2017 PSE Integrated Resource Plan

4 Key Analytical Assumptions

This chapter describes the forecasts, estimates and assumptions that PSE developed for this IRP analysis; the scenarios created to test how different sets of economic conditions affect portfolio costs and risks; and the sensitivities used to explore the impact of individual resources on the portfolio.

Contents

1. OVERVIEW

Economic Scenarios

Scenarios allow us to test how different combinations of three fundamental ***economic conditions*** impact the least-cost mix of resources. Given the set of static assumptions that define the scenario, deterministic optimization analysis is used to identify the least-cost portfolio of demand- and supply-side resources that will meet need under those conditions. For this IRP, PSE developed 14 scenarios for the electric portfolio and 11 scenarios for the gas portfolio.

Three Fully Integrated Economic Scenarios

Low, Base and High scenarios reflect different sets of assumptions for each of the three key economic inputs: customer demand, natural gas prices and CO_2 prices.

Eleven One-off Economic Scenarios

The one-off scenarios start with one of the fully integrated scenarios and change just one of the three fundamental economic inputs. In reality, when one economic condition changes, others usually do, too; however, one-off scenarios allow us to identify which of the three fundamentals has the most significant impact on the least-cost mix of resources.

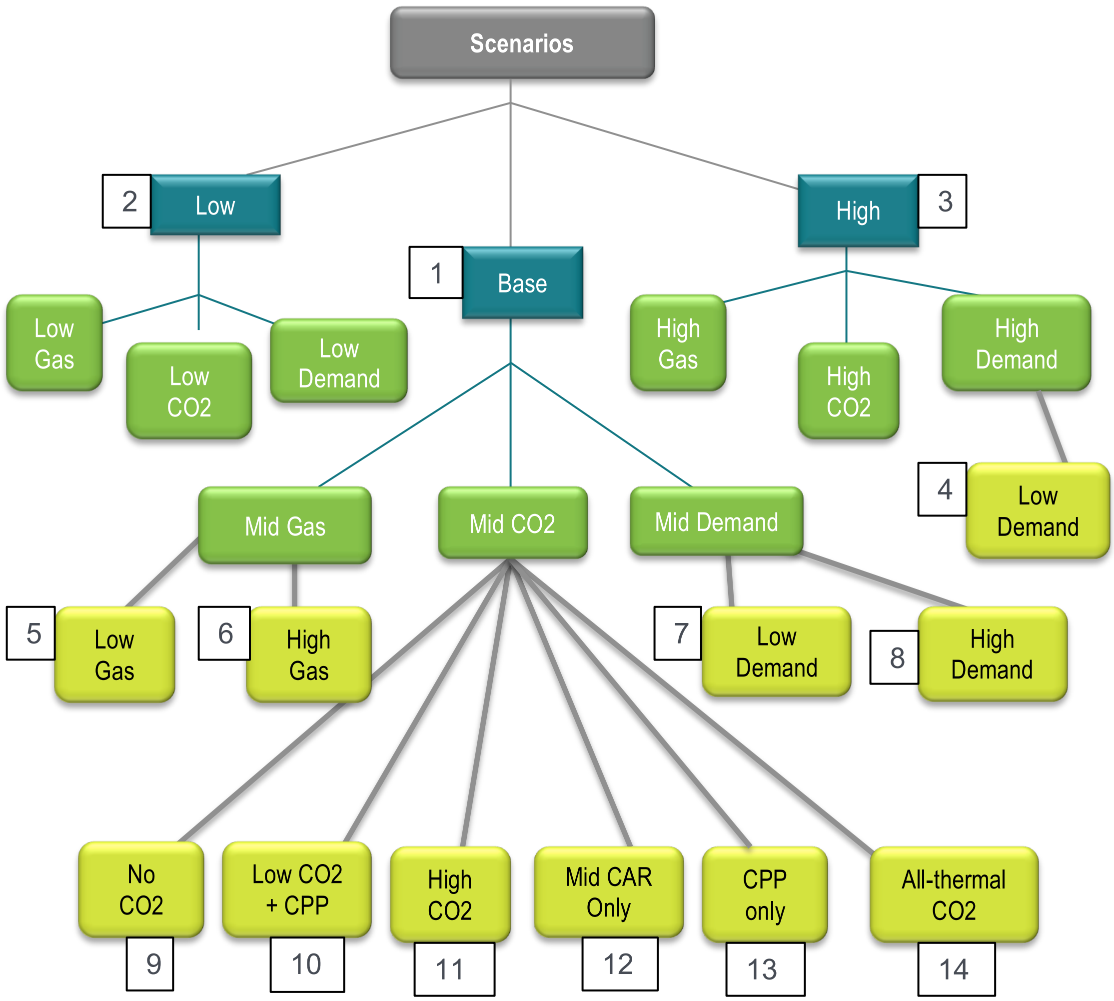
To complete the scenarios, we create wholesale power price forecasts for each one using production cost analysis described later in this chapter. Figure 4-1 illustrates the relationship between the fully integrated and one-off scenarios.

Portfolio Sensitivities

Portfolio sensitivities focus on the cost-effectiveness of a specific ***resource*** and the value it brings to the portfolio. First, PSE uses a portfolio optimization analysis to identify the least cost resource portfolio for each scenario. Then, starting with the least cost portfolio for the Base Scenario, the sensitivities change a single resource in the portfolio. Sensitivity analysis also allows us to explore how PSE might need to respond to unexpected changes in resource availability. The sensitivities are summarized in Figure 4-3.

Scenarios test how different combinations of three fundamental economic conditions impact the least cost mix of resources – demand, gas prices and CO_2 costs.

Figure 4-1: Diagram of 2017 IRP Scenarios



NOTES
CAR refers to Washington state Clean Air Rule regulations.
CPP refers to federal Clean Power Plan regulations.

The figure below presents the scenarios in tabular format.

Figure 4-2: 2017 IRP Scenarios
(A detailed description of scenarios begins on page 26.)

	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.

Portfolio sensitivities test the cost-effectiveness of a specific resource on the portfolio. Starting with the Base Case least cost portfolio, they change one resource.

Figure 4-3: 2017 IRP Portfolio Sensitivities

(A detailed description of portfolio sensitivity reasoning begins on page 38.)

	Sensitivities	Alternatives Analyzed
	ELECTRIC ANALYSIS	
A	**Colstrip** How do different retirement dates affect decisions about replacing Colstrip resources?	*Baseline – Retire Units 1 & 2 mid-2022, Units 3 & 4 remain in service into 2035.* 1. Retire Units 1 & 2 in 2018 2. Retire Units 3 & 4 in 2025 3. Retire Units 3 & 4 in 2030
B	**Thermal Retirement** Would it be cost effective to accelerate retirement of PSE's existing gas plants?	*Baseline – Optimal portfolio from the Base Scenario* *Retire baseload gas plants early.*
C	**No New Thermal Resources** What would it cost to fill all future need with resources that emit no carbon?	*Baseline – Fossil fuel generation is an option in the optimization model.* Renewable resources, energy storage and DSR are the only options for future resources.
D	**Stakeholder-requested Alternative Resource Costs** What if capital costs of resources are different than the base assumptions?	*Baseline – PSE cost estimate for generic supply-side resources* 1. Lower cost for recip peakers 2. Higher thermal capital costs 3. Lower wind and solar development costs Apply more aggressive solar cost curve.
E	**Energy Storage** What is the cost difference between a portfolio with and without energy storage?	*Baseline – Batteries and pumped hydro included only if chosen economically.* 1. Add 50 MW battery in 2023 instead of economically chosen peaker. 2. Add 50 MW pumped hydro storage in 2023 instead of economically chosen peaker.
F	**Renewable Resources + Energy Storage** Does bundling renewable resources with energy storage change resource decisions?	*Baseline – Evaluate renewable resources and energy storage as individual resources in the analysis.* Bundle 50 MW battery + 200 MW solar.
G	**Electric Vehicle Load** How much does electric vehicle charging affect the resource plan?	*Baseline – IRP Base Demand Forecast* Add the forecasted electric vehicle load.
	DEMAND-SIDE RESOURCES (CONSERVATION)	
H	**Demand-side Resources (DSR)** How much does DSR reduce cost, risk and emissions?	*Baseline – All cost-effective DSR per RCW 19.285 requirements.* No DSR. All future needs met with supply-side resources.
I	**Extended DSR Potential** What if future DSR measures extend conservation periods through the second decade of the study period?	*Baseline – All DSR identified as cost-effective in this IRP is applied in the first 10 years of the study period.* Assume future DSR measures will extend conservation benefits to the following 10-year period.

	Sensitivities	Alternatives Analyzed
	ELECTRIC ANALYSIS	
J	**Alternate Residential Conservation Discount Rate** How would using a societal discount rate on conservation savings from residential energy efficiency impact cost-effective levels of conservation?	*Baseline: Assume the base discount rate.* Apply a societal discount rate to residential conservation savings to examine whether changing the discount rate for conservation impacts cost effectiveness of conservation.
	WIND RESOURCES	
K	**RPS-eligible Montana Wind** [1] What is the cost difference between a portfolio with "regular" Montana wind and RPS-eligible Montana wind?	*Baseline – Montana wind included only if chosen economically by the analysis.* 1. Add RPS-eligible Montana wind in 2023 instead of solar 2. Montana wind tipping point analysis to determine how close it is to being cost effective compared to other resources.
L	**Offshore Wind Tipping Point Analysis** How much would costs of offshore wind need to decline before it appears to be a cost-effective resource?	*Baseline – Base Scenario portfolio* Offshore wind tipping point analysis to determine how much costs would have to drop to be cost effective compared to other resources.
M	**Hopkins Ridge Repowering** [2] Would repowering Hopkins Ridge for the tax incentives and bonus RECs be cost effective?	*Baseline – Hopkins Ridge repowering is not included in the portfolio.* Include Hopkins Ridge repowering in the portfolio to replace the current facility.

	Sensitivities	Alternatives Analyzed
	NATURAL GAS ANALYSIS	
A	**Demand-side Resources (DSR)** How much does DSR reduce cost, risk and emissions?	*Baseline – All cost-effective DSR per RCW 19.285 requirements.* No DSR. All future needs met with supply-side resources.
B	**Resource Addition Timing Optimization** How does the timing of PSE-controlled resource additions affect resource builds and portfolio costs?	*Baseline – PSE-controlled additions offered every 2 years.* PSE-controlled resource additions offered every year.
C	**Alternate Residential Conservation Discount Rate** Would using a societal discount rate on conservation savings from residential energy efficiency impact cost effective levels of conservation?	*Baseline – Assume the base discount rate.* Apply a societal discount rate to residential conservation savings.
D	**Additional Gas Conservation** What happens if DSR is added beyond what is cost-effective per RCW 19.285?	*Baseline – All cost-effective DSR per RCW 19.285 requirements.* Add 2 additional demand-side bundles.

NOTES
1. Montana wind is not currently an RPS-eligible resource; however, PSE has asked BPA under what conditions it could be qualified as an RPS-eligible resource.
2. Repowering refers to refurbishing or renovating a plant with updated technology to qualify for Renewable Production Tax Credits under the PATH Act of 2015. These sensitivities capture the impact of tax credit incentives and increased operating efficiency on cost.

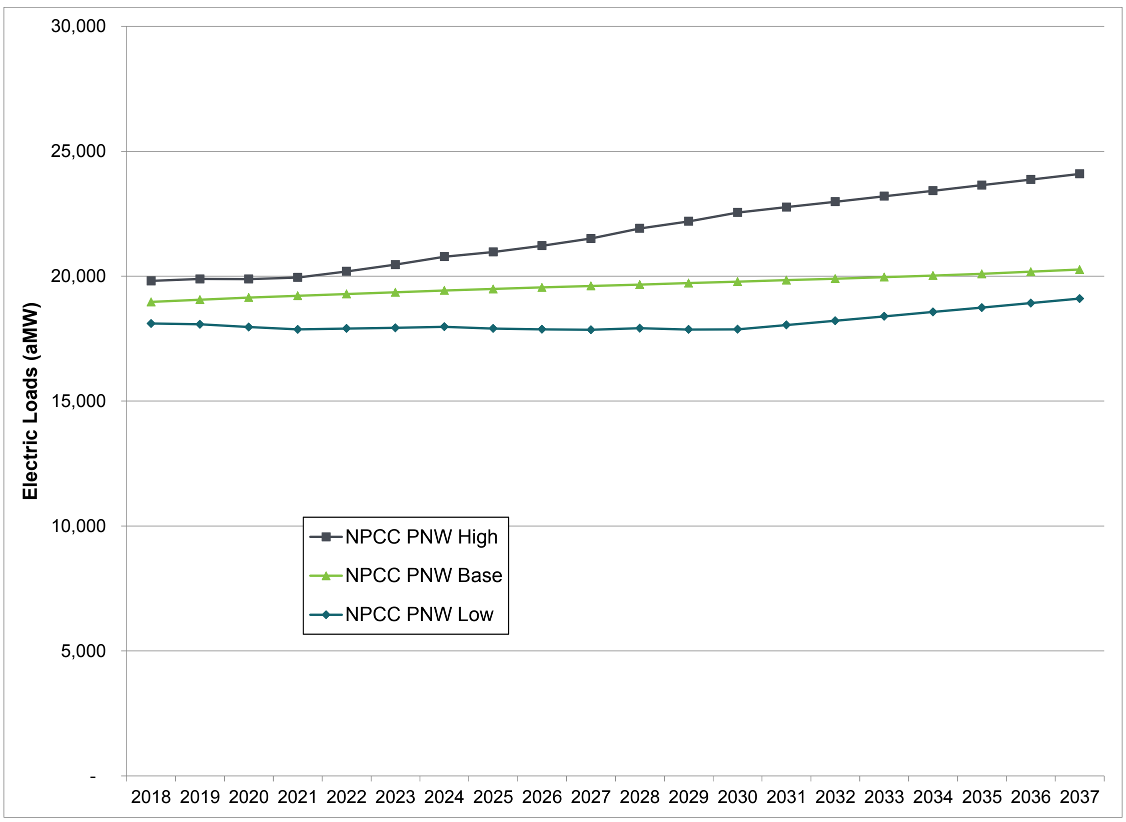
2. KEY INPUTS

Demand Forecasts

Regional Demand

Regional demand significantly affects power prices, so it must be taken into consideration. This IRP uses the regional demand developed in the Seventh Power Plan by the Northwest Power and Conservation Council (NPCC or "the Council").[1] Regional demand is used only in the WECC-wide[2] portion of the AURORA analysis that develops wholesale power prices for the scenarios.

