Key Assumptions

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This chapter describes the forecasts, estimates, and assumptions that were developed as key inputs to the quantitative analysis conducted for this IRP. We combine these into scenarios and sensitivities to test resource portfolios in different possible futures and to measure the effects of an isolated variable.

PSE develops ranges of forecasts, estimates and assumptions for the following key areas.

- Demand
- Power prices
- Gas prices
- CO_2 costs

We then combine these in different ways to create scenarios. Scenarios are "pictures" of the future that reflect a set of integrated assumptions that could occur together. This enables us to test how portfolio costs and risks respond to changes in economic conditions, environmental legislation, natural gas prices, and energy policy. In addition, we develop sensitivities that allow us to isolate the effect of a single variable; sensitivities start with the Base Case and change only one input. The scenarios and sensitivities developed for this IRP are listed below.

Scenarios

Base Case
Low Growth
High Growth
Very Low Gas Prices
Very High Gas Prices
Base + CO2
Green World

Sensitivities

No Northwest Coal
No Peakers
Thermal Mix
Fixed (firm) gas transport cost for peakers
Renewable tax credit extends to 2013
Renewable tax credit extends to 2016
Renewable tax credit extends to 2020
Renewable tax credit extends to 2031
DSR Ramp Rates
Plug-in vehicles

1. Key Inputs

Demand Forecasts

Customer load is the single most important input assumption to the IRP analysis. The demand forecast PSE develops for the IRP is an estimate 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. To develop assumptions about national and regional economic trends has been particularly challenging due to continually changing conditions throughout the period. These included a series of abrupt declines throughout the second half of 2008, and an uncertain and slow recovery process during 2009 and early 2010.

Three demand forecasts were used for portfolio analysis in this IRP.

The 2011 IRP Base scenario uses the F2010 Base load forecast. This forecast is based on 2010 macroeconomic conditions such as population growth and unemployment. Details of the load forecast can be found in Appendix H.

The 2011 IRP Low Growth scenario uses the F2010 Low load forecast. This load forecast was developed to be a pessimistic view of the macroeconomic variables identified in the base forecast. The pessimistic view creates a lower demand that PSE needs to meet.

The 2011 IRP High Growth scenario uses the F2010 High Load forecast which is a more optimistic view of the base load forecast.

Why don't they match?

The load forecasts that appear in the IRP often do not match the load forecasts presented in rate cases or during acquisition discussions. Why is this?

The IRP analysis takes 12 to 18 months to complete. Load 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, the company will have updated the load forecast. The range of possibilities in the IRP forecast is sufficient for long-term planning purposes, but PSE will always present the most current forecast for rate cases or when making acquisition decisions.

The graphs below show the peak load and annual energy load forecasts for Gas Sales and Electric. See Appendix H for a full discussion of how the IRP forecasts were developed.

