovations will reduce the relative cost of energy storage, conservation and demand response, such that development of new dual-fuel peaker plants will continually be pushed into the future. And, as the need for new resources gets pushed out, it gives the region more time to continue heavy investments in conservation, which will continue to improve the reliability of market purchases.

Figure 2-1: Electric Resource Plan Forecast,
Cumulative Nameplate Capacity of Resource Additions

	2023	2027	2037
Conservation (MW)	374	521	714
Demand Response (MW)	103	139	148
Solar (MW)	265	377	486
Energy Storage (MW)	50	75	75
Redirected Transmission (MW)	188	188	188
Baseload Gas (MW)	0	0	0
Peaker (MW)	0	717	1,195

Portfolio Optimization Results across Scenarios

PSE examined 14 different market scenarios. The scenarios included different combinations of load, gas/power prices, and carbon costs/forms of regulation. Each scenario is a unique combination of factors that could affect market power prices or load. Scenario analysis is an important form of risk analysis. It helps us understand how specific assumptions that represent very different futures would affect the least-cost mix of resources. Figure 2-2, below summarizes

the relationship between these scenarios and sensitivities. Additional detail is provided in Chapter 4.

Figure 2-2: 2017 IRP Scenarios

	Scenario Name	Demand	Gas Price	CO$_2$ Price
1	**Base Scenario** [1,2,3]	Mid	Mid	Mid
2	**Low Scenario**	Low	Low	Low
3	**High Scenario**	High	High	High
4	**High + Low Demand**	Low	High	High
5	**Base + Low Gas Price**	Mid	Low	Mid
6	**Base + High Gas Price**	Mid	High	Mid
7	**Base + Low Demand**	Low	Mid	Mid
8	**Base + High Demand**	High	Mid	Mid
9	**Base + No CO$_2$**	Mid	Mid	None
10	**Base + Low CO$_2$ w/ CPP** [2]	Mid	Mid	Low + CPP
11	**Base + High CO$_2$**	Mid	Mid	High
12	**Base + Mid CAR only (electric only)**	Mid	Mid	Mid CAR only
13	**Base + CPP only (electric only)**	Mid	Mid	CPP only
14	**Base + All-thermal CO$_2$ (electric only)**	Mid	Mid	CO$_2$ price applied to all thermal resources in the WECC (baseload and peakers)

NOTES
1. Washington CAR (Clean Air Rule) regulations apply to both electric and gas utilities. These are applied to all scenarios.
2. Federal CPP (Clean Power Plan) regulations affect only baseload electric resources, so the gas portfolio models scenarios 1 through 11 only. CPP rules are modeled as if the entire WECC is part of an integrated carbon market, with carbon prices applied to all baseload generation, so that even if the CPP is ultimately not put into effect, the analysis still represents a form of carbon price regulation.
3. Carbon regulations are assumed to transition from CAR to CPP in 2022.

Figures 2-3 and 2-4 summarize 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. The scenario risk examined in this IRP includes a wide range of different kinds of carbon regulations, load growth assumptions and natural gas prices, which drive wholesale power prices.

That is, Figures 2-3 and 2-4 summarize the least-cost solution across all the market scenarios that were examined. 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 Figures 2-3 and 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 redirecting transmission, demand side resources, energy storage, renewables and dual-fueled peakers to meet remaining capacity needs. 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 2-3: Resource Builds by Scenario, Scenarios 1-9

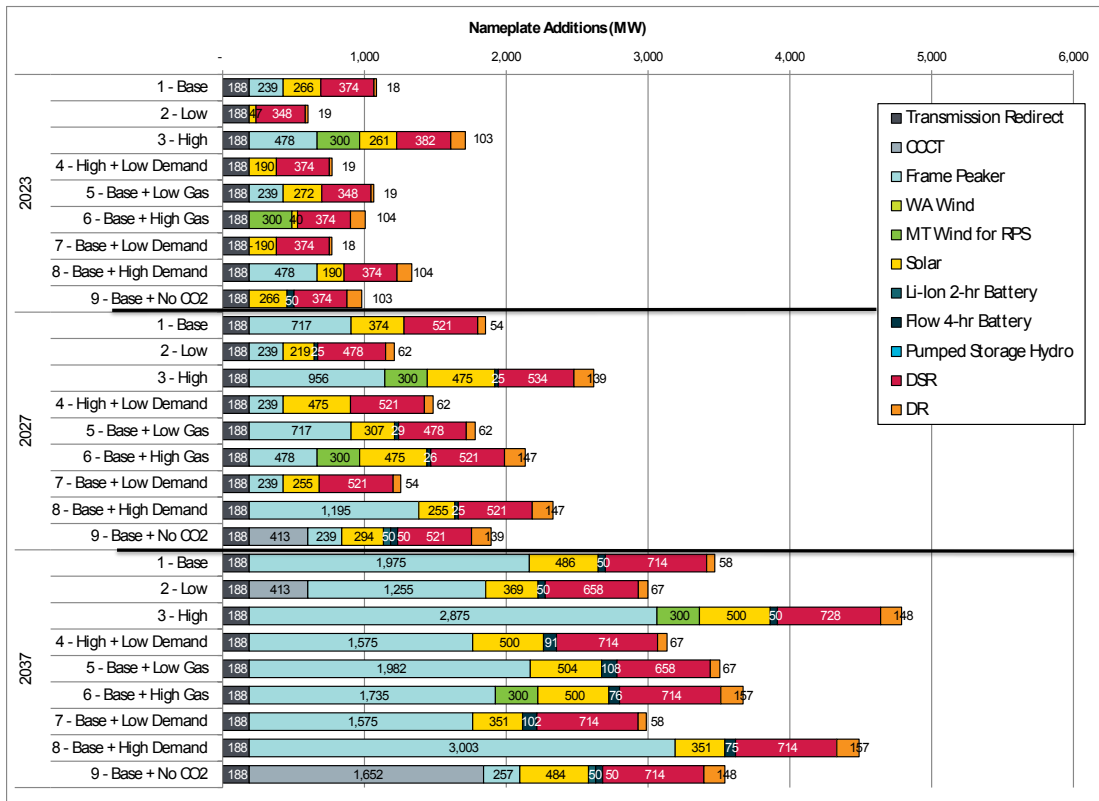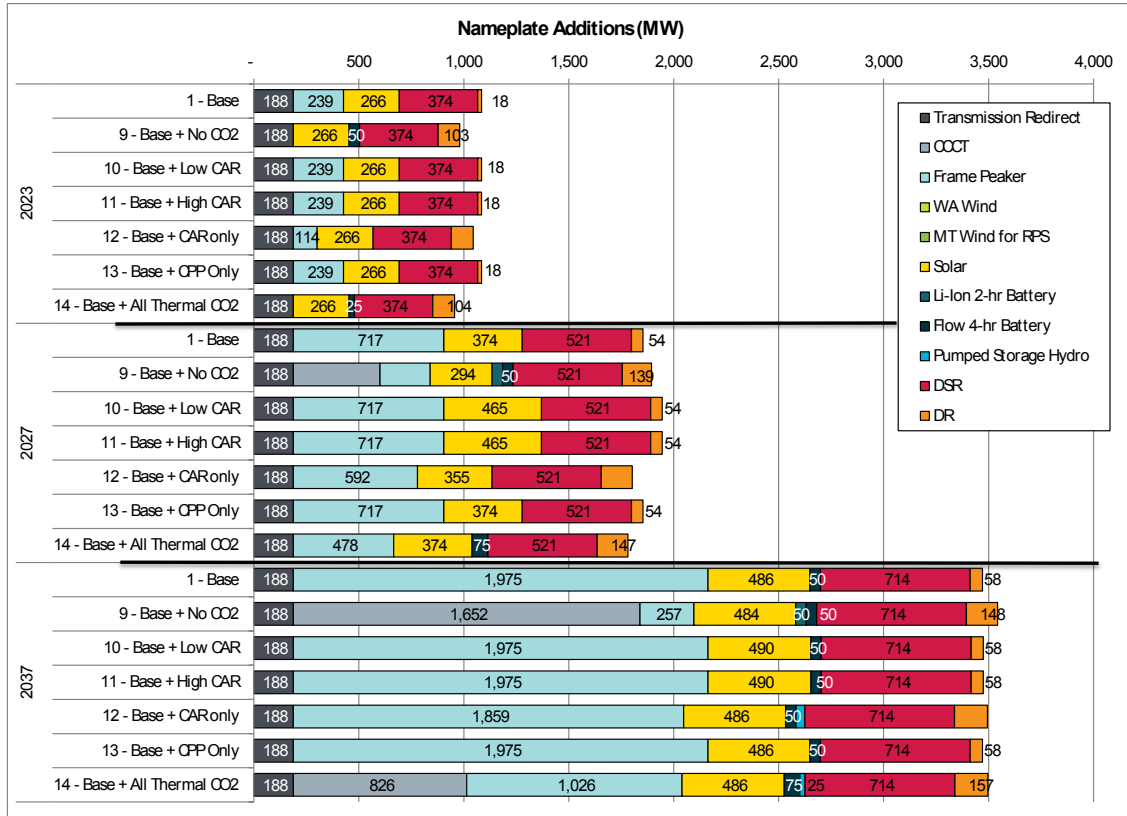*Cumulative Additions by Nameplate (MW)*

