Electric Analysis

Contents

More than a million customers in Washington state depend on PSE for safe, reliable, and affordable electric services. The IRP analysis described in this chapter enables PSE to develop valuable foresight about how resource decisions may unfold over the next 20 years in conditions that depict a wide range of possible futures.

1. Resource Need

For PSE, resource need has three dimensions. The first is physical: Can we provide reliable service to our customers at peak demand hours and at all hours? The second is economic: Can we meet the needs of customers across all hours cost effectively? The third is policy-driven: Are there enough renewable resources in the portfolio to fulfill the state's renewable portfolio standard requirements? Each dimension is described below.

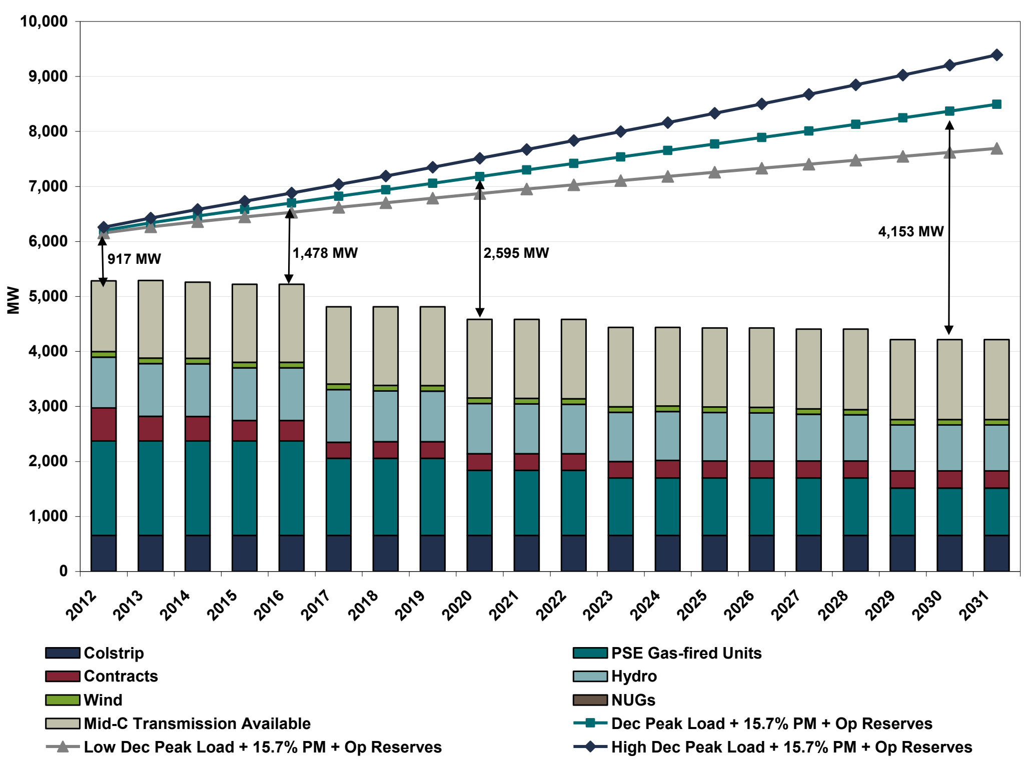
Physical Reliability Need

Physical reliability need refers to the resources required to ensure reliable operation of the system. This operational requirement has three components: customer demand, planning margins, and operational reserves. The word "load" – as in "PSE must meet load obligations" – specifically refers to the total of generated demand plus planning margins and operating reserve obligations. The reserves must be maintained in order to minimize interruption of service due to extreme weather or the unlikely event of equipment failure or transmission interruption.

Physical characteristics of the electric grid are very complex, so for planning purposes PSE simplifies physical resource need into a peak-hour capacity metric through a loss of load probability analysis. That is, if PSE has sufficient resources modeled in the IRP to meet its normal peak hour demand plus a 15.7% planning margin and the operating reserves required to dispatch those resources, the company will be able to maintain an adequate level of reliability across all hours. We can simplify physical resource need in this way because PSE is much less hydro-dependant than other utilities in the region, and because resources in the IRP are assumed to be available year-round. If we were more hydro-dependent, issues like the sustained peaking capability of hydro and annual energy constraints could be important; likewise, if seasonal resources/contracts were contemplated, supplemental capacity metrics may be appropriate to ensure adequate reliability in all seasons

Figure 5-1 shows physical reliability need for the three demand scenarios modeled in this IRP. The components of this “peak need” are described more fully following the chart.

Figure 5-1
Electric Peak Need (Physical Reliability Need)
Comparison of projected peak hour need with existing resources



Demand. PSE uses national, regional, and local economic and population data to develop a range of demand forecasts for the 20-year IRP planning horizon.[1] These forecasts are incorporated into the scenarios modeled in the electric analysis. (See Chapter 4 and Appendix H for a complete description of the forecasting methodologies and inputs used in demand forecasting.)

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

Planning margin. PSE incorporates a 15.7% planning margin in its description of resource need in order to achieve a 5% loss of load probability (LOLP). The 5% LOLP is an industry standard resource adequacy metric used to evaluate the ability of a utility to serve its load, and one that is used by the Pacific Northwest Resource Adequacy Forum.[2] The process has two steps. First, we perform an analysis on the likelihood that load will exceed resources on an hourly basis over the course of a full year. Included are uncertainties around temperature impacts, hydro conditions, wind, and forced outage rates (both their likelihood and duration). This analysis allows us to identify the amount of resources needed to achieve a 5% LOLP. In step two, the 5% LOLP is translated into the planning margin of 15.7%. The calculations used to determine the planning margin are described in Appendix I, Electric Analysis.

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

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

[2] *See* http://www.nwcouncil.org/library/2008/2008-07.htm

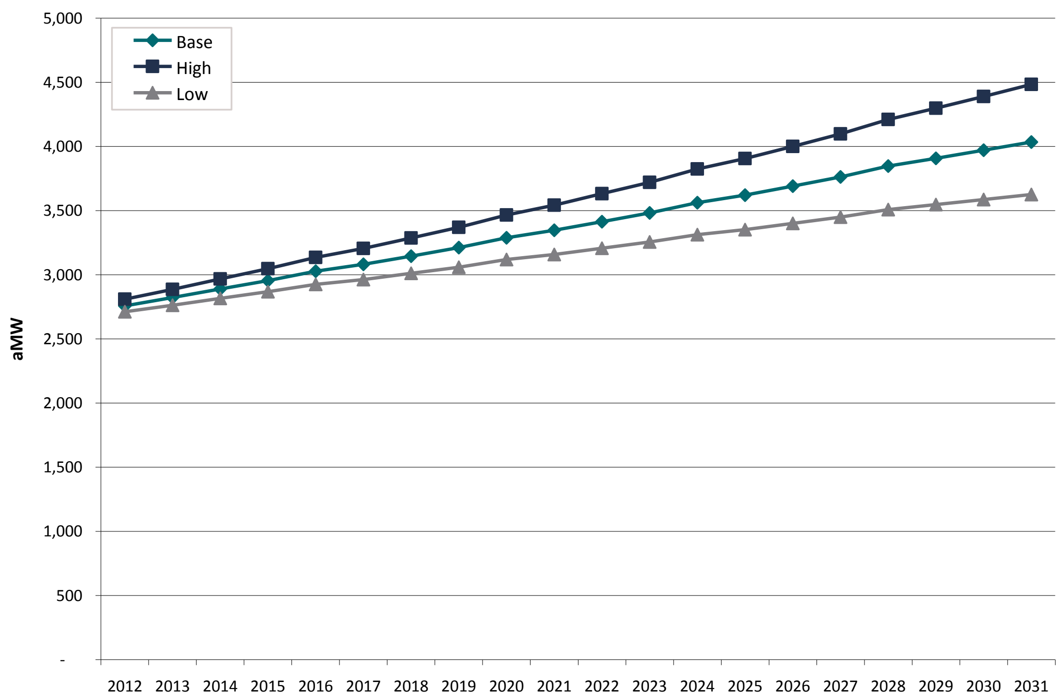
Contingency reserves. Contingency reserves are intended to bolster short-term reliability in the event of forced outages. Under the Northwest Power Pool's contingency reserve sharing agreement, generators must reserve an additional 5% of hydro or wind resources and 7% of thermal resources, when such units are dispatched to meet firm sales obligations. This capacity must be available within 10 minutes, and 50% of it must be spinning. For example, if a 100 MW thermal generator is dispatched to meet firm sales, the utility must have an additional 7 MW of resources available to meet the contingency reserve sharing obligation. Each member of the power pool maintains such reserves. If any member's generator experiences a forced outage, the contingency reserve sharing agreement is activated. Reserves from other members come online to make up for the lost generation. This is a very short-term arrangement. Contingency reserve sharing covers such forced outages for up to one hour. After that, the utility must balance its load (firm sales plus operating reserves) by either purchasing resources on the market or, if necessary, shedding load.

Regulating reserves. Utilities must also have sufficient reserves available to maintain a constant frequency on the system; in other words, they must be able to ramp up and down as loads and resources fluctuate instantaneously. For PSE, this amount is 35 MW. Regulating reserves do not provide the same kind of short-term, forced-outage reliability benefits as contingency reserves; they include frequency support, load forecast error, and actual load and generation changes.

Energy Need

Meeting customers' "energy need" is more of a financial concept that involves minimizing cost rather than a physical planning constraint for PSE. Portfolios are required to cover the amount of energy needed to meet physical loads, but our models also examine how to do this most economically. We do not have to constrain (or force) the model to dispatch resources that are not economical; if it is cheaper to buy power than dispatch a generator, the model will choose to buy. Similarly, if a zero (or negative) marginal cost resource like wind is available, the model will displace higher-cost market purchases and use the wind to meet the "energy need." Figure 5-2, below, illustrates the company's energy need into the future, based on the energy load forecasts presented in Chapter 4.

Figure 5-2
Annual Energy Need



Renewable Resources

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

Washington State RPS Targets

- 3% of supply-side resources by 2012
- 9% of supply-side resources by 2016
- 15% of supply-side resources by 2020

For all practical purposes, wind remains the main resource available to fulfill RPS requirements for PSE. Existing hydroelectric resources may not be counted towards RPS goals except under certain circumstances, and other renewable technologies are not yet capable of producing power on a large enough scale to make substantial contributions to meeting the targets.

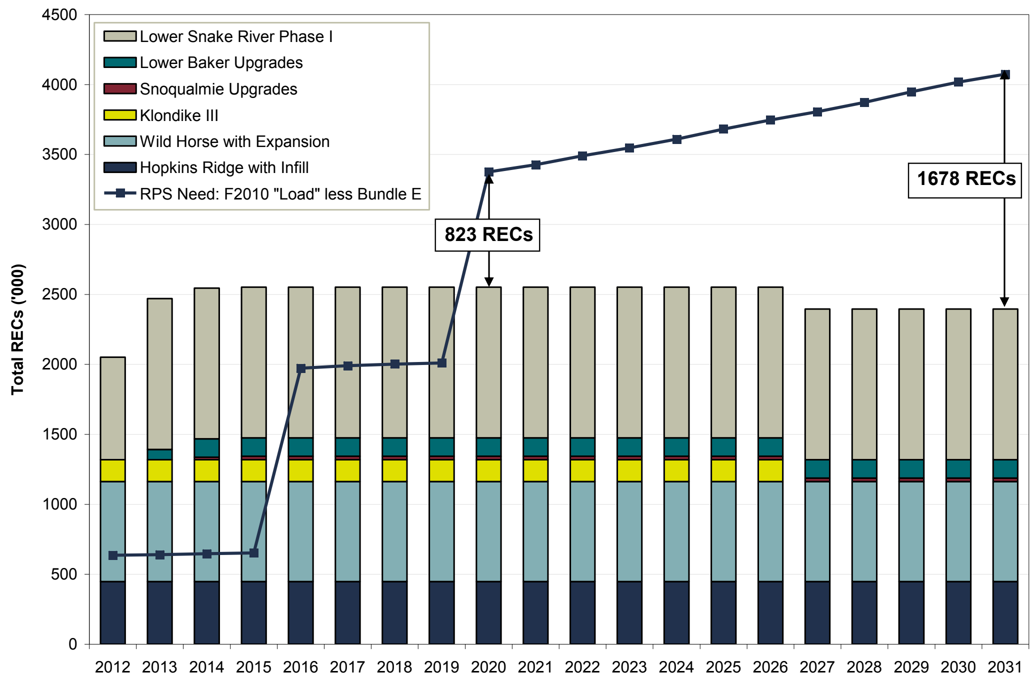
Renewable resources influence supply-side resource decisions. Adding wind to the portfolio increases the need for stand-by back-up generation that can be turned on and off or adjusted up or down quickly. The amount of electricity supplied to the system by wind drops off when the wind stops, but customer need does not. As the amount of wind in the portfolio increases, so does the need for reliable back-up generation. Appendix G discusses PSE wind integration challenges in more detail.

Demand-side achievements affect renewable amounts.

Washington's renewable portfolio standard calculates the required amount of renewable resources as a percentage of the supply-side resources used to meet load; therefore, if the amount of supply-side resources decreases, so does the amount of renewables we need to plan for. Achieving demand-side resources (DSR) has precisely this effect: DSR decreases the amount of supply-side resources needed, and therefore the amount of renewables needed.

Figure 5-3 illustrates the need for renewable energy after accounting for the savings from demand-side resources that were found cost effective for the 2011 IRP.

Figure 5-3
RPS Need Based on Achievement of All Cost-effective DSR



2. Resource Alternatives

Resources are divided into two categories, depending on where they originate. Supply-side resources originate on the company side of the meter, while demand-side resources (DSR) generally originate on the customer side of the meter.

With supply-side resources, power is generated by means of water, natural gas, coal, wind, etc., and then transmitted (or "supplied") to customers.

Demand-side resources include energy efficiency measures, demand-response, and other techniques that reduce the amount of power customers need (or "demand") in order to operate their homes and businesses.

In order to test if current conditions make it economical, this IRP also models transmission combined with short-term market power purchases as a resource.

Power Purchase Agreements (PPAs)
PPAs are contracts of varying lengths for purchasing electricity in the market. The IRP did not evaluate PPAs as a resource alternative because costs and commitment terms are market-driven and known only at the time of the offer, so they are not possible to model over a 20-year period. However, when actual acquisitions are made and terms and conditions *can* be known, they will certainly be considered and evaluated as alternatives.

Thermal resources

Coal. The coal resources that are part of PSE's existing portfolio provide a low-cost, stable fuel source and resource diversity. However, additional coal resources were not modeled because of the emissions restrictions set forth in Washington state law RCW 80.80. The IRP does, however, consider one scenario in which our existing coal resource – the Colstrip generating plant in Montana – is no longer available to us.

Natural gas. Additional long-term coal-fired generation is not a resource alternative. RCW 80.80 precludes utilities in Washington from entering into new long-term agreements for coal. New large-scale hydro projects would not practical to develop today. Therefore, natural gas generation is extensively modeled in this IRP analysis due to the following characteristics.

- Proximity. Gas-fired generators can often be located within or adjacent to PSE's service area, thereby avoiding costly transmission investments required for long-distance resources like coal or wind.
- Timeliness. Gas-fired resources are dispatchable, meaning they can be turned on when needed to meet loads, unlike "intermittent" resources that generate power sporadically such as wind and run-of-the-river hydropower.
- Versatility. Gas-fired generators have varying degrees of ability to ramp up and down quickly in response to variations in load and/or wind generation.
- Environmental burden. Natural gas resources produce significantly lower emissions than coal resources (approximately half the CO_2).

Three types of gas-fired generators are modeled in this analysis, because each brings particular strengths into the overall portfolio.

Combined-cycle combustion turbines (cccts). In CCCTs, the heat that a simple-cycle combustion turbine produces when it generates power is captured and used to create additional energy. This makes it a more efficient means of generating power than simple-cycle turbines. CCCT plants currently entering service can convert about 50% of the chemical energy of natural gas into electricity. Because of their high thermal efficiency and reliability, relatively low initial cost, and low emissions, CCCTs have been the resource of choice for power generation for well over a decade.

Simple-cycle combustion turbines (peaker). Simple-cycle combustion turbines are better at serving peak need than CCCTs because they can be brought online more quickly. They also have lower capital costs. However, simple-cycles are less efficient and have higher heat rates, which make them more expensive to run.

> **"Peaker"** is a term used to describe generators that can ramp up and down quickly in order to meet spikes in need.

Reciprocating engines (peaker). Like simple-cycle combustion turbines, they can be brought online quickly to serve peak loads. Unlike gas turbines, reciprocating engines demonstrate consistent heat rate and output during all temperature conditions. Generally these units are small and are constructed in power blocks with multiple units. Reciprocating engines are more efficient than simple-cycle combustion turbines, but have a higher capital cost. The small size of the units allows a better match with peak loads thus increasing operating flexibility relative to the simple-cycle combustion turbine.

Thermal resources not modeled: nuclear. Development and construction costs for nuclear power plants are so much higher than the next highest baseload option as to be prohibitive to all but a handful of the largest capitalized utilities. In addition, permitting, public perception, and waste disposal pose substantial risks.

Transmission

In this IRP, PSE modeled additional transmission capacity plus market power purchases. We wanted to test whether adding additional transmission and purchasing market power at times of peak need would result in lower portfolio costs than adding other resources. We modeled the addition of 500 MW of transmission capacity. PSE currently relies on approximately 1,200 MW of transmission to acquire electric energy and capacity from the market; during the planning period, this increases to over 1,400 MW.

Renewable Resources

Hydroelectric. Hydroelectric resources are valuable because of their ability to follow load, and because they cost less relative to other resources. Although water is a renewable resource, existing hydroelectric may not be counted toward fulfilling Washington’s RPS requirement unless it is an efficiency upgrade to an existing project; this IRP does reflect upgrades in Snoqualmie and Lower Baker that qualify under RPS rules. For new hydroelectric to qualify, it must be a low-impact, run-of-the-river project.

Wind. Wind energy is the primary renewable resource that qualifies to meet RPS requirements in our region due to wind’s technical maturity, reasonable lifecycle cost, acceptance in various regulatory jurisdictions, and large “utility” scale compared to other technologies. However, it also poses challenges. Because of its variability, wind’s daily and hourly power generation patterns don’t necessarily correlate with customer demand; therefore, more flexible thermal and hydroelectric resources must be standing by to fill the gaps. This variability also makes it challenging to integrate into transmission systems.

Finally, because wind projects are often located in remote areas, they frequently require long-haul transmission on a system that is already crowded and strained.

Biomass. Biomass fuels, fuels sources, and generation technologies vary widely. Fuels range from wood and agricultural field residues, to municipal solid waste and animal manure, to landfill and wastewater treatment plant gas. Most existing biomass in the Northwest is tied to steam hosts, typically in the timber, pulp, and paper industries, and use direct combustion or gasification technology. PSE has received several biomass proposals through its RFP process.

Renewable technologies not modeled for this IRP include solar, geothermal, tidal, long-haul wind, and unbundled REC contracts. At this time, these technologies are not capable of producing power on a scale and at a cost that would make sense for PSE customers. We completed the Wild Horse Solar Facility in 2008, a demonstration project that uses photovoltaic technology to produce electricity, and we continue to collect data from the facility to evaluate equipment performance and fit with our resource portfolio. We continue to monitor technology developments in geothermal as well, and entertain proposals for geothermal power projects. PSE has also supported two Northwest ocean energy studies, one tidal assessment and one wave demonstration project. Long-haul wind outside the Pacific Northwest was not modeled in this IRP. Analysis in the 2009 IRP demonstrated that the additional transmission costs for such resources rendered them uncompetitive with wind resources in Pacific Northwest; this finding was reinforced by analysis on actual resource/contract bids in the 2010 RFP process. Finally, unbundled REC contracts were not analyzed. Unbundled RECs are a form of a contract similar to PPAs. Just like other alternatives, if the acquisition process found unbundled REC contracts to be more cost effective and lower risk than self-building resources to comply with RCW 19.285, the company would pursue those alternatives. Our experience in the 2010 RFP process found very limited quantities of unbundled RECs available, but the Company will continue to consider such offers in the future acquisition processes.

Demand-side Resources

Energy efficiency measures. This label is used for a wide variety of measures that result in a smaller amount of energy doing the same work as a larger amount of energy. Among them are codes and standards that make new construction more energy efficient, retrofitting programs, appliance upgrades, and HVAC and lighting changes.

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

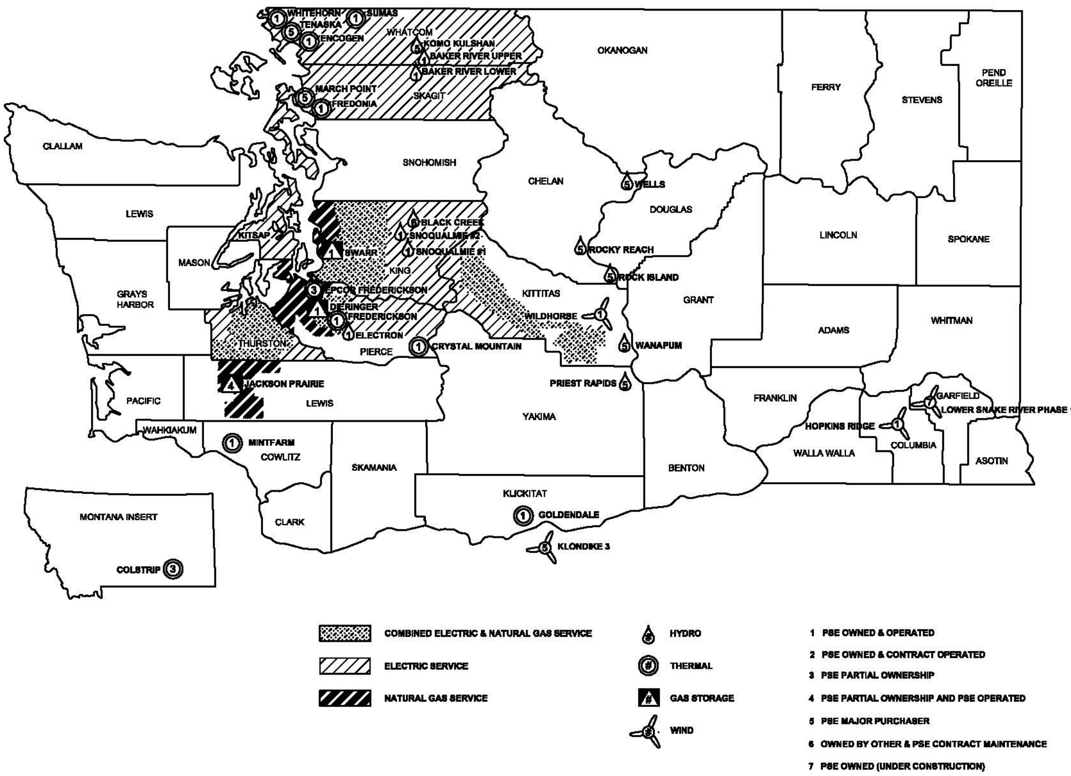
Distributed generation. Distributed generation refers to small-scale electricity generators located close to the source of the customer's load.