Figure 4-4: NPCC Regional Demand Forecast for Pacific Northwest (PNW) – Average, not Peak



1 / The NPCC has developed some of the most comprehensive views of the region's energy conditions and challenges. Authorized by the Northwest Power Act, the Council works with regional partners and the public to evaluate energy resources and their costs, electricity demand and new technologies to determine a resource strategy for the region.
2 / WECC, the Western Electricity Coordinating Council, is the regional forum for promoting regional electric service reliability in the Western United States.

PSE Demand

PSE customer demand is the single most important input assumption to the IRP portfolio analysis. The demand forecast is discussed in detail in Chapter 5, and the analytical models used to develop it are explained in Appendix E, Demand Forecasting Models. For long-range planning, customer demand is expressed as if it were evenly distributed throughout PSE's service territory, but in reality demand grows faster in some parts of the territory and slower in others.

The three demand forecasts used in this IRP analysis represent estimates of energy sales, customer counts and peak demand over a 20-year period. Significant inputs include information about regional and national economic growth, demographic changes, weather, prices, seasonality and other customer usage and behavior factors. Known large load additions or deletions are also included.

The **2017 IRP BASE DEMAND FORECAST** is based on 2016 macroeconomic conditions such as population growth and employment. *The 2017 IRP Base Scenario uses this forecast.*

The **2017 IRP LOW DEMAND FORECAST** represents a pessimistic view of the macroeconomic variables modeled in the base forecast. It creates lower demand on the system and is used in the 2017 IRP Low Scenario.

The **2017 IRP HIGH DEMAND FORECAST** is a more optimistic view of the base forecast. It creates a higher demand on the system and is used in the 2017 IRP High Scenario**.**

Why don't demand forecasts in rate cases and acquisition discussions match the IRP forecast?

The IRP analysis takes 12 to 18 months to complete. Demand forecasts are so central to the analysis that they are one of the first inputs we need to develop. By the time the IRP is completed, PSE will have updated its demand forecast. The range of possibilities in the IRP forecast is sufficient for long-term planning purposes, but we will always present the most current forecast for rate cases or when making acquisition decisions.

The graphs below show the peak demand and annual energy demand forecasts for electric service and gas sales without including the effects of conservation. Both the electric and gas demand forecasts include sales (delivered load) plus system losses. The electric peak demand forecast is for a one-hour temperature of 23° Fahrenheit at SeaTac airport. The gas sales peak demand forecast is for a one-day temperature of 13° Fahrenheit at SeaTac airport.

Figure 4-5: PSE Electric Peak Demand Forecast (Low, Base, High)

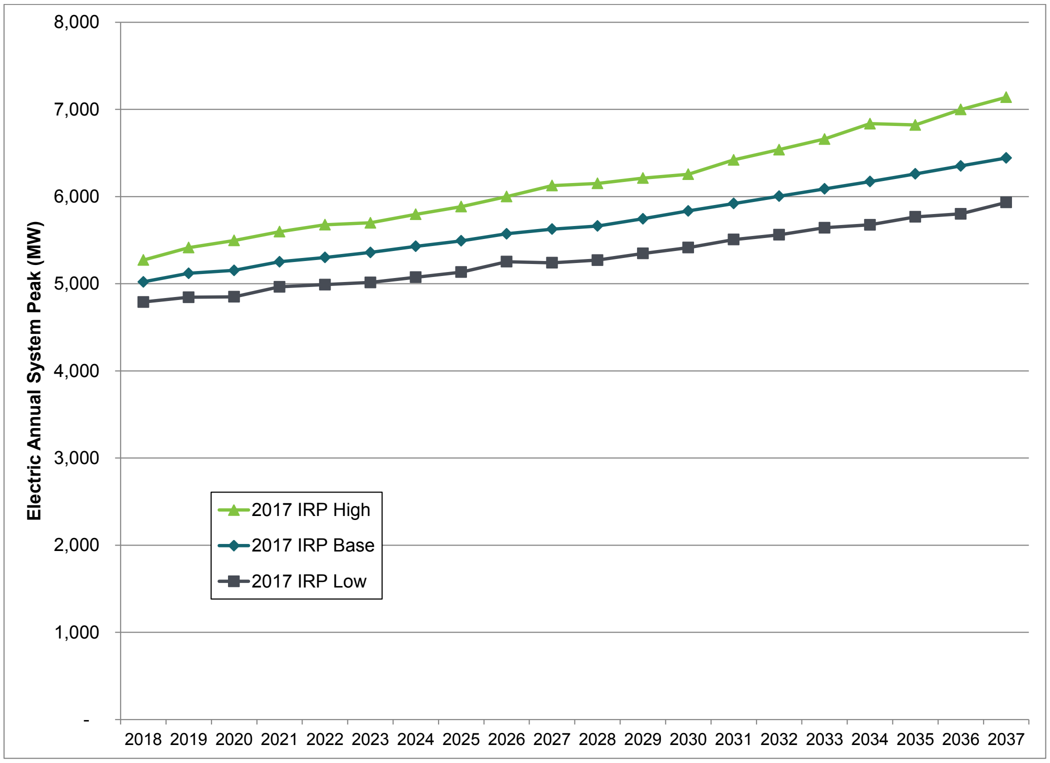


Figure 4-6: PSE Annual Electric Energy Demand Forecast (Low, Base, High)

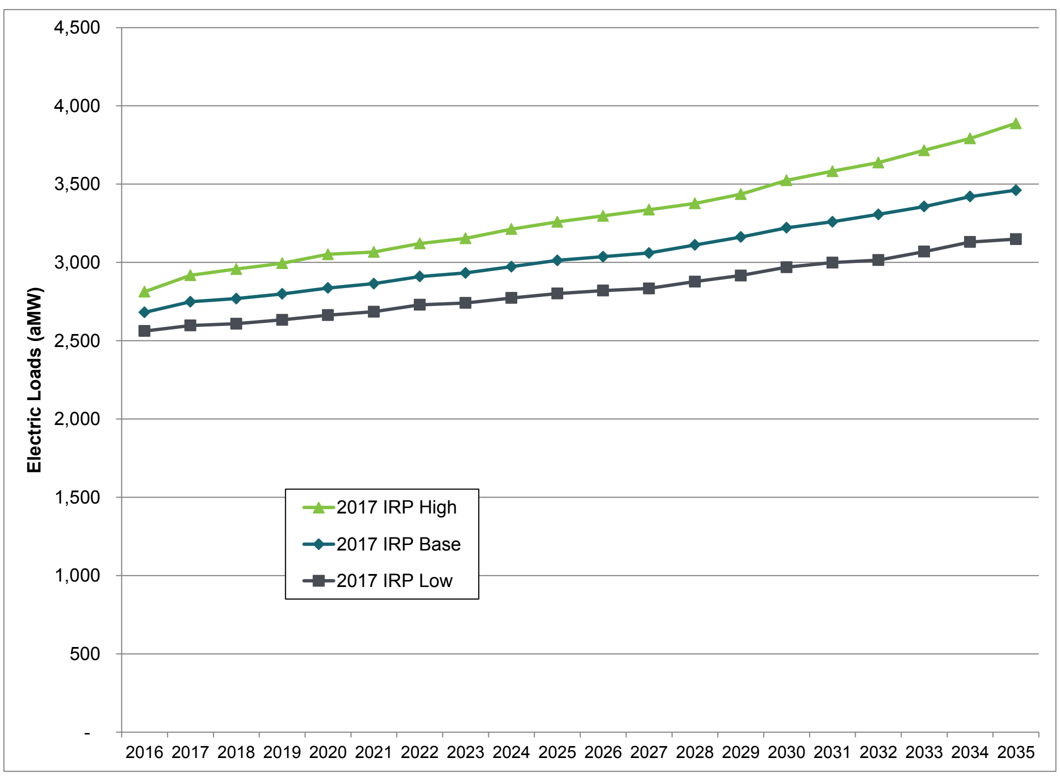


Figure 4-7: PSE Peak Day Gas Sales Demand Forecast (Low, Base, High)

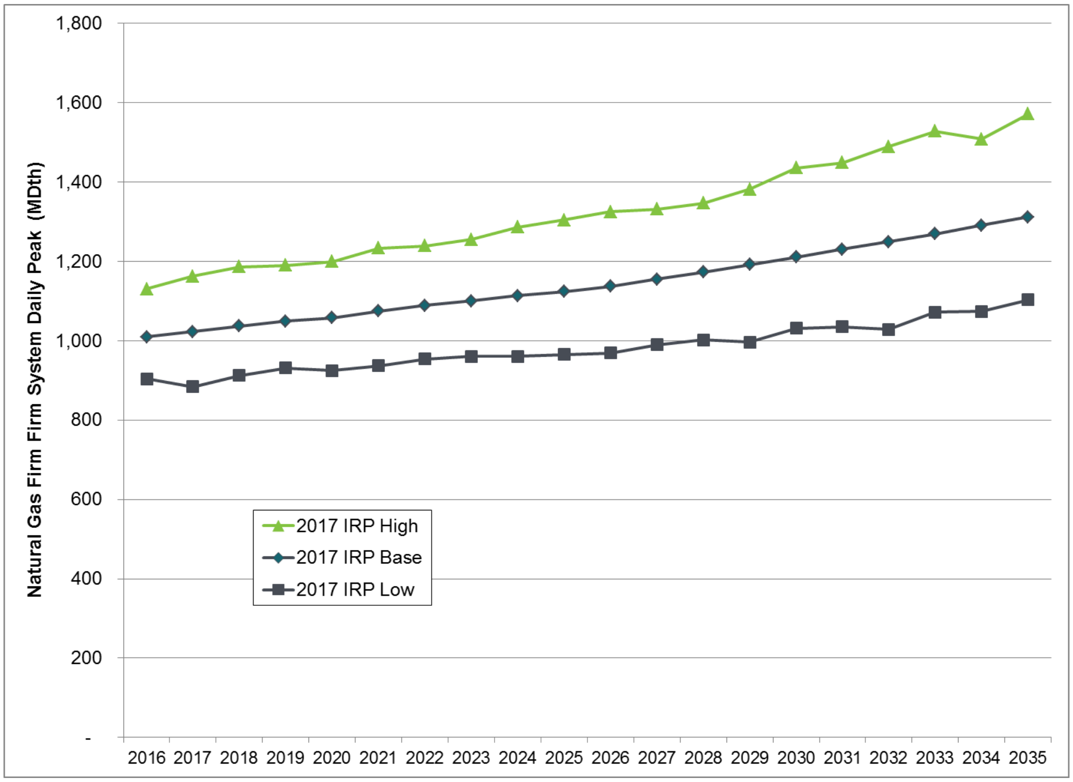
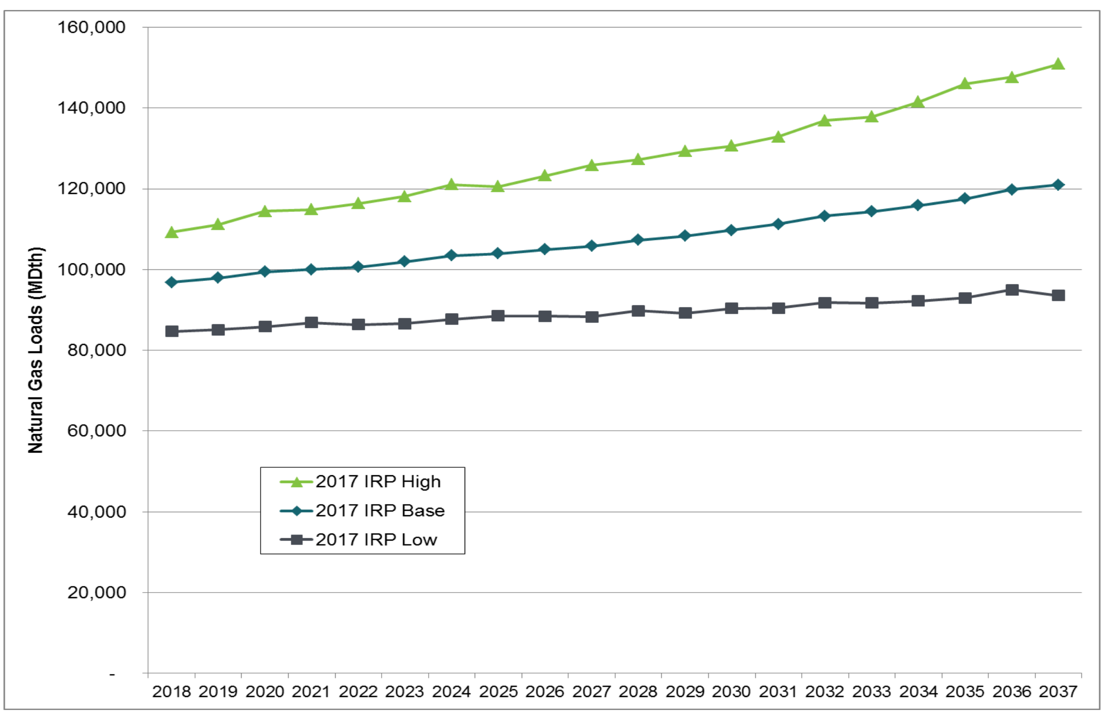