Figure 2-4: Resource Builds by Scenario, Scenarios 9-14
Cumulative Additions by Nameplate (MW)

Portfolio Optimization Results by Resource Type

Conservation

Cost-effective conservation does not vary across scenarios. This is consistent with findings in prior IRPs, where the variability in costs across scenarios has little impact on the amount found to be cost effective, which highlights it is a low-risk resource with regard to possible changes in carbon regulation, load growth and gas market conditions across the 14 scenarios and sensitivities examined.

2017 PSE IRP

Demand Response

All scenarios have at least 60 MW of demand response, with a few scenarios having as much as nearly 160 MW. In the context of a portfolio that needs over 3,000 MW of resources by 2037, this is a small degree of variability.

Redirected Transmission

Increasing market reliance by redirecting 188 MW of transmission from Hopkins Ridge and Lower Snake River is least cost across all scenarios and sensitivities, meaning it is a low-risk long-term decision from a deterministic risk perspective. Increasing market reliance could have risks that would be unseen in a deterministic analysis; these must be examined from a stochastic perspective.

Energy Storage

A small amount of utility-scale batteries appears cost effective at some point in the planning horizon in every scenario, given the assumed transmission and distribution benefits. By 2037, all scenarios have at least 50 MW, while a few have approximately 100 MW. It appears batteries are cost effective primarily because they can be sized to fit needs with slowly growing loads, in addition to being very flexible.

Renewable Resources – Eastern Washington Solar

Solar appears to be the most cost-effective renewable resource to comply with RCW 19.285, given the assumed transmission costs. PSE spent considerable resources refining our wind data, only to find solar appears more cost effective, so this was an unexpected shift. Solar provides no peak capacity value to PSE, because we are a winter peaking utility. The sun rises after PSE's system peaks on winter mornings and sets before our winter peaks begin in the afternoon. Despite the fact that solar had no peak capacity value, it still appears to be the least cost renewable resource for compliance with RCW 19.285. Figure 2-5 illustrates that the levelized cost of solar, even if it required transmission, is lower than Montana or Pacific Northwest wind. However, this figure shows the levelized costs including peak capacity value are close. Actual bids in an RFP process could yield a different conclusion.

Renewable Resources – Montana Wind

Wind in eastern Montana would not be a qualifying renewable resource under RCW 19.285, unless it were delivered all the way to Washington state on a real-time basis without shaping or storage. In this IRP, we examined whether being designated as a qualifying renewable resource would make Montana wind appear cost effective. It did not. However, Montana wind was reasonably close to being cost effective, as shown in Figure 2-5, below. In the acquisition process where actual projects are bid to the company and depending on the transmission costs, it is possible that PSE will find Montana wind projects could be more cost effective than Washington

solar projects. However, there are three key barriers to Montana wind being designated an eligible renewable resource under RCW 19.285.

1. **TRANSMISSION STUDY PROCESS**. Montana wind would have to be scheduled into Washington state on a real-time basis without shaping or storage in order to qualify as a renewable resource under RCW 19.285. Being able schedule wind from Montana all the way to Washington state in this manner would require coordination of transmission studies across Northwestern, BPA and possibly the WECC. Recently, BPA scheduled a workshop in December 2017 in Montana to begin discussion about issues relating to transmission for Montana resources. For the region to move forward on this question is an optimistic step. A blanket policy that ensured wind from Montana could be "dynamically scheduled" to Washington without the need to do transmission studies on a project-by-project basis would avoid the issue described below about who pays for such studies. PSE supports addressing the challenges concerning transmission of Montana wind resources and will participate in BPA's workshop and other regional discussions on this issue.

2. **CHALLENGES WITH PROJECT-BY-PROJECT DETERMINATION – TIMING AND WHO PAYS.** Incentives may not be aligned to facilitate completion of studies for individual projects. Montana wind developers may be reluctant to pay for such studies without knowing that PSE would purchase the resource if it was determined to be a qualifying resource. If the study did not support dynamic scheduling capability, or if the costs to facilitate dynamic scheduling were significant, the resource would have no value to Washington state utilities as a renewable resource under RCW 19.285. PSE would also be reluctant to pay for these studies based on incentives created under current regulatory policies. For example, if PSE paid for such studies, we may not be allowed to recover the cost of the study if it did not directly lead to a resource acquisition (via PPA or ownership). Had this IRP found RPS-eligible Montana wind to clearly be a least-cost resource, the prudence risk associated with paying for such study might be reasonable – but that conclusion was not supported by the analysis. In addition, timing during the acquisition process could also be a challenge. If PSE has the choice of two resources that are very close in cost but one clearly meets eligibility requirements of RCW 19.285 while the other requires additional study to make that determination, it may not make sense to expose PSE's customers to that risk. The study could take several months, and should it determine the Montana wind resource would not being a qualifying resource, the alternative opportunity may no longer be available.