Figure 4-1
PSE Peak Electric Load Forecast

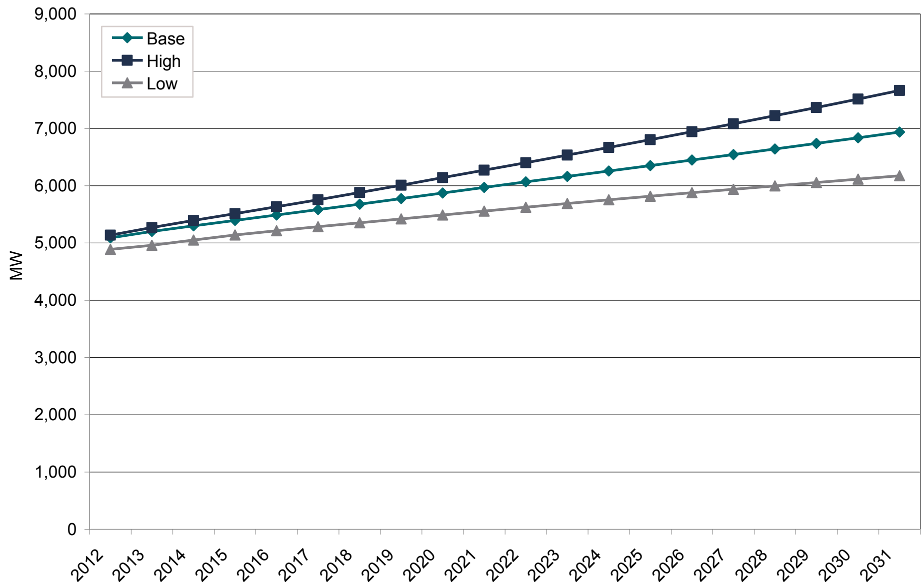


Figure 4-2
PSE Annual Electric Load Forecasts 2010-201

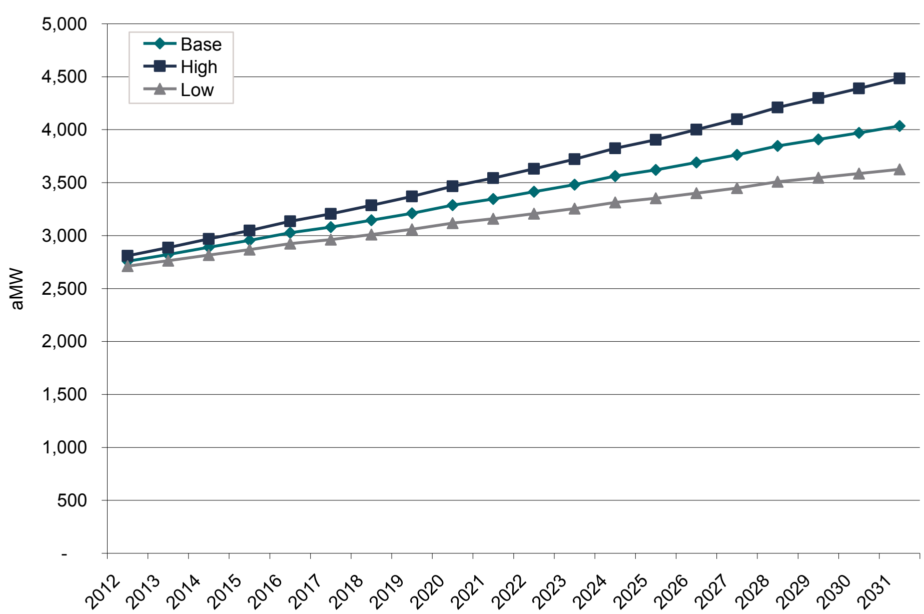


Figure 4-3
PSE Peak Day Gas Sales Forecast

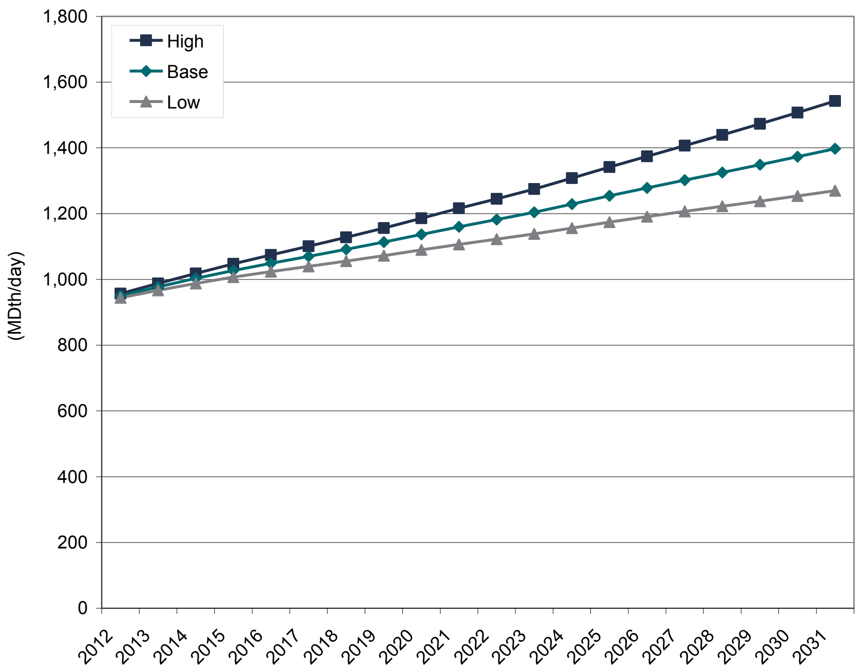
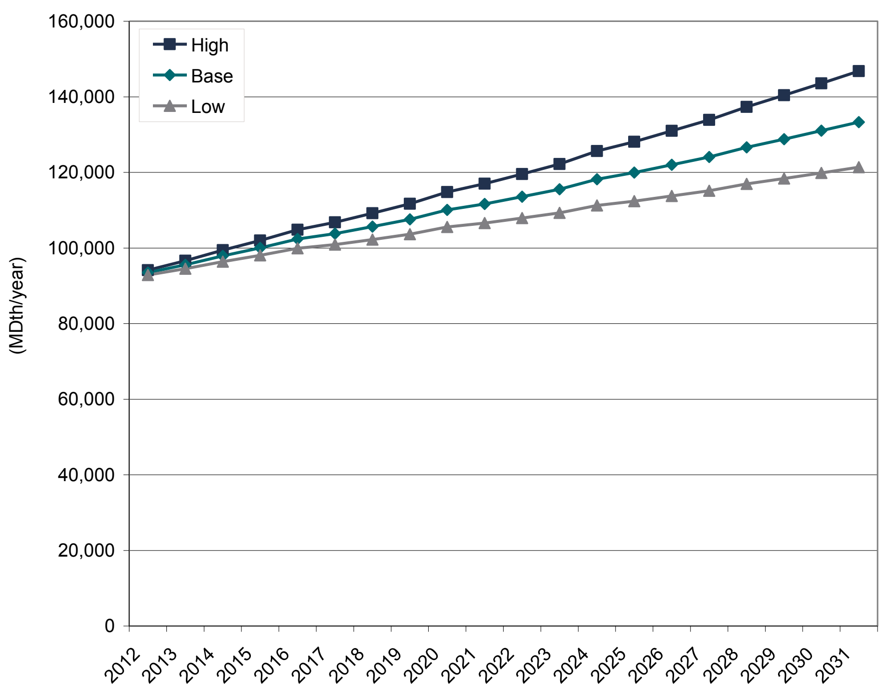