Figure 4-8: PSE Annual Gas Sales Demand Forecast (Low, Base, High)



Gas Prices

For gas price assumptions, PSE uses a combination of forward market prices and fundamental forecasts acquired in November 2016 from Wood Mackenzie. Wood MacKenzie is a well-known macroeconomic and energy forecasting consultancy whose gas market analysis includes regional, North American and international factors, as well as Canadian markets and liquefied natural gas (LNG) exports. Three gas price forecasts are used in the scenario analysis.

MID GAS PRICES. From 2018-2021, this IRP uses the three-month average of forward marks for the period ending December 27, 2016. Forward marks reflect the price of gas being purchased at a given point in time for future delivery. Beyond 2021, this IRP uses Wood Mackenzie long-run, fundamentals-based gas price forecasts that were published in Fall 2016. *The 2017 IRP Base Scenario uses this forecast.*

LOW GAS PRICES. These reflect Wood Mackenzie's long-term low price forecast for 2018-2037.

HIGH GAS PRICES. These reflect Wood Mackenzie's long-term high price forecast for 2018-2037.

Figure 4-9 below illustrates the range of 20-year levelized gas prices and associated CO_2 costs used in this IRP analysis.

Figure 4-9: Levelized Gas Prices by Scenario
(Sumas Hub, 20-year levelized 2018-2037, nominal $)

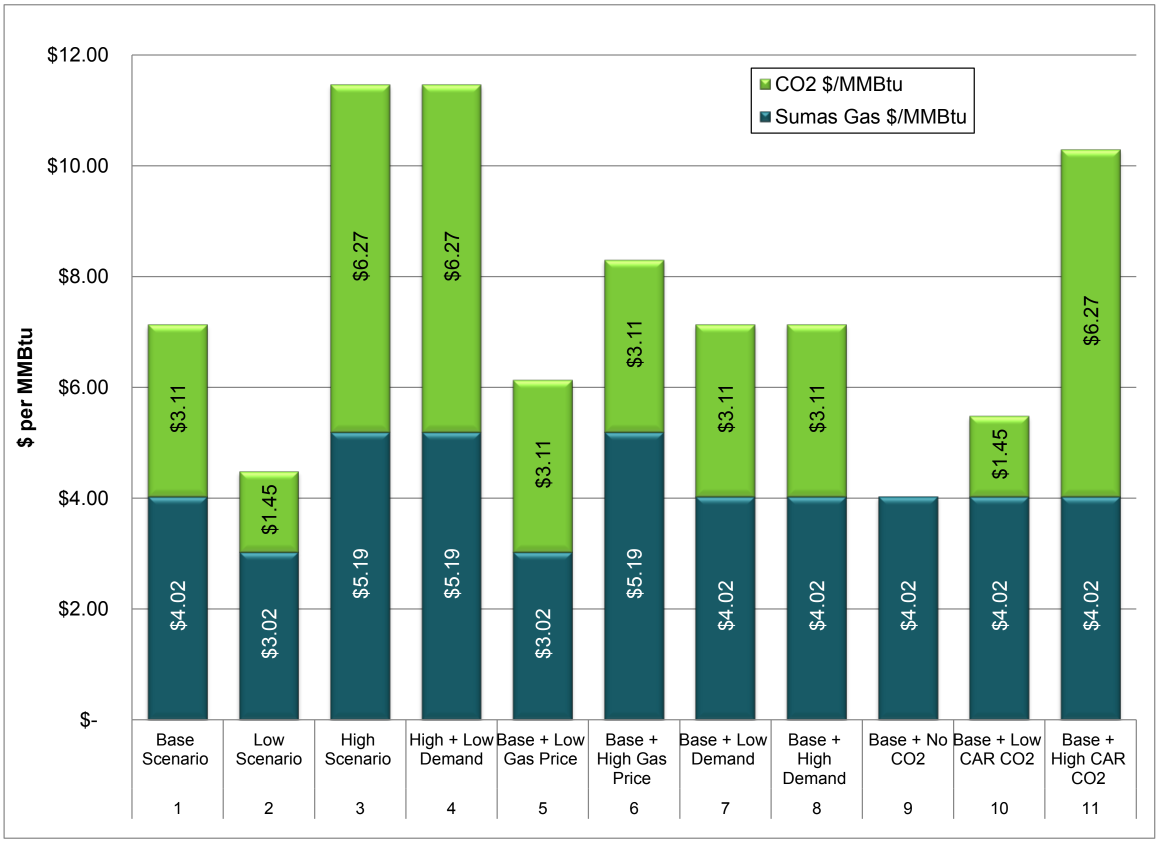
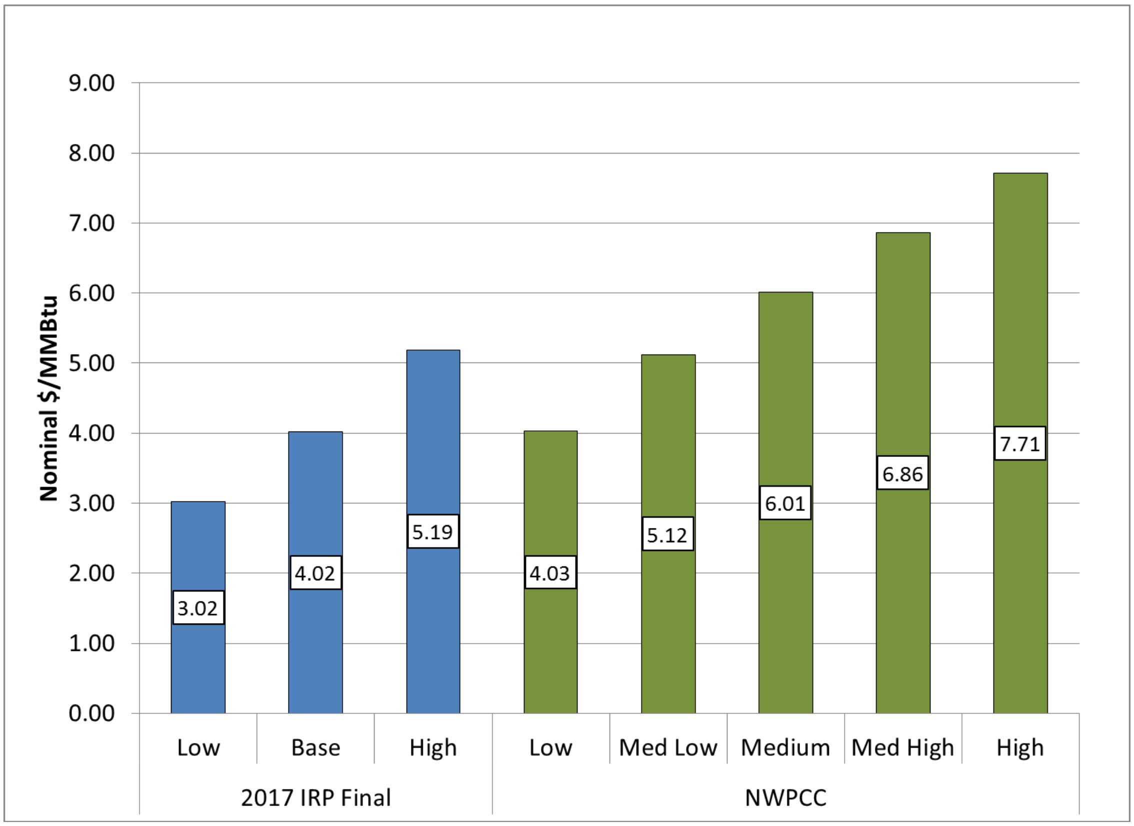


Figure 4-10 below, compares the levelized gas prices PSE used in this IRP with those used by the NPCC in its Seventh Power Plan.[3] This illustrates that the range of PSE's gas prices are consistent with the range of gas prices being used by the Council. It also shows PSE's Base Scenario gas price is slightly lower than the Council's medium gas price forecast.

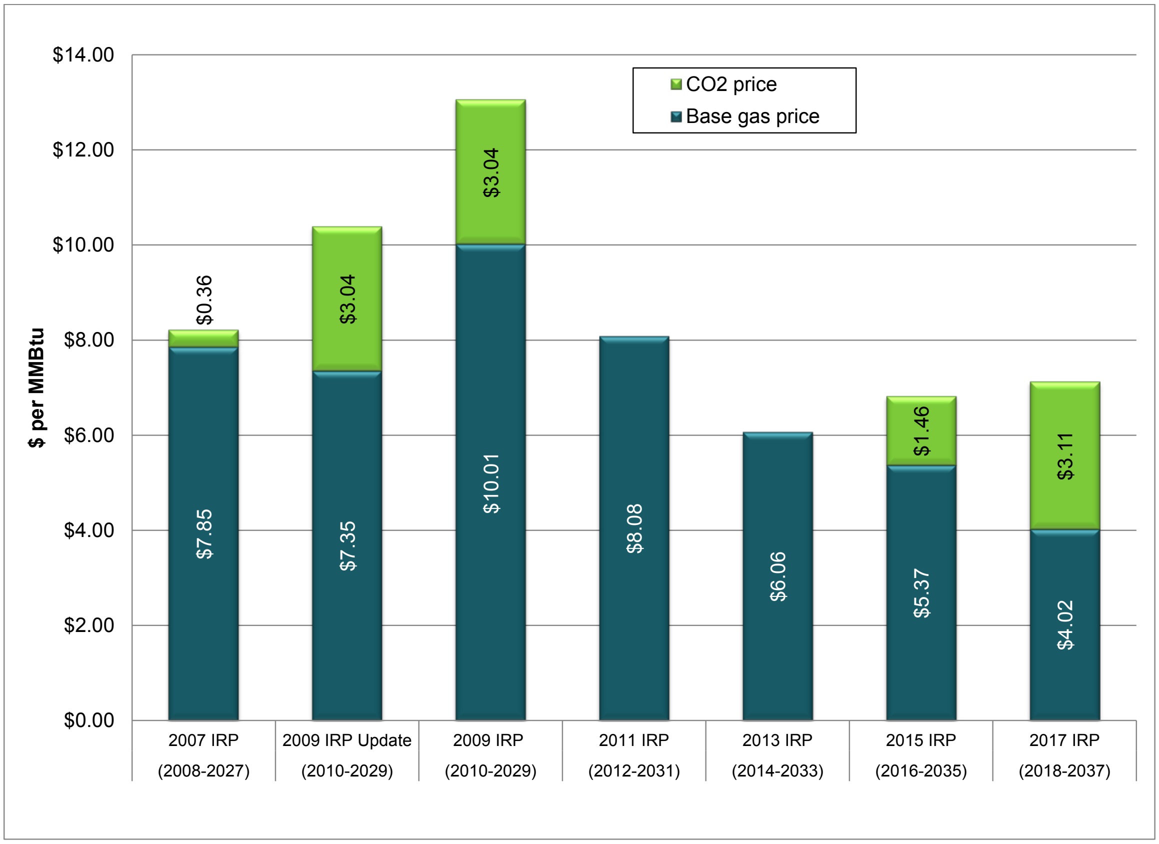
Figure 4-10: PSE 2017 IRP Gas Prices Compared to NPCC Seventh Power Plan Gas Prices (adjusted to nominal values)



3 / *PSE's input assumptions use nominal dollars (inflation adjusted) whereas the Council uses real dollar input assumptions (excluding the effects of inflation). Figure 4-10 converts the Council's assumptions to a nominal basis for an apples-to-apples comparison.*

Figure 4-11 below compares the levelized gas prices used in past PSE IRP analyses. The 2017 IRP gas price of $7.60 per MMBtu includes an estimated CO_2 price for the Washington Clean Air Rule (CAR).