Distribution efficiency. This involves voltage reduction and phase balancing. Voltage reduction is the practice of reducing the voltage on distribution circuits to reduce energy consumption, as many appliances and motors can perform properly while consuming less energy. Phase balancing eliminates total current flow losses that can reduce energy loss.

Summary of Existing Resources

Existing supply-side resources. To build the portfolios for the IRP analysis, we begin with a snapshot of PSE's existing resources. The map and tables that follow summarize PSE's existing resources and their expiration dates as of January 2011. The location of PSE's existing supply-side generation resources is pictured in Figure 5-4.

Figure 5-4
Location of Supply-side Resources



PSE's supply-side resources are diversified geographically and by fuel type. Most of the company's gas-fueled resources are in western Washington. The major hydroelectric contracted resources are in central Washington, outside PSE's service area. Wind facilities are located in central and eastern Washington. Coal-fired generation is located in eastern Montana.

Figure 5-5

Hydroelectric Resources

PLANT	OWNER	PSE SHARE %	NAMEPLATE CAPACITY (MW)[1]	EXPIRATION DATE
Upper Baker River	PSE	100	105	Not within study
Lower Baker River[2]	PSE	100	85	Not within study
Snoqualmie Falls[3]	PSE	100	49	Not within study
Electron	PSE	100	16	12/31/26
Total PSE-Owned			**255**	
Wells	Douglas Co. PUD	29.89	231	3/31/18
Rocky Reach	Chelan Co. PUD	25.0[4]	320	10/31/31
Rock Island I & II	Chelan Co. PUD	25.0[5]	156	10/31/31
Wanapum	Grant Co. PUD	.64[6]	6	04/04/52
Priest Rapids	Grant Co. PUD	.64[6]	6	04/04/52
Mid-Columbia Total			**720**[7]	
Total Hydro			**975**	

Notes

1) *Nameplate capacity reflects PSE share only.*
2) *Lower Baker Unit 4 will be completed in March 2013, adding 30 MW of nameplate capacity to this project.*
3) *Snoqualmie Falls is offline until March 2013 for repairs. The new capacity will be 49 MW.*
4) *Rocky Reach share is 38.9% through October 2011 and 25% thereafter.*
5) *Rock Island I & II share is 50% through June 7, 2012, and then 25% beginning July 1, 2012.*
6) *Based on Grant Co. PUD current load forecast for 2010; our share will be reduced to this level in 2012.*
7) *As indicated in the above notes, several of the expiring Mid-C contracts have been renegotiated. Figure 5-5 reflects PSE's share, capacity and the expiration dates that will take effect between publication of this IRP and mid-2012 as a result of the new contracts. Individual resource and Mid-Columbia totals are rounded to the nearest megawatt.*

Figure 5-6

Coal, CCCT, and Wind Resources

POWER TYPE	UNITS	PSE OWNERSHIP	NAMEPLATE CAPACITY (MW)[1]	ASSUMED RETIREMENT DATE
Coal	Colstrip 1 & 2	50%	330	Not within study period
Coal	Colstrip 3 & 4	25%	386	Not within study period
Total Coal			**716**	
CCCT	Encogen	100%	159	Dec 2028
CCCT	Frederickson 1[2]	49.85%	129	Not within study period
CCCT	Goldendale	100%	261	Not within study period
CCCT	Mint Farm	100%	305	Not within study period
CCCT	Sumas	100%	121	Jul 2023
Total CCCT			**975**	
Wind	Hopkins Ridge	100%	157	Not within study period
Wind	Lower Snake River, Phase 1[3]	100%	343	Not within study period
Wind	Wild Horse[4]	100%	273	Not within study period
Wind	Klondike 3 PPA	0%	50	Nov 2026
Total Wind			**823**	

Notes

1) *Nameplate capacity reflects PSE share only. Ratings are at the following ISO conditions: ambient temperature 59˚ F, altitude 0 feet, atmospheric pressure 14.7 psia, relative humidity 60%, fueled by natural gas, 1000 BTU/SCF (HHV), and 900 BTU/SCF (LHV).*
2) *Frederickson 1 CCCT unit is co-owned with Capital Power Corporation - USA.*
3) *PSE began construction of Lower Snake River Phase I in spring 2010. Located in Garfield County, Wash., the 343 MW wind project is scheduled to be completed in the first or second quarter of 2012.*
4) *Wild Horse includes the original 229 MW wind project and a 44 MW expansion.*

Figure 5-7

Simple-cycle Combustion Turbines

NAME	PSE OWNERSHIP	NAMEPLATE CAPACITY (MW)[1]	ASSUMED RETIREMENT DATE
Fredonia 1 & 2	100%	208	Dec 2019
Fredonia 3 & 4	100%	108	Not within study period
Whitehorn 2 & 3	100%	149	Dec 2016
Frederickson 1 & 2	100%	149	Dec 2016
Total		**614**	

[1] Nameplate capacity reflects PSE share only. Ratings are at the following ISO conditions: ambient temperature 59˚ F, altitude 0 feet, atmospheric pressure 14.7 psia, relative humidity 60%, fueled by natural gas, 1000 BTU/SCF (HHV) and 900 BTU/SCF (LHV).

Long-term contracts consist of agreements with independent producers and other utilities to supply electricity to PSE. Fuel sources include hydro, gas, waste products, and system deliveries without a designated supply resource. These contracts are summarized below. Short-term contracts negotiated by PSE's energy trading group are not included in this listing.

Figure 5-8
Long-term Contracts for Electric Power Generation

TYPE	NAME	POWER TYPE	CONTRACT EXPIRATION	NAMEPLATE CAPACITY (MW)[1]
NUG	Tenaska	Thermal	12/31/2011	245
NUG	March Point I	Thermal	12/31/2011	80
NUG	March Point II	Thermal	12/31/2011	62
Total NUG				**387**
Other Contracts	BPA- WNP-3 Exchange	System	6/30/2017	82
Other Contracts	Powerex/Pt. Roberts	System	9/30/2014	8
Other Contracts	BPA Baker Replacement	Hydro	10/1/2029	7
Other Contracts	PG&E Seasonal Exchange-PSE	Thermal	Ongoing	300
Other Contracts	Canadian EA	Hydro	09/15/2024	-58
Other Contracts	Powerex	System	02/29/2012	150
Other Contracts	Shell Energy	System	03/31/2013	50
Other Contracts	RBS Sempra Commodities	System	03/31/2013	75
Other Contracts	Barclays Bank	System	02/28/2015	75
Total Other				**689**
Independent Producers	Twin Falls	Hydro	3/8/2025	20
Independent Producers	Koma Kulshan	Hydro	3/31/2037	14

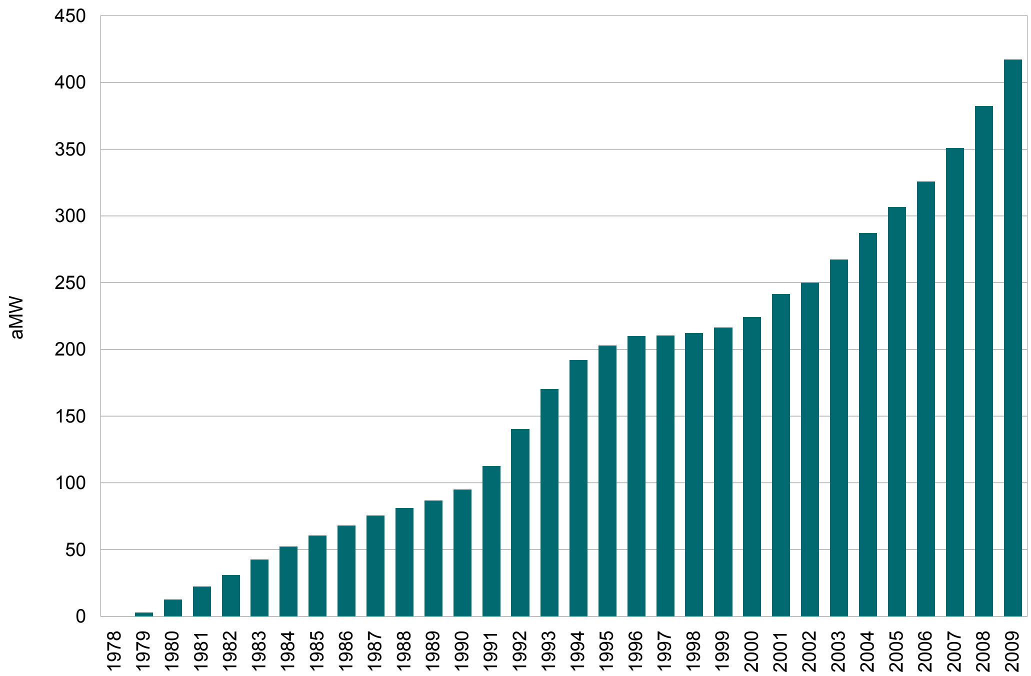
TYPE	NAME	POWER TYPE	CONTRACT EXPIRATION	NAMEPLATE CAPACITY (MW)[1]
Independent Producers	North Wasco	Hydro	12/31/2012	5
Independent Producers	Nooksack Hydro	Hydro-QF	01/01/2014	2.5
Independent Producers	Weeks Falls	Hydro	12/1/2022	4.6
Independent Producers	Hutchison Creek	Hydro-QF	9/30/2016	1
Independent Producers	Cascade Clean Energy-Sygitowicz	Hydro-QF	2/22/2014	<1
Independent Producers	Port Townsend Paper	Hydro-QF	06/30/09	<1
Independent Producers	VanderHaak Dairy	Biomass	12/31/2019	<1
Independent Producers	Qualco Dairy	Biomass	12/11/2013	<1
Independent Producers	Farm Power Lynden	Biomass	1/31/2019	<1
Independent Producers	Farm Power Rexville	Biomass	1/31/2019	<1
Total Independent				**49**

[1] *Nameplate capacity reflects PSE share only.*

Existing demand-side resources.

Demand-side resources are generally generated or saved on the customer side of the meter. While they include demand-response, fuel conversion, distributed generation, and distribution efficiency, energy efficiency measures are by far the most substantial contributor to resource need. During the 2008-2009 tariff period, the 66.4 aMW contributed by these programs amounted to enough energy to power approximately 50,000 homes. Between 1978 and 2009, gains of 363 aMW have accumulated on an investment of $650 million – more than the annual output from our share of Colstrip 1 & 2 and equivalent to the electricity used by about 270,000 homes for a year. As with supply-side resources, PSE evaluates energy efficiency programs for cost-effectiveness and suitability within a lowest reasonable cost strategy.

Figure 5-9
Cumulative Electric Energy Savings from DSR, 1978 to 2009



Our energy efficiency programs serve all types of customers—residential, low-income, commercial, and industrial. Energy savings targets and the programs to achieve those targets are established every two years. The 2008-2009 biennial program period concluded at the end of 2009; current programs operate January 1, 2010 through December 31, 2011. The majority of electric energy efficiency programs are funded using electric "rider" funds collected from all customers.

For the 2010-2011 period, a two-year target of approximately 71 aMW in energy savings was adopted. This goal was based on extensive analysis of savings potentials and developed in collaboration with key external stakeholders represented by the Conservation Resource Advisory Group (CRAG) and Integrated Resource Plan Advisory Group (IRPAG).

Current electric energy efficiency programs.
The two largest programs offered by PSE to customers are the Commercial and Industrial Retrofit Program and the residential Energy Efficient Lighting Programs.

The Commercial and Industrial Retrofit Program offers expert assistance and grants to help existing commercial and industrial customers use electricity and natural gas more efficiently via cost-effective and energy efficient equipment, designs, and operations. This program gave out grants totaling more than $22 million to over 1,000 business customers in 2010 to achieve a savings of over 80,000 MWh.

The Energy Efficient Lighting Programs offer instant rebates for residential customers and builders who purchase Energy Star fixtures and compact fluorescent light bulbs. This program provided incentives totaling more than $5 million, which resulted in the installation of over 2.2 million CFL lamps and fixtures in 2010 to achieve savings of over 56,000 MWh.

Figure 5-10
Annual Energy Efficiency Program Summary, 2008-2010
(Dollars in millions, except MWh)

Program	2008 - 2009 Actual	'08-'09 2-Year Budget./Goal	'08/'09 Actual vs. '08/'09 % Total	2010 Actual	'10-'11 2-Year Budget./Goal	'10 vs. '11/'09 % Total
Electric Program Costs	$ 123,000,000	$ 130,000,000	95.0%	$ 75,000,000	$ 167,000,000	45%
Megawatt Hour Savings	581,000	513,000	113%	295,000	622,000	47.5%

Figure 5-10 shows program performance compared to two-year budget and savings goals for the biennial 2008-2009 electric energy efficiency programs, and records 2010 progress against 2010-2011 budget and savings goals.

During 2008-2009, electric energy efficiency programs saved a total of 66.4 aMW of electricity at a cost of $123 million. The company surpassed two-year savings goals while operating at a cost that was under budget. In 2010, these programs saved 32 aMW of electricity at a cost of $75 million. The average cost for acquiring energy efficiency in 2008-09 was approximately $210 per MWh, compared to a budgeted cost of approximately $270 per MWh in the 2010-2011 program cycle.

3. Analytic Methodology

This section describes the quantitative analysis of electric demand- and supply-side alternatives. It explains how portfolios were created in response to a variety of key economic assumptions expressed as scenarios, and how these portfolios were evaluated for cost and risk. The resulting analysis allowed the company to quantify how sensitive portfolios were to the planning assumptions, and provided insight into how adding different types of generation would affect PSE ratepayers' costs. Among the critical questions posed were the following.

- How might economic conditions and load growth affect resource decisions?
- What is the cost-effective level of energy efficiency?
- How sensitive are the demand-side portfolios to different levels of avoided costs?
- What are the key decision points and most important uncertainties in the long-term planning horizon, and when should we make those decisions?
- What impact might very different levels of natural gas prices have on resource decisions?
- How might future carbon regulation affect the relative value of resource alternatives?
- What carbon emissions are produced by portfolios under different scenarios?
- How do changes in financial incentive assumptions affect resource decisions?

Electric analytic methodology followed the three basic steps illustrated in Figure 5-11. (For a detailed technical discussion of models and methods, see Appendix I, Electric Analysis).

Figure 5-11
Methodology Used to Create and Evaluate Portfolios

Step 1. Identify Needs and Resources

1. Forecast Resource Needs
   Capacity, Energy, and Renewable Needs

2. Gather Assumptions and Screen Supply Side Resources
   Ensure Supply side resource to be modeled are commercial available

3. Gather Assumptions and Screen Demand Side Resources (DSR)
   Screen for Technical and Achievable Potential
   Develop Bundles and Ramp Rates

Step 2. Create optimal, integrated portfolios for each scenario.

1. Gather input data for each scenario
   Develop Power Prices for each Scenario
   Generate Dispatch of resources for each Scenario

2. Evalute portfolio costs based on inputs
   Develop lowest cost portfolio for each scenario ensuring that each Portfolio:
   - Meets resource need (customer demand + operating reserves + planning margin)
   - Meets renewable resources/RECS need
   - Includes optimal DSR bundle

Step 3. Evaluate costs and risks.

1. Use input variable distributions to Develop 1000 risk trials

2. Calculate Cost and Risk metrics using the results of the 1000 risk trials

Step 1: Identify needs and resources.

The analysis begins by using the most recently available forecast of customer demand. We use this load forecast to develop resource need assumptions.
Next, all resources that are available to fill unmet need are identified.

Supply-side resources included natural gas-fired generation, wind, and biomass.

Demand-side resource selection followed the three-step process illustrated in Figure 5-12.

- First, each demand-side measure was screened for technical potential.
- Second, a screen eliminated any resources not considered achievable.
- Finally, the remaining measures were combined into bundles based on levelized cost for inclusion in the optimization analysis.

Screening for technical potential assumed that all opportunities could be captured regardless of cost or market barriers, so the full spectrum of technologies, load impacts, and markets could be surveyed.

To gauge achievability, we relied on customer response to past PSE energy programs, the experience of other utilities offering similar programs, and the Northwest Power and Conservation Council's most recent energy efficiency potential assessment. For this IRP, PSE assumed economic electric energy efficiency potentials of 85% in existing buildings and 65% in new construction.

This methodology is consistent with the methodology used by the Northwest Power and Conservation Council. A comparison of the two can be found in Appendix B.

For a more detailed discussion of demand-side resource evaluation and the development of DSR bundles, see Appendix K, Demand-side Resource Analysis.

Figure 5-12
General Methodology for Assessing Demand-side Resource Potential

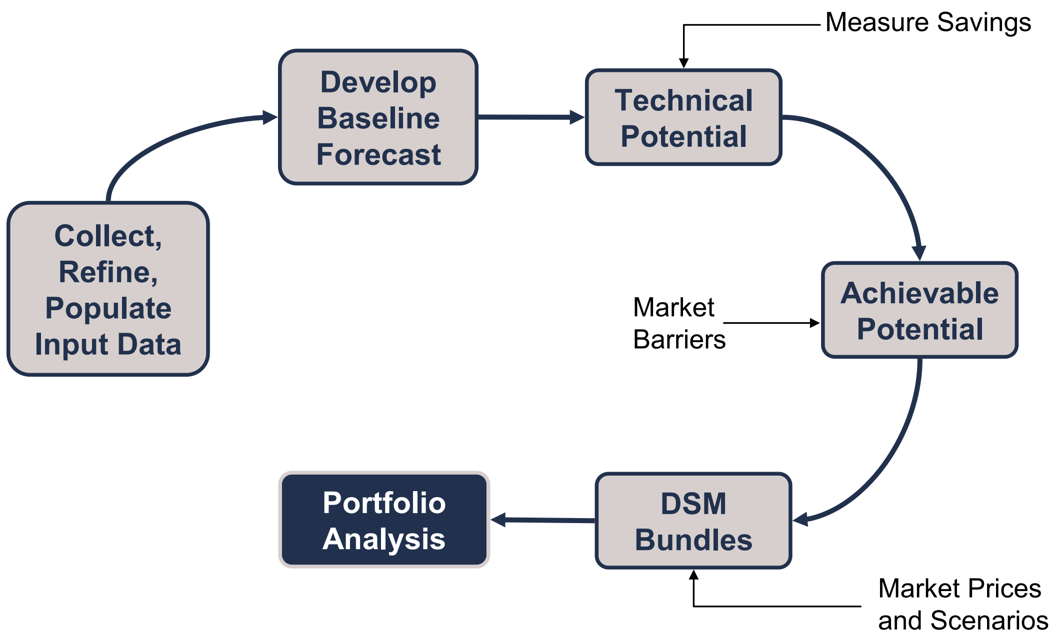
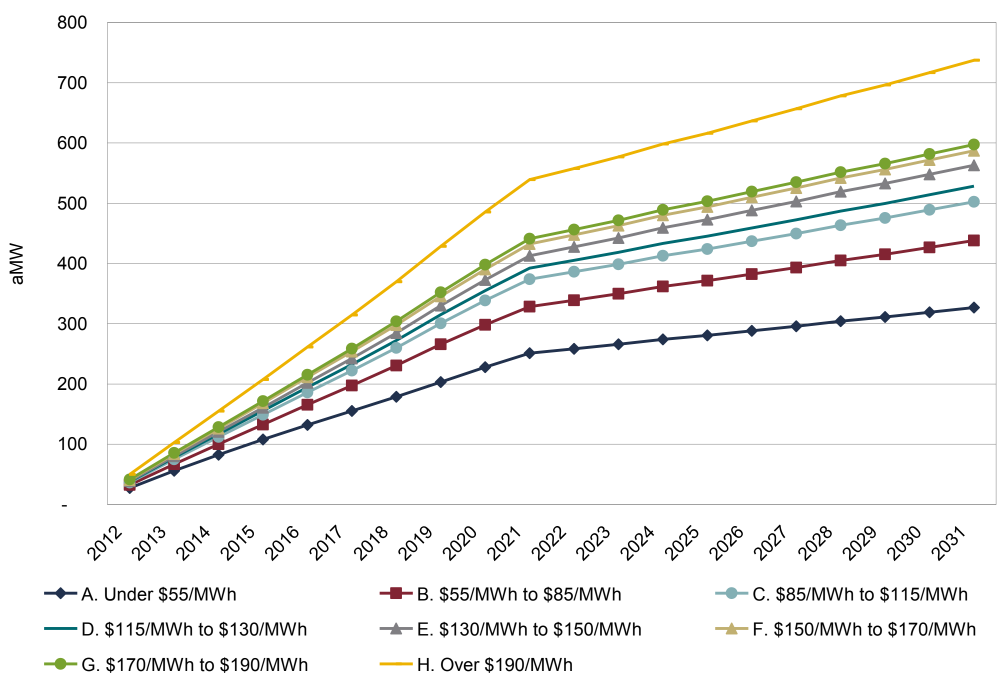


Figure 5-13 shows the achievable potential of all DSR bundles tested in the IRP. The effect of these bundles is to reduce load, so the costs of achieving the savings are added to the cost of the electric portfolios.

Figure 5-13

Achievable Technical Potential by Demand-side Cost Bundles (aMW)



Step 2: Create optimal, integrated portfolios for each scenario.