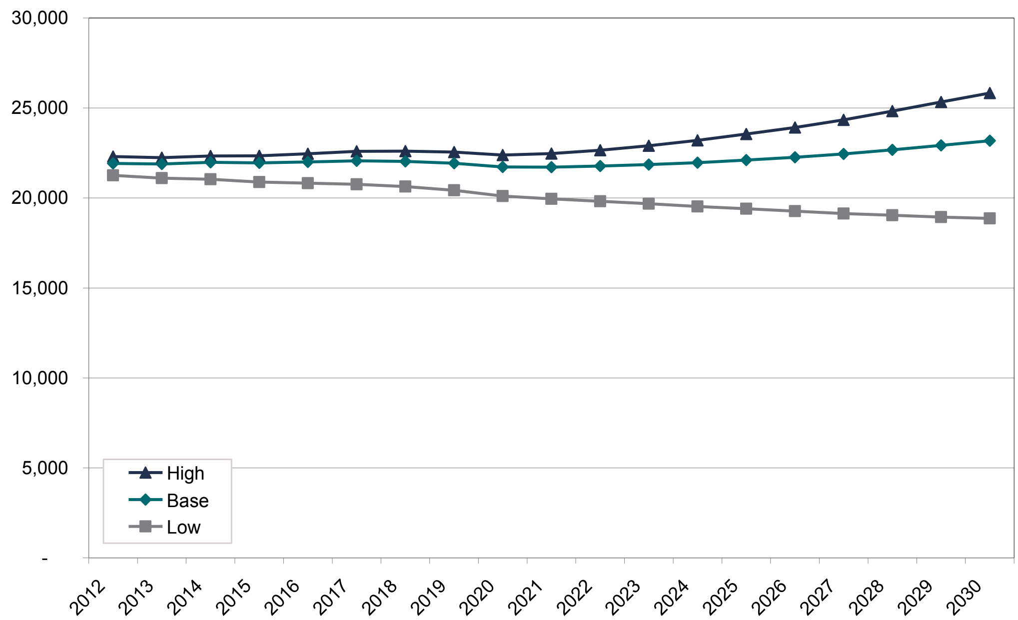
Figure 4-4
PSE Annual Gas Sales Load Forecast



Regional Load

To develop power prices, PSE must use a forecast of regional load. This IRP uses the Northwest Power and Conservation Council's regional forecast from the 6th Power Plan. Figure 4-5 below shows the regional forecast, as well as high and low variations.

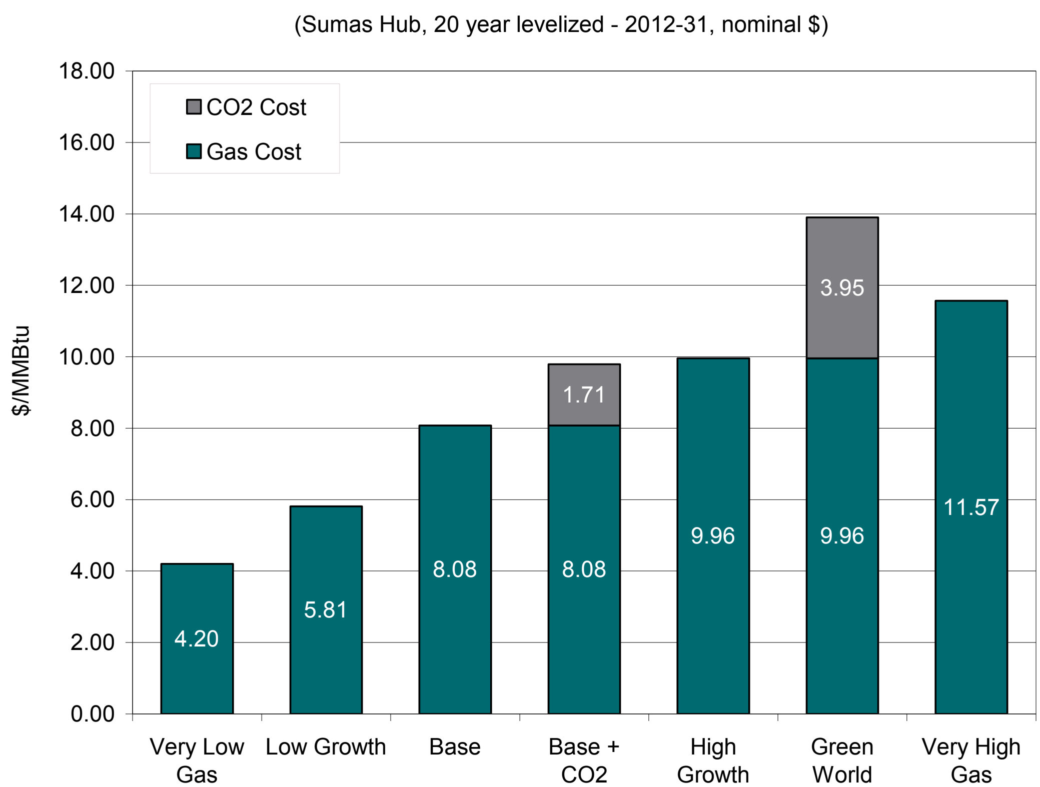
Figure 4-5
NPCC Regional Forecast



Gas Prices

Gas price assumptions for the Base Case are a combination of forward market prices and fundamental forecasts acquired from Wood Mackenzie, a well known macroeconomic and energy forecasting consultancy. Wood Mackenzie's gas market analysis includes regional, North American, and international factors, as well as Canadian markets and LNG imports. They also provide a high and low fundamental forecast from which PSE derived the very high and very low gas price forecasts used in two of the scenarios. The range of 20-year levelized gas prices and associated CO_2 costs used in the analysis is illustrated in Figure 4-6 below.