Figure 4-11: PSE 2007 IRP – 2017 IRP Levelized Gas Prices



CO_2 Prices

The carbon prices in this IRP reflect the range of potential impacts from several key pieces of carbon regulation. The two most important are Washington state's Clean Air Rule (CAR) and the federal Environmental Protection Agency Clean Power Plan (CPP) rules. CAR regulations apply to both electric and gas utilities, and CPP regulations apply only to baseload electric resources. Even if CAR and CPP are ultimately not implemented, some form of carbon regulation is likely to be enacted during the 20-year period covered in this IRP, so it is important that the analysis reflect this possibility.

The Base Scenario in this IRP assumes the current rules – the Clean Air Rule and Clean Power Plan – will be implemented because it is impossible to model a generic carbon regulation scheme. Carbon taxes, carbon caps, or carbon cap and trade schemes could produce very different resource plans. Likewise, applying carbon regulation in one state versus the entire WECC would also produce very different results.

CAR. Washington state's CAR regulations took effect in January 2017. These regulations require state electric and gas utilities that exceed state CO_2 emissions to buy CO_2 allowances to compensate. Low, mid and high CAR prices have been developed as inputs to the analysis, because these allowances will come from a variety of sources whose costs can vary substantially. On the electric side, CAR only applies to in-state electric generating sources. CAR allows development of a carbon trading market, but it is not really a "cap and trade" system, because there is no cap. Under CAR, PSE (or any market participant) can build new natural gas plants that will essentially receive carbon allowances that diminish over time.

CPP. Federal CPP regulations are scheduled to take effect in 2022. These rules apply carbon costs to existing and new baseload electric generating facilities throughout the country. In this analysis, they are reflected as a carbon cost of $19 per ton in 2022, rising to $51 per ton in 2037. This cost is applied to all affected generating units in WECC states. CPP rules do not apply to gas utilities.

BASE CASE ASSUMPTIONS. PSE's Base Case assumes that federal CPP rules will supersede state CAR regulations in 2022. While it is possible that neither the CAR or CPP will actually be enforced, it is likely that some form of carbon regulation will be enacted during the 20-year study period. This IRP also examines a scenario in which no carbon regulation is ever implemented (the Base + No CO_2 Scenario), in the event that policy makers are unable to implement any binding regulations.

A table showing the annual CO_2 prices modeled can be found in Appendix N, Electric Analysis. All prices shown below are in short tons.

Mid CO_2 prices

The 2017 IRP Base Scenario uses this forecast.

MID CAR TO 2022 - $30 PER TON IN 2018 TO $111 PER TON IN 2037

CPP FROM 2022-2037 – $19 PER TON IN 2022 TO $51 PER TON IN 2037

CAR estimate is based on the Washington Dept. of Ecology's cost/benefit analysis of the CAR. CPP estimate is based on Wood MacKenzie's estimated CO_2 price for California AB32 and is applied WECC-wide as a CO_2 price to all existing and new baseload generating units affected under the CPP.

Low CO_2 prices

LOW CAR CO_2 PRICE TO 2022: $14 PER TON IN 2018 TO $51 PER TON IN 2037

NO CPP

CAR estimate is based on Wood MacKenzie's estimated CO_2 price for California.

High CO_2 Prices

HIGH CAR CO_2 PRICE TO 2022: $108 PER TON IN 2018 TO $108 PER TON IN 2037

CPP FROM 2022-2037: $19 PER TON IN 2022 TO $51 PER TON IN 2037

CAR estimate is based on PSE's fundamental REC price from the 2015 IRP. (The 2015 REC price was used because an input was needed before the 2017 IRP analysis output was available.) It reflects the difference between the levelized cost of power and the levelized cost of wind in the 2015 IRP. CPP estimate is based on Wood MacKenzie's estimated CO_2 price for California AB32 and is applied WECC-wide as a CO_2 price to all existing and new baseload generating units affected under the CPP.

In addition, PSE modeled the following CO_2 prices in one-off scenarios.

Why model carbon price regulation instead of the societal cost of carbon?

By rule, the IRP focuses on the costs and benefits that will be experienced by the utility and its customers. Costs and benefits outside of this construct are called externalities. The societal cost of carbon does not fit this regulatory model. Reducing carbon emissions may benefit society as a whole, but the population of our service territory is only 2.6 million (0.04 percent of world population). To reflect the externality impact of carbon reductions to PSE's customers would require either a reasonable estimate of the economic impact on the Pacific Northwest region (which is not available) or prorating the societal benefits that will accrue to our customers only. This explains why internalizing these externalities in typical IRP analyses is not a substitute for federal-level carbon regulation policies.

No CO_2 prices

Low CO_2 + CPP

LOW CAR CO_2 PRICE TO 2022: $14 PER TON IN 2018 TO $51 PER TON IN 2037

CPP FROM 2022-2037 – $19 PER TON IN 2022 TO $51 PER TON IN 2037

Mid CAR only (No CPP)

MID CAR TO 2037: $30 PER TON IN 2018 TO $111 PER TON IN 2037

CPP only (No CAR)

CPP FROM 2022-2037: $19 PER TON IN 2022 TO $51 PER TON IN 2037

All-thermal CO_2

$19 PER TON IN 2022 TO $51 PER TON IN 2037, APPLIED TO ALL CO_2 EMITTING RESOURCES IN THE REGION

This estimate is based on Wood MacKenzie's estimated CO_2 price for California AB32 and is applied WECC-wide to all CO_2 emitting resources, peaking plants and baseload generators. (CPP and CAR apply only to baseload generators).

Figure 4-12: Annual Range of CAR-related CO_2 Prices Used in the 2017 IRP

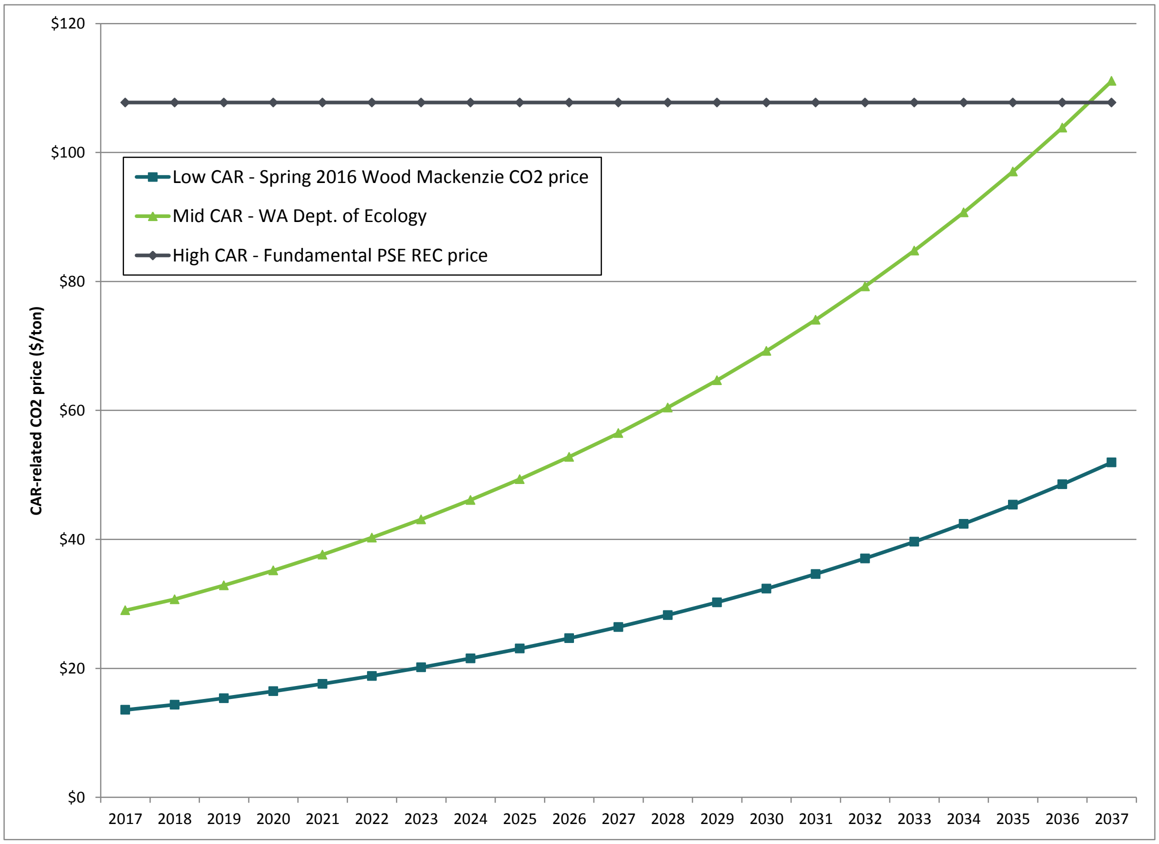
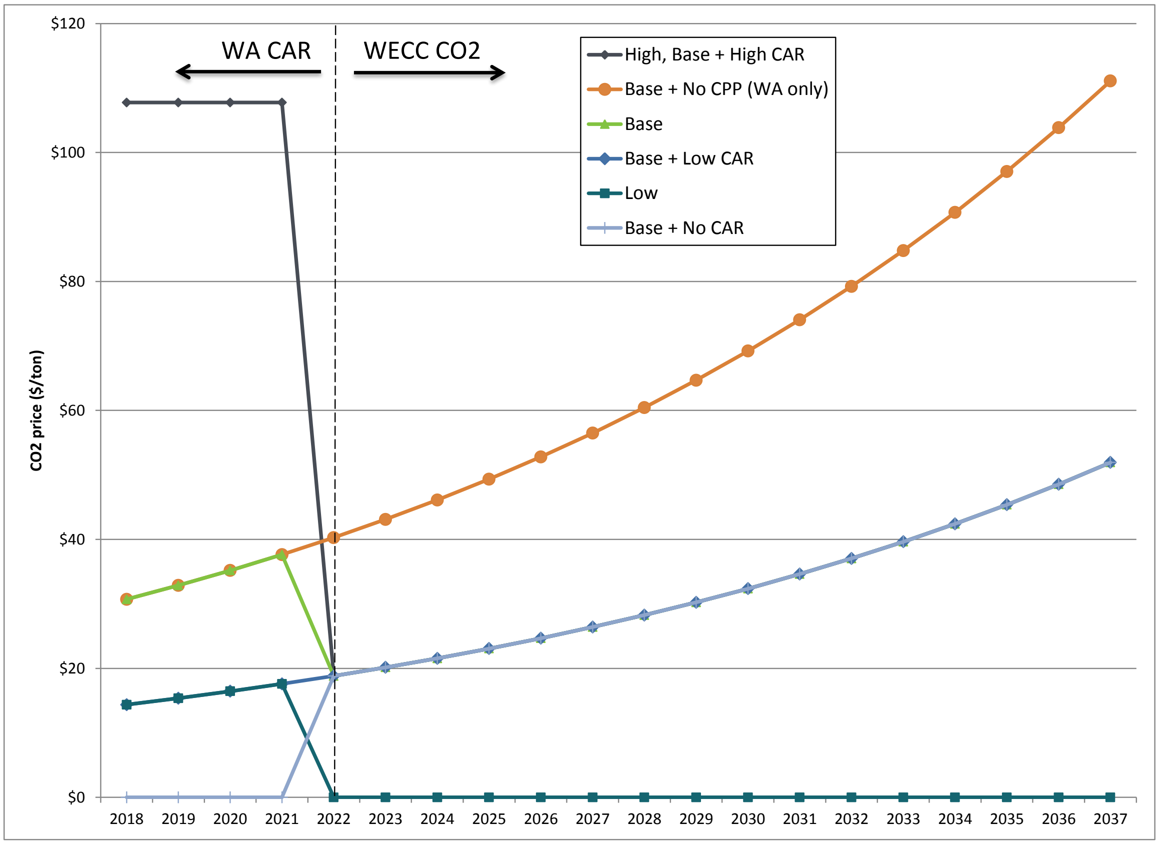