An optimal, integrated portfolio for each scenario and sensitivity was created using the portfolio optimization model PSM III to combine supply-side resources with the demand-side bundles. The optimization model used the inputs provided to identify the lowest cost portfolio that:

- Meets capacity need
- Meets renewable resources/RECS need
- Includes as much conservation as is cost effective

PSE models lowest cost from the customer perspective, so it is measured in as the lowest net present value (NPV) revenue requirement of a portfolio. To arrive at this calculation the company aligns three analytical efforts:

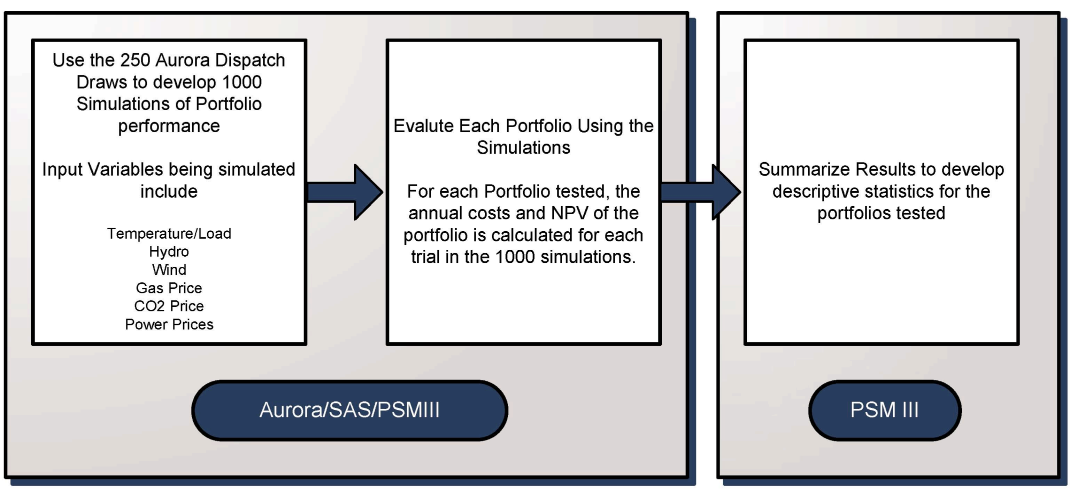
- An economic dispatch model that can provide a reasonable forecast of variable costs and wholesale market revenue from operating plants, given market assumptions. For this process, PSE uses Aurora.
- A revenue requirement model, to incorporate the costs of capital investments and other fixed costs the way customers will experience them in rates; the IRP uses the same financial model the general rate case uses for calculating revenue requirements.
- An optimization model, to develop and test different portfolios to find the lowest cost combination of resources; PSM III uses a linear optimization model.

Step 3: Evaluate costs and risks.

Once the optimal portfolio for each scenario was identified, PSE conducted risk analysis on select portfolios. The PSM III process illustrated in Figure 5-14 was used to calculate risk measures for each.

A Stochastic model was used to create 250 simulations of input variables for the Base Case scenario. The average, or expected, output from the 250 draws was used to find an optimal portfolio. We then fed the 250 draws into PSM III and used that tool to simulate 1,000 trials for the optimal portfolio. These trials allowed us to fully understand risks associated with differing gas prices, power prices, and weather conditions that affect loads, hydropower, and wind generation levels. For each trial, PSE could extract annual dispatch, costs, and loads for all the portfolios tested. (A full discussion of PSE's risk modeling approach appears in the "Stochastic Model" section of Appendix I, Electric Analysis).

Figure 5-14
Risk Analysis Process



4. Results

Figure 5-15 displays the MW additions for the optimal portfolios in 2016, 2020, and 2031. See Appendix I, Electric Analysis, for more detailed information.

Figure 5-15 below shows resource builds for the different scenarios. Note that with the exception of Green World all the portfolios end up looking very similar. The differences are described in the last section of this chapter.

Figure 5-15
Resource Builds by Scenario
Cumulative additions by nameplate

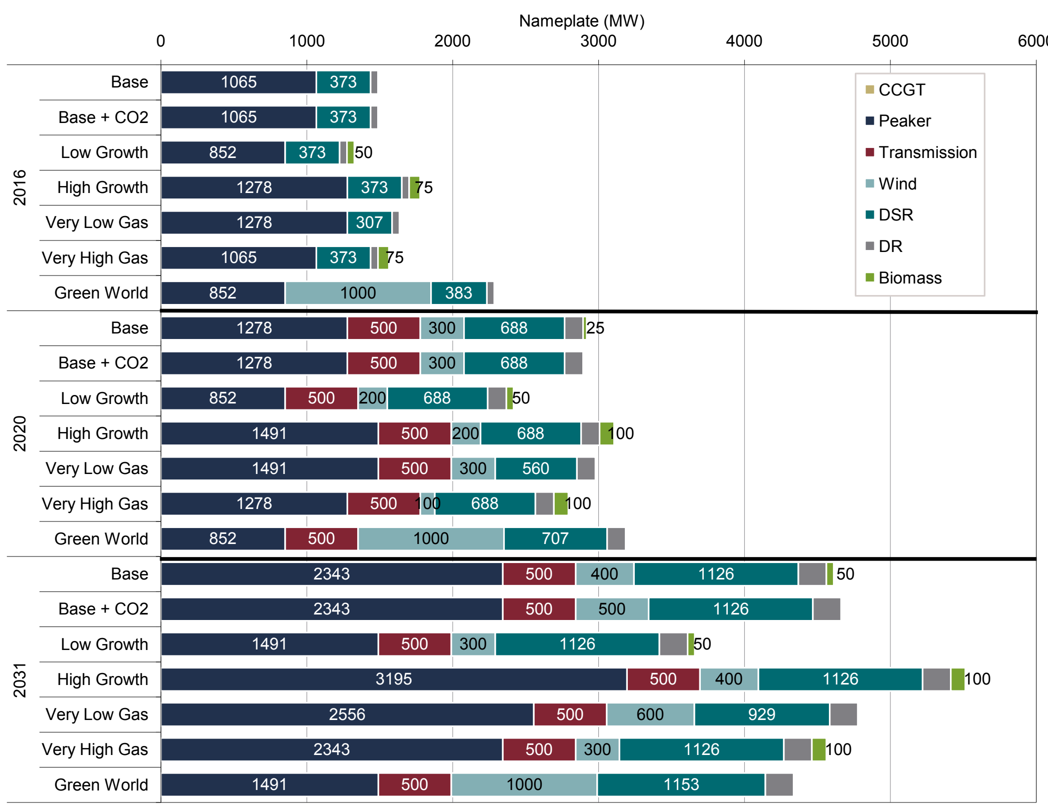


Figure 5-16 shows the 20-year net present value of costs for each of the portfolios.

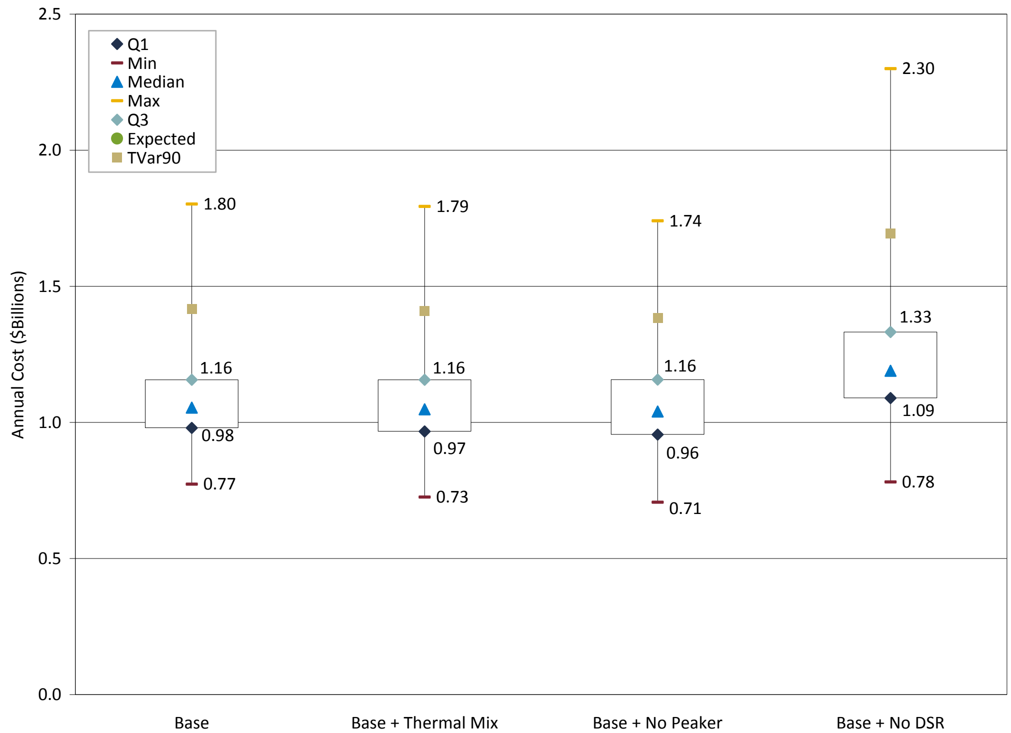
Figure 5-16
Net Present Value Expected Portfolio Cost

Scenarios	20-year NPV Expected Cost (Incremental Rev Req $Billions)
Base	$13.36
Base + CO2	$15.93
Low Growth	$9.83
High Growth	$18.58
Very Low Gas Prices	$10.87
Very High Gas Prices	$16.45
Green World	$21.06

NPV of costs shown above in Figure 5-16 represent the expected value of the least cost portfolio based on a comprehensive set of stochastic analyses. Results of the stochastic analysis can also be examined. Figure 5-17 represents the variability and the range of the portfolio costs of a few different portfolio sensitivities in the Base Case scenario. The different portfolios were designed to test cost versus risk trade-offs of demand-side resources and substituting combined cycle plants for some or all of the peakers (the peaker/CCCT portfolios are described in more detail below in the Key Findings and Insights section.) Figure 5-17 demonstrates that going from the No DSR portfolio to the Base portfolio—or any other portfolio—reduces both costs as well risk measured by Tail Var 90. However, there is no clear trade off between the cost and risk profiles of the Base, Thermal Mix, and No Peaker portfolios.

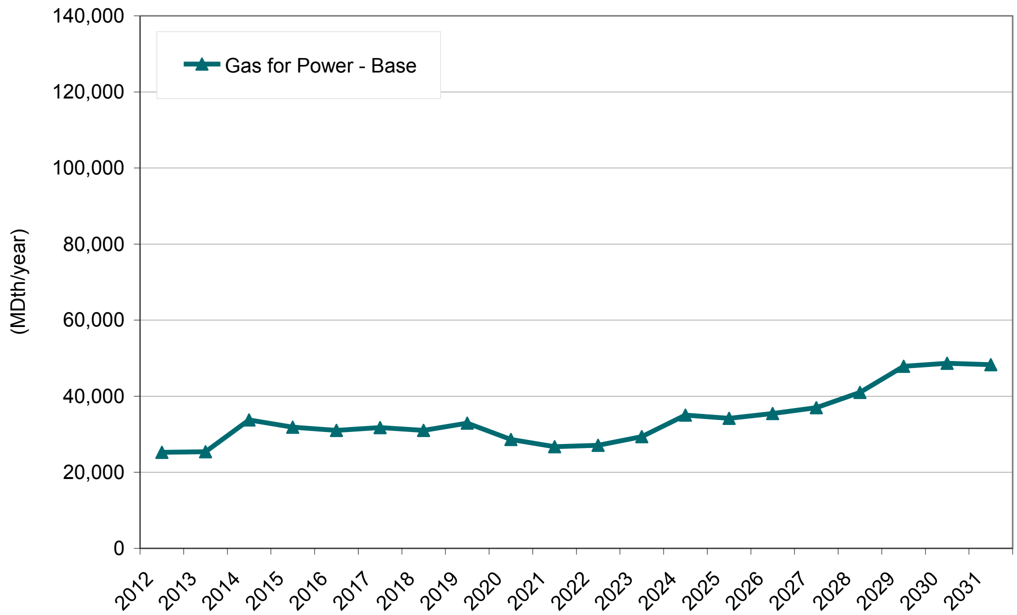
Figure 5-17

Variability and Range of Portfolio Costs in Base Case Scenario



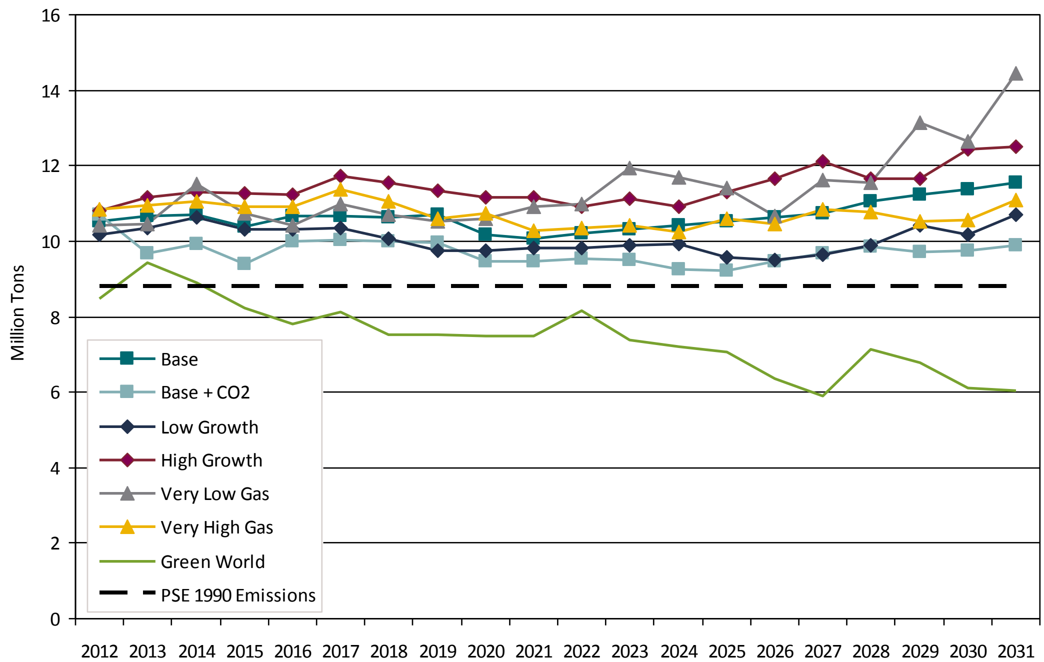
Generation fuel requirements are shown in the following chart. A discussion on how the optimal portfolio affects gas planning can be found in Chapter 6, Gas Analysis.

Figure 5-18
Generation Fuel Requirements



CO_2 emissions for each of the scenarios is shown in Figure 5-19

Figure 5-19
Emissions by Portfolio



5. Key Findings and Insights

The quantitative results produced by this extensive analytical and statistical evaluation led to several key findings that guided the long-term resource strategy presented in this IRP.

1. Portfolio builds are similar across most scenarios.

Resource alternatives are so limited that the portfolio builds for all scenarios look very similar. For all but Green World, the optimal portfolio uses new transmission and peakers to meet physical reliability need, conservation and market power purchases to meet annual energy needs, and wind to meet RPS requirements. Small variations occur due to load variations and "right sizing" (building a small bio-mass unit rather than adding an entire peaker or wind farm, for example), but the similarities are striking.

Green World is the only exception. In this scenario, high gas, CO_2 and market power costs create a situation where wind power is cheaper than market power. Left unconstrained, Green World would have chosen an unlimited amount of wind. Because it is unrealistic for a load-serving utility to take such a speculative position, we constrained the amount of wind allowed to be developed in this scenario.

Figure 5-20
Relative Portfolio Builds and Costs by 2031
Energy in total MW, dollars in billions

	Base	LG	HG	GW	VLG	VHG
Demand-side Resources	1319	1319	1319	1345	1121	1319
Wind	400	300	400	1000	600	300
Biomass	50	50	100	0	0	100
Peaker	2343	1419	3195	1419	2556	2343
New Transmission	500	500	500	500	500	500
Costs	$13.36	$9.83	$18.58	$21.06	$10.87	$16.54

2. Peakers are lower cost than CCCT plants.

Peakers proved to be a lower cost resource alternative than CCCT plants across all planning scenarios. Figure 5-21 below compares the net revenue requirement of peakers and combined-cycle plants across selected scenarios. Net revenue requirements were calculated by taking all capital and fixed costs of a plant and then subtracting the margin (variable costs less market revenue). This calculation lets one quickly compare how these resources are evaluated by the model. PSE also performed a study that burdened the peaking units with the higher-priced, fixed fuel transportation costs that CCCTs are burdened with, but even under these conditions peakers resulted in a lower net cost than CCCTs.

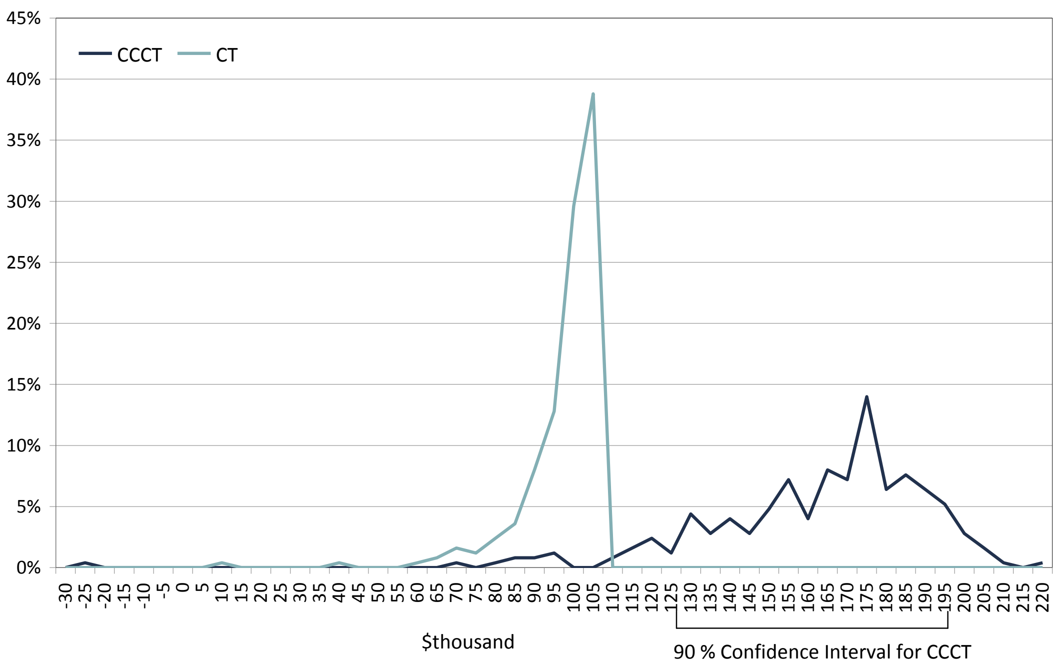
Figure 5-21
Peaker and CCCT Net Thermal Costs Compared

	Base	Base + CO2	Base No Coal	LG	GW
Peaker Rev Requirement (Capital + Fixed)	$242,369	$242,369	$242,369	$242,369	$242,369
Margin	$14,541	$61,876	$83,151	$37,812	$55,266
Net Cost of a Peaker	$227,828	$180,493	$159,218	$204,557	$187,103
$/MW	$1359	$1036	$1136	$1250	$1167

	Base	Base + CO2	Base No Coal	LG	GW
CCCT Rev Requirement (Capital + Fixed)	$812,971	$812,971	$812,971	$812,971	$812,971
Margin	$272,446	$335,292	$325,895	$228,492	$468,812
Net Cost of a CCCT	$540,525	$477,679	$487,076	$584,480	$344,160
$/MW	$1792	$1632	$1604	$1924	$1204

The net cost of a CCCT plant is significantly affected by the margin it generates, and that margin varies as market conditions change. Figure 5-21 illustrates that in the Base Case, the CCCT margin is about one-third of the capital and fixed costs; as market conditions change, so does the margin. Figure 5-22 illustrates the impact of margin on the net cost per MW of a peaker and CCCT plant in the Base Case scenario. This Figure uses a 250-draw Monte Carlo analysis for a single year (2016) to illustrate how the net cost per MW of peakers and CCCT plants are distributed under different market conditions. The cost distribution for peakers is very tight, because peakers do not dispatch or create much margin in many draws. On the other hand, the margin on CCCT plants is widely dispersed, which drives a more wide-spread distribution. That broader CCCT distribution is significantly higher than the distribution on the peaker. The distribution of the peaker lies entirely below the 90% confidence interval for the CCCT plant. This demonstrates that while CCCT plants are expected to operate more and generate margins from those operations, such margins are not expected to be large enough to offset the higher fixed cost of the CCCT.

Figure 5-22 Comparison of Net Cost Distribution: CCCT and Peakers



3. CCCTs do not reduce portfolio risk cost effectively.

Because the all-peaker result differed from past IRP analyses, PSE decided to test whether there were risk reduction benefits to building CCCTs instead, or to building a portfolio that blended CCCTs and peaking units. To do this, we developed two additional sensitivities using the Base Case scenario: The "Thermal Mix" sensitivity forced the optimization model to build enough CCCTs to ensure that the total dollar value of net market power purchases did not exceed 40% of total power cost in any year. The "No

Peakers" sensitivity forced the optimization model to create a lowest-cost portfolio without any peaking plants, with the result that all peakers were replaced with CCCT plants and a minor amount of biomass. Figure 5-23 through 5-26 below show the results of the analysis.

As figure 5-17 shows, adding CCCTs to the portfolio increased costs but did not significantly reduce risk. The two sensitivities observably reduced the portfolio's exposure to market power prices, but at the same time they increased exposure to market gas prices. Adding CCCT generation did not reduce the company's overall exposure.

Figure 5-23 below shows the resource builds by sensitivity. Note that the only measurable differences between the portfolios are the types of gas-fired plants being added. Additionally, the No Peakers sensitivity adds marginally more DSR.

Figure 5-23
CCCT Sensitivities, Builds vs. Base Case Build

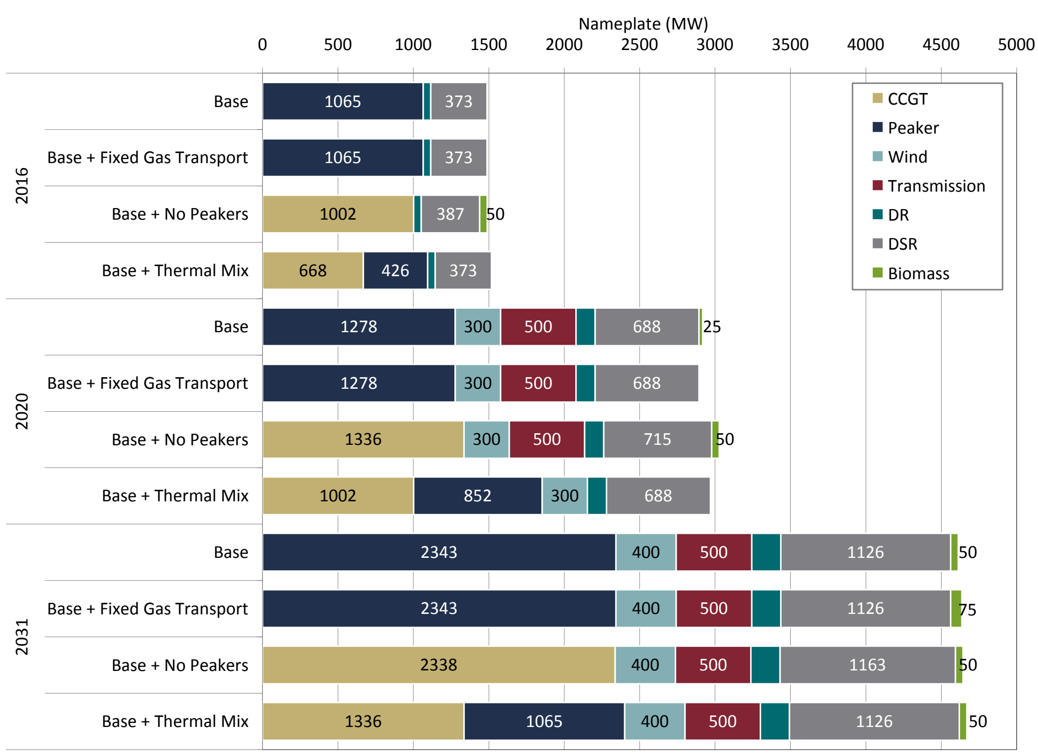


Figure 5-24 shows the costs of the various sensitivities.