Figure 4-6
Levelized Gas Prices by Scenario



CO_2 Prices

To capture a range of uncertainty around CO_2 costs, PSE developed the following estimates as inputs.

Low CO_2 cost. **$0.32 per ton.** This estimate is based on existing Washington law RCW 80.70, which applies to new fossil fuel-fired thermal generation built within the state. For modeling purposes, a reasonable simplification is that compliance requires payment of $1.60 per ton of CO_2 to cover 20% of emissions, or $0.32 per ton. This $0.32 per ton is applied to CO_2 emissions for the entire WECC. Low CO_2 cost was modeled in all scenarios except Base + CO_2 and Green World.

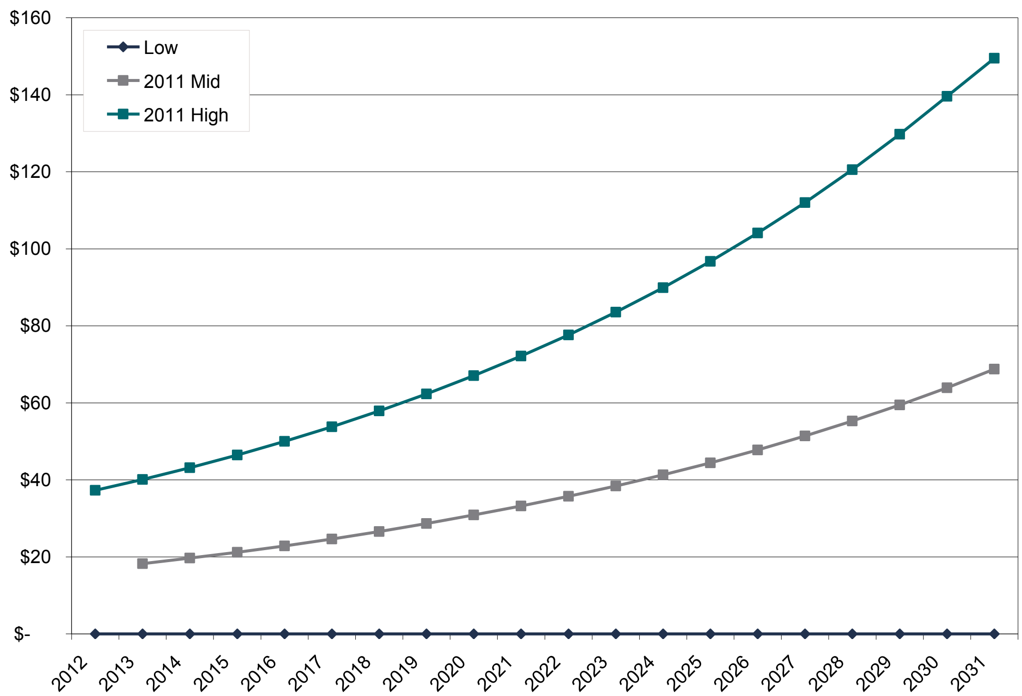
Moderate CO_2 cost. **$18 per ton in 2013 to $69 per ton in 2031.** This estimate was developed using the CO_2 prices modeled and published by the Environmental Protection Agency (EPA) in their analysis of the Kerry-Lieberman "American Power Act" cap-and-trade scheme. In this environment, CO_2 costs are reflected in gas prices and power prices. Moderate CO_2 cost was included in the Base + CO_2 scenario.

High CO_2 cost. **$37 per ton in 2013 to $149 per ton in 2031.** This estimate was developed using the CO_2 prices modeled and published by the EPA in their analysis of the Waxman-Markey "American Clean Energy and Security Act" cap-and-trade scheme. In this environment, CO_2 costs are reflected in gas prices and power prices. High CO_2 cost was included in the Green World scenario.

The range of CO_2 costs used in the IRP is illustrated below in Figure 4-7.

Figure 4-7

CO_2 Costs Used in the Analysis



2. *Scenarios and Sensitivities*

The scenarios and sensitivities developed for this IRP enable us to test portfolio costs and risks in a wide variety of possible future conditions and isolate the effects of an individual variable.

The full range of scenarios is described first, followed by a detailed description of the Base Case against which others are defined by reference. Descriptions of the sensitivities follow. Finally, a summary table of scenario and sensitivity assumptions appears at the end of this chapter.

Scenarios

PSE developed eight scenarios for this IRP. (Note that subjective probabilities are not assigned to the likelihood of any particular scenario occurring; in other words, it is important to remember that no scenario is judged to be more likely to occur than any other).

The Base Case scenario provides a starting set of assumptions; other scenarios are described by how they differ from it. A full description of the Base Case follows these summaries.

Low Growth models weaker long-term economic growth than the Base Case.

- Demand for energy is lower in the region and in PSE's service territory.
- Natural gas prices are lower due to lower energy demand.
- The cost of energy resources is lower because demand for power plants is depressed by lower economic growth.

A low growth rate has been applied for the WECC region, and the F2010 Low Growth demand forecast has been applied for PSE. Wood Mackenzie's long-run low forecast is applied to natural gas prices.

High Growth models more robust long-term economic growth than the reference case.