Figure 4-13: Annual CO_2 Prices for the Electric Price Modeling

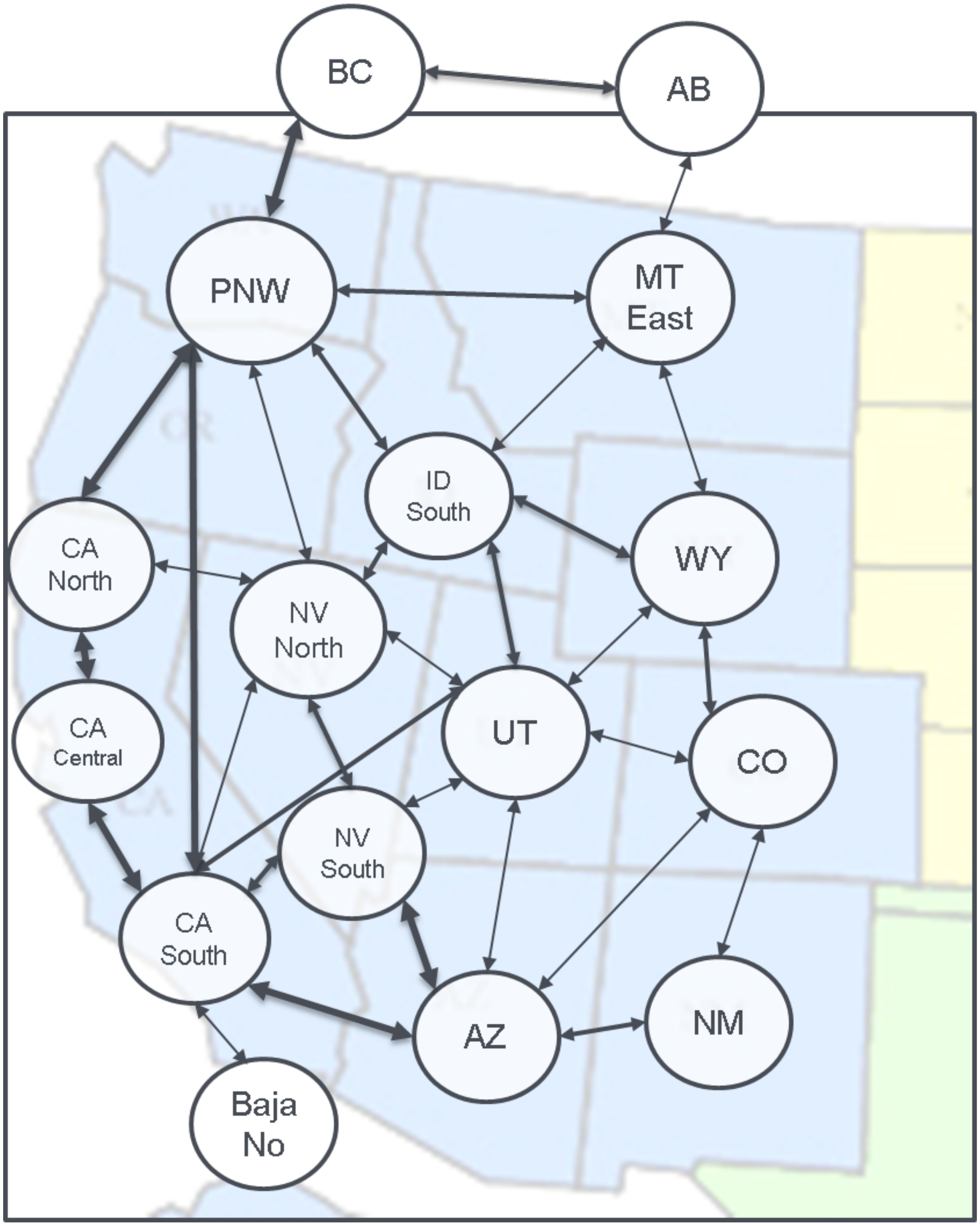


Developing Wholesale Power Prices

A wholesale power price forecast is developed for each of the 14 scenarios modeled. In this context, “wholesale power price” does not mean the rate charged to customers, it means the price to PSE of purchasing or selling 1 megawatt hour (MWh) of power on the wholesale market given the economic conditions that prevail in that scenario. This is an important input to the analysis, since market purchases make up a substantial portion of PSE’s resource portfolio. Wholesale market prices are also very important with respect to establishing the value of energy supply resources or conservation; e.g., if wholesale power prices are $45 per MWh, the value of 1 MWh of energy saved by a conservation measure or produced by a generator is $45.

AURORAxmp is an hourly chronological price forecasting model based on market fundamentals. The model reflects the dispatch and operating costs of about 3,700 individual generators, representing approximately 250 GW of installed generation capacity that are interconnected throughout the Western Electric Coordinating Council region (WECC). AURORA also reflects transmission constraints between sub-regions. Creating wholesale power price assumptions requires performing two WECC-wide AURORA model runs for each of the 14 scenarios (AURORA is discussed in more detail in Appendix N, Electric Analysis). The first run identifies needed capacity expansion to meet regional loads. AURORA considers loads and peak demand plus a planning margin, and then identifies the most economic resource(s) to add to make sure that the entire system maintains adequate resources. Results of the capacity expansion run are included in Appendix N, Electric Analysis. The second AURORA run produces hourly power prices. A full simulation across the entire WECC region simulates power prices in all 16 zones shown in Figure 4-14 below. The lines and arrows in the diagram indicate transmission links between zones. The heavier lines represent greater capacity to flow power from one zone to another.

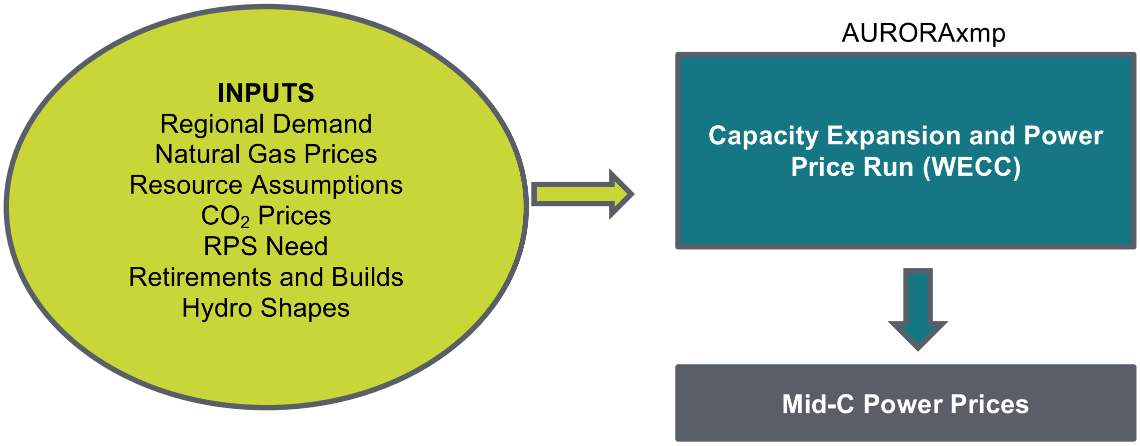
Figure 4-14: AURORA *System Diagram*



The Pacific Northwest Zone, labeled PNW in the preceding diagram, is modeled as the Mid-Columbia (Mid-C) wholesale market price. The Mid-C market includes Washington, Oregon, Northern Idaho and Western Montana.

Figure 4-15 illustrates PSE's process for creating wholesale market power prices.

Figure 4-15: PSE IRP Modeling Process for AURORA Wholesale Power Prices



The database of inputs for AURORA starts with inputs and assumptions from the EPIS 2016 v3 database. PSE then includes updates such as regional demand, natural gas prices, resource assumptions, CO_2 prices, RPS need, and resource retirements and builds. Details of the inputs and assumptions for the AURORA database are included in Appendix N, Electric Analysis.

Figure 4-16 shows the 14 power prices produced by the 14 scenario conditions.

Figure 4-16: Power Price Inputs by Scenario,
Annual Average Flat Mid-C Power Price (nominal $/MWh)

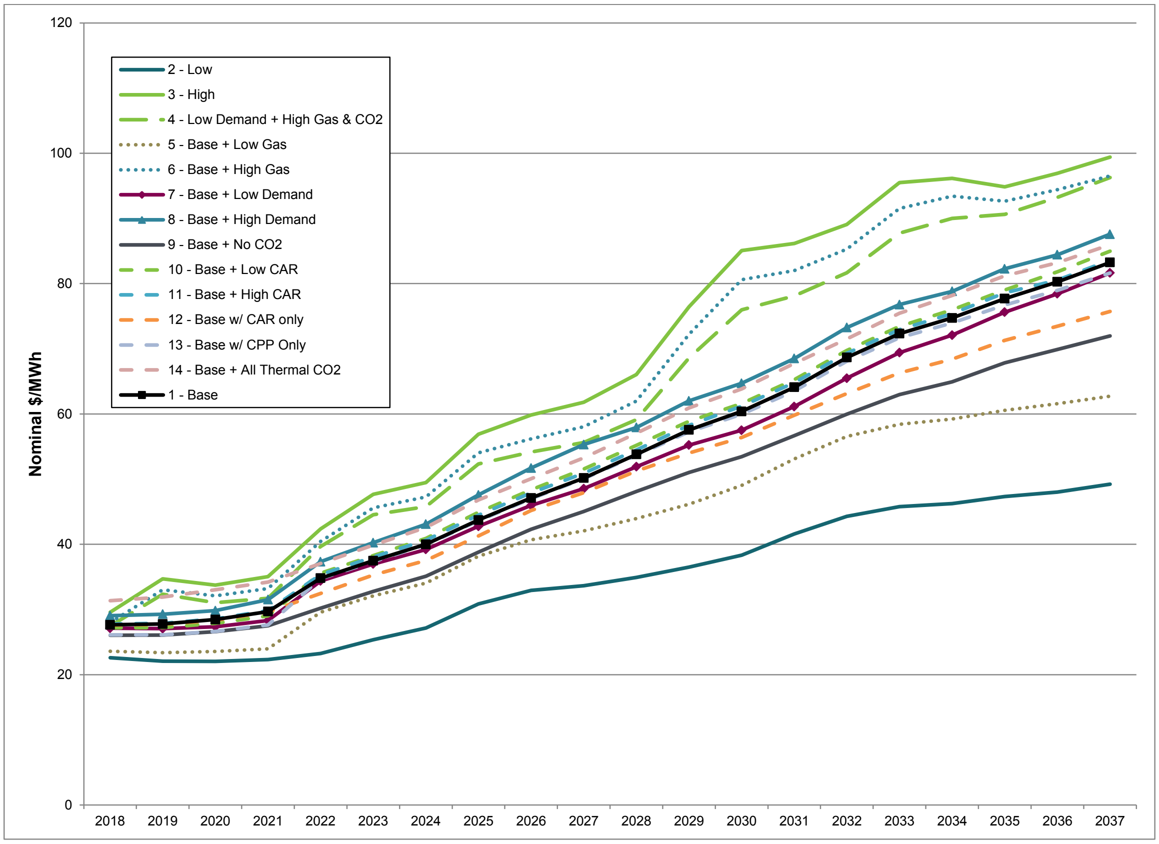
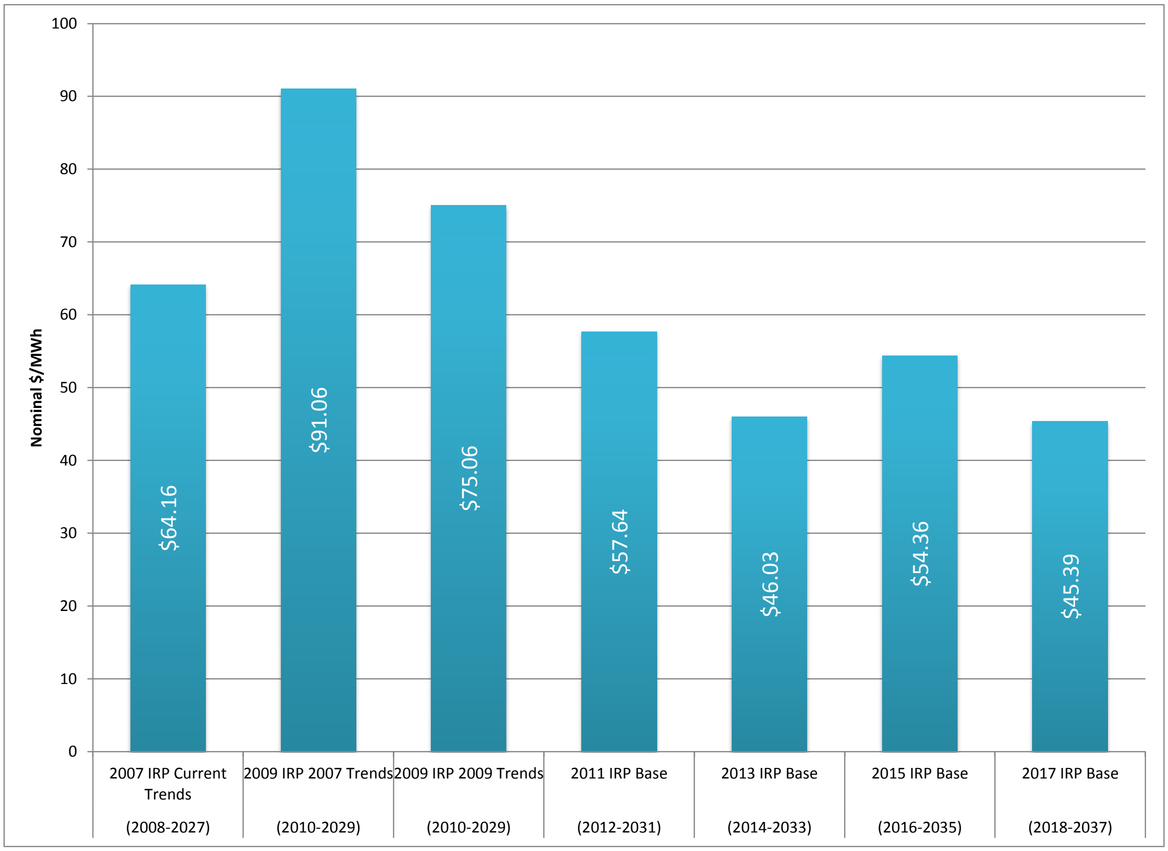


Figure 4-17 below compares the 2017 Base Scenario power prices to past IRP power prices. The downward revisions in forecast power prices correspond to the downward revisions in natural gas prices, as shown in Figure 4-11.