Figure 5-24
CCCT Sensitivities, NPV Portfolio Cost Comparisons

Scenario	20-year NPV Expected Cost (Incremental Rev Req $Billiions)
Base	$13.36
Base + Peaker Fixed Gas Transport Cost	$14.10
Base + No Peaker	$14.54
Base + Thermal Mix	$14.26

Figure 5-25
Power Market Exposure

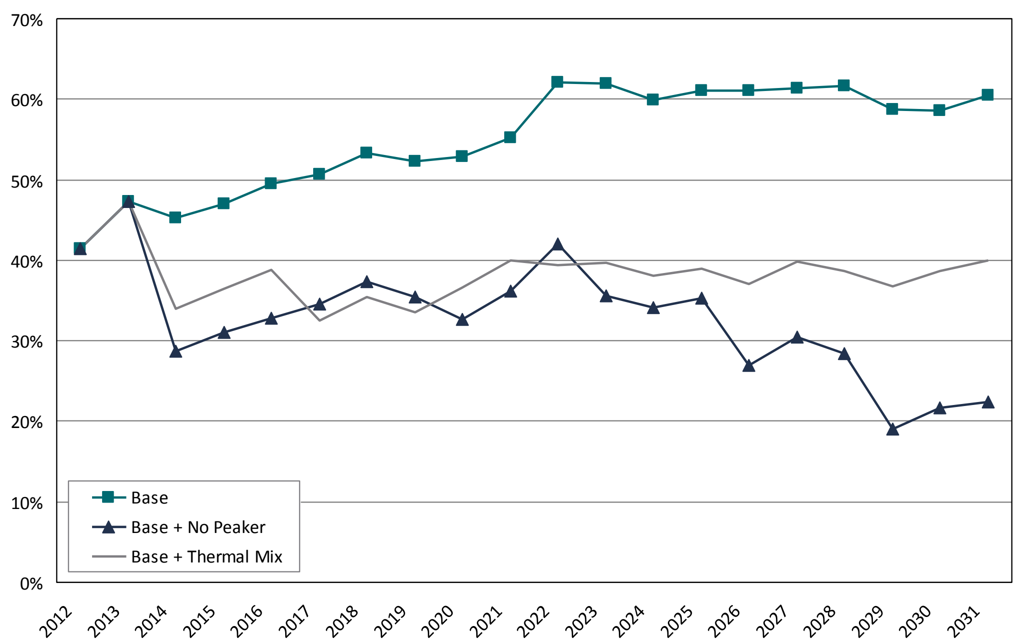
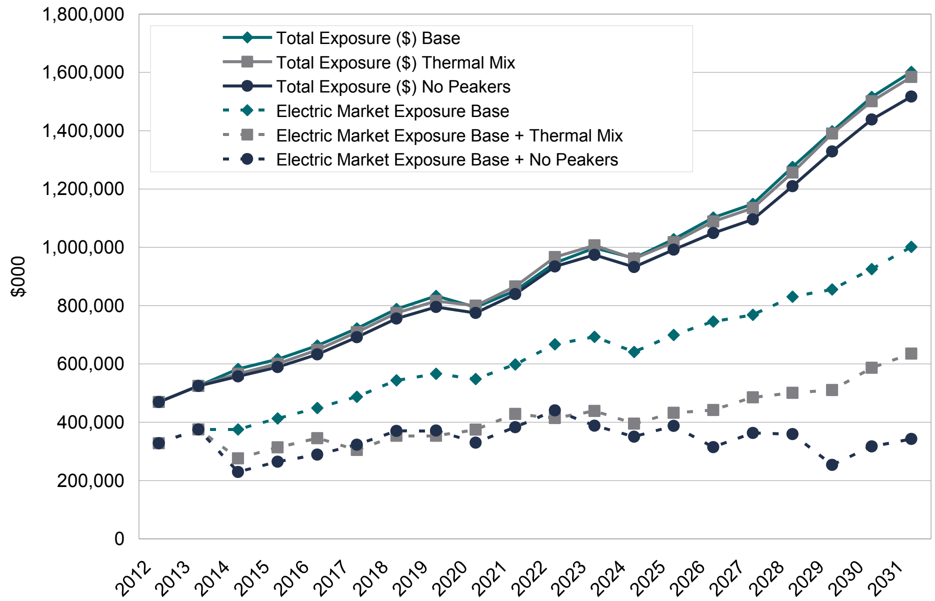


Figure 5-25, above, shows the power market exposure for the different sensitivities. Market exposure is calculated by dividing the dollar amount of net market purchases by the total variable costs of the portfolio. If power market exposure were the only consideration, adding CCCTs to the portfolio would appear to reduce the portfolio's exposure to risk. However, when gas market exposure is considered in addition to power market exposure, adding CCCTs does not reduce risk exposure, as Figure 5-26 illustrates.

Figure 5-26
Total Market Exposure



CCCT plants do reduce variable cost risk relative to peakers but at too high a price to be reasonable. The first part of the table in Figure 5-27 illustrates that the Tail Var 90[3] of variable costs for the portfolio with all CCCT plants instead of peakers is a little over $0.5 billion lower than the Base portfolio with all peakers. The second part of the table illustrates the CCCT portfolio's revenue requirement is $1.18 billion more than the Base Portfolio, which reflects the higher fixed costs of the CCCT plants. This is clearly not a reasonable cost/risk trade-off. The "insurance premium" of the CCCT portfolio costs twice as much as the risk being avoided.

Figure 5-27
Trade Off Table ($Billions) 20-Year NPV

Variable Costs				
	Base Portfolio	Fixed Gas Transport	Peaker/CCCT Blend	No Peaker
Tail Var 90 Variable Costs	$13.15	$13.14	$12.82	$12.60
Relative to Base		-0.01	-0.33	-0.55
Incremental Revenue Requirement[4]				
	Base Portfolio	Fixed Gas Transport	Peaker/CCCT Blend	No Peaker
Expected Incremental Rev Req	$13.36	$14.10	14.26	14.54
Relative to Base		+0.74	+.09	+1.18

[3] *Tail Var 90 is a risk measure, calculated as the mean of the worst 10% of possible outcomes.*
[4] *Incremental Revenue Requirement includes fixed and variable costs for new resources and variable costs for existing resources.*

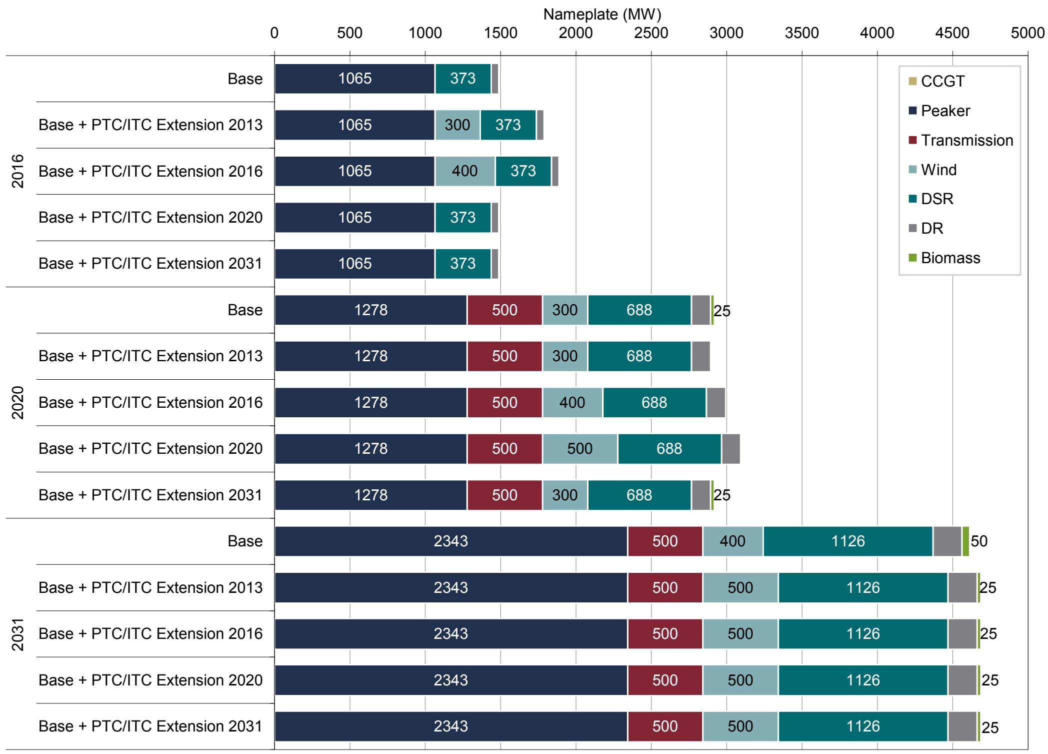
4. RPS requirements drive renewable builds.

The amount of renewable resources included in portfolios is driven by RPS requirements. Figures 5-28 and 5-29 show results of portfolio comparisons performed to test how changes in CO_2 costs, load growth, demand-side resources, and financial incentives such as the cash grant or production tax credit (PTC) extensions, would affect wind additions to the portfolios. As explained in Chapter 4, this analysis assumed treasury grants were the financial incentive being used. Green World is the only scenario that increases wind more than required by the RPS.

Figure 5-28
The Effect of Variables on Wind Additions in 2029

Variable	Portfolio's to Compare	Effects of Change
CO_2 Cost Changes	Base Case Base + CO_2	The Base Case builds 400 MW of wind and 50 MW of biomass. Increased CO_2 costs in Base +CO_2 resulted in 500 MW of wind and no biomass.
Load Changes	Low Growth Base High Growth	At the low end of the spectrum, Low Growth adds 300 MW of wind and 50 MW of biomass. At the high end, High Growth adds 400 MW of wind and 100 MW of biomass.
DSR Changes	Base No DSR vs. Base	Adding the optimal amount of DSR in the Base Case reduced the amount of wind built.
Financial Incentive Changes	Financial Incentive extensions	Renewable additions coincide with the expiration of financial incentives. Extending the incentives farther out into the future results in similar pushing renewables into the future.

Figure 5-29
Financial Incentive Extension Comparison



The chart above shows how portfolios are optimized using different assumptions for financial incentive extensions. In the Base Case, PSE assumes no extension of financial incentives and that all wind additions coincide with filling REC need. The other portfolios extend financial incentives until 2013, 2016, 2020, and 2031. With the exception of the 2031 portfolio (which assumes such incentives are available during the entire planning period), renewable additions are accelerated to take advantage of the expiring incentives.

5. Limiting emissions will be difficult.

PSE examined how different carbon mitigation strategies will affect portfolio builds, costs, and emissions. Figure 5-30 illustrates that only two of the three carbon mitigation strategies modeled achieve emissions below 1990 levels – Green World and No Northwest Coal. However, both would lead to significant future costs; Figure 5-31 shows the annual revenue requirements for these portfolios. By 2021, No Northwest Coal increases the company's revenue requirement by about $196 million over the Base Case; Green World increases the revenue requirement by about $ 787 million. While both strategies achieve 1990 emissions levels, the costs are considerable.

It is important to consider the limitations of this analysis when considering the scenario in which all Northwest coal plants are forced to retire, as PSE used some simplifying assumptions to complete the IRP analysis in a timely manner. In reality, as these resources are forced to expire the region will be required to build additional CCCT plants to replace the lost energy and capacity of the coal plants. In the IRP analysis, Aurora assumed that "the region" would build them; then the optimization model took advantage of their "existence" and so did not recommend adding CCCT to PSE's portfolio. If the region were to retire all coal plants, PSE's options may indeed include the economic development of these plants. This highlights a need for the company to investigate updating our analytical frameworks to better address issues that may arise if regional coal plants are put out of service. .

Figure 5-30

Annual Emission Rates for Base, Base + CO2, No NW Coal and Green World Portfolios

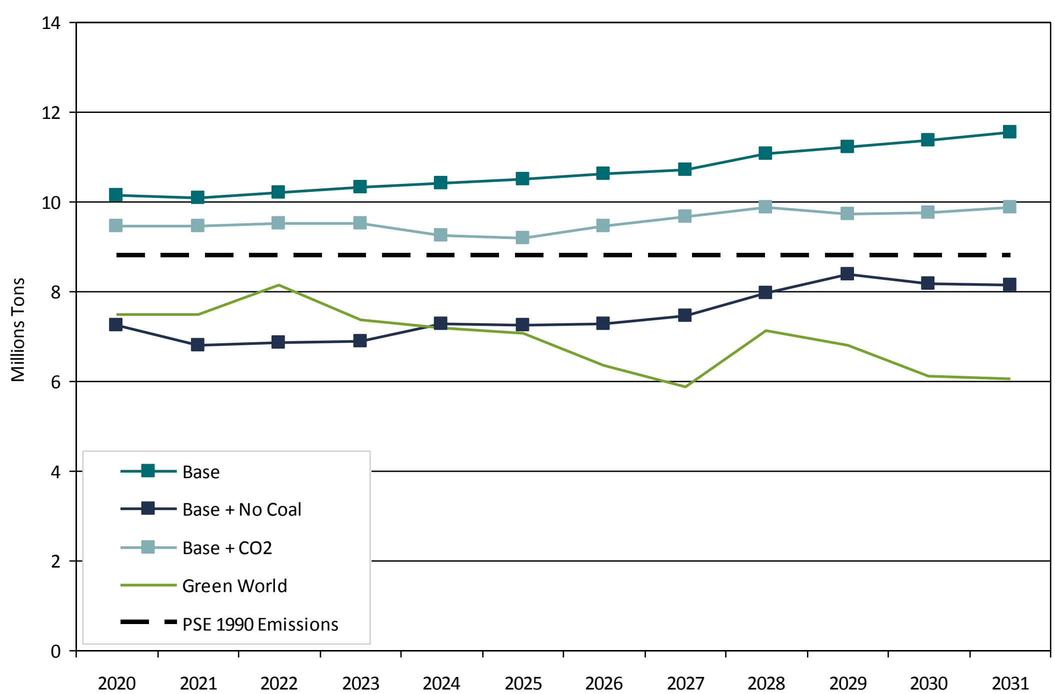
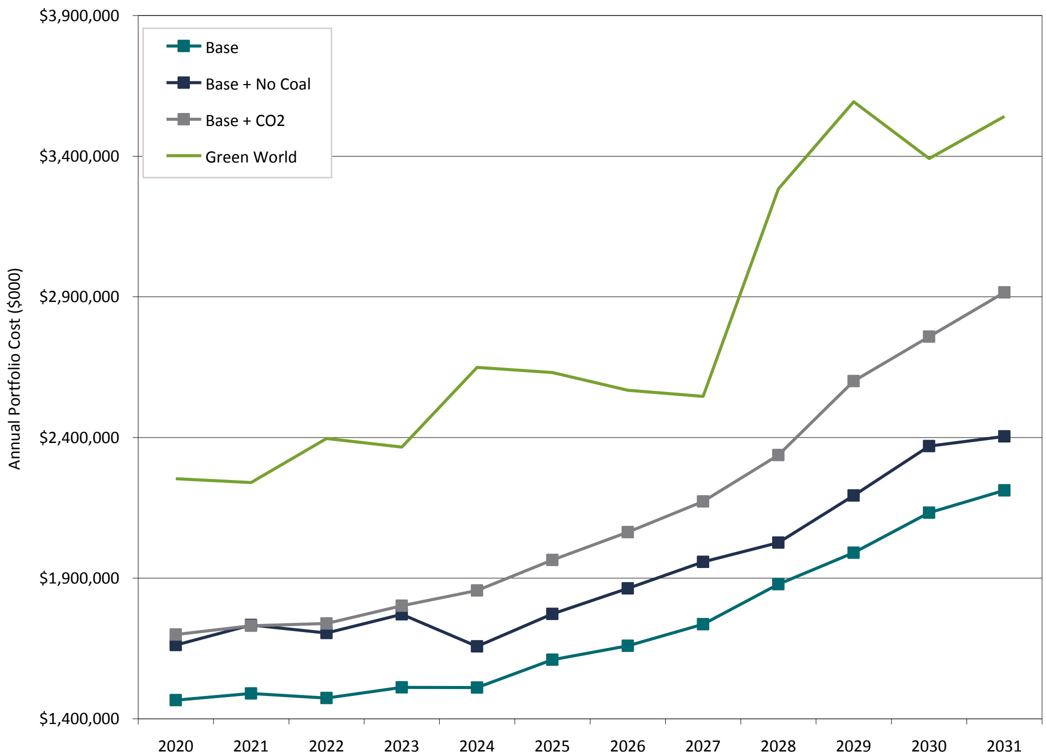


Figure 5-31
Annual Revenue Requirements for Base, Base + CO_2, No NW Coal, and Green World Portfolios



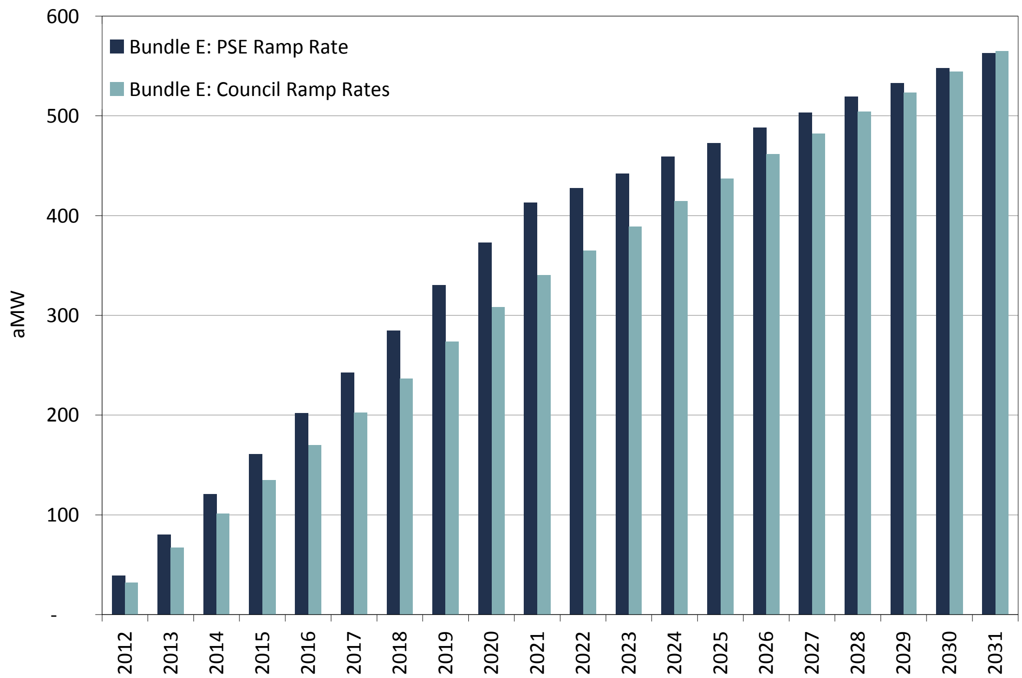
6. DSR is the only resource that reduces cost and risk – and the sooner it's acquired, the more cost-effective it is.

Demand-side resources are the only resources that reduce both cost and risk in portfolios. The amount of cost-effective conservation acquired is the same in all but one scenario (Green World). At minimum, all other scenarios identified DSR Bundle E to be cost effective. The cost-effective level of DSR remained fairly constant even though "avoided market costs" varied. We also found that a more rapid ramp rate for DSR improved the cost-effectiveness of these measures.

PSE's plan applies a 10-year ramp rate for DSR that is more aggressive than the rate applied in the NPCC's 6th Power Plan for similar measures. To compare the two, Cadmus developed a detailed, measure-by-measure assessment of the NPCC's ramp rates based on the customer mix and appliance/measure saturation for PSE's service territory.[5] Figure 5-33 uses Bundle E to compare the two. PSE's 10-year ramp rate acquires DSR more quickly than the NPCC's ramp rate, though by the end of the planning horizon the total amounts are the same.

Figure 5-33

DSR Sensitivity: NPCC's Ramp Rates from the 6th Power Plan applied to PSE's service territory



[5] *Note this was a more in-depth analysis than the NPCC's "calculator" which allocates conservation potential based on kWh sales.*

This IRP analysis also tested whether acquiring DSR more or less quickly affected the cost effectiveness of the measures. To test this, we first used portfolio optimization analysis to find the least-cost combination of demand-side and supply-side resources in the Base Case scenario. Then we applied the NPCC's ramp rate in one analysis and PSE's 10-year ramp rate in another. Figure 5-34 summarizes the result. Bundle E with the more aggressive, 10-year ramp rate proved more cost effective.

Figure 5-34
PSE's 10-year ramp rate is more cost effective than the ramp rate from the 6th Power Plan

Base Scenario	20-yr Expected Incr Rev Req ($Billions)	Bundle	DR
Base (PSE Ramp)	$13.36	E	Yes
Base + 6th Power Plan Ramp	$13.53	E	Yes

Demand-side resources are the only resources that reduce both cost and risk in portfolios. They must be cost effective to be included in the plan, so by definition they are also least cost resources. Figure 5-35 shows the expected power costs and risk ranges for a No DSR portfolio and the optimal Base Case portfolio, which includes 1,319 MW of DSR by 2031. Figure 5-36 compares their expected costs and cost ranges.

The amount of cost-effective conservation acquired is the same in all but one scenario. At a minimum, all scenarios identified DSR Bundle E to be cost effective; other bundles became cost effective only in Green World. Figure 5-37 shows the selected DSR bundle and the associated avoided market costs by scenario. It is interesting to note that the cost-effective level of DSR remains fairly constant even though "avoided market costs" vary. A full description of the bundles and the associated measures in each bundle can be found in Appendix K, Demand-side Resource Analysis.