3. **DELIVERY TO PSE.** For Montana wind to have a peak capacity value, the resource must be delivered all the way to PSE. This IRP assumes additional transmission to PSE's

system is available at a price from BPA. However, that may not be the case. If the developer (or PSE) cannot obtain additional cross-Cascades transmission, the power may be delivered only to Mid-C. If PSE has to use existing transmission to Mid-C to transport that power to load, no capacity value is created at all. It simply offsets market purchases, since we have already counted on the transmission as a capacity resource. It is possible that contracts PSE uses to deliver energy from Colstrip to PSE could be used to deliver Montana wind. This topic will need to be explored more fully in future studies.

Pacific Northwest Wind

Wind in the Pacific Northwest did not appear to be a cost-effective resource in any scenario. Solar has lower costs and Montana wind has greater value because of the higher capacity factor and higher peak capacity value. As with Montana wind, this IRP assumes additional cross-Cascades transmission will be available at a price. If additional cross-Cascades transmission cannot be acquired, there will be no peak capacity value associated with Pacific Northwest wind – just like Montana wind. However, Figure 2-5, below, illustrates the levelized cost of solar, Montana wind, and Pacific Northwest wind are all fairly close – assuming Montana wind could qualify as a renewable resource.

Figure 2-5: Wind and Solar Cost Components
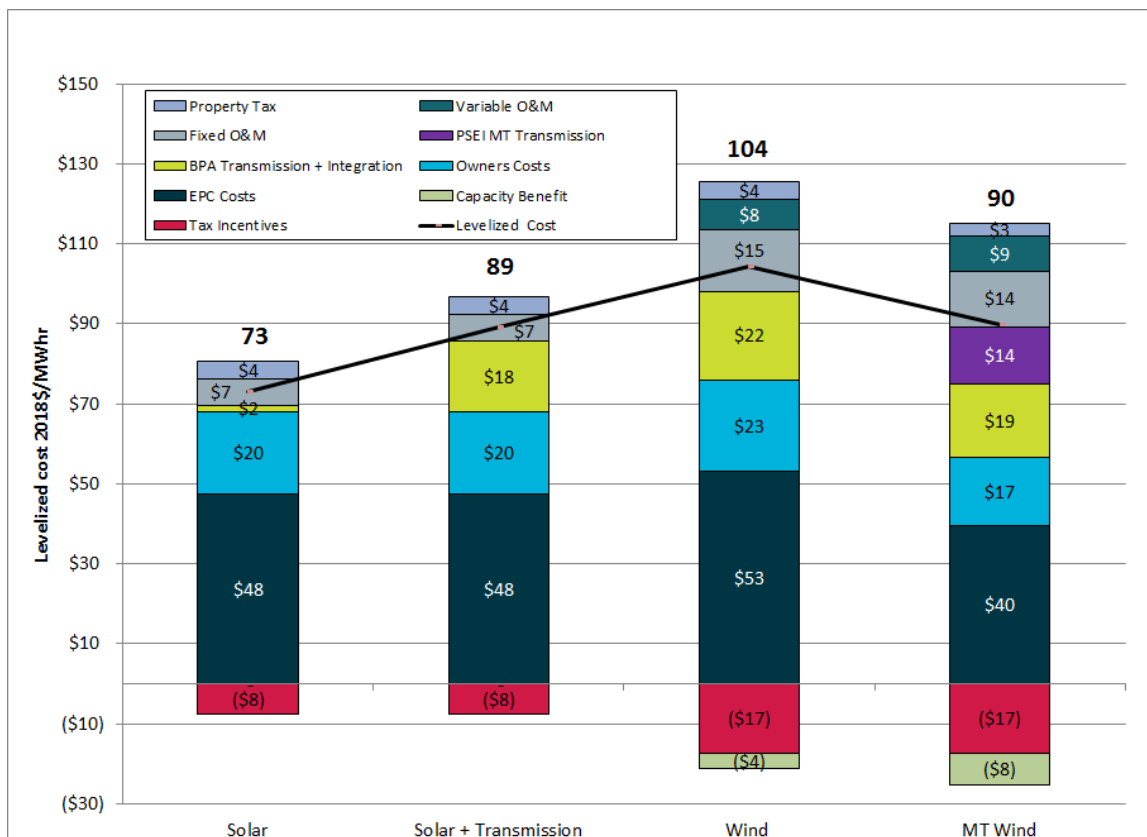
Baseload Gas Plants

Combined-cycle natural gas plants do not appear cost effective in most scenarios. Scenario 2 (Low) has 413 MW and Scenario 9 (Base + No CO_2) has over 1,650 MW. Both of these scenarios essentially have no long-term carbon pricing. The pricing in Scenario 14 (Base + All-thermal CO_2) on all thermal plants shows just over 800 MW of baseload gas plants being added. This highlights that the way carbon regulation will be implemented is important. In scenarios where carbon regulation primarily affects baseload gas plants but not peakers, baseload gas plants are not cost effective. The only two carbon regulation rules currently on the books that may affect PSE's operations – the CAR[2] and the CPP – generally affect baseload gas plants, but not peakers.

Peakers

Dual fuel frame peakers were found cost effective in every scenario. Most scenarios show it as the go-to capacity resource later in the planning horizon, with at least 1,000 MW by 2037. The only exception is in Scenario 9 (Base + No CO_2), which has only 257 MW of dual fuel peakers – but it seems unlikely there will be no carbon regulation of any kind. In many scenarios, carbon regulation is applied unevenly – to baseload gas but not peakers. This tends to increase the value of peakers relative to other capacity resources, such as energy storage and demand response. This can be seen by comparing energy storage and demand response in the Base Scenario and Scenario 13 (the CPP Only Scenario), which impose carbon costs on baseload gas plants but not peakers, with the results from Scenario 9 (Base + No CO_2) and Scenario 14 (Base + All Thermal CO_2), which treat peakers and baseload gas plants equally with respect to carbon pricing. The two scenarios with uneven application of carbon pricing (1 and 13) show about 60 MW of demand response would be cost effective by 2037, but scenarios with consistent application of carbon regulation (9 and 14) find about 150 MW of demand response cost effective. Application of carbon costs only on baseload gas also reduces the amount of energy storage. Scenarios 1 and 13 (carbon costs only on baseload plants) have 50 MW of energy storage as least cost, compared to 100 MW in scenarios 9 and 14 (consistent application of carbon costs to all resources).

---

2 / Under the CAR, peakers are not exempt, but they also do not dispatch enough to hit the limits that would trigger compliance. For this IRP, PSE capped run times for new peakers to ensure they would not hit the emission triggers under CAR, so that we would avoid inflating the economic value of dispatching peakers.

Adequate backup fuel oil makes peakers significantly less costly than baseload gas plants. Baseload gas plants require firm pipeline capacity in lieu of backup fuel. Firm pipeline capacity is expensive relative to a fuel-oil storage tank. The firm pipeline cost for a 300 MW baseload gas plant would be about $20 million per year. An oil tank for a 300 MW peaker would be a one-time cost of about $15 million. There is a reliability concern with extensive reliance on dual fuel peakers. That is, will the backup fuel inventory be adequate? In this IRP, we present a comprehensive analysis demonstrating 48 to 72 hours of backup fuel supply would be adequate, even if PSE added several hundred MW of dual fuel peakers.