- Demand for energy is higher in the region and in PSE's service territory.
- Natural gas prices are higher as a result of increased demand.

The High growth rate has been applied in the WECC region, and the F2010 High Growth demand forecast for PSE. Wood Mackenzie's long-run high forecast is applied to gas prices.

Very Low Gas Price models the impact of very weak long-term gas prices.

- Gas prices remain constant in nominal terms throughout the study period.

Prices remain at 2012 levels ($4.20 per MMBTu) throughout the 20-year period, which translates to a levelized price approximately $1.61 per MMBTu lower than the low gas price forecast.

Very High Gas Price models a future in which gas prices are extremely high.

- Gas prices are substantially higher than other forecasts.

Prices were developed to be “symmetrical” with the very low price forecast. Thus, the levelized price is $1.61 per MMBtu higher than the high gas price forecast ($11.57 compared to $9.96 for the high price forecast).

Base + CO_2 This scenario tests portfolio decisions in a world with moderate CO_2 costs.

- Power and gas prices reflect higher CO_2 costs than the Base Case.

Moderate CO_2 prices based on the American Power Act are used.

Green World tests portfolio decisions in a world with high CO_2 costs.

- CO_2 emission costs are much higher.
- Gas prices are much higher.
- Demand for electricity is lower because of price and social preference.

CO2 emission costs rise from $37 per ton in 2012 to $149 per ton in 2031 – per the High CO2 cost estimates developed from on the American Clean Energy and Security Act. Gas prices move higher as developers of new generating resources switch to gas from coal to satisfy legal and environmental requirements, thereby increasing demand. The region’s use of gas-fired generation increases as more intermittent, renewable energy generation comes online (wind and solar). In Green World, the high gas price forecast applies. A low growth rate applies for the WECC region, and the F2010 Low Growth demand forecast applies for PSE.

Base Case Description

Modifications made in the other scenarios and sensitivities are deviations from the reference points established in the base case assumptions described below.

Resource costs. The estimated cost of generic resources is based on offers received in response to PSE's formal 2010 Requests for Proposals (RFPs), along with information obtained during 2010 as part of PSE's ongoing market activity. Offer prices received were not firm and were occasionally revised. The cost of each resource is escalated at varying rates over the 20-year time horizon. A 2.5% annual inflation rate was assumed in this analysis.

In general, cost assumptions represent the "all-in" cost to deliver a resource to customers, which includes plant, siting, and financing costs. PSE's activity in the resource acquisition market during the past five years informs the company's 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.

Heat rates. PSE applies the improvements in new plant heat rates as estimated by the Energy Information Administration (EIA) in the Annual Energy Outlook (AEO) Base Case scenario. New equipment heat rates are expected to improve slightly over time, as they have in the past.

Regional demand growth. PSE based regional demand growth on the forecast published in the 6th Power Plan by the Northwest Power and Conservation Council (NPCC).

PSE demand growth. PSE-specific demand growth incorporates assumptions about regional demand growth, but also includes many factors specific to the service territory. Development of PSE demand forecasts is discussed in detail in Appendix H. For this reference scenario, we assume the F2010 Base demand forecast.

Natural gas prices. Gas price forecasts are a combination of forward marks in the near term and Wood Mackenzie forecasts for the longer term.

- From 2010 through 2015, PSE used the three month average of forward marks for the period ending July 30, 2010. Forward marks reflect the price of gas being purchased at a given point in time for future delivery.
- Beyond 2015, PSE uses long-run, fundamentals-based gas price forecasts acquired from Wood Mackenzie. Wood Mackenzie's modeling assumptions and resulting forecasts are first compared with other forecasts for reasonableness.

CO_2 costs. This scenario assumes a CO_2 costs in current state law, this is effectively a charge of $0.32 per ton starting in 2012 which remains constant over the study period.

Production tax credits. The Production Tax Credit (PTC) is a federal subsidy identified in the American Recovery and Reinvestment Act of 2009 (ARRA) for production of renewable energy. Currently, the PTC amounts to approximately $22 (in 2010 dollars) per MWh for 10 years of production after a project is placed into service. The PTC is indexed for inflation and is currently scheduled to expire at the end of 2012 for wind resources and 2013 for other qualifying resources. This scenario assumes PTCs are extended at the current rate through 2012, and that no further PTCs are available for new resource development as of 2013.

Investment tax credits. The Investment Tax Credit (ITC) is another federal subsidy related to production of renewable energy. Currently, the ITC amounts to 30% of the eligible capital cost for renewable resources; it is scheduled to expire at the end of 2012. Through 2012, this scenario assumes ITCs remain at current levels.

Treasury Grant. The Treasury Grant (Grant) is a third federal subsidy available to qualifying renewable energy projects. This subsidy differs from the previous two in that it is a cash payment, versus a tax credit, from the federal government. Currently, the Grant amounts to 30% of the eligible capital cost for renewable resources; it is scheduled to expire at the end of 2012. Through 2012, this scenario assumes the Grant remains at current levels. It is important to note that this is the financial incentive modeled in the 2011 IRP analysis. This simplifies the modeling as the grant is not a function of taxable income.