Figure 4-17: Levelized Power Price Compared to Past IRPs ($/MWh)



3. SCENARIOS AND SENSITIVITIES

The scenarios developed for the IRP enable us to test portfolio costs and risks in a wide variety of possible future economic conditions using deterministic optimization analysis. Sensitivities enable us to isolate the effects of an individual resource on portfolio builds. The full range of scenarios is described first, followed by a description of the baseline assumptions that apply to all scenarios. The reasoning behind the sensitivities is explained after that.

Fully Integrated Scenarios

Three fully integrated scenarios model a complete range of key economic indicators: customer demand, natural gas prices and CO_2 prices.[4]

1. Base Scenario

- The Base Scenario applies the NPCC Seventh Power Plan regional demand forecast to the WECC region and the 2017 IRP Base Demand Forecast for PSE.
- Mid gas prices are applied, a combination of forward market prices and Wood Mackenzie's fundamental long-term base forecast.
- The Washington Clean Air Rule (CAR) is modeled on affected power plants in Washington state using mid CAR CO_2 prices from 2018-2021 for the electric portfolio and from 2018-2037 for the gas portfolio: $30 per ton in 2018 to $111 per ton in 2037. In 2022, when the EPA Clean Power Plan takes effect, electric utilities will move to the CPP price: $19 per ton in 2022 to $51 per ton in 2037. From 2022 – 2037, the CPP price is applied to all WECC states.

2. Low Scenario

- This scenario models weaker long-term economic growth than the Base Scenario. Customer demand is lower in the region and in PSE's service territory. The NPCC Seventh Power Plan low demand forecast is applied for the WECC region, and the 2017 IRP Low Demand Forecast is applied for PSE.
- Natural gas prices are lower due to lower energy demand; the Wood Mackenzie long-term low forecast is applied to natural gas prices.
- Low CAR CO_2 prices are modeled from 2018-2021 for the electric portfolio and from 2018-2037 on the gas portfolio: $14 per ton in 2018 to $51 per ton in 2037. No CO_2 price is applied to the WECC for compliance with the CPP.

4 / See Figures 4-1 and 4-2.

3. High Scenario

- This scenario models more robust long-term economic growth, which produces higher customer demand. The NPCC Seventh Power Plan high demand is applied for the WECC, and the 2017 IRP High Demand Forecast is applied for PSE.
- Natural gas prices are higher as a result of increased demand, so the high gas price assumptions are modeled (Wood Mackenzie long-term high forecast for 2018-2037).
- High CAR CO_2 prices are modeled from 2018-2021 for the electric portfolio and from 2018-2037 for the gas portfolio: $108 per ton in 2018 to $108 per ton in 2037. In 2022 the CPP price is then applied to all WECC states: $19 per ton in 2022 to $51 per ton in 2037.

One-off Scenarios

Eleven one-off scenarios start with one of the fully integrated scenarios and change just one of the three key economic conditions.

4. High Scenario + Low Demand

This stakeholder requested scenario models low customer demand in the context of High Scenario assumptions (high gas prices and high CO_2 prices); it applies the 2017 IRP Low Demand Forecast.

5. Base + Low Gas Price

This scenario models the impact of a weak long-term gas price by applying the Wood Mackenzie long-term low gas price forecast to Base Scenario assumptions.

6. Base + High Gas Price

This scenario models the impact of a higher long-term gas price by applying the Wood Mackenzie long-term high gas price forecast for 2018-2037 to Base Scenario assumptions.

7. Base + Low Demand

This scenario models low customer demand in the context of Base Scenario assumptions; it applies the 2017 IRP Low Demand Forecast.

8. Base + High Demand

This scenario models high customer demand in the context of Base Scenario assumptions; it applies the 2017 IRP High Demand Forecast.

9. Base + No CO_2

This scenario removes a CO_2 price for CAR and CPP from Base Scenario assumptions.

10. Base + Low CO_2 w/ CPP

This scenario models a low CO_2 price for CAR compliance from 2017-2021 and the CPP carbon price from 2022-2037 in the context of the Base Scenario assumptions.

11. Base + High CO_2

This scenario models a high CO_2 price for CAR compliance from 2018-2021 and the CCP carbon price from 2022-2037 in the context of the Base Scenario assumptions.

12. Base + Mid CAR only (electric only)

This scenario removes CPP compliance for the electric portfolio in the context of the Base Scenario assumptions. CAR is modeled from 2018-2037.

13. Base + CPP only (electric only)

This scenario removes CAR compliance for the electric portfolio in the context of the Base Scenario assumptions. CPP is modeled from 2022-2037.

14. Base + All-thermal CO_2 (electric only)

Both CAR and CPP target baseload resources only, which excludes peaking plants. This scenario models a CO_2 price applied to all thermal resources in the WECC in the context of Base Scenario assumptions for demand and gas prices.

Baseline Scenario Assumptions – Electric

Baseline scenario assumptions are constant in all scenarios and portfolios and do not change.

Resource Assumptions

PSE modeled the following generic resources as potential portfolio additions in this IRP analysis. (See Appendix D, Electric Resources and Alternatives, for more detailed descriptions of the resources listed here.)

Demand-side resources included the following.

ENERGY EFFICIENCY MEASURES. This label is used for a wide variety of measures that result in a lower level of energy being used to accomplish a given amount of work. These include three categories: retrofit programs that have shorter lives, such as efficient light bulbs; lost opportunity measures that have longer lives, such as high-efficiency furnaces; and codes and standards that will drive down energy consumption through government regulation. (Codes and standards have no direct cost to utilities).

DEMAND RESPONSE. Demand response resources are like energy efficiency in that they reduce customer load, but unlike energy efficiency, they are also dispatchable. These programs involve customers curtailing load when needed. The terms and conditions of demand response programs vary widely, and are discussed in more detail in Appendix J, Conservation Potential Assessment.

DISTRIBUTED GENERATION. Distributed generation refers to small-scale electricity generators (like rooftop solar panels) located close to the source of the customer's load. This also includes combined heat and power systems.

DISTRIBUTION EFFICIENCY. Voltage reduction and phase balancing. Voltage reduction is the practice of reducing the voltage on distribution circuits to reduce energy consumption. Phase balancing eliminates total current flow losses that can reduce energy loss.

GENERATION EFFICIENCY. Energy efficiency improvements at PSE generating plant facilities.

CODES AND STANDARDS. No-cost energy efficiency measures that work their way to the market via new efficiency standards that originate from federal and state codes and standards.

For detailed information on demand-side resource assumptions, see Appendix J, Demand-side Resources.

Renewable supply-side resources included the following.

WIND. Wind was modeled in southeast Washington and central Montana. Washington wind is assumed to have a capacity factor of 30.4 percent. Montana wind is assumed to be located east of the continental divide and have a capacity factor of 46 percent.

OFFSHORE WIND. Although wind off the coast of Washington is not a commercially available resource at this time, it was modeled in the portfolio analysis in response to stakeholder interest. Wind off the coast would have to be located in deep water more than 22 miles offshore since established shipping lanes run the entire length of the Washington coast. The only technology suitable for such depths would be floating platforms, and so far there has been only a one-turbine demonstration project. Offshore wind is described in more detail in Appendix D.

ENERGY STORAGE: BATTERIES. Two battery storage technology systems are analyzed: lithium-ion and flow technology. These systems are modular, and made up of individual units that are generally small. Batteries provide both peak capacity and sub-hourly flexibility value. In addition, since they are small enough to be installed at substations, they can potentially defer local transmission or distribution system investments. PSE analyzed 2-hour, 4-hour and 6-hour battery systems for both technologies.

ENERGY STORAGE: PUMPED HYDRO. Pumped hydro resources are generally large, on the order of 250 to 3,000 MW. This analysis assumes PSE would split the output of a pumped hydro storage project with other interested parties. Pumped hydro resources can provide sub-hourly flexibility values similar to batteries, and they are utility scale. Because they are located remote from substations, they cannot contribute the transmission and distribution benefits that smaller battery systems can provide at the local system level. Pumped hydro can provide some benefits to the bulk transmission system, however, such as frequency response and black start capability.

SOLAR. Utility-scale solar PV was modeled in central Washington in PSE's service territory and southern Idaho. This solar is assumed to use a tracking system and have a capacity factor of 27 percent in Washington and 30 percent in Idaho.

Other supply-side resources included the following.

BASELOAD GAS PLANTS (COMBINED-CYCLE COMBUSTION TURBINES OR CCCTS). F-type, 1x1 engines with wet cooling towers are assumed to generate 359 MW plus 54 MW of duct firing, and to be located in PSE's service territory. These resources are designed and intended to operate at base load, defined as running more than 60 percent of the hours in a year.

FRAME PEAKERS. (SIMPLE-CYCLE COMBUSTION TURBINES). F-type, wet-cooled turbines are assumed to generate 239 MW and to be located in PSE's service territory. Those modeled without oil backup were required to have firm gas supplies and storage.

AERO PEAKERS. (AERODERIVATIVE COMBUSTION TURBINES). The 2-turbine design with wet cooling is assumed to generate a total of 227 MW and to be located in PSE's service territory. Those modeled without oil backup were required to have firm gas supplies and storage.

Baseload and peakers

"Baseload" generators are designed to operate economically and efficiently over long periods of time, which is defined as more than 60 percent of the hours in a year.

"Peaker" is a term used to describe generators that can ramp up and down quickly in order to meet spikes in need. They are not intended to operate economically for long periods of time like baseload resources.

RECIP PEAKERS. (RECIPROCATING ENGINES). This 12-engine design with wet cooling (18.7 MW each for gas-only and 17.1 MW for duel fuel), is assumed to generate a total of 222 MW (202 MW duel fuel) and to be located in PSE's service territory.

REDIRECTED TRANSMISSION. "Redirecting" transmission means moving a primary receipt point on BPA's system. According to BPA's business practice, PSE can redirect an existing long-term or short-term, firm or non-firm transmission that it has reserved on BPA's transmission system. BPA will grant the redirect request as long as there is sufficient capacity on the system to accommodate the change.

Resource Cost Assumptions

The estimated cost of generic thermal resources are based on a September 2016 study by Black and Veatch done on behalf of PSE (see Appendix N for the full report). Renewable resource costs are based on information from a different consultant, DNV-GL.

Resource costs are generally expected to fall in the future, as technology advances push costs down. The declining cost curves applied to different resource alternatives come from the Energy Information Administration (EIA) Annual Energy Outlook (AEO). A sensitivity that examines more aggressive cost reductions for utility-scale solar was also examined. Appendix D, Electric Resources and Alternatives, contains a more detailed description of resource cost assumptions, including transmission and gas transport assumptions.

In general, cost assumptions represent the "all-in" cost to deliver a resource to customers; this includes plant, siting, sales tax, system upgrades and financing costs. PSE's activity in the resource acquisition market during the past ten years informs resource cost assumptions, and our extensive discussions with developers, vendors of key project components and firms that provide engineering, procurement and construction services lead us to believe the estimates used here are appropriate and reasonable.

- Figure 4-18 summarizes generic resource assumptions.
- Figure 4-19 displays the monthly capacity factor for Washington wind, Montana wind, Washington solar.
- Figure 4-20 summarizes annual capital cost by vintage year for supply-side resources and energy storage.