Summary of Stochastic Portfolio Analysis

The deterministic scenario analysis described above is helpful in understanding how changes in key assumptions would affect the least-cost mix of resources. It is not, however a complete picture of risk. The deterministic analysis assumes perfect foresight, so we know what factors – such as natural gas prices or carbon policies – will be far in advance of having to make decisions. It also assumes all markets and weather conditions are "normal." In reality, we do not know what natural gas prices will be, what hydro or wind conditions will be, or what kinds of carbon regulation will be imposed by 2025. To examine the implications of these risks, we develop a number of portfolios and run them through 250 simulations (or draws)[3] that model varying power prices, gas prices, hydro generation, wind generation, load forecasts (energy and peak), plant forced outages and CO_2 regulations/prices. From this analysis, we can observe how costs change across portfolios and identify whether differences occur when risk is analyzed.

We chose eight different portfolios to test in the stochastic analysis. The portfolios examined in this analysis were designed to test whether different resource alternatives would have a significant impact on expected cost or risk. PSE defines "risk" as the TailVar90 metric – which we adopted from the NPCC several years ago. That is the average value of all observations above the 90th percentile in the distribution of costs. TailVar90 of revenue requirement is a clear risk metric. It specifically focuses on how bad portfolio costs could be over the planning horizon. It allows us to see how different resources would affect bad outcomes. The portfolios tested included the following.

---

3 / *Each of the 250 simulations is for the twenty-year IRP forecasting period, 2018 through 2037.*

1. **BASE SCENARIO.** This is the least cost mix of resources that resulted from the Base Scenario. the primary capacity resources after conservation are dual fuel peaking units.

2. **RESOURCE PLAN.** The resource plan relies on additional demand response and batteries to push out the first dual fuel peaker to 2025.

3. **BASE + NO CO$_2$.** This was the least cost mix of resources that resulted from the Base + No CO$_2$ Scenario. It includes 1,652 MW of baseload gas plants by the end of the planning horizon.

4. **NO ADDITIONAL DSR.** This is the least cost portfolio in the Base Scenario, if we did not consider any additional DSR. The purpose is to illustrate the impact of conservation on both cost and portfolio risk.

5. **ADD 300 MW OF SOLAR.** This portfolio adds 300 MW of solar beyond RPS requirements in 2022 to the least cost portfolio from the Base Scenario. Solar was chosen because it was found to be the least-cost renewable resource across all scenarios. Adding solar would avoid exposure to market purchases if prices run up – though it also reduces the ability to take advantage of low prices. The purpose is to examine whether adding solar beyond requirements would reduce portfolio risk, and if so, would it reduce risk enough to justify the cost of including more in the resource plan.

6. **NO TRANSMISSION REDIRECT.** To develop this scenario, we excluded the transmission redirect as a resource choice, and re-optimized the portfolio, which added more peakers. However, increasing PSE's reliance on firm transmission backed by short-term market purchases could also increase risk. Even a dual fuel peaker could mitigate risk of very high power prices. This analysis was performed to test whether the transmission redirect that was chosen as low cost in every scenario would create unreasonable risk exposure.

7. **NO NEW THERMAL RESOURCES.** This is the least-cost portfolio from the No New Thermal Resources portfolio sensitivity, which was developed in the Base Scenario. When no new thermal resources were allowed, pumped hydro storage became the go-to capacity resource. The deterministic analysis showed it was expensive; this analysis is to determine if reducing exposure in high market cost conditions justified the high cost of pumped hydro.

8. **MORE CONSERVATION.** This portfolio adds 70 aMW of energy efficiency which provides an additional 4 MW of capacity, to explore whether an incremental increase in conservation would reduce portfolio risk, and if so, whether the reduction would justify adding conservation beyond what was found to be least cost.

Summary of Stochastic Portfolio Results

KEY FINDING. Resource additions have little impact on portfolio risk. This is primarily because the portfolio is already quite large – 6,000 MW today – and what's being added to it is small. The resource plan forecast calls for approximately 2,750 MW of resources by 2037. However, only 1,150 MW of those resources reduce exposure to wholesale natural gas or power market risk – namely, conservation and solar. While we can examine cost versus risk of individual resources, aggregated up to the portfolio level, additions are small in relation to the portfolio. The take-away is that resource additions do not appear to be a meaningful way to try and manage portfolio risk. Instead, natural gas price and wholesale power price risk needs to be financially managed in the shorter-run – which is exactly what PSE does.

Results Across Portfolios Tested

There were some differences between the mean, or expected costs, of the various portfolios and the TailVar90 risks. Some are intuitive, others are not, and will be explained in the following discussion. Figure 2-6, below, summarizes results of the stochastic analysis. The mean, or expected values, from the stochastic analysis are relationally the same as results of the deterministic analysis. That is, the deterministic analysis showed the optimal Base Scenario portfolio was slightly lower cost than resource plan. We see the same in the stochastic analysis. All the other scenarios show expected portfolio costs greater than the resource plan forecast.

Figure 2-6: NPV of Portfolio Cost Metrics – Costs are NPV $Millions

NPV ($Billion)	"Average" Conditions			Worst Conditions		
	Mean	Difference from Base	% Change	TVar90	Difference from Base	% Change
1 – Base Scenario Portfolio	10.52			11.79		
2 – Resource Plan	10.57	0.05	0.5%	11.84	0.05	0.4%
3 – Base + No CO2 Portfolio	11.13	0.61	5.8%	12.5	0.71	6.0%
4 – No DSR	10.84	0.32	3.1%	12.8	.4	3.4%
5 – Add 300 MW Solar in 2023	10.54	0.03	0.3%	11.8	.01	0.1%
6 – No Transmission redirect	10.62	0.1	0.9%	11.89	0.1	0.8%
7 – No new thermal	12.69	2.18	20.7%	14.65	2.86	24.3%
8 – More conservation (Bundle 5)	10.81	0.29	2.7%	12.06	0.27	2.3%

2017 PSE IRP

Key Observations from Figure 2-6

RESOURCE PLAN COMPARED TO BASE SCENARIO PORTFOLIO. The resource plan includes more demand response and early batteries in order to delay the need for peakers until 2025, otherwise it is quite similar to the Base Scenario least-cost portfolio. The Base Scenario portfolio incorporates significant amounts of peaker units. The expected cost of the resource plan is slightly higher than the Base Scenario portfolio – by about 0.5 percent, or an NPV increase of $50 million over the planning horizon. Risk is also slightly higher: The mean of the worst 10 percent of cases (TailVar90) is higher by 0.4 percent. This illustrates that including more demand response and early batteries will not have a material effect on portfolio risk.

PEAKERS COMPARED TO BASELOAD GAS. A portfolio with baseload gas plant (CCCT) additions has an expected value significantly higher than the Base Scenario portfolio, which includes peakers instead of baseload gas plants. Substituting over 1,600 MW of baseload gas plants for peakers increases expected costs – by $610 million, a 5.8 percent increase. Risk increases as well, by about the same amount – 6 percent. This illustrates baseload gas plants do not reduce risk relative to peakers. Both substitute exposure to wholesale electric prices for exposure to wholesale natural gas prices. Both plants protect against market heat rate blow-outs, in which the price of electricity increases relative to natural gas prices. Focusing just on variable costs, baseload gas plants provide a better hedge against market heat rates because they use less natural gas. However, baseload gas plants come at a significantly higher initial cost. This risk analysis shows baseload gas plants provide no additional risk protection. Additional discussion on this issue appears below.