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[1] and British Columbia. They affect PSE because they increase competition for development of such 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 first identifies the applicable load for each state in the model and the renewable benchmarks of each state's RPS (e.g. 3% in 2015, then 15% in 2020, etc.). For each state the company then applies those requirements to loads. No retirement of existing WECC renewable resources is assumed, which perhaps underestimates the number of new resources that need to be constructed. After existing and "proposed" renewable energy resources are accounted for, "new" renewable energy resources are matched to the load to meet the applicable RPS. Following an internal and external review for reasonableness, these resources are created in the AURORA database. Technologies included wind, solar, biomass, and geothermal. Creation of RPS resources was guided by estimates of potential production by states that appear in the "Renewable Energy Atlas of the West," which can be found at www.EnergyAtlas.org. These vary considerably depending on local conditions; Arizona, for example, has little wind potential but great solar potential. Appendix I, Electric Analysis, includes a table that identifies renewable portfolio standards by jurisdiction.

Build constraints. PSE added constraints on coal technologies to the AURORA model in order to reflect current political and regulatory trends. Specifically, we limited conventional coal to the central states to meet load growth. For certain other states, coal resources were reduced even further due to regulatory constraints or uncertainties. For instance, Washington state law RCW 80.80 (Greenhouse Gases Emissions-Baseload Electric Generation Performance Standard) clearly prohibits construction of new coal-fired generation within the state without carbon capture and sequestration. Absent constraints, the AURORA model would have identified coal as a least-cost resource and built a large number of coal units in the WECC – more than seems reasonable given present-day trends and attitudes.

[1] *At* http://www.eere.energy.gov/states/maps/renewable_portfolio_states.cfm#chart*, the U.S. Department of Energy website includes a summary of state RPS requirements with links to more detailed information.*

Sensitivities

Sensitivities change only one variable in the Base Case, so that we can isolate the effect that variable has on the portfolio. One analyzed how PSE would design a portfolio if the three regional coal plants were unavailable. Three were designed to investigate how peaking plants compared with CCCT plants with regard to cost and risk. Four tested how tax incentive extensions would affect portfolio decisions. One compared the cost-effectiveness of a 10-year ramp rate for DSR with the longer ramp rate in the NPCC's 6th Power Plan. Finally, one asked how electric vehicle adoption might affect decisions.

No Northwest Coal

analyzes how PSE would design a portfolio if policy decisions forced the shutdown of the three regional coal plants, Centralia in Washington, Boardman in Oregon, and Colstrip in Montana. This is not an investigation of what policy changes would be required, just a focus on how such a condition would impact the least-cost mix of resources. PSE's analysis does not reflect important details, such as impacts on the regional transmission system. This is a first look – not the last look – that PSE will be taking at this issue.

Comparing peakers and CCCTs.

This analysis recommended adding increasing numbers of natural gas-fired single-cycle peaking engines over the next 20 years, instead of combined-cycle combustion engines (CCCTs). This was a somewhat surprising result, as CCCTs had often been preferred in the past. Peakers operate for short periods of time, generally during load peaking events when demand is greatest, and they most often use fuel purchased on the short-term market. Although CCCTs have higher capital costs, they operate more efficiently and for longer periods of time. CCCTs usually depend on mid- to long-term fuel supply commitments. To better understand the benefits and costs are associated with selecting peakers versus CCCTs, PSE developed three sensitivities:

- No Peakers
- Thermal Mix
- Fixed (Firm) Gas Transport Cost for Peakers

"No Peakers" forces the optimization model to select CCCTs to meet need and does not allow it to select any peakers.

"Thermal Mix" forces the model to select a mix of CCCTs and peakers. It also places a limit of 40% on the amount of annual cost that can be met with market purchases.

"Fixed (Firm) Gas Transport Cost for Peakers" adds higher-priced, firm pipeline capacity costs to the peakers. This sensitivity also assumes that peakers are unable to use oil as a back-up fuel when natural gas is unavailable; the Base Case assumes that they can.

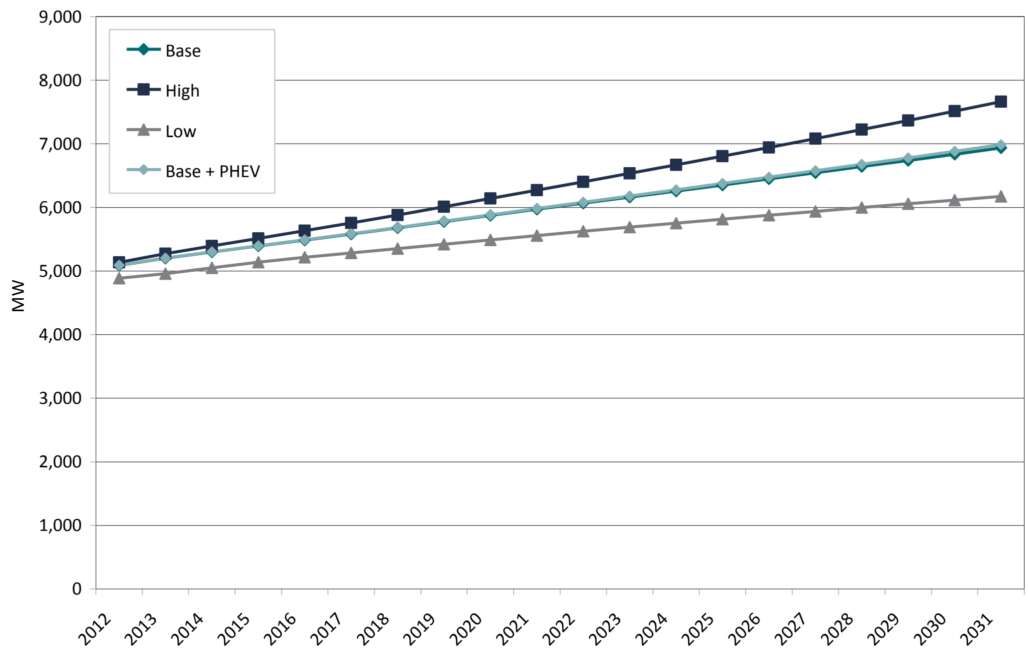
Extension of renewable resource financial incentives. As part of the 2009 IRP and as part of the RFP process, PSE has consistently found that the lowest cost method for meeting the company's obligation under I-937 is to take advantage of expiring financial incentives and develop renewable resources ahead of the target deadlines in the law. However, we wanted to test how possible extensions to the financial incentives would affect portfolio decisions. To do this we analyzed the following sensitivities.