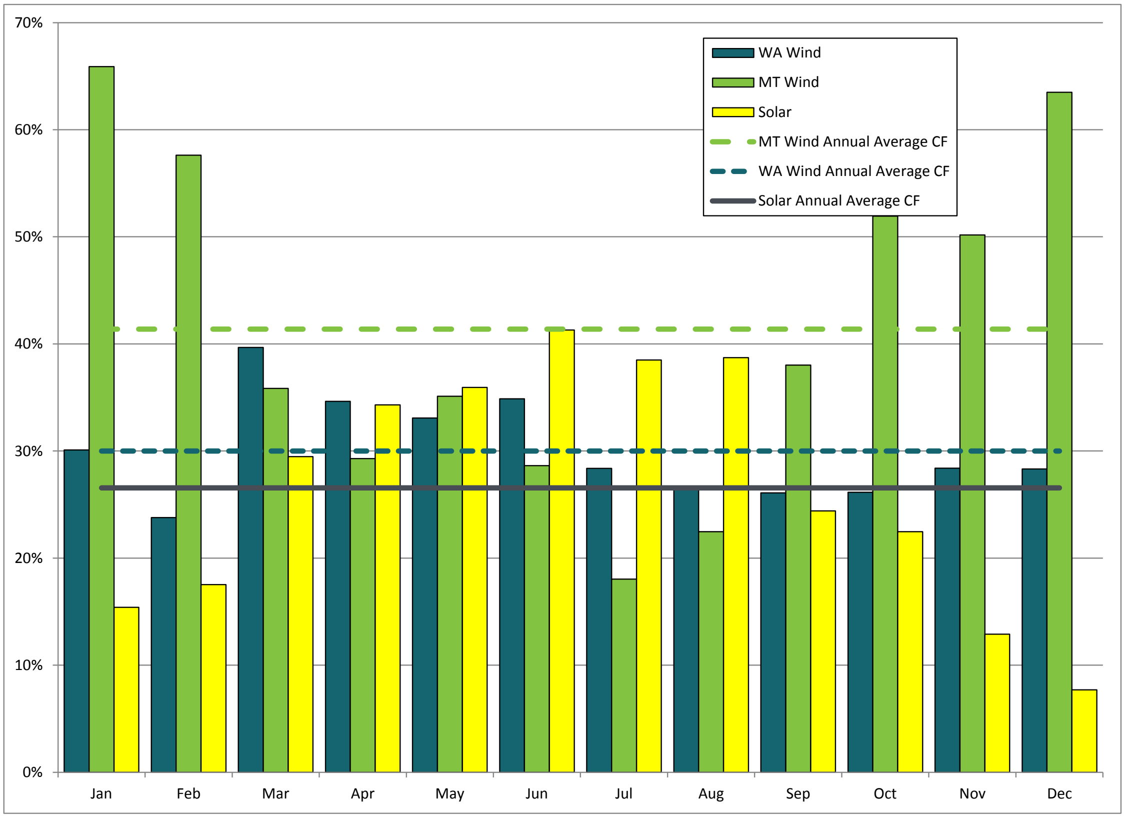
Figure 4-18: New Resource Cost Assumptions

IRP Modeling Assumptions (2016 $)	Name -plate (MW)	First year available	Capacity Factor[1] (%)	Overnight Capital Cost ($/kw)	Fixed O&M [2] ($/kw-yr)	Variable O&M ($/MWh)	Baseload Heatrate[3] (Btu/kWh)
F-Class CCCT 1x1 with DF	413	2022	N/A	$1,267	$8.10	$2.50	6,650
Frame Peaker Duel-Fueled 1x0 with Oil Back-up	239	2021	N/A	$639	$11.23	$0.95	9.823
Frame Peaker NG only 1x0	239	2021	N/A	$571	$6.40	$0.95	9.823
Aero Peaker Duel-Fueled 2x0 with Oil Back-up	227	2021	N/A	$1,070	$10.92	$10.20	8,986
Aero Peaker NG only 2x0	227	2021	N/A	$1,004	$6.50	$10.20	8,986
Recip Peaker Duel-Fueled 12x0 with Oil Back-up	202	2021	N/A	$1,477	$10.70	$7.80	8,527
Recip Peaker NG only 12x0	222	2021	N/A	$1,277	$6.50	$7.80	8,425
Wind Plant - Washington	100	2020	30%	$1,939	$27.12	$3.15	N/A
Wind Plant - Montana	300	2022	46%	$2,065	$33.79	$3.50	N/A
Offshore Wind	100	2022	35%	$7,150	$77.30	$3.15	N/A
Central Station Solar Tracking PV	25	2020	26%	$2,041	$10.00	$0.00	N/A
Biomass	15	2021	85%	$3,950	$113.70	$5.66	N/A
2-hour Lithium Ion Battery	25	2019	N/A	$1,514	$23.68	$0.00	N/A
4-hour Lithium Ion Battery	25	2019	N/A	$2,439	$36.49	$0.00	N/A
4-hour Flow Battery	25	2019	N/A	$2,324	$26.82	$0.00	N/A
6-hour Flow Battery	25	2019	N/A	$3,042	$23.40	$0.00	N/A
Pumped Storage Hydro	25	2030	N/A	$2,400	$15.00 ,	$0.00	N/A

NOTES
1. Expected factor for wind, solar and Biomass; for thermal resources, the capacity factor is dependent on dispatch cost for the scenario.
2. Fixed O&M with oil backup includes the cost for 48 hours worth of oil.
3. Heat rate for CCCT is for the primary unit, the heat rate for the secondary duct firing is expected to be 8,500 Btu/kWh.

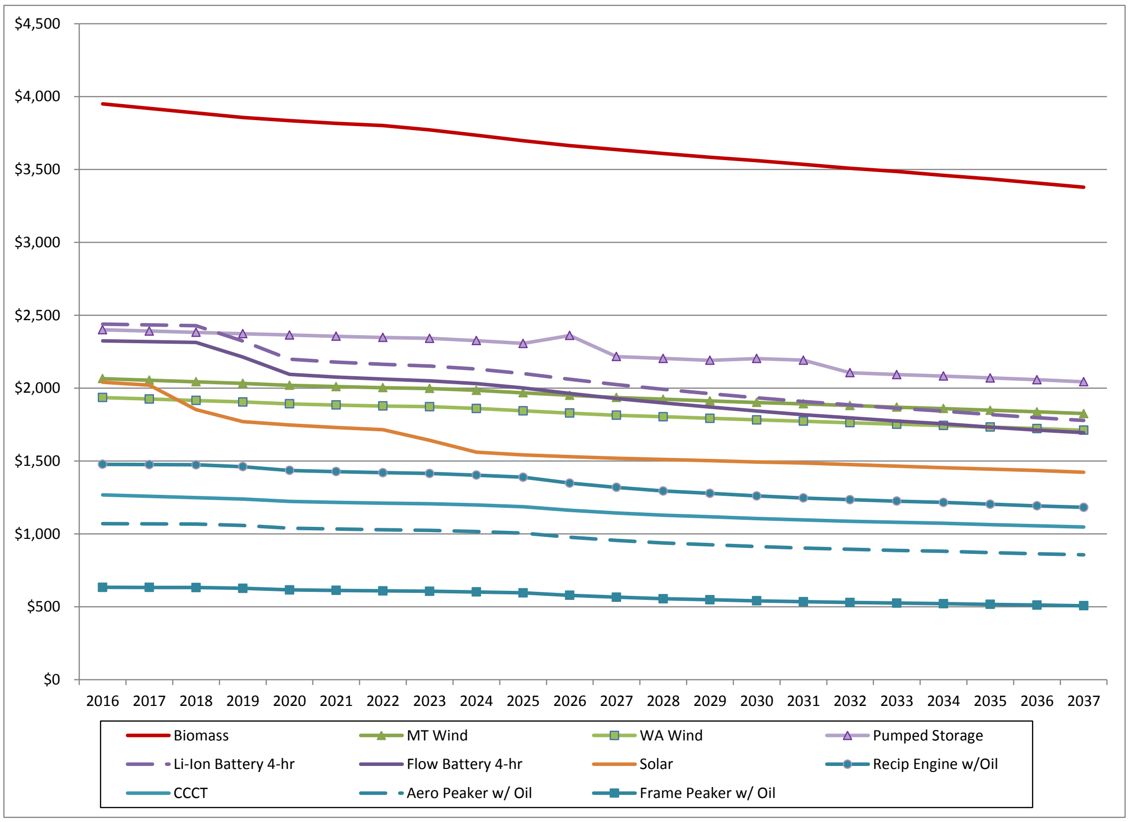
Figure 4-19 displays the monthly capacity factor for Washington wind, Montana wind, and Washington solar.

Figure 4-19: Capacity Factor for Wind and Solar



The change in capital cost by vintage year (year the plant is built) is based on the EIA AEO 2015 Overnight Cost curves. These costs are decreasing on a real basis, but we then add a 2.5 percent annual inflation rate for nominal costs. Figure 4-20 shows the annual capital cost of a resource by year built in 2016 real dollars.

Figure 4-20: Annual Capital Costs by Vintage Year (real 2016 dollars)



Heat Rates

PSE applies the improvements in new plant heat rates as estimated by the EIA in the AEO Base Case Scenario. New equipment heat rates are expected to improve slightly over time, as they have in the past. PSE also applies a 2 percent increase to the heat rates to account for the average degradation over the life of the plant.

Federal Subsidies

Two federal subsidies are currently available to reduce renewable resource costs in the U.S; the production tax credit (PTC) and the investment tax credit (ITC). Both wind and solar projects are given the option to choose between the PTC or ITC.

PTC. The PTC is phased down over time for wind facilities (starting at 100 percent) and expires for other technologies commencing construction after December 31, 2016.

- For wind facilities commencing construction in 2017, the PTC amount is reduced by 20 percent
- For wind facilities commencing construction in 2018, the PTC amount is reduced by 40 percent
- For wind facilities commencing construction in 2019, the PTC amount is reduced by 60 percent

To meet the safe harbor rules, a project must meet the “physical work” test or show than 5 percent or more of the total cost of the project was paid during that year. For example, if a project began construction or paid 5 percent or more in costs in the year 2019, it will receive the 40 percent PTC even if the facility doesn’t go online until 2022. The PTC is received over 10 years and is the rate prescribed annually by the IRPs in dollars per MWh.

ITC. The ITC is a one-time benefit based on the total capital cost invested in the project. The phase-down over time varies depending on the technology;

- wind: 30 percent in 2016, 24 percent in 2017, 18 percent in 2018 and 12 percent in 2019;
- solar: 30 percent 2016-2019, 26 percent in 2020, and 22 percent in 2021, , and 10 percent in years after 2021.
- Batteries if matched with a solar project can receive ITC if 75 percent of the energy comes from the project.

ITC benefit is based on the year that construction begins. For example, if a wind project starts construction in 2016 but does not go online until 2018, it will receive a 30 percent tax credit based on the total capital cost. So, if the project cost $300 million, then the developer will receive $90 million in tax benefits.

BONUS DEPRECIATION. This is an additional amount of tax deductible depreciation that is awarded above and beyond what would normally be available in the first year of a project. Bonus depreciation is available for all technology types, not just renewable resources, and is based on the when the plant is placed in service. This incentive is designed to promote investment sooner rather than later. The bonus depreciation is also phased down over time; 50 percent in 2016, 50 percent in 2017, 40 percent in 2018 and 30 percent in 2019.

Renewable Portfolio Standards

Renewable portfolio standards (RPS) currently exist in 29 states and the District of Columbia, including most of the states in the WECC and British Columbia. They affect PSE because they increase competition for development of renewable resources. Each state and territory defines renewable energy sources differently, sets different timetables for implementation, and establishes different requirements for the percentage of load that must be supplied by renewable resources.

To model these varying laws, PSE identifies the applicable load for each state in the model and the renewable benchmarks of each state's RPS; e.g., 3 percent in 2012, 9 percent in 2016, then 15 percent in 2020 for Washington state. Then we apply these requirements to each state's load. No retirement of existing WECC renewable resources is assumed, which may underestimate the number of new resources that need to be constructed. After existing and renewable resources are accounted for, the difference is taken from the total RPS need and the existing resources and the net RPS need is then added to AURORA as a constraint. We then run the long-term capacity expansion with the RPS constraint, and AURORA adds renewable resources to meet the RPS need. Technologies modeled included wind and solar.

California Carbon Prices

The California Global Warming Solutions Act of 2006 (AB32) mandates a carbon price be applied to all power generated in or sold into that state. To model this cost, PSE used the Wood MacKenzie forecast of California CO_2 prices based on AB32.

Build and Retirement Constraints

PSE added constraints on different technologies to the AURORA model. Specifically:

- No new coal builds are allowed in Washington. State law RCW 80.80 (Greenhouse Gases Emissions – Baseload Electric Generation Performance Standard) prohibits construction of new coal-fired generation within the state without carbon capture and sequestration.
- No new coal builds are allowed in any state in the WECC. In addition, all WECC coal plants must meet the National Ambient Air Quality Standards (NAAQS) and the Mercury and Air Toxics Standards (MATS).
- Any plant that has announced retirement is reflected in the database.
- California power plants that would be shuttered by that state's Once-through Cooling regulations are retired.

Further discussion of planned builds and retirements in WECC are discussed in Appendix N, Electric Analysis.

Electric Portfolio Sensitivity Reasoning

Starting with the optimized, least cost Base Scenario portfolio, sensitivities change one resource assumption within the portfolio in order to isolate the effect of that resource change on the portfolio.

NOTE: The table in Figure 4-3 presents this information in abbreviated form.

A. Colstrip

Several proposed or recently enacted rules will affect the operation of the Colstrip plant in eastern Montana in coming years, so this sensitivity tests reducing reliance on Colstrip and eliminating it entirely.

BASELINE ASSUMPTION: Units 1 & 2 retire in 2022 and Units 3 & 4 remain in service into 2035.
SENSITIVITY 1 > Retire Units 1 & 2 in 2018.
SENSITIVITY 2 > Retire Units 3 & 4 in 2025.
SENSITIVITY 3 > Retire Units 3 & 4 in 2030.