VALUE OF DSR. Conservation reduces both cost and risk relative to the alternative, which would be to add more dual fuel peaker capacity. The stochastic analysis demonstrates that cost-effective DSR saves $320 million on an expected value basis – a 3.1 percent savings. DSR also reduces risk, but not quite as much as it reduced cost. One might expect the risk reduction to be greater than the cost reduction, but there is an important difference between conservation and peakers. Conservation for PSE reduces exposure to gas and power prices by reducing load – typically winter loads – which avoids the need to build additional generation resources. Peakers represent an option to generate that can be exercised at any time. There may be circumstances in which summer market prices and heat rates are quite high. Conservation programs that primarily target heating loads have no value during those periods. Peakers, on the other hand, can provide value in the summer during times when natural gas and power prices diverge and capture margins that pass through to customers as an offset to power costs in rates. The analysis still shows conservation provides a significant reduction in risk.

ADDING 300 MW OF SOLAR. Adding solar beyond requirements of RCW 19.285 increases expected portfolio costs somewhat – by $30 million, or 0.3 percent. The additional solar also increases risk very slightly – by $10 million, or 0.1 percent. The much smaller reduction in risk means solar is reducing power costs during bad market conditions, but still not quite enough to offset the higher fixed cost. Also, something to consider is that solar output is lower in the winter when PSE's loads are highest, but solar output is higher in the summer, when prices can be high and volatile. Thus, the risk reduction is mostly a financial benefit, not a physical one – which is not a problem as we are trying to minimize costs of complying with RCW 19.285. With such close results, should PSE add solar to mitigate risk? That conclusion is not supported by this analysis. However, if solar costs continue to fall, it is possible that PSE will find solar reduces risk in future IRPs. Because PSE is winter peaking, we would need to develop planning standards to ensure such additions do not exceed loads so that PSE does not acquire more generation resources than our customers can use just so the surplus could be sold into the market.

INCREASING MARKET RELIANCE – IMPACT OF THE TRANSMISSION REDIRECT. The transmission redirect to access more short-term market energy is low-cost capacity. This comparison shows that if PSE did not pursue the transmission redirect, expected portfolio costs would be higher – by $100 million, or 0.9 percent. Risk would also be higher, again by $74 million, or 0.8 percent. The minor increase in risk means that an additional peaker would reduce variable power costs when power prices are high, but not enough to cover the higher cost. It is also interesting to compare the percentage change in risk from adding solar with the percentage change in risk from substituting a peaker for market purchases. Relative to cost, on a percentage basis solar performs as a better hedge because it avoids electric *and* natural gas price risk, whereas a peaker does not avoid the fuel price risk.

NO NEW THERMAL RESOURCES. This analysis illustrates that peakers are quite valuable to the portfolio. This portfolio covers much of the peak capacity need with pumped hydro storage as the most cost-effective alternative. This would be costly. The expected value is more than $2 billion higher than the Base Scenario portfolio, about a 20.7 percent increase. Risk is even higher, too – by over $2.8 billion, which is a 24.3 percent increase. This illustrates that energy storage does not effectively protect against natural gas price or power price risk. At best, energy storage allows for some short-term arbitrage between hours, but it is still charged with electricity, and therefore subject to the variability of market electric prices.

ADDITIONAL CONSERVATION. In this IRP we tested an increase in conservation beyond what was found cost effective across all scenarios. The deterministic analysis showed Bundle 3 was cost effective in every scenario. We included two additional bundles (through Bundle 5), which added 4 more MW of conservation and 68 aMW more energy savings. We tested this portfolio to determine if the additional conservation would reduce risk, and if so, whether the risk reduction benefits were worth the higher cost. Expected costs for this portfolio are $290 million higher than the Base Scenario portfolio, an increase of approximately 2.7 percent. The additional conservation did not, however, lower risk. Risk increased by $270 million (2.3 percent), meaning the higher cost of conservation was not offset by power cost savings, on average, in the worst 10 percent of simulations. While conservation that addresses heating loads is helpful for reducing peak capacity needs and reducing exposure to winter power and natural gas price risk, it provides no value outside the heating season. Peakers can help mitigate power price risk in the winter and present a year-round option to generate savings in excess of fuel costs that will flow back to customers.

Resource Plan Forecast: Application of Judgment

Discussion above summarizes key findings from the deterministic and stochastic portfolio analyses. These analyses do not necessarily drive an answer, but provide information upon which decisions can be made. While the models are comprehensive, there are risks and opportunities that are not reflected in the resource modeling. This section will step through each element of the resource plan and provide an explanation of why it is reasonable.

Increased Demand Response and Energy Storage: The Resource Plan Through 2024

Increasing demand response and energy storage, relative to the least cost mix of resources in the Base Scenario is an important risk mitigation decision. Technology is driving down the cost of alternative resources. Solar and energy storage appear cost effective for the first time in this IRP. While we do reflect improving technology costs in the portfolio analysis, it is possible energy storage costs will fall even faster than expected. Additionally, as we analyze additional kinds of demand response programs in the 2019 IRP, those could prove a cost effective way to avoid new fossil fuel generation. In addition to technology reducing cost of alternative resources, carbon regulation looms as a significant source of uncertainty. Even the form of carbon regulation is uncertain. The way carbon regulation is implemented is just as important as the per-unit cost of carbon. Additional demand response and batteries, sufficient to push the need for additional fossil fuel plants to 2025 or beyond is a reasonable strategy. This will provide time for technology to work on reducing alternative resource costs as well as time for carbon regulations to become clearer.

The specific amounts of additional demand response and energy storage were taken from the least cost portfolios under Scenario 9 (Base + No CO_2) and Scenario 14 (Base All-thermal CO_2). We substituted the early builds from these scenarios for the early peaker build from the Base Scenario, as shown in Figure 2-7. Both of those scenarios had sufficient demand response and energy storage to push the need for additional fossil fuel generation resources out to 2025. These scenarios have an unbiased application of carbon regulation, whereas the CAR and CPP in the other scenarios create an unintended bias that favors peakers over other capacity resources. In the Base Scenario, substituting demand response and energy storage increased NPV of portfolio costs by about $9 million – less than 0.1 percent. This is an insignificant cost to avoid building a fossil fuel plant that will have at least a 35-year life, to make sure it will be a good long-term investment on behalf of our customers.

Cost-effective Conservation

The same level of conservation was found cost effective across all the scenarios. This provides a high degree of confidence that we have the right amount of conservation in the resource plan. As described above, we tested adding more conservation to determine if it would provide a reasonable way to mitigate financial portfolio risk. It did not. Therefore, the decision on conservation is very well supported by both the deterministic and stochastic analysis.

Transmission Redirect

Similar to conservation, redirecting transmission to increase our firm access to short-term wholesale markets was least cost across all scenarios. This resource addition does cause some concern for PSE, as we already rely on a significant amount of firm transmission to access wholesale market. This transmission redirect clearly appears cost effective, but it is not without risk. One important risk is BPA operational/policy risk—it is possible that in the future, BPA may not facilitate this redirect. There are two other important risks to consider. One is physical resource adequacy risk. PSE performed a robust wholesale market risk analysis – one that is tied to the regional resource adequacy framework developed and implemented by the NPCC and BPA. This analysis shows wholesale market is nearly as reliable as a new peaker. The other risk is financial. The stochastic portfolio risk analysis confirms that increasing reliance on wholesale markets does increase risk. However, as described above, the increase in risk is reasonable, given the significant cost savings.