- Financial Incentives Credit extended to 2013
- Financial Incentives Credit extended to 2016
- Financial Incentives Credit extended to 2020
- Financial Incentives Credit extended to 2031

DSR Ramp Rates. To investigate ramp rates, PSE had Cadmus develop two detailed alternatives. One was based on a detailed, measure-by-measure analysis of ramp rates used in the NPCC's 6th Power Plan, which generally tended to spread some discretionary measures over 12-16 years. The other modeled a more aggressive pace of acquisition, using a 10-year ramp rate for acquiring discretionary measures. .

Plug-in vehicles. As in the last IRP, PSE developed a sensitivity to test how adding electric plug-in vehicle load on a mass scale would affect portfolio decisions. To the Base Case scenario, we added a vehicle load forecast based on the 2010 AEO study. The figure below compares the Base Case forecast with the Base Case forecast plus vehicle loads. While PSE considered this sensitivity important enough to test, the chart below clearly demonstrates that the electric vehicle load is well with in the tolerances of a High load forecast and that these results will be replicated in the other scenarios. Even in 2031 Peak load due to vehicles is only expected to be about 51 MW.

Figure 4-8
Comparison of Peak Forecast with and with out Vehicle load



3. Input Matrices

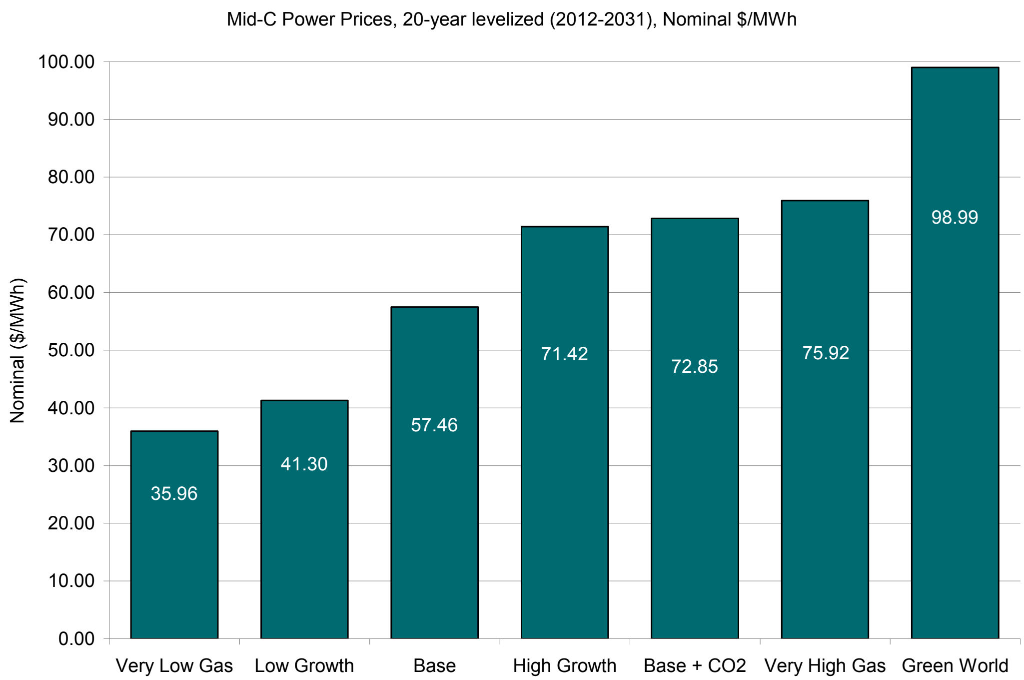
Power Prices

One of the primary reasons for conducting scenario analysis is to develop the power prices used in the optimization model.

From a modeling standpoint, a key difference between scenarios and sensitivities is how they are used to develop power prices. For the Base, Base + CO2, Green World, and No Northwest Coal scenarios, PSE used a stochastic method to develop power price curves. For each of these scenarios, we ran Aurora 250 times using a range of inputs to arrive at expected prices. The High Growth, Low Growth, Very High, and Very Low Gas Price scenarios, are effectively subsets of the Base scenario. Their power prices were calculated by focusing on specific ranges of the distribution used in the Base; for example, the High Growth expected power price is the mean of the 25 base draws with the highest prices and loads. The individual sensitivities do not require Aurora runs since they rely on the assumption in the Base Case; they are simply manipulations of the constraints and assumptions in the optimization model. Please see Appendix I for a discussion of how power prices and the stochastic model were used.