Figure 5-35
Effect of DSR on Costs and Risk

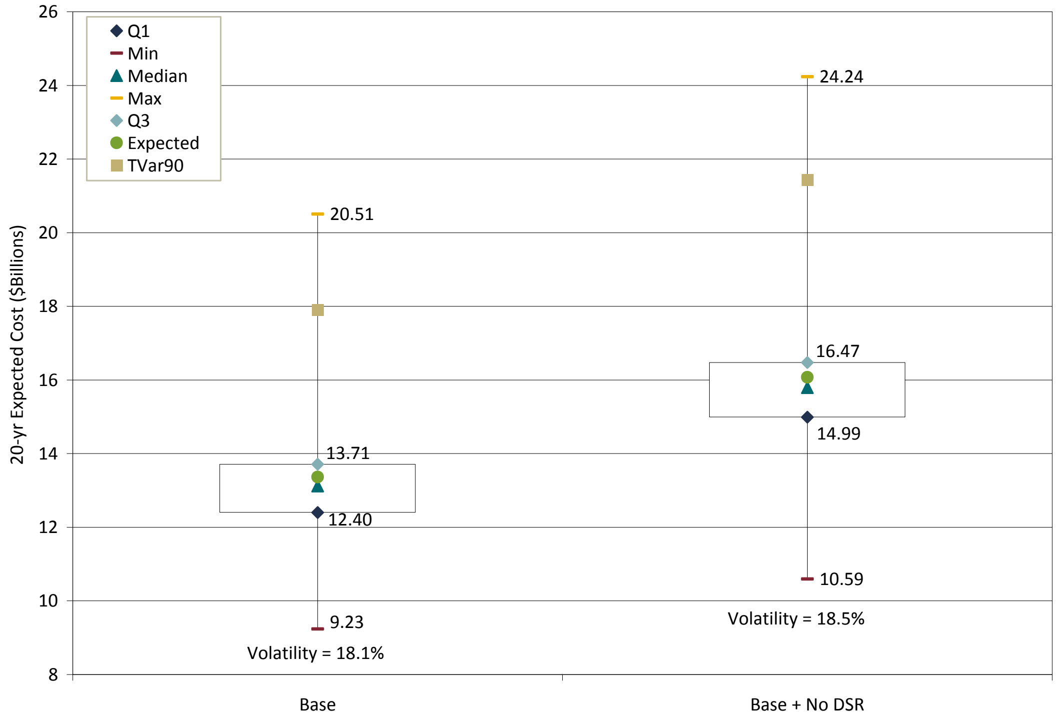


Figure 5-36
Comparison of Expected Costs and Cost Ranges for No-DSR and Base Case Portfolios
20-yr NPV Portfolio Cost (dollars in billions)

	Base	Base + No DSR	Difference
Expected Cost	13.36	16.07	2.71
TVar90	17.90	21.43	3.53

DSR reduces power cost risk relative to No DSR. Figure 5-36 illustrates that the Tail Var 90 of variable costs for the portfolio with No DSR would be a little over $3.53 billion higher than the Base portfolio with DSR. Figure 5-36 illustrates that the No DSR portfolio revenue requirement is $2.71 billion more than the Base Portfolio, which reflects the higher costs of adding peakers instead of DSR. This is clearly a reasonable cost/risk trade-off. Adding DSR to the portfolio reduces cost and significantly reduces risk at the same time.

Figure 5-37
Optimal DSR Bundles and Avoided Market Costs by Scenario

Scenarios	20-year Levelized Net Market Value	DSR Bundle
Base	$62.78	E
Base + CO2	$78.21	E
Low Growth	$49.35	E
High Growth	$90.94	E
Very Low Gas Prices	$45.48	B
Very High Gas Prices	$91.34	E
Green World	$127.57	G

Public Participation

Contents

PSE is committed to public involvement in the planning process. Stakeholder meetings generated valuable constructive feedback, and the suggestions and practical information we received from both organizations and individuals helped guide the development of this 2011 IRP. We wish to thank all who participated.

At the time this plan was filed with the Washington Utilities and Transportation Commission (WUTC), the following meetings had taken place: seven formal Integrated Resource Plan Advisory Group (IRPAG) meetings, numerous Conservation Resource Advisory Group (CRAG) meetings, and dozens of informal meetings and communications. Stakeholders who actively participated in one or more meetings include WUTC staff, Public Counsel, Northwest Industrial Gas Users, Northwest Pipeline, conservation and renewable resource advocates, the Northwest Power and Conservation Council, project developers, other utilities, and the Washington State Department of Community, Trade and Economic Development (CTED).

This appendix briefly describes the purpose of the IRPAG and CRAG, and summarizes the formal IRPAG meetings held to date. We especially want to thank those who attended these meetings, for both the time and energy they invested, and we encourage their continued participation. The IRPAG covers all elements of the IRP, while the CRAG focuses on energy efficiency and demand-side resources. While the two groups meet separately, they have many members in common.

1. Integrated Resource Planning Advisory Group (IRPAG)

PSE works with external stakeholders through an informal group called the IRPAG. The IRPAG is the primary means of satisfying the requirements of WAC 480-100/90-238 for public involvement. During the development of the 2011 IRP, PSE engaged the IRPAG in two ways: through a series of structured IRPAG meetings, and in individual discussions with various IRPAG members.

As part of the formal IRPAG meetings, we presented and discussed each building block in developing the IRP, often stepping through significant levels of detailed analysis. Other PSE departments were also invited to talk about topics of interest, such as the 2010 Request for Proposals (RFP). IRPAG meetings are open to all comers, including individual customers and other utilities.

In addition to the more structured IRPAG meetings, PSE spoke one-on-one with individual IRPAG members. These conversations were very productive, allowing a freer flow of ideas that would have been more difficult to achieve in group settings. The combination of one-on-one discussions and group meetings was particularly helpful in generating feedback.

Discussions with IRPAG members provide new avenues for broadening the scope of information available to PSE in our planning process. Additionally, these interactions enhance our thinking by bringing a variety of perspectives to the process. Following are specific examples of significant factors that were influenced by conversations with the IRP Advisory Group:

- No Northwest Coal Sensitivity: Conversations with stakeholders about the costs of reducing emissions via carbon pricing and coal plant closure prompted PSE to develop this sensitivity.
- Capacity Contribution of Wind: As we have done in the past, PSE initially planned to rely on regional studies for estimates of how wind contributes to capacity needs. Stakeholders suggested PSE could benefit from performing our own analysis, the results of which are presented and used in this IRP.

- Regional 10 percent Credit and Non-Energy Benefits for Conservation: PSE included these factors in the value of demand-side resources, as suggested by stakeholders.
- "Incremental Cost" of Renewables Analysis and 4 percent Revenue Requirement Cap: PSE had performed analysis to estimate whether the company would hit the cost cap under I-937 before the physical target. Stakeholders suggested this analysis be discussed in the IRP (Appendix I). Discussions with stakeholders results in some revision to the analysis.
- Additional Reports/Information: Stakeholders suggested that PSE provide a comparison between PSE's IRP methodology and that of the Northwest Power and Planning Council. Also after their suggestion, we included the coversheet report from the Department of Commerce's reporting requirements. Both can be found in Appendix B.

Summary of IRPAG Meetings

A. IRPAG Kick-off Meeting, April 20, 2010

PSE's 2011 IRPAG kick-off began with a discussion of lessons learned from the 2009 IRP process. We discussed key uncertainties, scenarios and sensitivities, and resource alternatives. PSE shared highlights from the IRP work plan. The company's Resource Acquisition department gave a presentation on the status of the evaluation process for PSE's Request for Proposals for All Generation Sources, which was underway at the time.

B. IRPAG Meeting, July 22, 2010

PSE invited the IRPAG to its Wild Horse Wind and Solar facility near Ellensburg, Wash. for an update on the IRP process followed by a tour of the facility. The meeting began with a discussion of current climate considerations, challenges and proposed legislation. This was followed by a continuation of the April discussion of proposed assumptions, scenarios, and sensitivities. PSE wrapped up the meeting portion of the day with a discussion about flexibility needs and wind integration.

C. IRPAG Meeting, October 7, 2010

This meeting began with an overview of our IRP analysis process and the methodology used for the demand side resources analysis. PSE presented an update on scenarios and sensitivities, resource alternatives and assumptions including gas prices, CO2 costs and the load forecast. PSE also presented draft electric price forecasts.

D. IRPAG Meeting, November 18, 2010

PSE began by presenting a review of the load forecast. A discussion of resource need for both electric and gas followed. On the electric side, this included a discussion of renewable and capacity need, as well as the methodology for determining the appropriate value of wind power's contribution toward meeting capacity need. On the gas side, PSE discussed resource need to meet the needs of its gas sales book. The latter portion of the meeting focused on demand-side resources analysis process and potentials.

E. IRPAG Meeting, January 13, 2011

The discussion began with a review of PSE's process for selecting a long-term resource plan, including a review of the scenario assumptions used in quantitative modeling. PSE presented both its electric and gas portfolio modeling results and next steps. The meeting concluded with a brief preview of the overall organization of the plan document.

F. IRPAG Meeting, March 15, 2011

The March meeting offered a first look at PSE's draft electric and gas resource plans. PSE presented a review of the electric and gas analysis results. The resource planning team also offered a summary review of its electric and gas scenarios and sensitivities, its analytical approach to electric planning and its gas resource alternatives.

G. IRPAG Meeting, April 19, 2011

PSE opened the April meeting with a request for feedback on its draft IRP. The draft was posted for public review on the company's web site on April 1, 2011. Afterward, PSE led a discussion of the incremental cost of renewable resources, followed by a detailed discussion of natural gas-fired peaking plants compared to combined cycle combustion turbines (CCCTs) in its planning analysis.

2. *Conservation Resources Advisory Group (CRAG)*

The CRAG was formally established as part of the settlement of PSE's 2001 General Rate Case, which the WUTC approved in Docket No. UE-11570 and UG-011571. The group specifically works with PSE on development of energy efficiency plans, targets and budgets. The CRAG consists of ratepayer representatives, regulators, and energy efficiency policy organizations.

The CRAG participated in the development of the 2011 IRP and energy efficiency program review through formal meetings in which it reviewed and offered feedback on the assessment of all demand-side resources (energy efficiency, fuel conversion, and demand response). The CRAG is also instrumental in reviewing IRP guidance to develop PSE’s biennial energy efficiency targets and programs, as well as to review our progress toward achieving those targets. Many members participated in other aspects of the IRP advisory process as well.

Electric Analysis

Contents

This appendix presents details of the methods and models employed in PSE's electric resource analysis, and the data produced by that analysis.

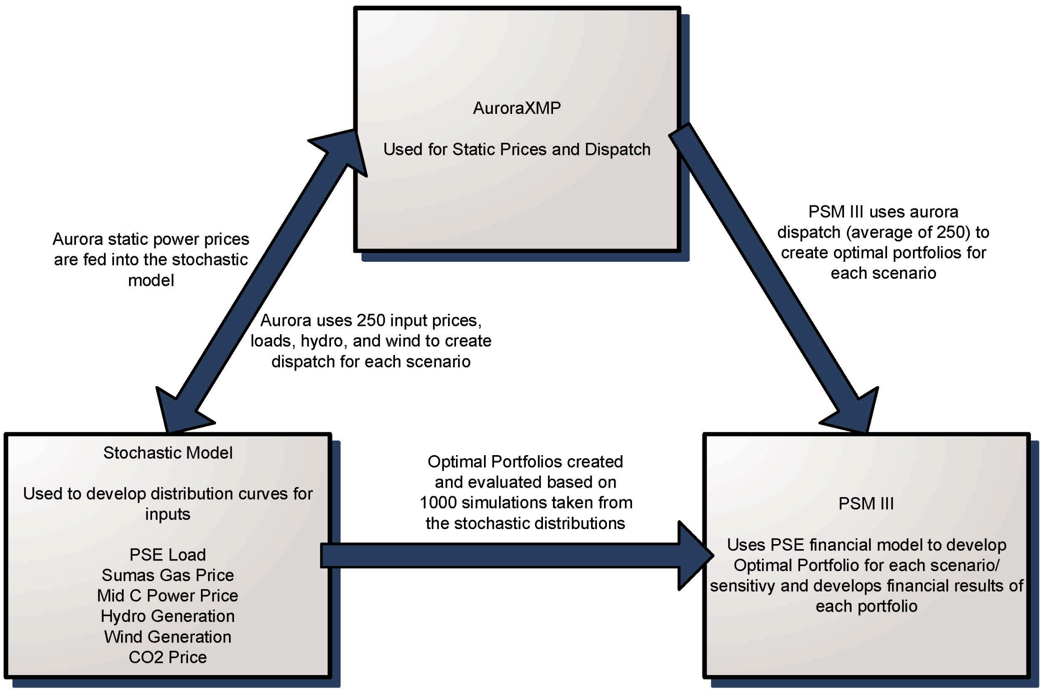
1. Methods and Models

I. Methods

A. Diagram of Process for 2011 IRP

PSE uses three models for electric integrated resource planning: AURORAxmp, a Stochastic Model, and the Portfolio Screening Model III (PSM III). AURORA analyzes the western power market to produce hourly electricity price forecasts of potential future market conditions and resource dispatch, as described later in this appendix. The stochastic model is used to create draws and distributions for various variables. PSM III creates optimal portfolios and tests these portfolios to evaluate PSE's long-term revenue requirements for the incremental portfolio and risk of each portfolio. The following diagram shows the methods used to quantitatively evaluate the lowest reasonable cost portfolio.

Figure I-1
Electric Analysis Methodology



B. Risk Analysis

i. Scenarios

A description of the scenarios and sensitivities can be found in Chapter 4. The monthly price output from these scenarios can be found in section 2 of this appendix.

ii. Portfolios

An optimal portfolio was found for each scenario and sensitivity described in Chapter 4. The optimal portfolio for each scenario is the lowest-cost combination of supply and demand side resources that meets PSE's needs. More details on these portfolios can be found in section 2 of this appendix.

iii. Probabilistic Analysis of Risk Factors

In addition to using scenarios to assess risk, this 2011 IRP continues to assess portfolio uncertainty through probabilistic Monte Carlo modeling in PSM III. It relies on Monte Carlo simulations of six uncertainty factors: natural gas prices, power prices, CO2 prices, weather and economic-demographic variability for load, wind generation variability, and hydroelectric generation availability. The simulations are based on assumptions about correlations and volatilities between the risk variables and also across time, based on the Stochastic model. This model and its assumptions are further described later in this appendix.

iv. Risk Measures

The results of the risk simulation allow PSE to calculate portfolio risk. Risk is calculated as the average value of the worst 10 percent of outcomes (called TailVar90). This risk measure is the same as the risk measure used by the Northwest Power Planning and Conservation Council (NWPCC) in its power plans. Additionally, PSE looked at annual volatility by measuring year-to-year changes in revenue requirements. Then we calculated the standard deviation of those year-to-year changes. The final measure of volatility is the average of the standard deviation across the simulations. It is important to recognize that this does not reflect actual expected rate volatility. The revenue requirement used for portfolio analysis does not include rate base and fixed cost recovery for existing assets.

II. Models

A. The AURORA Dispatch Model

i. Overview

PSE uses the AURORA model to estimate the market price of power used to serve our core customer load. The model is described below in general terms to explain how it operates, with further discussion of significant inputs and assumptions.

The following text was provided by EPIS, Inc. and edited by PSE.

> AURORA is a fundamentals-based program, meaning that it relies on factors such as the performance characteristics of supply resources, regional demand for power, and transmission, to drive the electric energy market using the logic of a production costing model. AURORA models the competitive electric market, using the following modeling logic and approach to simulate the markets: prices are determined from the clearing price of marginal resources. Marginal resources are determined by “dispatching” all of the resources in the system to meet loads in a least-cost manner subject to transmission constraints. This process occurs for each hour that resources are dispatched. Resulting monthly or annual hourly prices are derived from that hourly dispatch.
>
> AURORA uses information to build an economic dispatch of generating resources for the market. Units are dispatched according to variable cost, subject to non-cycling and minimum-run constraints until hourly demand is met in each area. Transmission constraints, losses, wheeling costs and unit start-up costs are reflected in the dispatch. The market-clearing price is then determined by observing the cost of meeting an incremental increase in demand in each area. All operating units in an area receive the hourly market-clearing price for the power they generate.

ii. Long Run Optimization

AURORA also has the capability to simulate the addition of new generation resources and the economic retirement of existing units through its long-term optimization studies. This optimization process simulates what happens in a competitive marketplace and produces a set of future resources that have the most value in the marketplace. New units are chosen from a set of available supply alternatives with technology and cost characteristics that can be specified through time. New resources are built only when the combination of hourly prices and frequency of operation for a resource generate enough revenue to make construction profitable, unless reserve margin targets are selected; that is, when investors can recover fixed and variable costs with an acceptable return on investment. AURORA uses an iterative technique in these long-term planning studies to solve the interdependencies between prices and changes in resource schedules.

iii. Use of Reserve Margin Targets

During the summer of 2006, EPIS, Inc. released a new version of AURORAxmp, along with an input database that included the necessary inputs to perform long-term studies using planning reserve margin targets. The model builds resources to meet target reserve margins and estimates the "capacity price payments necessary to support the marginal entrants supplying capacity to the system."[1]

PSE uses reserve margin targets at the pool level, which consists of the Northwest Power Pool territory. The overall pool reserve margin target is 15 percent. PSE tested capacity pool reserve margins at 0 percent, 5 percent, and 15 percent. A pool reserve margin of 15 percent best mitigated summer price spreads without increasing average prices unreasonably. Many U.S. regions plan for at least a 15 percent reserve margin.

Existing units that cannot generate enough revenue to cover their variable and fixed operating costs over time are identified and become candidates for economic retirement. To reflect the timing of transition to competition across all areas, the rate at which existing units can be retired for economic reasons is constrained in these studies for a number of years.

B. Stochastic Model

i. Overview

The goal of the stochastic modeling process is to understand the risks of alternative portfolios in terms of costs and revenue requirements. This requires developing stochastic inputs for the Portfolio Screening Model for risk simulation analysis, which then allows for the development of risk metrics to evaluate alternative portfolios. The stochastic modeling process used in this IRP consists of developing stochastic inputs using Monte Carlo analysis, using the Monte Carlo draws to generate a distribution of resource outputs (dispatched to prices and must take), costs and revenues from AuroraXMP, and utilizing these distributions to perform risk simulations in the PSMIII model for any given portfolio. The stochastic inputs considered in this IRP are MidC

[1] *EPIS, Inc., "Long-Term Studies Using Reserve Margins," from AURORAxmp electronic documentation, December 2005.*

power price, Sumas gas price, CO2 price (once it is introduced), PSE load, hydropower and wind generation. This section describes how PSE developed these stochastic inputs.

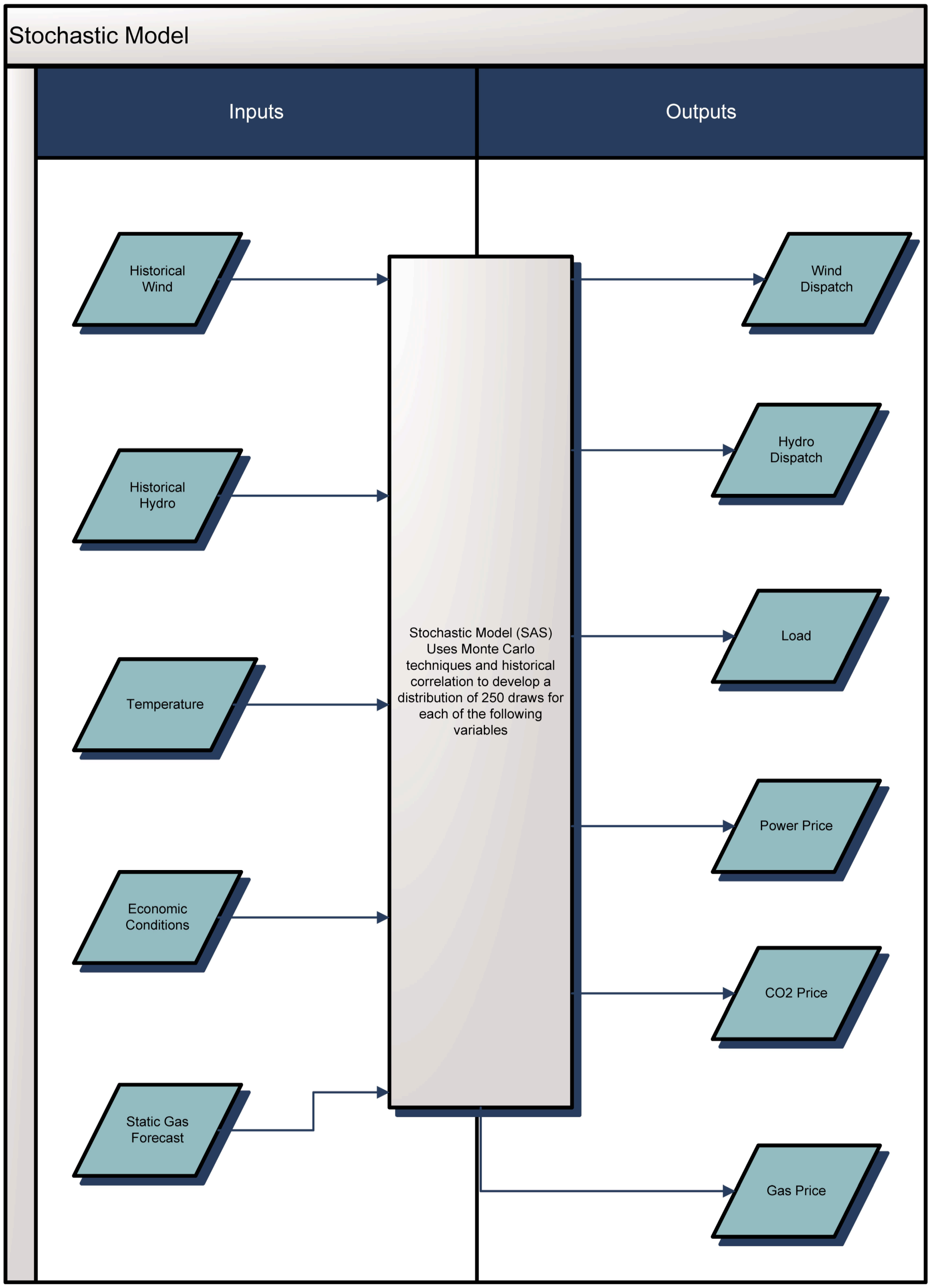
ii. Development of Monte Carlo Draws for the Stochastic Variables

One important aspect in the development of the stochastic variables is the imposition of consistency across draws and key scenarios. This required ensuring, for example, that the same temperature conditions prevail for a load draw and for a power price draw. Figure I-2 shows the key drivers in developing these stochastic inputs. In essence, weather variables and long-term economic conditions determine the variability in the stochastic inputs. Furthermore, two distinct approaches were used to develop the 250 Monte Carlo draws for the inputs: a) loads and prices were developed using econometric analysis given their connection to weather variables (temperature and water conditions) and key economic assumptions, and b) hydro and wind variability were based directly on historical information.

The econometric equations estimated using regression analysis provide the best fit between the individual explanatory values and maximize the predictive value of each explanatory variable to the dependent variable. However, there exist several components of uncertainty in each equation, including: i) uncertainty in the coefficient estimate, ii) uncertainty in the residual error term, iii) the covariate relationship between the uncertainty in the coefficients and the residual error, and iv) uncertainty in the relationship between equations that are simultaneously estimated. Monte Carlo draws utilizing these econometric equations capture these elements of uncertainty.