Renewables – Eastern Washington Solar

Every scenario showed eastern Washington solar was the most cost-effective qualifying renewable resource, so this is a very durable answer across all scenarios. While our base assumption had no transmission costs, it appears solar would be cost effective even if it required transmission – as shown above in Figure 2-5. The other primary qualifying renewable resource is wind in eastern Washington. While Montana wind was analyzed as if it were a qualifying resource, RCW 19.285 would have to be changed for that to be the case. Montana wind did not appear cost effective relative to eastern Washington solar, so the issue is resolved for this IRP. The stochastic risk analysis showed that solar beyond that needed for compliance with RCW 19.285 would reduce portfolio risk, but not sufficient to justify the up-front investment.

Peakers Instead of Baseload Gas Plants –
Capacity Resources Later in the Planning Horizon

Dual-fuel peakers were found to be the least cost capacity resource in most scenarios. The exceptions were Scenario 9 (Base + No CO_2), which had 1,652 MW of baseload gas plants by 2035 instead of peakers, and Scenario 14 (Base + All Thermal CO_2), which had 826 MW of baseload gas plants instead of peakers. The stochastic analysis results in Figure 2-6 illustrated that baseload gas plants increased both cost and risk. While baseload gas plants use natural gas more efficiently and will be economically dispatched more often than peakers, the margin (market price – variable cost) is not sufficient to overcome the significantly higher fixed costs, both capital costs for the plant and firm pipeline capacity costs. Figure 2-7, below, shows the frequency distributions for the net cost of both peakers and baseload gas plants. "Net cost" means the revenue requirement of the plant (including recovery of both fixed and variable costs) minus the market value of the energy it generates. Each plant is economically dispatched for each hour, using the AURORA model, and this net cost is calculated for each simulation to create the distribution of net costs. This figure shows the expected value for net peakers is near the lower end of the baseload gas plant's 90 percent confidence interval of net cost. There were some simulations where both kinds of plants created enough margin to offset the fixed costs. Notice the tail on the left for both plants is quite similar. This is because as power prices diverge from gas prices, both plants will capture increasing margins, though baseload plants will capture a bit more because they are more efficient. However, in general, the greater margins do not appear to overcome the higher fixed costs of the plants. On the other end of the distribution, baseload gas plants have net costs that go significantly higher than peakers. In fact, the *mean* net cost for baseload gas plants is $85/kW-yr, which is slightly higher than the *worst* case for a peaker, at just over $85/kW-yr.

Figure 2-7: Comparison of Net Cost Distribution
*Baseload Gas and Peakers with Oil Backup (in 2018 dollars per kW)*
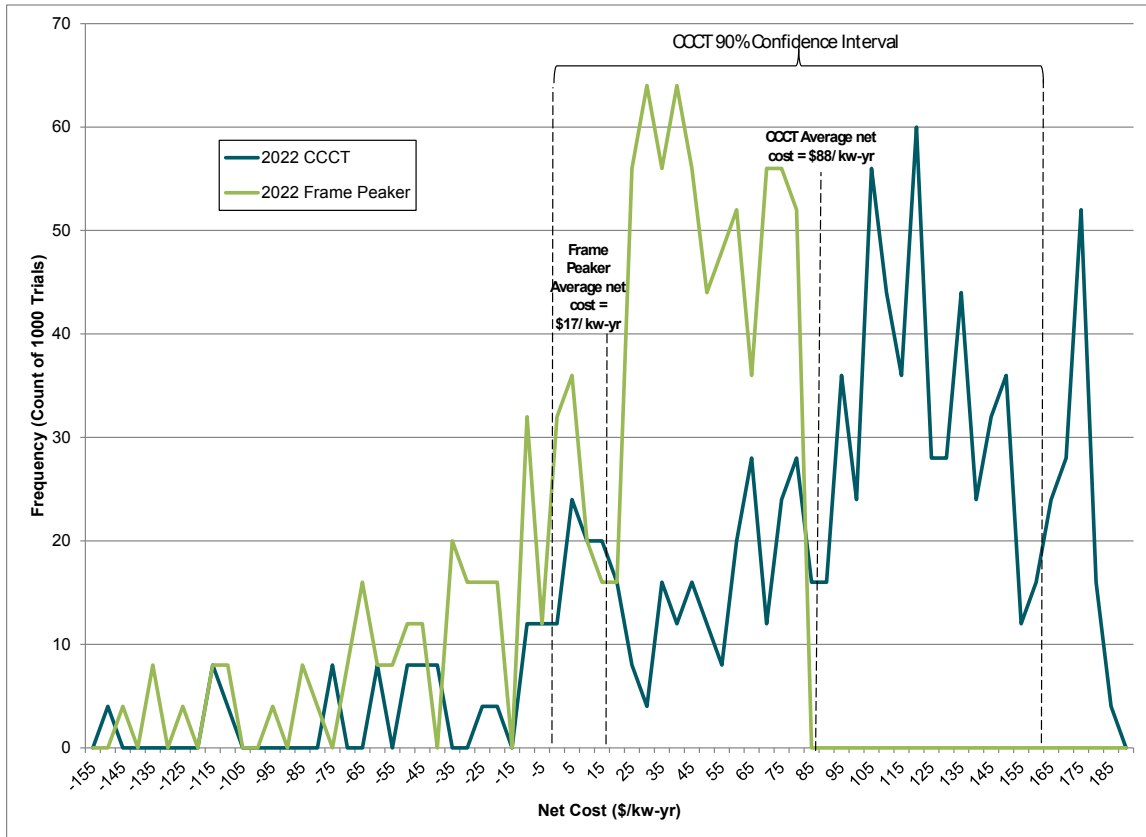
The other concern PSE has had with dual-fuel peakers is whether the backup fuel would be adequate. In this IRP, we examined whether backup fuel was sufficient for our existing dual fuel peaker generators and also examined implications of adding several hundred additional MW. We used our resource adequacy modelling framework to identify the number of hours in a year that we would physically need to rely on backup fuel. This was performed by first removing all peakers from the portfolio and calculating the number of hours the portfolio would be physically short. Then we also subtracted Colstrip 1 & 2 from the portfolio, followed by Colstrip 3 & 4. Figure 2-8 demonstrates that 48 hours of backup fuel was adequate to cover 100 percent of the needs for the existing fleet and new peakers when Colstrip 1 & 2 are retired. When we removed Colstrip 3 & 4 from the portfolio, 48 hours of backup fuel for the new and existing peakers would cover the need for approximately 95 percent of the simulations in the RAM. However, if the backup fuel tank were increased to 72 hours, that would cover 100 percent of the needs. Air permits to operate on backup fuel for 72 hours per year would probably not be a problem.

Therefore, PSE included dual fuel peakers later in the planning horizon – though we hope advances in energy storage will continue to push out the need for fossil fuel generation in all future IRPs.