The following table shows the power prices used in each of the core scenarios.

Figure 4-9
Input Power Prices by Scenario



Resource Assumptions

In addition to the key inputs described already, PSE also uses the following resource assumptions in its analysis. Figure 4-10 shows the electric resource assumptions. In addition to these supply-side resources, PSE uses the demand-side resource assumptions indentified in Appendix K.

Figure 4-10
Electric Supply Side Resources

2010 $	Units	CCCT	Peaker	Wind	Biomass	Transmission
Winter Capacity	MW	334	213	100	25	500
Capital Cost	$/KW	$1,540	$1,010	$2,151	$4,330	$436
O&M Fixed	$/KW-yr	$22.00	$15.90	$29.90	$190.00	$15.25
O&M Variable	$/MWh	$0.44	$0.67	$3.50	$3.40	
Force Outage Rate	%	3%	3%		6.3%	
Wind Capacity Factor	%			30%		
Capacity Credit	%	93%	93%	1.8%	93%	100%
Heat Rate – GT	Btu/KWh	7,085	10,440		13,420	
Heat Rate – DF	Btu/KWh	9,350				
Fixed Gas Transport	$/KW-yr	$31.80	$0.00			
Variable Gas Transport	$/MWh	$2.00	$5.20			
Fixed Transmission	$/KW-yr	$0.00	$0.00	$34.30	$18.01	
Variable Transmission	$/MWh	$0.00	$0.00	$3.30	$1.71	
Water Consumption	Gallons/MWh	26				
Emissions:						
SO_2	lbs/MMBtu	0.010	0.010			
NO_x	lbs/MMBtu	0.007	0.009			
CO_2	lbs/MMBtu	115.9	115.9			
Location		PSE Control	PSE Control	WA/OR	PSE Control	Mid-C to PSE
First Year Available		2014	2014	2014	2014	2017

4. Summary Table of Scenario and Sensitivity Assumptions

Puget Sound Energy 20011 IRP (2012-2031)

	Reference Assumptions	Planning Scenarios: Base Case	Base + CO2	Low Growth	High Growth	Very High Gas	Very Low Gas	Green World	No Coal	Transport
Theme		Best estimate of current resource costs and characteristics, fuel prices, state and federal laws	Best estimate of current costs with moderate environmental policies	Lower regional and PSE demand load growth based on lower long-term economic growth.	Higher regional and PSE demand load growth based on related long-term economic growth.	Impact of very high gas prices	Impact of Very Low Gas Prices	Support for stronger environmental legislation at the federal level, with continuation of state level RPS	Impact of legislation shutting down regional coal plants	Impact of plug-in electric hybrid vehicles (PHEV) loads
WECC Demand (AURORA)	EPIS Averages: CA: 1.16% SW: 2.5% PNW: 0.4% RM: 2.4%	Reference	Reference	Low Growth	High Growth	Reference	Reference	Low Growth	Reference	Reference
PSE Demand	Base: 2.%	Base	Base	Low	High	Base	Base	Low	Base	Base + Transport load
Gas Price	Forward marks for 2012-2015, and WoodMac long-run fundamental forecast	Reference	Reference	Wood Mac long-run low forecast	Wood Mac long-run high forecast	Very High Gas price forecasts $11.57/MMBtu	Very low Gas price forecast $4.2/MMBtu	Wood Mac long-run high forecast	Reference	Reference
Coal Price	Global Insight	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference
Generic Resource Cost ($/KW) Escalation	PSE market based estimates	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference
Emissions (Nominal $/Ton) CO2		RCW 80.70 - Carbon Mitigation Plan	EPA APA Analysis	RCW 80.70 - Carbon Mitigation Plan	RCW 80.70 - Carbon Mitigation Plan	RCW 80.70 - Carbon Mitigation Plan	RCW 80.70 - Carbon Mitigation Plan	High	RCW 80.70 - Carbon Mitigation Plan	RCW 80.70 - Carbon Mitigation Plan

Puget Sound Energy 20011 IRP (2012-2031)

			Planning Scenarios								
		Reference Assumptions	Base Case	Base + CO2	Low Growth	High Growth	Very High Gas	Very Low Gas	Green World	No Coal	Transport
			250 MW or greater	2013: $18	250 MW or greater	250 MW or greater	250 MW or greater	250 MW or greater	2012: $55	250 MW or greater	250 MW or greater
			$1.60/ton for 20% of total CO2	2020: $31 2031: $69	$1.60/ton for 20% of total CO2	$1.60/ton for 20% of total CO2	$1.60/ton for 20% of total CO2	$1.60/ton for 20% of total CO2	2020: $129 2029: $158	$1.60/ton for 20% of total CO2	$1.60/ton for 20% of total CO2
	SO2	Wood Mackenzie 2012: $283 2020: $1261 2031: $3981	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference
	Nox	Wood Mackenzie 2012: $2221 2020: $1692 2031: $2478	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference
Financial Incentive: Treasury Grant		30% through 2012 For all eligible technologies	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference
RPS		Meet Current State RPS through 2031	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference
Build Constraints		Limited amount of coal and IGCC builds to meet load growth only. No new nuclear builds.	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference
Renewable Energy Credit ($/MWh)		2010: $8.00 Increase at same rate as wind capital cost: 2012-2031	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference	Reference