By preserving the covariate relationships between the coefficients and the residual error, we are able to maintain the relationship of the original data structure as we propagate results through time. For a system of equations, correlation effects between equations are captured through the residual error term. The logic of the linked physical and market relationships needs to be supported with solid benchmark results demonstrating the statistical match of the input values to the simulated data.

Figure I-2
Stochastic Model Diagram



PSE's Load Forecast

PSE developed a set of 250 Monte Carlo load forecast draws by allowing two sets of variable inputs to vary for each draw: 1) weather, and 2) economic-demographic conditions. The load forecast draws were created in three steps. First, PSE created 250 unique annual temperature profiles to use in the place of "normal" weather. Second, we created three separate long-term economic-demographic scenarios to use as the drivers of long-term growth. In the final step, for each of the 250 load forecast draws, a load scenario was created by selecting a unique weather pattern from the first step, plus an economic-demographic scenario selected probabilistically from the second step.

The 250 unique annual temperature profiles were created synthetically. For each temperature profile, an annual hourly temperature shape was selected randomly from the 60 years worth of hourly shapes at Sea-Tac Airport: 1950 to 2010. Each annual hourly temperature shape was adjusted in an additive process to fit an annual average temperature selected according to a probabilistic distribution of historical annual average temperatures, also from Sea-Tac: 1950-2010. By this process, PSE is able to create an infinite amount of unique temperature profiles to test possible load outcomes. For the current IRP, 250 annual temperature profiles were generated.

The three economic-demographic scenarios used in the analysis are the ones underlying the following load forecast scenarios: "2010 Base Case," "2010 Structural Alternate Low," and "2010 Structural Alternate High." Information about the economic-demographic conditions forecast for these three scenarios is detailed in Appendix H. For the Monte Carlo draws, the following probabilities were assigned to the selection of economic scenarios: 80 percent Base Case, 10 percent Structural Low, 10 percent Structural High.

For each of the 250 Monte Carlo load forecast draws, a temperature profile was selected sequentially from the 250 pre-created weather scenarios detailed above, ensuring that each profile was used once and not repeated. For each draw, an economic scenario was selected according to the probabilities listed above. In each draw, the selected weather and economic inputs were used in the econometric load models to forecast a unique load scenario. For more details on the econometric load forecast models, see Appendix H.

Gas and Power Prices

The econometric relationship between prices and their explanatory variables is shown in the two equations below:

Sumas Gas Price = f(US Gas Storage Deviation fr. 5 Yr Avg, Oil Price, Lagged Oil Price, Time Trend)

MidC Power Price = f(Sumas Gas Price, Regional Temperature Deviation from Normal, MidC Hydro Generation, Day of Week, Holidays)

A semi-log functional form is used for each equation. The two equations are estimated simultaneously with one period autocorrelation using historical daily data from January 2003 to August 2010.

Monte Carlo draws were obtained based on the error distributions of the estimated equations, oil price draws, temperature draws, and hydro condition draws. The temperature draws are consistent with those drawn for the load forecast, while the hydro draws are consistent with those drawn directly from the 70-year historical hydro data as described below. Gas price draws were further adjusted so that the 5th percentile, 10th percentile, 90th percentile and 95th percentiles correspond to the very low, low, high and very high gas price scenarios, respectively, based on the rank levelized price of each draw. The price draws were calibrated to ensure that the means of adjusted distributions are equal to the base case prices. Hourly power prices were then obtained using the hourly shape for the base case from AuroraXMP.

Figures I-3 and I-4 show the monthly distribution of gas and power prices for January 2016. As expected, the distribution is skewed positively or right-skewed, implying that there is a higher probability of realizing high prices relative to the mean compared to low prices. The correlation coefficient between gas and power prices for the draws in January 2016 is .75.

Figure I-3
Monthly Sumas Gas Price Distribution – Jan. 2016

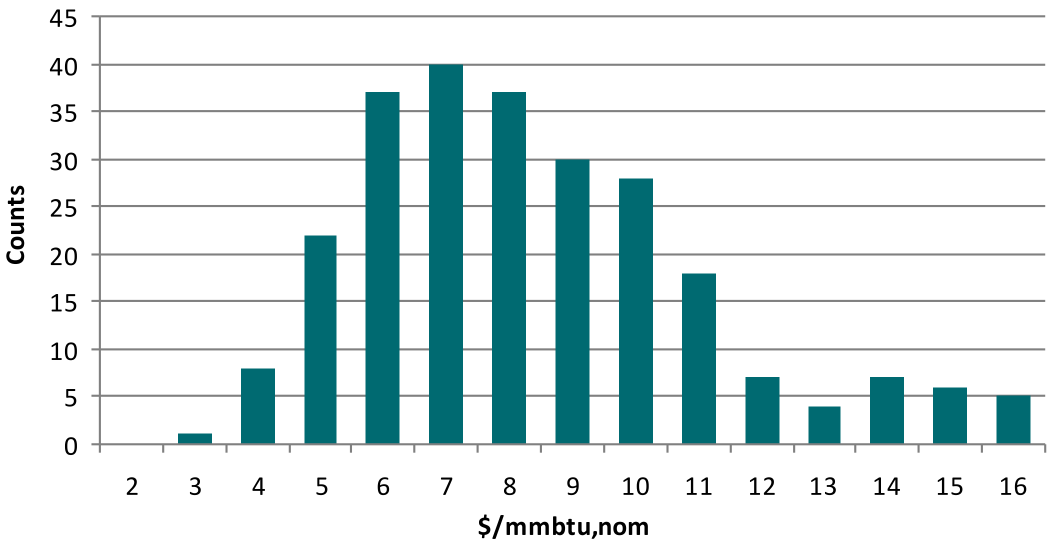
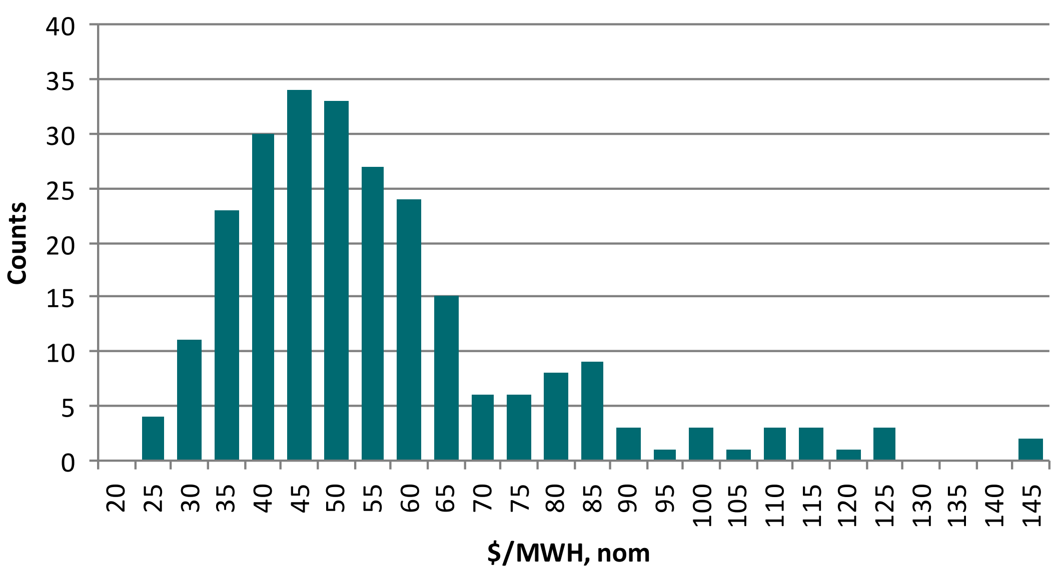


Figure I-4
Monthly Mid-C Power Price Distribution – Jan. 2016



The annual Sumas gas price and MidC power price draws are shown in Figures I-5 and I-6, respectively.

Figure I-5
Annual Sumas Price Draws

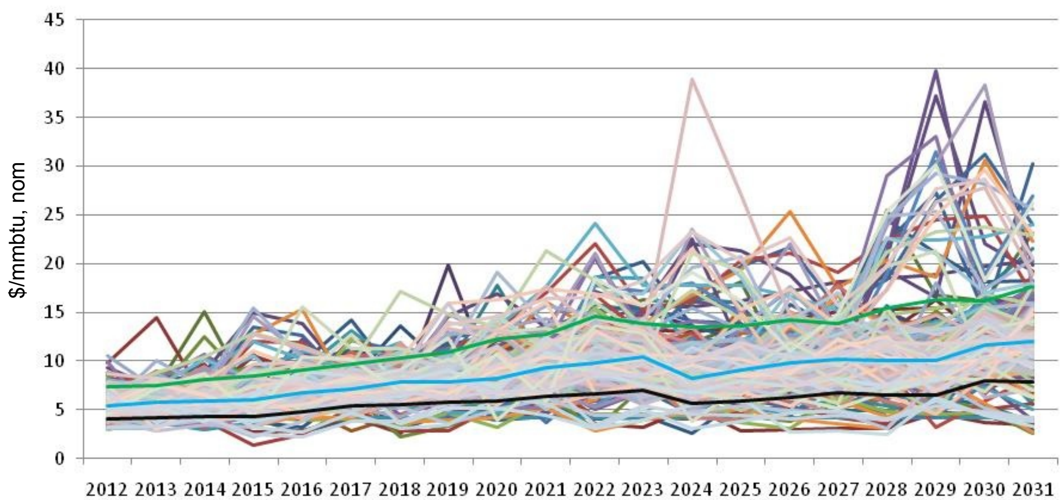
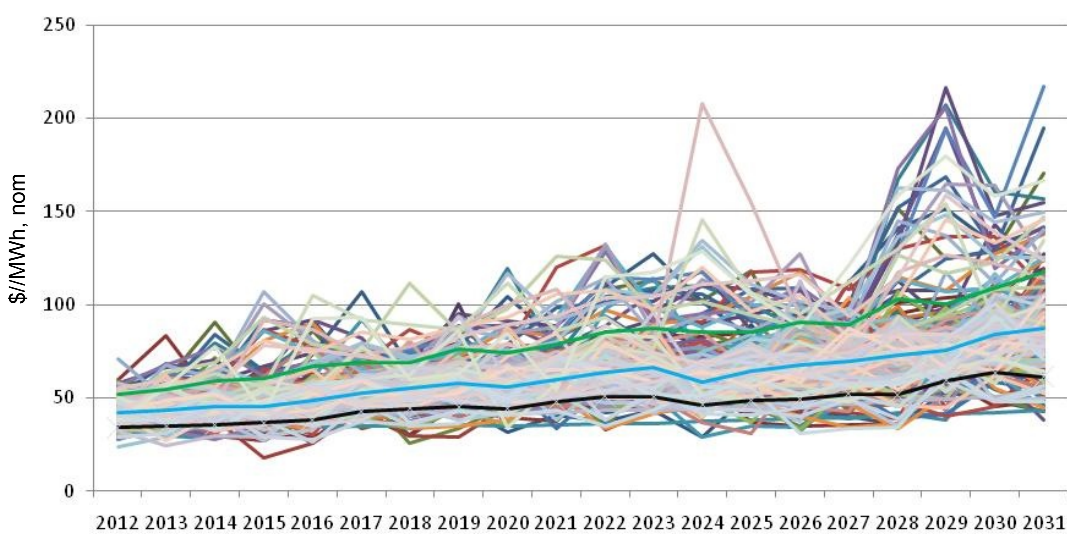


Figure I-6
Annual Mid-C Price Draws

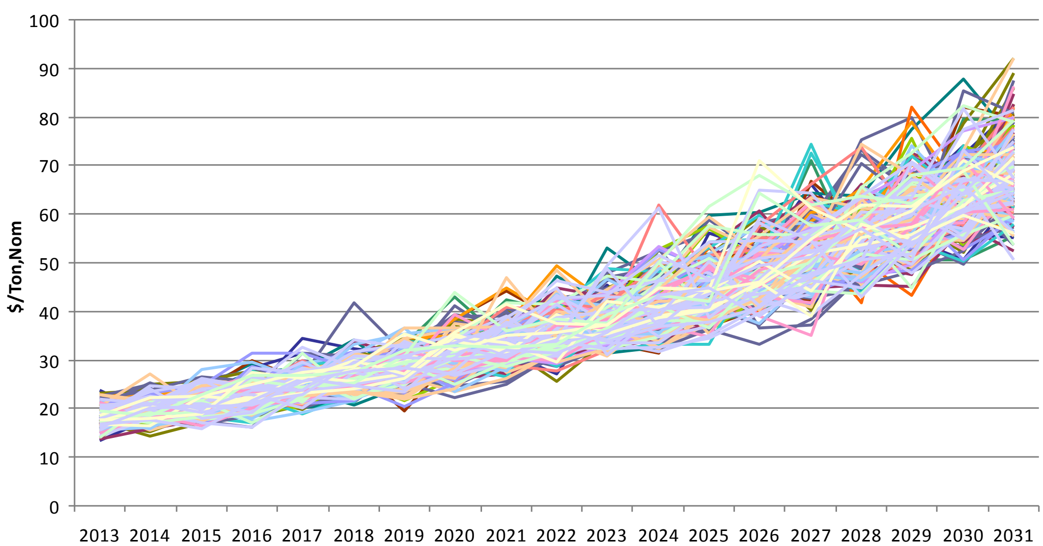


CO2 Prices

Annual CO2 prices in nominal dollars per ton are assumed to follow the EPA study as described in Chapter 4. This implies that the annual price variation will be determined more by how much allowances are put out by the government and the overall macroeconomic conditions. However, given these average annual prices, monthly variations around the annual averages are assumed to vary with the market heat rate based on the gas and power price draws. When gas prices are low, there is less demand for allowances since generators will shift more from coal to gas fuels, and vice versa. Figure I-7 shows the annual CO2 price draws.

Figure I-7

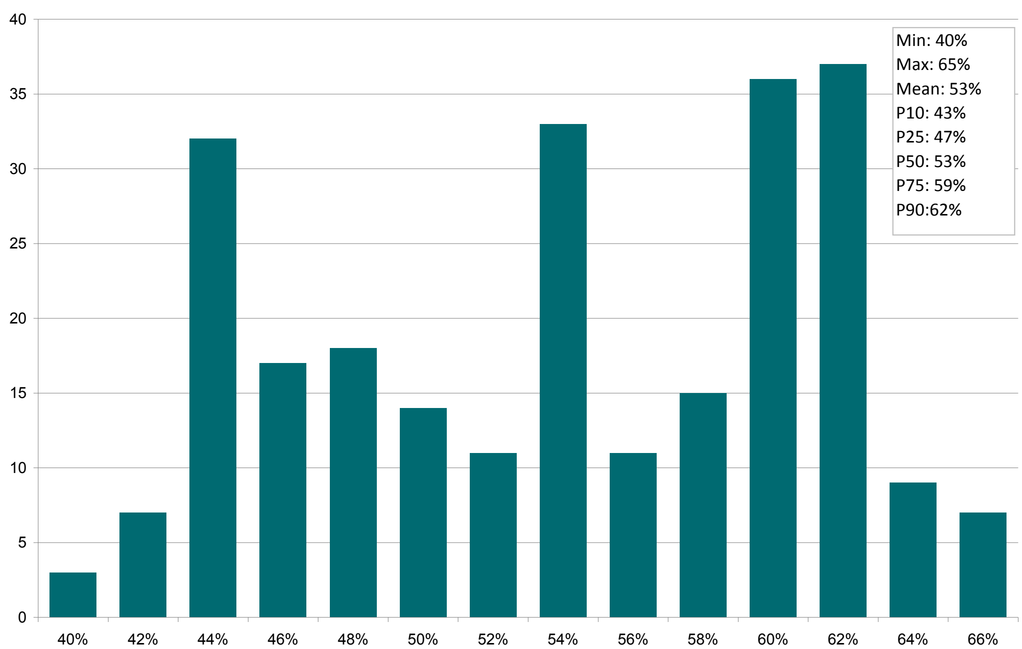
Annual CO2 Price Draws



Hydro Generation

Monte Carlo draws for each of PSE's hydro projects were obtained using the 70-year historical Pacific Northwest Coordination Agreement Hydro Regulation data published in 2010. Each hydro year is assumed to have an equal probability of being drawn in any given calendar year in the planning horizon. Capacity factors and monthly allocations are drawn as a set for each of the 250 draws. This set of 250 hydro draws is applied for each year in the planning horizon. Figure I-8 shows the frequency distribution of capacity factors for Wells based on the 250 draws.

Figure I-8
Frequency of Annual Hydro Capacity Factor for Wells

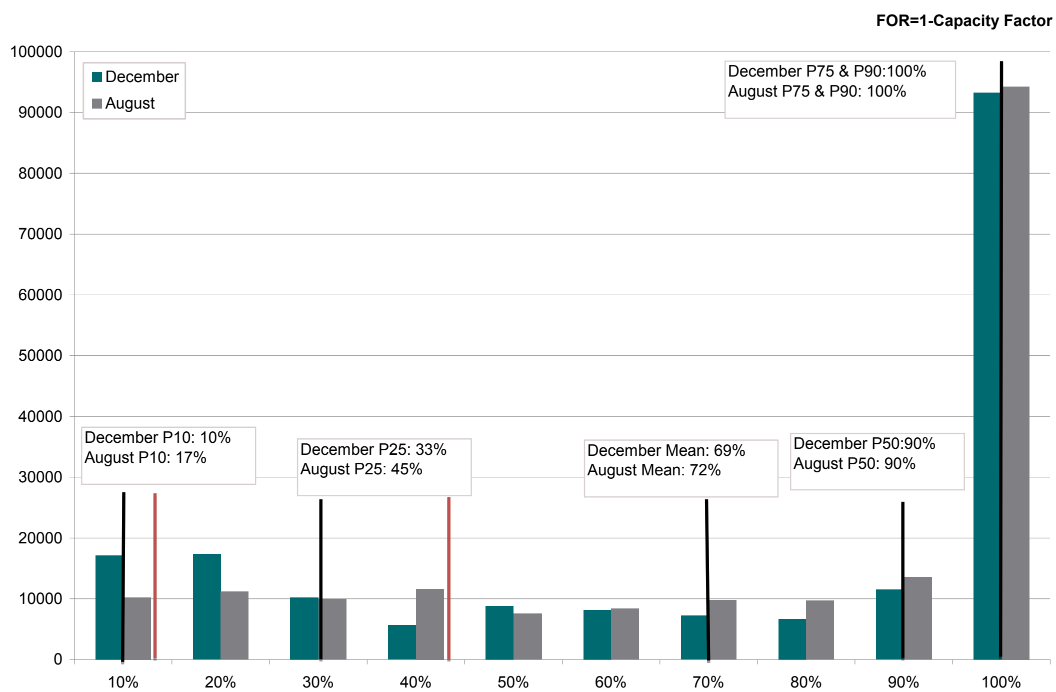


Wind Generation

Since wind is an intermittent resource, one of the goals in developing the generation profile for each wind project considered in this IRP is to ensure that this intermittency is preserved. The other goals are to ensure that there could be correlations across wind farms and the seasonality of wind generation. The wind distributions were derived from 3.5 years of historical data from Hopkins Ridge and Wild Horse. Given the limited historical data that is available to generate the 250 hourly wind profiles, draws of daily 24-hour wind profiles are made each month with each day having an equal probability of being chosen until all days in the month are populated. Since draws for each month are based only on daily profiles within each month, the seasonality of wind generation is also preserved. Finally, draws across wind farms are synchronized on a daily basis to preserve any correlations that may exist between Hopkins Ridge and Wild Horse. The Lower Snake River wind farm, which has not been built yet, is assumed to have the same wind profile as Hopkins Ridge, with a lag since it is located near Hopkins Ridge, and scaled to its nameplate capacity and pro-forma capacity factor. Finally, the generic wind farm is assumed to have a wind profile distribution similar to that of Hopkins Ridge, scaled to a 100 MW capacity. Again, the same set of 250 draws is used for each of the calendar years in the planning horizon. Figure I-9 below shows the frequency distribution of hourly forced outage rate for the generic wind farm for August and December.

Figure I-9

Frequency of Hourly Forced Outage Rate for Generic Wind Farm



iii. Aurora Risk Modeling of PSE Portfolios

The advanced risk modeling capabilities of AuroraXMP are utilized to generate the variable costs, outputs and revenues of any given portfolio. The main advantage of using AuroraXMP is its fast hourly dispatch algorithm for 20 years that is already well known by the majority of Northwest utilities. It also calculates market sales and purchases automatically, and produces other reports such as fuel usage and generation by plant for any time slice. Instead of defining the distributions of the risk variables, however, the set of 250 draws for all of the risk variables (power prices, gas prices, CO2 prices, PSE loads, hydro generation and wind generation) are fed into the AuroraXMP model. Given each of these input draws, AuroraXMP then dispatches PSE's existing portfolio and all generic resources to market price. The results are then saved and passed on to the PSMIII model where expected dispatch energy, expected costs, and revenues are utilized to obtain the optimal set of generic portfolio builds. Revenue requirements based on the expected energy outputs, costs, and revenues can then be computed for each set of portfolio generated by PSMIII.

iv. Risk Simulation in PSM III

In order to perform risk simulation of any given portfolio in PSMIII, the distribution of the stochastic variables must be incorporated into the model. The base case 250 draws of dispatched outputs, costs and revenues for PSE's existing and generic resources were fed into PSMIII from AuroraXMP and the Stochastic Model as described above. Note that these AuroraXMP outputs have already incorporated the variability in gas and power prices, CO2 price, PSE's loads, hydro and wind generation from the Stochastic Model. Frontline System's Risk Solver Platform Excel Add-On allows for the automatic creation of distributions of energy outputs, costs, and revenues based on the 250 draws that PSMII can utilize for the simulation analysis. In addition, peak load distribution, consistent with the energy load distribution, was incorporated into the PSMII. Given these distributions, the risk simulation function in the Risk Solver Platform allowed for drawing 1,000 trials to obtain the expected present value of revenue requirements, TailVar90, and the volatility index for any given portfolio. In addition to computing the risk metrics for the present value of revenue requirements, risk metrics are also computed for annual revenue requirements and power costs. The results of the risk simulation are presented in Chapter 5.