Figure 2-8: Cumulative Distribution of Incremental Deficit for Bad Simulations in MWh/yr

2017 PSE IRP
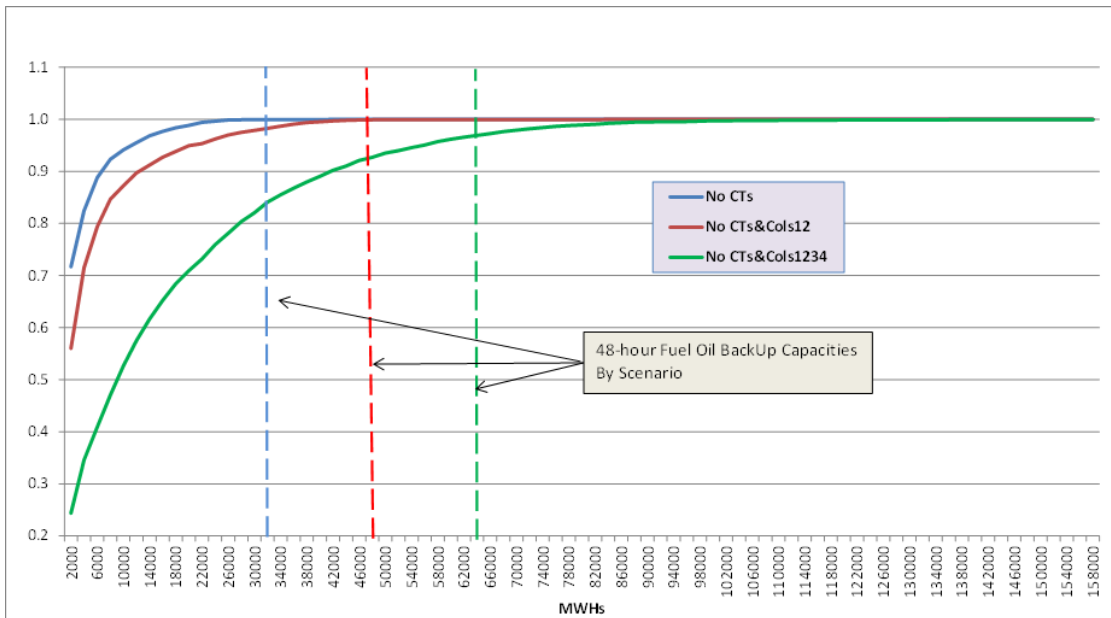
3. GAS SALES RESOURCE PLAN

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. The years shown here reference the gas year, so 2025/26 means the gas year starting November 2025 through October 2026.

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

	2025/26	2029/30	2037/38
Conservation	27	49	84
Swarr Upgrade	30	30	30
LNG Distr. Upgrade	0	16	16
Additional NWP + Westcoast	0	61	140

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.

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 scenarios. Figure 2-10 illustrates the lowest reasonable cost portfolio of resources across those eleven potential future conditions.

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

Gas Resource Portfolio Builds - Peak Day Capacity in MDth/day
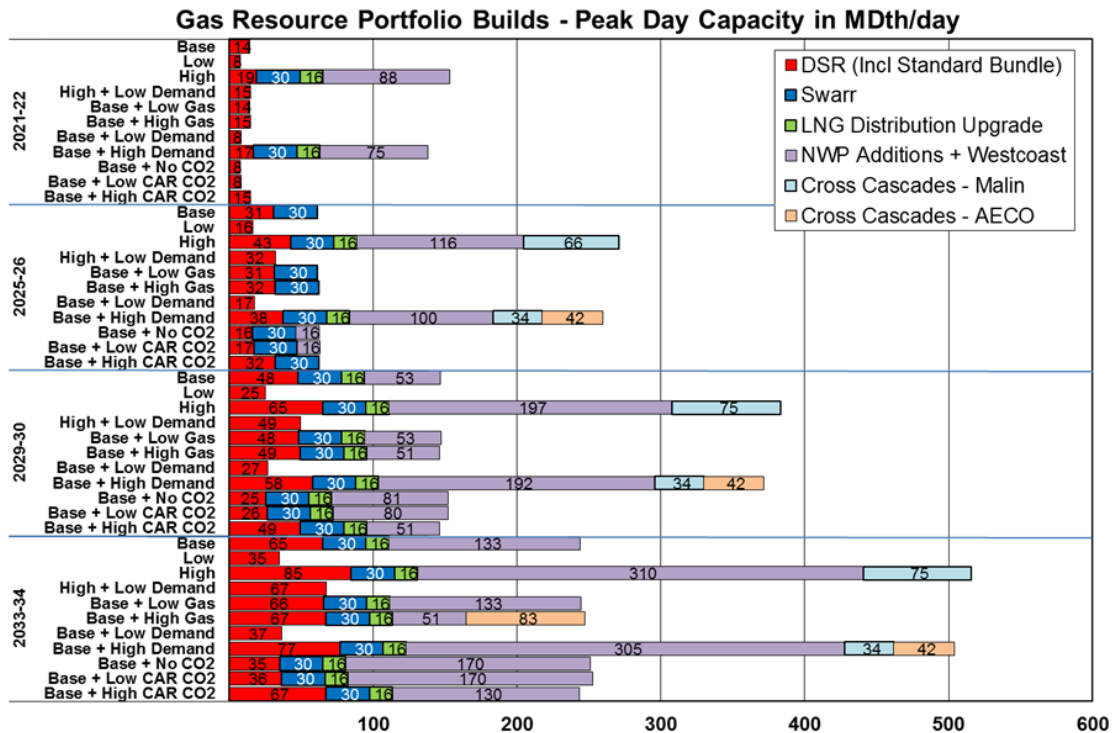
Key Findings by Resource Type

Demand-side Resources

Cost effective DSR (conservation) does not vary dramatically across scenarios, especially in the early years, which is most important for program planning. Figure 2-11, below, shows the results of cost-effective DSR sorted by low, medium and high levels by 2022/23. The lowest levels of cost-effective DSR correspond to scenarios with low demand or low carbon costs. The highest levels of cost-effective DSR correspond to cases with high load growth. The mid-level cost-effective DSR includes scenarios with mid load growth and mid-to-high carbon costs.

2017 PSE IRP

Figure 2-11: DSR Results Sorted by Cost Effective Levels

	Low DSR 8 MDth/Day	Mid DSR 14-15 MDth/Day	High DSR 17-19 MDth/Day
Scenarios	Low	Base	High
	Base + Low Demand	High + Low Demand	Base + High Demand
	Base + No CO2	Base + Low Gas	
	Base + Low CAR CO2	Base + High Gas	
		Base + High CAR CO2	

Swarr Upgrades

Upgrades to PSE's propane injection facility, Swarr, is a least cost resource in every scenario except for the three scenarios with low demand, which do not require any resources beyond DSR. The timing of the Swarr upgrade is driven by the load forecast. In scenarios with high load forecasts, Swarr is needed by 2021/22. In the mid-growth scenarios, Swarr is needed by 2025/26. Upgrades to Swarr are essentially within PSE's ability to control, so we have the flexibility to fine-tune the timing. PSE has less control over pipeline expansions, as expansions often require a number of shippers to sign up for service in order for an expansion to be cost effective. We focused on this flexibility in the Timing Optimization Sensitivity, and found we could push the Swarr upgrade out one year, from 2022/23 to 2023/24. A decision on the timing of the Swarr upgrade is not needed now; the upgrade has a short lead-time, and we have the flexibility to adjust as the future unfolds.