B. Thermal Retirement

This sensitivity examines whether it would be cost effective to accelerate retirement of PSE's existing gas plants.

BASELINE ASSUMPTION: Optimal portfolio from the Base Scenario
SENSITIVITY 1 > Retire baseload gas plants early.

C. No New Thermal Resources

This sensitivity looks at the cost of filling all future supply-side portfolio resource needs with resources that emit no carbon.

BASELINE ASSUMPTION: Fossil fuel generation is an option in the model.
SENSITIVITY 1 > Renewable resources, energy storage and DSR are the only options for future resources.

D. Stakeholder-requested Alternative Resource Costs

This sensitivity models changes to the generic resource cost assumptions based on recommendations from IRP stakeholders.

BASELINE ASSUMPTION: PSE cost estimates for generic supply-side resources.

SENSITIVITY 1 > Lower cost for recip peakers: $1,105 per kW without oil backup, $1,257 per kW with oil backup

SENSITIVITY 2 > Higher thermal resource costs, based on the 2015 IRP capital cost estimates. Numbers are in 2016 dollars and include 30 percent owner's costs consistent with the 2017 IRP instead of the 40 percent owner's costs modeled in the 2015 IRP.

Frame peaker with oil: $879 per kW
Recip peaker: $1,563 per kW
Aero peaker with oil: $1,214 per kW
Baseload CCCT: $1,227 per kW

SENSITIVITY 3 > Lower wind and solar development cost (includes 30% owner's costs)

Wind: $1,478 per kW
Solar: $1,755 per kW

SENSITIVITY 4 > Apply more aggressive solar cost curve.

E. Energy Storage

This sensitivity examines the cost difference between a portfolio with energy storage and a portfolio without energy storage.

BASELINE ASSUMPTION: Batteries and pumped hydro included only if chosen economically.

SENSITIVITY 1 > Add 50 MW battery in 2023 instead of economically chosen peaker.

SENSITIVITY 2 > Add 50 MW pumped hydro storage in 2023 instead of economically chosen peaker.

F. Renewable Resources + Energy Storage

The baseline assumption is that the battery storage will be placed in an optimal location on the system to get the maximum transmission and distribution benefit. This sensitivity pair pairs 50 MW of battery storage with 200 MW of solar. If 75 percent of the energy used to charge the battery comes from a renewable resource, the battery storage will receive the same investment tax credit as the solar resource. However, locating the battery near the solar project in eastern Washington means it will no longer deliver the transmission and distribution benefit.

> **BASELINE ASSUMPTION:** Solar and batteries modeled individually.
> **SENSITIVITY 1 >** 200 MW solar bundled with 50 MW batteries

G. Electric Vehicle Load

This sensitivity examines how much electric vehicle charging loads will affect the resource plan forecast.

> **BASELINE:** IRP Base Demand forecast
> **SENSITIVITY >** Add forecasted electric vehicle load

The following three sensitivities test the impact of different demand-side resource configurations.

H. Demand-side Resources (DSR)

This sensitivity looks at the effect of no additional DSR on portfolio cost and risk; all future needs are met with supply-side resources.

> **BASELINE ASSUMPTION:** All cost-effective DSR per RPS requirements (RCW 19.285).
> **SENSITIVITY 1 >** Existing DSR measures stay in place, but all future needs are met with supply-side resources.

I. Extended DSR Potential

The baseline assumption applies a 10-year ramp rate to all DSR identified as cost-effective in this IRP, meaning that all of these DSR measures are applied in the first decade of the study period. This sensitivity models future DSR measures that extend conservation benefits through the second decade of the study period.

> **BASELINE ASSUMPTION**: All DSR identified as cost-effective in this IRP is applied in the first 10 years of the study period.
> **SENSITIVITY 1 >** Assume future DSR measures will extend conservation benefits through the second 10 years of the study period.

J. Alternate Residential Conservation Discount Rate

This sensitivity examines how using a societal discount rate on conservation savings from residential energy efficiency would impact cost-effective levels of DSR.

BASELINE ASSUMPTION: Assume the base discount rate.
SENSITIVITY 1 > Apply a societal discount rate to residential conservation savings.

The next five sensitivities test the impact of different wind resource configurations.

K. RPS-eligible Montana Wind

The baseline assumption is that Montana wind does not qualify as an RPS-eligible resource. To qualify under RCW 19.285, Montana wind would have to be dynamically scheduled into Washington state on a real-time basis without shaping or storage. "Dynamically scheduled" means PSE's balancing authority would have to balance real-time changes in wind energy output as if it were located in PSE's balancing authority. This would require coordination and agreement between Northwestern (the balancing authority where the wind plant would be built) and BPA (which would transmit the power to PSE). Complex studies on both systems would be required to determine if each transmission system could facilitate the dynamic transfer without adversely affecting the other transmission customers on its system. PSE formally requested assistance from BPA in April 2017, explaining the potential importance to PSE customers of finding a way to resolve this issue, and asking specifically: 1) what information and studies would be required to determine whether Montana wind qualified as a renewable resource under RCW 19.285, and 2) for any summary information concerning the information and studies, and/or whether tariffs or regulations would need to be addressed before qualifying studies could be conducted. Since that request was sent, BPA has announced its intention to convene with a forum with the State of Montana and other regional stakeholders to work on these issues, and PSE will participate and contribute to the identification and implementation of solutions concerning Montana wind. While Montana wind is not currently an RPS-eligible resource, this sensitivity examines whether Montana wind would be a cost-effective resource if it did qualify and therefore capture the extra 20 percent apprenticeship credit. If RPS-eligible Montana wind does not appear to be cost effective, a second sensitivity estimates how close its cost comes to other cost-effective resources.

BASELINE ASSUMPTION: Montana wind included only if economically chosen as a non-RPS resource
SENSITIVITY 1 > Add Montana wind in 2023 as an RPS-eligible resource instead of solar.
SENSITIVITY 2 > Montana wind tipping point analysis

L. Offshore Wind Tipping Point Analysis

This sensitivity examines how much the costs of offshore wind would need to decline before it appears to be a cost-effective resource.

BASELINE ASSUMPTION: Base Scenario portfolio
SENSITIVITY 1 > Offshore wind tipping point analysis to determine how much costs would have to drop to be cost effective compared to other resources.

M. Hopkins Ridge Repowering

Repowering refers to refurbishing or renovating a plant with more efficient, updated technology and equipment to qualify for Renewable Production Tax Credits under the PATH Act of 2015. Repowering would make the facility operate more efficiently and capture savings from the production tax credit. This sensitivity examines whether it would be cost effective to repower the Hopkins Ridge wind facility for the tax incentives and bonus RECs that would result.

BASELINE ASSUMPTION: Repowering Hopkins Ridge is not included in the portfolio.
SENSITIVITY 1 > Include repowering Hopkins Ridge in the portfolio to replace the existing facility.

Gas Sales Assumptions

Transportation and storage are key resources for natural gas utilities. Transporting gas from production areas or market hubs to PSE's service area generally requires assembling a number of specific pipeline segments and/or gas storage alternatives. Purchases from specific market hubs are joined with various upstream and direct-connect pipeline alternatives and storage options to create combinations that have different costs and benefits. See Chapter 7, Gas Sales Analysis, for further information.

In this IRP, six alternatives were tested in the analyses.

Combination # 1 & 1a – NWP Additions + Westcoast

This option expands access to northern British Columbia gas at the Station 2 hub beginning November 2021, with expanded transport capacity on Enbridge/Westcoast Energy pipeline to Sumas and then on expanded NWP to PSE's service area. Gas supplies are also presumed available at the Sumas market hub. In order to ensure reliable access to supply and achieve diversity of pricing, PSE believes it will be necessary to acquire Enbridge/Westcoast capacity equivalent to 100 percent of any new NWP firm take-away capacity at Sumas.

COMBINATION #1A – NWP-TF-1. This is a short-term pipeline alternative that represents excess capacity on the existing NWP system from Sumas to PSE that could be contracted to meet PSE needs from November 2017 to October 2020 only. PSE believes that the vast majority of under- utilized firm pipeline capacity in the I-5 corridor will be absorbed by other new loads by the fall of 2020. Beyond October 2020, other long-term resources would be added to serve PSE demand.

Combination # 2 – FortisBC/Westcoast (KORP)

This combination includes the Kingsvale-Oliver Reinforcement Project (KORP) pipeline proposal, which is in the development stages and sponsored by FortisBC and Enbridge/Westcoast. Availability is estimated beginning November 2021. Essentially, the KORP project expands and adds flexibility to the existing Southern Crossing pipeline. This option would allow delivery of Alberta (AECO hub) gas to PSE via existing or expanded capacity on the TC-NGTL and TC-Foothills pipelines, the KORP pipeline across southern British Columbia to Sumas, and then on expanded NWP capacity to PSE.

Combination # 3 – Cross Cascades - AECO

This option provides for deliveries to PSE via the prospective Cross Cascades pipeline. The increased gas supply would come from Alberta (AECO hub) via existing or new upstream pipeline capacity on the TC-NGTL, TC-Foothills and TC-GTN pipelines to Stanfield. Final delivery from Stanfield to PSE would be via the proposed Cross Cascades pipeline and a northbound upgrade to NWP. As a major greenfield project, this resource option is dependent on significant volume of additional contracting by other parties.

Combination # 4 – Cross Cascades - Malin

This option provides for deliveries to PSE via the prospective Cross Cascades pipeline. The increased gas supply would come directly from Malin or from the Rockies hub on the Ruby pipeline to Malin, with backhaul on the TC-GTN pipeline to Stanfield. Final delivery from Stanfield to PSE would be via the proposed Cross Cascades pipeline and a northbound upgrade to NWP. As a major greenfield project, this resource option is dependent on significant volume of additional contracting by other parties.

Combination # 5 – LNG-related Distribution Upgrade

This combination assumes completed construction and successful commissioning of the LNG peak-shaving facility for the 2019/20 heating season, providing 59.5 MDth per day of capacity. This option considers the timing of the contemplated upgrade to the Tacoma area distribution system, allowing an additional 16 MDth per day of vaporized LNG to reach more customers. The effect is to increase overall delivered supply to PSE customers because gas otherwise destined for the Tacoma system is displaced by vaporized LNG and delivered to other parts of the system. The incremental volume resulting from the distribution upgrade can be implemented on two years' notice starting as early as winter 2021/22.

Combination # 6 – Mist Storage and Redelivery

This option provides for PSE to lease storage capacity from NW Natural after an expansion of the Mist storage facility. Delivery of gas would require expansion of pipeline capacity from Mist to PSE's service territory for Mist storage redelivery service. The expansion of pipeline capacity from Mist to PSE will be dependent on an expansion on NWP from Sumas to Portland with significant additional volume contracting by other parties.

Combination # 7 – Swarr Propane/Air Upgrade

This is an upgrade to the existing Swarr LP-air facility. This upgrade would increase the peak day planning capability from 10 MDth per day to 30 MDth per day. This plant is located within PSE's distribution network.

Build Constraints

Gas expansions are done in multi-year blocks to reflect the reality of the acquisition process. There is inherent “lumpiness” in gas pipeline expansion, since expanding pipelines in small increments every year is not practical. Pipeline companies need minimum capacity commitments to make an expansion economically viable. Thus the model is constrained to evaluate pipeline expansions in four-year blocks: 2021, 2025, 2028 and 2033, 2037. Similarly, some resources have more flexibility. The Swarr LP gas peaking facility’s upgrade and the LNG distribution system upgrade were made available in two year increments since these resources are PSE assets.

Gas Sales Sensitivities

A. Demand-side Resources (DSR)

This sensitivity looks at the effect of no additional DSR on portfolio cost and risk; all future needs are met with supply-side resources.

BASELINE ASSUMPTION: All cost-effective DSR per RPS requirements (RCW 19.285).
SENSITIVITY 1 > Existing DSR measures stay in place, but all future needs are met with supply-side resources.

B. Resource Addition Timing Optimization

Two of the resource additions selected in most scenarios are within PSE’s control, the Swarr upgrade and the LNG-related distribution upgrade. This sensitivity examines how the timing of those PSE-controlled resource additions affect resource builds and portfolio costs.

BASELINE ASSUMPTION: Swarr and the LNG-related distribution upgrade are offered every two years in the model.
SENSITIVITY 1 > Allow these resources to be offered every year in the model.

C. Alternate Residential Conservation Discount Rate

This sensitivity examines how using a societal discount rate on conservation savings from residential energy efficiency would impact cost-effective levels.

BASELINE ASSUMPTION: Assume the base discount rate.
SENSITIVITY 1 > Apply a societal discount rate to residential conservation savings.

D. Additional Conservation

This sensitivity examines what happens if we add DSR above the levels found cost effective.

BASELINE ASSUMPTION: All cost-effective DSR per RCW 19.285.
SENSITIVITY 1 > Add two additional DSR bundles above those chosen as cost effective.