C. Portfolio Screening Model III

i. Overview

The risk model used for this IRP combines the strengths of the stochastic model in generating the Monte Carlo draws for the risk variables with the dispatch algorithm in AuroraXMP, plus the financial modeling detail of the portfolio screening model. Given each draw from the stochastic model, the Aurora model generates the variable costs of dispatched generation from existing/new resources and market purchases/sales for all 250 trials. These outputs are then averaged and the expected is used as inputs into the Portfolio Screening Model, which combines other data to generate the revenue requirements. Below is a description of the various models.

ii. Aurora Risk Modeling of PSE Portfolios

The advanced modeling capabilities of Aurora are utilized to generate the variable costs of any given portfolio. The main advantage of using Aurora is its fast hourly dispatch algorithm for 20 years that is already well known by the majority of Northwest utilities. It also calculates market sales and purchases automatically, and produces other reports such as fuel usage and generation by plant for any time slice. Instead of defining the distributions of the risk variables, however, the set of 250 draws for all of the risk variables (power prices, gas prices, CO2 prices, PSE loads, hydroelectric generation, and wind generation) are fed into the model. Given each of these input draws, Aurora then dispatches a given PSE portfolio to market price and computes the implied market sales and purchases each hour. The average of the 250 draws is then computed, and the expected results are saved and passed on to the portfolio screening model, where the model is optimized to find a portfolio based on a minimized expected revenue requirement. Expected costs and risk metrics can then be computed for each set of portfolio generated by the optimization.

iii. Portfolio Screening Model

The Portfolio Screening Model (PSM3 for version 3) is a spreadsheet-based capacity expansion model that the company developed to evaluate incremental costs and risks of a wide variety of resource alternatives and portfolio strategies. The model produces the optimal mix of resources that minimizes the present value of revenue requirements subject to planning margin and renewable portfolio standard constraints. Incremental cost includes: (i) the variable fuel cost and emissions for PSE’s existing fleet, (ii) the variable cost of fuel emissions and operations and maintenance for new resources, (iii) the fixed depreciation and capital cost of investments in new resources, (iv) the book cost and offsetting market benefit remaining at the end of the 20-year model horizon, and (v) the market purchases or sales in hours when resource dispatched outputs are deficient or surplus to meet PSE's need.

The primary input assumptions to the PSM are:

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

Mathematical representation of PSM III

The purpose of the programming model is to create an optimal mix of new generic resources that minimizes the 20-year net present value of the revenue requirement plus end effects (or total costs) given that the portfolio meets the planning reserve margin (PRM) and the renewable portfolio standard (RPS), and subject to other various non-negativity constraints for the decision variables. The decision variables are the annual integer number of units to add for each type of generic resources being considered in the model. We may add one or two more constraints later on. The revenue requirement is the incremental portfolio cost for the 20-year forecast.

Let:

gn, gr – index for generic non-renewable and renewable resource at time t, respectively;
xn, xr – index for existing non-renewable and renewable resource at time t, respectively;
d(gn) – index for decision variable for generic non-renewable resource at time t;
d(gr) - index for decision variable for generic renewable resource at time t;

AnnCapCost = annual capital costs at time t for each type of resource (the components are defined more fully in the excel model);
VarCost = annual variable costs at time t for each type of resource (the components are defined more fully in the excel model);
EndEff = end effects at T, end of planning horizon, for each type of generic resource only (the components are defined more fully in the excel model);
ContractCost = annual cost of known power contracts;
DSRCost = annual costs of a given demand side resources;
NetMktCost = Market Purchases less market sales of power at time t;
RECSales = Sales of excess over RPS required renewable energy at time t
Cap = capacities of generic and existing resources;
PM = planning margin to be met each t;
MWH = energy production from any resource type gn,gx,xn,xr at time t;
RPS = percent RPS requirement at time t;
PkLd = expected peak load forecast for PSE at time t;
EnLd = forecasted Energy Load for PSE at generator without conservation at time t;
LnLs = line loss associated with transmission to meet load at meter;
DSR = demand side resource energy savings at time t;
r = discount rate.

Annual revenue requirement (for any time t) is defined as:

$$RR_t = \sum_{gn} d(gn)*[AnnCapCost(gn) + VarCost(gn)] + \sum_{gr} d(gr)*[AnnCapCost(gr) + VarCost(gr)] + \sum_{xn} VarCost(xn) + \sum_{xr} VarCost(xr) + ContractCost + DSRCost + NetMktCost - RECSales.$$

a) The objective function for the model is the present value of RR to be minimized. This function is non-linear with integer decision variables.

$$PVRR = \sum_{t=1}^{T} RR_t *[1/(1+r)^t]+ [1/(1+r)^{20}]*[\sum_{gn} d(gn)*EndEff(gn) + \sum_{gr} d(gr)*EndEff(gr)].$$

b) The objective function is subject to two constraints

a. The planning margin was found using the loss of load probability (LOLP) approach. Details about the planning margin can be found later in this appendix. In the model, the planning margin of 15.7 percent is used as a lower bound on the constraint. That is, the model must minimize the objective function while maintaining a minimum of 15.7 percent capacity above the load in any given year. Below is the mathematical representation of how the planning margin is used as a constraint for the optimization.

$$\sum_{gn} d(gn)*Cap(gn) + \sum_{gr} d(gr)*Cap(gr) + \sum_{xr} Cap(xr) + \sum_{xn} Cap(xn) \geq PkLd + PM \text{ for all } t;$$

b. PSE is subject to the Washington state renewable target as stated in RCW 19.285. The load input for PSM is the load at generator, so that the company generates enough power to account for line loss and still meet customer needs. The RPS target is set to the average of the previous two years' load at meter less DSR. The model must minimize the objective function while maintaining a minimum of the total RECs need to meet the state RPS. Below is the mathematical representation of how the RPS is used as a constraint for the optimization.

$$\sum_{gr} \text{d(gr)*MWH(gr)} + \sum_{xr} \text{MWH(xr)} \geq \text{RPS*} \frac{\sum_{t-2}^{t-1} (\text{EnLd} * (1 - \text{LnLs}) - \text{DSR})}{2} \quad \text{for all t;}$$

d(gn), d(gr) ≥ 0, and are integer values for all t,

Other restrictions include total build limits. For example, only one biomass plant can be built a year for a total of four plants over the 20-year time horizon. For the generic wind, five plants may be built in a year, for a total of 10 plants over the 20-year time horizon.

The model is solved using Frontline System's Risk Solver Premium, software that provides various linear, quadratic and nonlinear programming solver engines in Excel environment. Frontline System is the developer of the Solver function that comes standard with Excel. The software solves this non-linear objective function typically in less than a minute. It also provides a simulation tool to calculate the expected costs and risk metrics for any given portfolio.

iv. Monte Carlo Draws for the Risk Simulation

PSE utilized the 250 draws from the stochastic model as the basis for the 1,000 simulated risk trials. For each of the 1,000 trials, a draw was chosen at random from the 250 draws and the revenue requirement for the portfolio was calculated using all the outputs associated with that draw (MidC power price, CO2 price, Sumas natural gas price, hydro generation, wind generation, and load).

2. Data

I. Key Inputs and Assumptions

A. Aurora Inputs

Numerous assumptions are made to establish the parameters that define the optimization process. The first parameter is the geographic size of the market. In reality, the continental United States is divided into three regions, and electricity is not traded between these regions. The western-most region, called the Western Electricity Coordinating Council (WECC), includes the states of Washington, Oregon, California, Nevada, Arizona, Utah, Idaho, Wyoming, Colorado, and most of New Mexico and Montana. The WECC also includes British Columbia and Alberta, Canada, and the northern part of Baja California, Mexico. Electric energy is traded and transported to and from these foreign areas, but is not traded with Texas, for example.

For modeling purposes, the WECC is divided into 30 areas primarily by state and province, except for California which has eight areas, Nevada which has two areas, and Oregon, Washington, Idaho and Montana, which combined have 12 areas. These areas approximate the actual economic areas in terms of market activity and transmission. The databases are organized by these areas and the economics of each area is determined uniquely.

Load forecasts are created for each area. These forecasts include the base year load forecast and an annual average growth rate. Since the demand for electricity changes over the year and during the day, monthly load shape factors and hourly load shape factors are included as well. All of these inputs vary by area: for example, the monthly load shape would show that California has a summer peak demand and the Northwest has a winter peak. For the 2011 IRP, load forecasts for Oregon, Washington, Montana, and Idaho were based on the Northwest Power and Conservation Council (NPCC) 6th Power Plan load forecast. All generating resources are included in the resource database, along with characteristics of each resource, such as its area, capacity, fuel type, efficiency, and expected outages (both forced and unforced). The resource database assumptions are based on EPIS's 2009.02 version produced in October 2009.

Many states in the WECC have passed statutes requiring Renewable Portfolio Standards (RPS) to support the development of renewable resources. Typically, an RPS state has a specific percentage of energy consumed that must come from renewable resources by a certain date (e.g., 10 percent by 2015). While these states have demonstrated clear intent for policy to support renewable energy development, they also provide pathways to avoid such strict requirements. Further details of these assumptions are discussed in Section B below.

Coal prices were adopted from Global Insight's 2009 U.S. Energy Outlook price forecasts.

Water availability greatly influences the price of electric power in the Northwest. PSE assumes that hydropower generation is based on the average stream flows for the 70 historical years of 1929 to 1998. While there is also much hydropower produced in California and the Southwest (e.g., Hoover Dam), it does not drive the prices in those areas as it does in the Northwest. In those areas, the normal expected rainfall and hence, the average power production, is assumed for the model. For sensitivity analysis, PSE can vary the hydropower availability, or combine a past year's water flow to a future year's needs.

Electric power is transported between areas on high voltage transmission lines. When the price in one area is higher than it is in another, electricity will flow from the low priced market to the high priced market (up to the maximum capacity of the transmission system), which will move the prices closer together. The model takes into account two important factors that contribute to the price: first, there is a cost to transport energy from one area to another, which limits how much energy is moved; and second, there are physical constraints on how much energy can be shipped between areas. The limited availability of high voltage transportation between areas allows prices to differ greatly between adjacent areas. EPIS updates the model to include known upgrades (e.g., Path 15 in California) but the model does not add new transmission "as needed."

B. Production Tax Credit and Renewable Portfolio Standard

i. Production Tax Credit Assumptions

The Production Tax Credit (PTC) is one of many federal subsidies related to production of nuclear, oil, gas, and alternative energy. The present PTC amounts to approximately $21 (in 2010 dollars) per MWh for ten years of production, and is indexed for inflation. As of September 2010, the PTC was scheduled to expire at the end of 2012. The reference assumption is that PTCs remain at the current rate through 2012. PTCs are still assumed to be given to a project for 10 years after it is placed into service. As of 2013, this reference assumes no further PTCs are available to new resource development.

ii. Investment Tax Credit Assumptions

The Investment Tax Credit (ITC) is one of many federal subsidies related to production of renewable energy. The present ITC amounts to approximately 30 percent of the capital cost for solar and wind resources, and 10 percent of the capital cost for biomass and geothermal resources. Currently, the ITC is scheduled to expire at the end of 2012. This scenario assumes ITCs remain at the current rate through 2012.

iii. 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, vs. a tax credit, from the federal government. Currently, the Grant amounts to 30 percent 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.

iv. Renewable Portfolio Standard (WECC)

RPSs exist in 29 states and the District of Columbia, including most of the states in the WECC. Each state defines renewable energy sources differently, has different timetables for implementation, and has different requirements for the percentage of load that must be supplied by renewable resources. To model these varying laws, PSE first identified the load forecast for each state in the model. Then the company identified the benchmarks of each RPS (e.g. 3 percent in 2015, then 15 percent in 2020) and applied them to the load forecast for that state. No retirement of existing WECC renewable resources was provided for, which perhaps underestimates the number of new resources that need to be constructed. After existing and expected renewable energy resources were accounted for, new renewable energy resources were matched to the load to meet the RPS. With internal and external review for reasonableness, these resources are created in the AURORA database. The renewable energy technologies included wind, solar, biomass, and geothermal. Estimates of potential production by states in the "Renewable Energy Atlas of the West" served to guide the creation of RPS resources by technology type. These vary considerably. For example, Arizona has little wind potential, but great solar potential.

The Table below includes a brief overview of the RPS for each state in the WECC that has one. The "Standard" column offers a summary of the law, as provided by the Lawrence Berkeley National Laboratory (LBNL), and the "Notes for AURORA Modeling" column includes a description of the new renewable resources created to meet the law.

Figure I-10

RPS Requirements for States in WECC

State	Standard (LBNL)	Notes for AURORA Modeling
Arizona	New Proposed RPS: 1.25% in 2006, increasing by 0.25% each year to 2% in 2009, then increasing by 0.5% a year to 5% in 2015, and increasing 1% a year to 14% in 2024, and 15% thereafter. Of that, 5% must come from distributed renewables in 2006, increasing by 5% each year to 30% by 2011 and thereafter. Half of distributed solar requirement must be from residential application; the other half from non-residential non-utility applications. No more than 10% can come from RECs, derived from non-utility generators that sell wholesale power to a utility.	Very little potential wind generation is available. Most of the requirement is met with central solar plants. The distributed solar (30%) is accounted for by assuming central renewable energy.
British Columbia	Clean renewable energy sources will continue to account for at least 90% of generation. 50% of new resource needs through 2020 will be met by conservation.	The assumption is that a majority of this need will be met by hydropower and wind.
California	IOUs must increase their renewable supplies by at least 1% per year starting January 1, 2003, until renewables make up 20% of their supply portfolios. The target now is to meet 20% level by 2010, with potential goal of 33% by 2020. IOUs do not need to make annual RPS purchases until they are creditworthy. CPUC can order transmission additions for meeting RPS under certain conditions.	The California Energy Commission created an outline of the necessary new resources by technology that could meet the 20% by 2010 goal. Technologies include wind, biomass, solar and geothermal in different areas of the state The renewable energy resources identified in the outline were incorporated into the model.
Colorado	HB 1281 -Expands the definition of "qualifying retail utility" to include providers of retail electric services, other than municipally owned utilities, that serve 40,000 customers or less. Raises the renewable energy standard for electrical generation by qualifying retail utilities other than cooperative electric associations and municipally owned utilities that serve more than 40,000 customers to 5% by 2008, 10% by 2011, 15% by 2015, and 20% by 2020. Establishes a renewable energy standard for cooperative electric associations and municipally owned utilities that serve more than 40,000 customers of 1% by 2008, 3% by 2011, 6% by 2015, and 10% by 2020. Defines "eligible energy resources" to include recycled energy and renewable energy resources.	The primary resource for Colorado is wind. The 4% solar requirement is modeled as central power only.

State	Standard (LBNL)	Notes for AURORA Modeling
Montana	5% of sales (net of line losses) to retail customers in 2008 and 2009; 10% from 2010 to 2014; and 15% in 2015 and thereafter. At least 50 MW must come from community renewable energy projects during 2010 to 2014, increasing to 75 MW from 2015 onward. Utilities are to conduct RFPs for renewable energy or RECs and after contracts of at least 10 years in length, unless the utility can prove to the PSC the shorter-term contracts will provide lower RPS compliance costs over the long-term. Preference is to be given to projects that offer in-state employees or wages.	The primary source for Montana is wind. The community renewable resources are modeled as solar units of 50 MW then 25 MW.
Nevada	6% in 2005 and 2006 and increasing to 9% by 2007 and 2008, 12% by 2009 and 2010, 15% by 2011 and 2012, 18% by 2013 and 2012, ending at 20% in 2015 and thereafter. At least 5% of the RPS standard must be from solar (PV, solar thermal electric, or solar that offsets electricity, and perhaps even natural gas or propane) and not more than 25% of the required standard can be based on energy efficiency measures.	The Renewable Energy Atlas shows that considerable geothermal energy and solar energy potential exists. For modeling the resources are located in the northern and southern part of the state respectively, with the remainder made up with wind.
New Mexico	Senate Bill 418 was signed into law in March 2007 and added new requirements to the state's Renewable Portfolio Standard, which formerly required utilities to get 10% of their electricity needs by 2011 from renewables. Under the new law, regulated electric utilities must have renewables meet 15% of their electricity needs by 2015 and 20% by 2020. Rural electric cooperatives must have renewable energy for 5$ of their electricity needs by 2015, increasing to 10% by 2020. Renewable energy can come from new hydropower facilities, from fuel cells that are not fossil-fueled, and from biomass, solar, wind, and geothermal resources.	New Mexico has a relatively large amount of wind generation currently for its small population. New resources are not required until 2015, at which time they are brought in as wind generation.
Oregon	Large utility targets: 5% in 2011, 15% in 2015, 20% in 2020 and 25% in 2025. Large utility sales represented 73% of total sales in 2002. Medium utilities 10% by 2025 Small utilities 5% by 2025.	
Washington	Washington state RPS: 3% by 2012, 9% by 2016, 15% by 2020. Eligible resources include wind, solar, geothermal, biomass, tidal. Oregon officials have been discussing the need for an RPS, and the governor has proposed 25% by 2025.	

v. Renewable Portfolio Standard (PSE)

The current PSE resources that meet the Washington state RPS include Hopkins Ridge, Wild Horse, Klondike III, Snoqualmie Upgrades, Lower Snake River I, and Lower Baker Upgrades. The Washington state RPS also gives an extra 20 percent credit to renewable resources that use apprenticeship labor. That is, with the adder a resource can contribute 120 percent to RCW 19.285. The PSE resources that can claim the extra 20 percent are Wild Horse Expansion, Lower Snake River I and Lower Baker Upgrades. For modeling purposes, we assume that the generic wind receives the extra 20 percent.

C. Generic Resource Costs and Characteristics

Figure I-11
Generic Resource Costs and Characteristics

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

The generic Combined Cycle Combustion Turbine (CCCT) is assumed to be a 1x1 facility with a dry air cooled condenser.

D. Financial Assumptions

We used the pre-tax weighted average cost of capital (WACC) from the 2009 General Rate Case of 8.1 percent nominal or 6.89 percent after-tax. The REC price of $8/MWh in 2012 was escalated at 2.5 percent.

E. Wind Capacity Credit

i. Methodology Used

The wind capacity credits for PSE's existing and prospective wind farms were developed by applying the ELCC (equivalent load carrying capability) approach with our LOLP (loss of load probability) model. In essence, the ELCC approach identifies the equivalent capacity of a peaker plant that would yield the same loss of load probability as the capacity of a given wind farm. The ratio of the equivalent peaker capacity to the wind capacity is the ELCC or the capacity credit of the wind farm. Appendix I of the 2009 IRP provides a detailed description of the LOLP model. The basic idea of the LOLP model is to shock the electric system with Monte Carlo draws of hourly loads, forced outages, hydro conditions, and availability of transmission for market purchases to determine the percent of the time that a load is greater than resources over the number of iterations. This might require adding more resources in order to achieve the industry standard of five percent LOLP.

In order to implement the ELCC approach in the LOLP model, the distribution of wind hourly generation for each of the existing and prospective wind farms was developed. These are described in Appendix I, in the Stochastic Model portion of the Methods and Models section, under the Wind Generation subheading. Given these distributions, the wind farms were incrementally added into the LOLP model to determine the reduction in peaker capacity to achieve the 5 percent loss of load probability. The ratio of the change in peaker capacity with and without the incremental wind capacity is that wind farm's capacity credit. The order in which the existing and prospective wind farms were added in the model follows the schedule when these wind farms were acquired or about to be acquired by PSE: Wild Horse, Hopkins Ridge, Lower Snake River, then a generic wind resource expected to be located in southeast Washington close to the Lower Snake River project, or a generic wind resource located in Kittitas County close to the Wild Horse project.

ii. Results

The figure below shows the results of the ELCC study.

Figure I-12
Effective Load Carrying Capability of Wind

Summary All Wind	Wind Capacity	Effective Thermal Capacity	ELCC
Hopkins Ridge	157	23	14.8%
Wild Horse	272	39	14.5%
Lower Snake River	342	33	9.6%
Generic SE WA(w/Added Transmission)	100	2	1.8%
Generic Kittitas(w/Added Transmission)	100	5	4.9%

* Wild Horse is supply only since it displaces existing transmission allocated for short-term market purchase.

These results indicate that wind power's contribution to capacity is not as significant as other resources, such as thermal power. Although the capacity contribution of existing wind facilities is higher than the regional assumption of 5 percent, subsequent wind farms are likely to show lower capacity contribution because of the correlation of wind outputs with pre-existing farms. This result is consistent with those found in earlier studies. While diversity may show different capacity credit, the differences in amounts are not significant. These results are highly dependent on PSE's resource mix, load characteristics, and projected distribution of wind profiles.

F. Planning Standard

The company's planning standard is a 15.7 percent planning margin for capacity plus relevant operating reserves. PSE's planning margin is net of operating reserves. This is so the specific implications of different resource operating reserve requirements can be modeled independently. For example, peakers must carry 7 percent contingency reserves, but demand-side resources have none. Embedding operating reserves in the planning margin would not allow the company to reflect such differences in our analytical framework. This planning standard was adopted in the 2009 IRP. It is consistent with the NW Regional Resource Adequacy Forum [2] on the adoption of a Loss of Load Probability approach to planning that is common in other parts of the country. PSE values the NW Regional Resource Adequacy Forum's work on resource adequacy. It is the best assessment available in the region and PSE actively participates on both the steering committee and technical committee.

The following summarizes how the company derived the 15.7 percent planning margin standard:

The primary objective of PSE's capacity planning standard analysis was to determine the appropriate level of planning margin for the utility. Planning margin for capacity is, in general, defined as the appropriate level of generation resource capacity reserves required to provide for a minimum acceptable level of system generation reliability. This is one of the key constraints in any capacity expansion planning model, because it is important to maintain a uniform reliability standard throughout the planning period to obtain comparable capacity expansion plans. This planning margin is measured as:

Planning Margin = (Generation Capacity – Normal Peak Loads)/Normal Peak Loads

The appropriate level of planning margin is typically identified in terms of its relationship with the loss of load probability (LOLP). LOLP is further defined as the probability of system loads greater than resource capability in any given hour, or

LOLP = Probability [-(Generation Capacity-Loads)>0].

Thus, as the reserve margin increases, one would expect that the LOLP also decreases. Because of uncertainties in loads due to extreme temperature events and resource capabilities due to outages and operating reserves, it is necessary to examine the probabilities using a Monte Carlo analysis.