LNG Distribution Upgrade

The cost effectiveness of upgrades to the distribution system to allow more gas to be withdrawn from PSE's Tacoma LNG storage facility are driven by the load forecast. In the three low-growth scenarios, this resource is not needed. In the high-growth scenarios, the LNG Distribution Upgrade is needed by 2021/22. The Base Scenario shows a need for it by 2029/30. Similar to Swarr, PSE has significant control over when the distribution system could be upgraded to increase withdrawal volumes from our Tacoma LNG peaking facility, so we have the flexibility to adjust the timing as the future unfolds.

NWP + Westcoast Pipeline Additions

Additional firm pipeline capacity on Northwest and Westcoast Pipelines North, to Station 2, is cost effective in every scenario, except those with low load growth. In the high load growth scenarios, 75-88 MDth/day is needed by 2021/22, growing to more than 300 MDth/day by the end of the planning horizon. In the mid-load growth scenarios, there are some slight timing differences. The Base + No CO_2 and Base + Low CAR CO_2 Scenarios show 16 MDth/Day of NWP + Westcoast Pipeline additions would be cost effective by 2025/26, but the other scenarios with mid-load growth do not. This is the effect of less conservation being cost effective in these two scenarios. Notice in Figure 2-10, above, those two scenarios have about 16 MDth less DSR than the other mid-growth scenarios – 16-17 MDth/day DSR in the former scenarios versus 31-32 MDth of DSR in the other mid-load growth scenarios.

Cross Cascades to Malin or AECO

These resources appear cost effective primarily in the high load growth scenarios. 83 MDth/day of Cross Cascades to AECO appears in the Base + High Gas Scenario by the end of the planning horizon as well. This is primarily being driven by price differentials between the different supply basins.

Resource Plan Forecast – Decisions

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

Conservation (DSR)

The resource plan incorporates cost-effective DSR from the Base Scenario – the same as several other scenarios, as shown in the table in Figure 2-10, above. Gas prices appear to have little impact on DSR within the mid-load growth forecast. The primary variable that affects the resource decision is the assumption for carbon prices. CAR is being challenged in court, so it may not be implemented, but even if it is, and carbon prices are in the range of the low carbon prices modeled, cost-effective DSR would be cut in half. Figure 2-12 illustrates the different carbon prices. At this time, we need to make a decision which significantly affects the result, with no confidence in our ability to forecast carbon prices. However, even if CAR is not implemented, PSE believes some kind of carbon regulation will affect our gas utility operations in the future. Low carbon prices have no effect on the cost effectiveness of conservation, but the base and high carbon cases have the same result; they include twice the amount of conservation. These results lead us to conclude that it would be more reasonable to incorporate DSR from the Base and High CO_2 scenarios. While in the future we may not see carbon prices in this range, conservation programs take years to accumulate savings. We believe this is a reasonable hedge against the risk of higher carbon prices.

Figure 2-12: Annual Range of CAR-related CO_2 Prices Used in the 2017 IRP
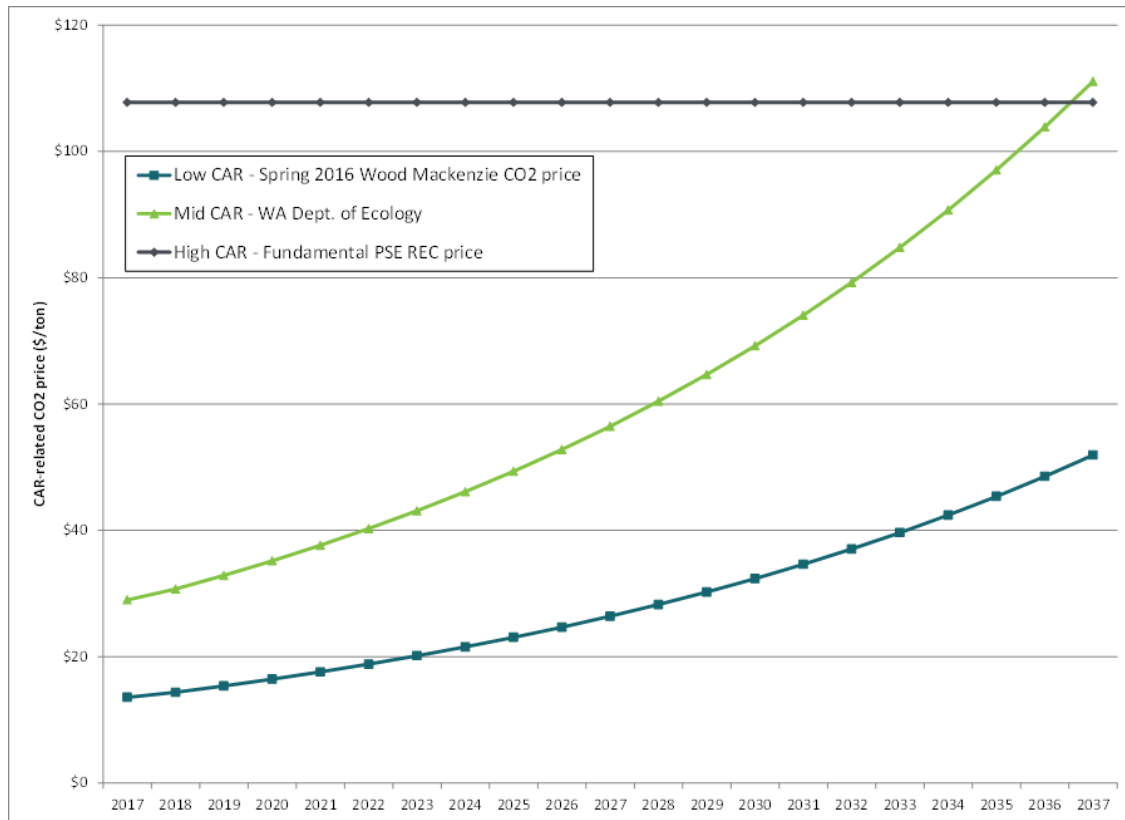
Supply-side Resources

The supply-side resources – Swarr, LNG Distribution Upgrade, and pipeline expansions – follow the Base Scenario resource additions, including results of the Timing Optimization Sensitivity, which moves Swarr out one year relative to the Base Scenario. All the resource plan forecasts based on mid-load growth have the same set of least-cost resource additions, once we account for the difference in DSR due to the No or Low CO_2 price scenarios. The only exception is in the Base + High Gas Scenario. In that scenario, some pipeline capacity on Cross Cascades up to AECO appears cost effective after 2030. This is driven by forecasted widening price differentials between AECO and Station 2, probably due to higher LNG exports from Northern British Columbia in that scenario. This is not an urgent issue to resolve, as PSE-controlled resources appear adequate to meet our customer's needs until 2029/30. It does highlight the importance of continuing to monitor the long-term outlook of natural gas prices at our different supply basins. We will file four more IRPs by the end of 2025, and we will be doing just that.