[2] *A description of the NW Regional Resource Adequacy Forum and the standards adopted can be found at:* http://www.nwcouncil.org/energy/resource/Default.asp

The starting point for the Monte Carlo simulation analysis is the short-term winter peaking analysis completed every summer for the subsequent winter. The analysis identifies various resources available to meet the 13 degree Fahrenheit, one-hour, predicted peak load, given available transmission capability. Historical data tells us that December is when the peak load condition is typically experienced. The resources included are Colstrip, Mid Columbia and western Washington hydroelectric resources, several gas plants (simple- and combined-cycle units), purchased power contracts, and market purchases up to the available transmission capability. The following sources of variation were considered:

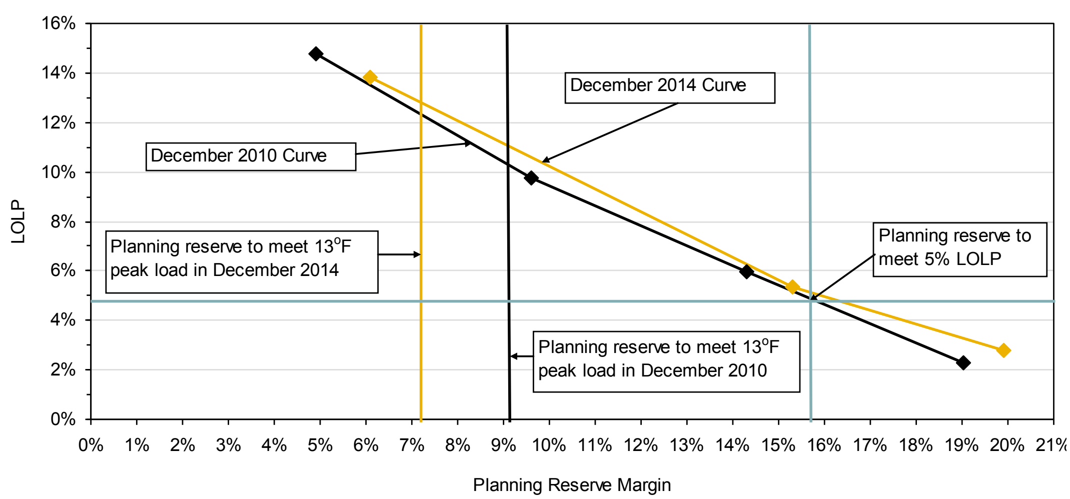
1. Forced Outage Rate for Thermal Units - modeled as a combination of an outage event and duration of an outage event (skewed beta distribution with fixed endpoints), subject to minimum up and down time conditions and total outage rate equal to GRC reported outage rate;
2. Hourly System Loads – modeled as an econometric function of hourly temperature for the month, and using the hourly temperature data in the last 100 years to preserve its chronological order;
3. Mid Columbia and Baker Hydropower – modeled as a binomial distribution with the critical hydro water year at 1/70th probability;
4. Market Purchases – modeled as 50 percent from hydropower with same variability as Mid Columbia resources; 50 percent from thermal with same variability as a combined cycle unit since it is difficult to determine the exact source of market purchases;
5. Load Forecast Error – modeled as a discrete distribution so that load error is +/- 1 percent for 60 percent of the trials, with a range of +/-3.5 percent.

As mentioned above, loss of load probability is defined as the number of trials where PSE observed a loss of load over the total number of trials. 3,000 trials were conducted. Such a large number was chosen because at this level the resulting loss of load frequency becomes very stable. The simulation is also done for all hours in 2010 and all hours in 2014. This allows the utility to capture the effects of increasing loads and the expiration of some Mid Columbia hydropower contracts, as well as non utility generator (NUG) contracts and other short-term purchase contracts.

The goal of the simulation analysis for any hour is to run the simulation for the existing resource and load conditions, which imply an existing reserve margin. Loss of load probability associated with this reserve margin is then computed based on the 3,000 Monte Carlo draws of the risk variables. Generating capacity is then incremented using a combined-cycle plant as the “typical” plant added which results in a higher reserve margin. Again, the loss of load probability associated with this higher reserve margin is computed based on the Monte Carlo simulation of the risk variables. The process is repeated until the loss of load probability is reduced to an industry standard level.

The results of these simulations are shown in Figure I-13. The figure illustrates that the planning reserve margin implied by a 5 percent LOLP is around 15.7 percent for both years. The figure also demonstrates that the LOLP implied by meeting the 13 degrees Fahrenheit peak loads from the B2 Energy Planning Standard is much higher (10 percent for December 2010 and 13 percent for December 2014) if no additional resources are added. The 5 percent LOLP is chosen to be consistent with the regionally adopted loss of load for resource adequacy standards. Similar LOLP analyses were performed for every month, primarily to reflect seasonal hydropower availability. PSE focused discussion on December because the company found that if we have resources adequate to meet the 5 percent LOLP in December, we will have resources sufficient to meet that reliability threshold during the rest of the year.

Figure I-13
Planning Margin and LOLP



II. Output

A. Aurora Electric Prices and Avoided Costs

Below is a series of tables with the AURORA price forecasts for the different scenarios. Consistent with WAC 480-107-055, this schedule of estimated Mid Columbia power prices is intended to provide only general information to potential bidders about the avoided costs of power supply. It does not provide a guaranteed contract price for electricity.

Figure I-14
Monthly Flat Mid-C Prices
(Nominal $/MWH)

Base

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2012	44.76	47.59	40.87	35.77	31.49	32.60	40.71	43.06	45.59	44.68	52.64	50.30	42.51
2013	47.30	50.48	43.39	39.00	32.32	32.83	42.07	45.01	48.56	46.03	52.87	52.20	44.34
2014	49.14	52.01	44.41	39.32	32.62	33.74	44.01	47.04	51.13	48.66	57.18	56.55	46.32
2015	49.97	53.45	45.78	40.87	34.13	36.56	46.13	48.59	52.50	49.76	58.18	57.34	47.77
2016	53.65	56.98	49.10	44.15	35.68	38.67	49.18	52.51	55.69	51.51	62.25	59.26	50.72
2017	58.06	60.26	49.71	44.74	36.03	39.64	52.88	57.01	60.10	57.52	68.33	65.55	54.15
2018	61.94	65.31	52.74	46.38	35.81	38.37	55.71	61.46	64.83	59.54	68.74	68.16	56.58
2019	63.96	67.89	55.89	51.50	39.35	40.75	58.82	63.58	66.98	61.65	71.63	70.90	59.41
2020	65.80	65.64	51.37	44.88	31.03	36.65	58.57	64.70	69.60	64.52	74.88	73.29	58.41
2021	69.80	69.77	54.58	47.17	32.47	39.56	64.57	70.24	74.13	64.48	80.28	77.19	62.02
2022	74.11	75.24	61.54	56.06	38.04	45.27	68.13	75.93	78.65	69.03	85.79	81.19	67.42
2023	75.46	75.02	57.75	48.70	34.58	42.00	69.48	78.45	82.12	76.57	90.53	84.73	67.95
2024	70.32	72.37	55.53	48.85	35.71	37.30	65.62	71.73	75.64	67.31	78.33	77.05	62.98
2025	73.05	74.97	60.27	55.60	39.58	42.59	67.85	73.75	78.18	68.59	80.95	80.93	66.36
2026	76.89	78.25	60.28	51.89	36.49	42.91	71.85	78.43	84.30	76.69	89.39	87.71	69.59
2027	78.36	81.21	62.04	52.20	37.37	45.12	73.84	80.09	83.76	72.55	90.78	89.16	70.54
2028	82.68	86.50	69.16	61.11	45.68	53.52	77.94	84.55	86.80	77.55	97.40	93.60	76.37
2029	89.35	93.43	69.50	57.92	44.22	47.37	82.14	92.93	98.68	88.65	102.76	101.27	80.68
2030	97.01	99.74	73.16	62.22	48.08	50.68	89.97	97.70	103.22	88.97	107.90	107.80	85.54
2031	98.78	103.57	79.91	73.09	54.86	60.14	92.16	98.37	106.15	91.09	111.71	112.22	90.17

Base + CO_2

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2012	43.22	46.30	41.14	35.71	31.40	32.60	40.52	42.68	45.34	44.55	52.31	48.80	42.05
2013	54.07	58.12	51.90	47.86	44.50	46.00	51.30	54.16	57.13	54.48	61.58	60.07	53.43
2014	56.48	60.65	54.29	50.10	46.77	47.99	53.71	56.85	60.49	57.01	66.40	63.78	56.21
2015	58.28	63.57	57.99	53.24	48.47	51.07	56.93	59.55	63.07	60.27	68.68	66.41	58.96
2016	62.10	67.26	60.27	55.14	51.39	53.52	59.63	63.01	66.26	63.82	73.71	71.28	62.28
2017	66.66	71.86	64.24	58.04	54.11	56.66	63.99	68.00	71.51	68.74	80.02	77.06	66.74
2018	71.39	77.50	68.89	62.08	55.82	58.29	68.20	73.02	76.75	73.47	82.56	81.13	70.76
2019	74.45	80.48	71.93	65.81	59.01	60.73	71.82	75.91	80.28	76.32	85.94	84.20	73.91
2020	77.28	81.75	72.55	65.74	57.11	59.90	74.30	78.45	83.37	78.84	90.80	87.94	75.67
2021	83.54	87.01	77.57	70.86	60.39	63.79	80.07	84.74	88.63	83.23	96.53	92.03	80.70
2022	89.06	91.33	84.00	78.46	63.44	67.52	84.75	91.31	93.97	87.79	101.64	95.34	85.72
2023	91.63	92.78	83.33	75.33	62.52	64.72	87.12	94.40	96.96	92.53	106.61	99.99	87.33
2024	89.50	94.70	84.04	75.63	61.24	61.21	86.84	93.01	96.30	90.63	100.18	97.68	85.91
2025	93.96	99.34	89.62	81.89	63.53	66.23	91.31	96.74	101.09	94.79	105.33	103.54	90.61
2026	99.01	105.05	91.96	81.99	65.77	68.66	96.14	103.07	108.46	101.86	114.47	111.57	95.67
2027	103.34	109.81	95.93	86.62	67.69	73.07	99.82	107.24	111.03	104.45	118.32	115.27	99.38
2028	109.28	115.94	103.72	93.58	75.31	83.07	105.32	112.73	114.86	110.55	125.41	120.75	105.88
2029	115.52	123.04	106.97	90.31	73.21	77.05	111.79	121.26	125.63	118.14	131.92	129.81	110.39
2030	123.64	130.68	111.97	97.82	77.49	82.35	120.42	127.17	131.26	123.26	138.28	136.58	116.74
2031	129.19	139.96	120.49	108.15	82.25	91.18	127.67	132.55	138.03	129.57	145.95	145.64	124.22

Load Growth

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2012	33.58	36.59	32.95	29.21	27.17	28.44	32.34	33.98	36.09	35.24	41.58	39.58	33.90
2013	35.89	38.27	34.31	31.09	27.69	28.13	33.36	35.34	37.81	36.21	41.90	40.79	35.07
2014	38.42	40.67	35.84	32.14	28.42	29.43	35.72	37.76	41.02	38.66	45.43	44.26	37.31
2015	40.45	43.49	38.14	34.27	30.19	32.03	38.14	40.05	43.25	41.56	48.41	46.35	39.69
2016	41.50	44.66	39.33	35.63	29.46	31.69	38.73	41.11	44.15	42.20	49.82	46.87	40.43
2017	43.04	45.28	39.46	35.34	29.29	31.72	40.14	42.86	46.01	44.13	52.84	49.63	41.65
2018	44.22	47.31	40.52	35.97	29.11	29.47	40.88	44.09	47.42	43.98	51.64	49.12	41.98
2019	45.29	48.26	41.89	38.17	30.11	30.70	41.85	44.63	48.29	44.92	52.42	50.22	43.06
2020	45.05	46.05	39.27	34.48	25.28	26.97	40.97	44.37	48.24	44.68	53.12	50.50	41.58
2021	45.66	46.88	40.08	34.63	25.07	27.27	41.71	45.08	48.12	43.84	53.28	50.03	41.80
2022	45.55	47.05	42.52	38.31	27.21	29.40	42.06	46.37	49.64	45.04	55.00	49.72	43.16
2023	46.73	47.03	40.38	34.76	24.71	26.47	42.41	47.68	50.62	47.57	57.29	52.21	43.16
2024	48.33	49.57	42.00	36.93	24.72	24.52	43.60	48.93	52.89	48.10	55.25	51.78	43.89
2025	49.68	50.80	44.58	40.34	25.25	27.08	44.31	49.39	53.85	48.70	56.31	53.27	45.30
2026	51.12	52.29	42.56	37.67	21.80	26.66	45.02	51.36	56.82	52.20	60.15	56.93	46.22
2027	52.27	53.60	43.67	37.92	21.23	27.04	45.37	52.36	56.88	51.15	60.69	57.07	46.60
2028	53.03	55.06	46.92	40.77	24.62	29.48	46.06	53.66	57.57	52.19	62.66	57.80	48.32
2029	54.88	56.64	46.27	38.61	21.99	25.12	46.76	55.67	61.63	56.45	63.82	60.78	49.05
2030	58.81	59.79	46.22	39.48	22.39	25.25	49.13	57.32	62.03	56.66	65.84	63.52	50.54
2031	58.14	61.49	53.33	48.60	27.33	33.17	51.66	59.36	65.12	59.69	69.18	64.22	54.27

High Growth

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2012	50.77	52.32	45.51	39.11	33.39	34.69	45.24	48.16	51.13	49.95	58.24	55.61	47.01
2013	56.91	58.88	51.36	44.90	36.71	36.50	50.11	53.65	58.07	54.69	62.20	61.65	52.14
2014	61.68	63.92	52.81	46.95	36.76	38.16	54.53	58.43	64.10	60.14	69.55	69.58	56.38
2015	68.70	71.84	58.66	52.41	40.39	43.11	61.03	65.31	70.52	66.12	76.93	76.61	62.64
2016	75.62	79.73	66.12	58.91	44.70	48.56	66.83	72.78	77.48	72.22	85.89	85.01	69.49
2017	75.05	77.52	61.09	54.29	42.17	46.64	66.65	72.83	77.89	73.53	86.49	85.30	68.29
2018	74.41	78.17	61.11	53.03	40.62	42.20	65.98	72.85	77.80	70.69	82.16	82.49	66.79
2019	80.14	83.66	66.77	61.23	45.55	46.60	72.39	78.52	83.62	74.74	88.06	88.27	72.46
2020	83.06	82.90	61.34	53.61	34.61	42.35	74.25	82.15	89.40	79.08	94.48	94.12	72.61
2021	84.45	83.95	63.45	53.70	33.83	43.68	76.04	83.62	88.77	74.40	94.71	94.25	72.90
2022	85.62	87.95	68.94	61.55	39.93	49.57	77.14	86.41	91.04	77.39	99.02	97.21	76.81
2023	95.97	92.98	69.12	57.47	38.14	48.52	85.64	97.00	104.05	93.87	114.53	110.11	83.95
2024	96.87	97.89	69.73	59.29	39.26	44.96	86.15	96.46	102.90	85.75	104.52	107.09	82.57
2025	97.57	98.98	74.71	66.33	43.02	51.14	87.44	95.63	103.96	85.31	107.36	109.11	85.05
2026	104.13	103.61	73.41	60.51	38.54	53.22	92.56	102.29	114.51	100.18	122.14	120.86	90.50
2027	109.69	110.19	78.34	63.96	42.11	57.90	97.49	107.05	116.13	94.81	126.31	125.17	94.10
2028	112.63	116.03	88.25	76.94	56.73	67.32	100.70	111.26	118.13	100.42	133.19	129.59	100.93
2029	117.04	119.61	84.55	68.90	52.37	59.14	104.06	118.87	128.99	114.51	136.69	136.19	103.41
2030	123.11	124.78	86.89	70.74	55.59	62.27	110.67	120.85	130.90	109.24	138.51	138.80	106.03
2031	131.91	139.52	108.65	97.19	76.12	81.24	117.34	128.53	138.20	121.49	146.00	149.45	119.64

Green World

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2012	49.41	51.03	44.78	38.61	32.93	34.39	44.92	47.43	50.32	48.98	57.09	54.65	46.21
2013	73.38	77.50	71.95	66.33	62.29	62.98	70.63	73.84	77.58	74.15	81.07	79.66	72.61
2014	77.35	82.59	76.28	70.49	65.79	67.07	75.19	78.37	83.01	78.87	88.09	86.01	77.43
2015	85.47	89.85	83.66	77.12	72.01	74.31	82.84	85.92	90.16	87.20	95.82	93.57	84.83
2016	90.41	95.61	88.32	82.43	76.99	80.39	87.73	91.93	95.71	92.45	104.57	100.30	90.57
2017	92.80	96.97	89.71	82.97	77.37	81.65	89.41	94.03	97.96	94.80	106.81	103.08	92.30
2018	94.60	101.44	93.76	85.85	75.60	80.03	92.02	96.52	100.91	97.13	105.50	103.22	93.88
2019	100.68	107.48	99.52	92.54	82.47	85.55	97.87	102.50	107.25	103.14	112.57	109.77	100.11
2020	106.86	111.36	102.82	92.90	73.62	77.06	101.34	106.77	113.14	108.14	120.43	115.98	102.53
2021	112.17	117.61	107.50	94.00	72.62	79.21	106.31	111.88	118.04	113.93	125.59	120.39	106.60
2022	118.11	123.45	115.56	105.86	79.70	85.91	111.73	118.29	124.24	119.84	132.06	126.03	113.40
2023	129.34	132.70	120.05	104.55	80.43	82.88	121.30	128.05	135.87	131.12	146.13	138.89	120.94
2024	133.71	138.71	124.67	109.10	80.40	74.02	123.08	132.28	140.64	134.36	145.42	141.25	123.14
2025	140.79	146.02	134.43	119.72	80.04	82.54	127.17	137.19	147.34	140.42	152.56	148.76	129.75
2026	148.54	154.30	129.74	100.98	69.09	75.76	134.45	145.06	156.69	150.12	163.43	159.66	132.32
2027	157.89	163.68	134.37	114.76	69.24	78.69	141.81	153.71	164.36	155.60	173.40	168.67	139.68
2028	165.66	170.88	147.76	129.40	84.09	87.71	145.37	158.91	168.39	162.53	179.58	174.05	147.86
2029	170.10	178.93	137.96	100.35	61.22	67.12	146.97	168.24	178.46	168.37	185.38	182.08	145.43
2030	178.60	184.42	135.59	106.77	62.83	67.61	153.98	174.94	184.64	171.53	192.06	191.29	150.36
2031	185.90	196.61	172.13	152.46	82.09	87.25	165.25	182.46	193.54	182.61	203.75	201.20	167.10

Very High Gas

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2012	49.89	51.79	45.45	39.14	33.92	34.95	45.27	48.03	50.67	49.09	57.61	54.55	46.70
2013	57.19	59.73	51.61	46.67	37.21	37.13	50.91	54.96	58.47	55.35	62.65	61.86	52.81
2014	63.85	66.33	55.30	49.17	37.95	39.79	57.16	61.71	66.39	62.21	71.71	71.44	58.58
2015	74.16	76.83	62.37	55.31	41.71	45.57	65.56	70.96	74.99	70.68	81.28	80.95	66.70
2016	82.25	84.72	70.33	61.10	47.34	51.47	72.56	79.35	82.75	77.59	91.24	89.88	74.22
2017	82.29	83.68	63.71	56.83	42.88	48.71	73.24	80.34	84.46	80.13	93.97	91.72	73.50
2018	82.88	85.07	65.30	56.94	41.19	45.00	73.32	81.21	85.54	77.68	90.43	90.66	72.94
2019	89.31	92.04	71.86	65.97	47.95	49.66	79.32	86.46	91.34	82.41	96.16	96.62	79.09
2020	90.93	85.49	64.44	53.50	33.69	44.14	78.66	88.29	96.15	87.96	102.52	100.61	77.20
2021	95.15	90.14	66.74	54.86	36.20	46.37	82.19	90.49	96.42	82.15	104.11	103.06	78.99
2022	95.37	95.46	75.74	67.23	41.99	52.83	84.33	94.48	99.17	84.74	109.29	105.52	83.85
2023	108.45	100.21	73.63	57.86	40.30	51.41	93.81	107.71	114.92	106.90	127.51	120.22	91.91
2024	109.32	104.36	75.17	61.92	40.81	45.90	95.77	107.23	113.85	95.35	116.85	115.70	90.19
2025	109.44	107.30	82.35	73.45	46.67	55.40	97.49	107.95	116.11	97.14	119.95	120.91	94.51
2026	117.38	111.35	79.00	63.07	39.77	55.30	106.37	119.40	130.91	117.19	138.98	134.95	101.14
2027	118.19	113.37	81.08	62.37	38.69	57.88	109.38	120.82	128.54	104.06	138.44	132.96	100.48
2028	121.72	121.26	94.17	79.39	50.79	67.95	113.15	124.18	128.47	108.51	143.83	135.96	107.45
2029	124.79	123.84	83.57	64.68	41.58	52.76	114.61	131.89	142.63	124.95	146.41	142.68	107.87
2030	129.73	126.83	84.49	67.62	43.62	54.98	121.21	132.12	140.81	114.57	143.52	142.54	108.50
2031	134.85	134.50	99.71	87.12	53.50	69.51	125.44	135.85	147.66	119.62	149.90	151.26	117.41

Very Low Gas

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2012	34.51	36.52	32.79	29.15	27.31	28.47	32.37	34.11	36.19	35.17	41.73	39.35	33.97
2013	34.65	37.07	33.25	30.32	27.52	27.88	32.47	34.50	36.90	35.27	40.45	39.15	34.12
2014	34.74	37.35	33.34	29.94	27.34	28.06	32.79	34.88	37.72	35.59	42.02	40.46	34.52
2015	35.69	38.78	34.69	30.84	28.08	29.38	33.68	35.64	38.18	36.85	41.97	40.79	35.38
2016	34.36	37.14	33.43	30.29	27.39	28.53	32.67	34.74	37.28	35.65	41.84	39.63	34.41
2017	34.99	38.38	33.72	29.88	27.17	28.70	33.02	35.43	37.62	36.70	44.03	41.51	35.10
2018	35.39	39.31	34.38	30.31	26.94	27.35	33.22	35.88	38.22	36.91	42.38	41.12	35.12
2019	35.46	39.68	34.34	30.47	27.12	27.26	33.55	35.91	38.79	37.16	43.17	41.53	35.37
2020	34.94	38.81	33.60	29.36	24.83	25.67	33.10	35.18	39.02	36.85	44.02	42.04	34.79
2021	35.61	39.85	34.10	29.86	25.07	26.45	33.66	35.80	39.45	37.27	44.46	42.21	35.32
2022	35.71	40.23	34.75	30.31	26.57	27.11	33.66	36.42	39.64	38.01	45.25	42.29	35.83
2023	36.70	40.94	34.95	29.95	25.49	26.51	34.36	37.16	40.60	39.57	46.99	43.99	36.43
2024	38.45	43.24	36.45	31.06	25.94	25.04	35.21	38.07	41.71	40.00	46.43	44.45	37.17
2025	38.78	44.05	37.40	31.44	26.89	26.65	35.71	38.26	42.32	40.37	47.41	45.94	37.94
2026	39.76	44.76	37.33	30.92	25.49	26.14	36.49	39.21	43.44	41.29	49.28	47.80	38.49
2027	41.18	47.02	38.29	31.36	26.04	27.49	37.38	40.39	44.33	41.80	50.90	48.88	39.59
2028	42.25	47.69	39.11	32.36	27.89	29.18	37.84	41.59	44.88	42.94	51.99	49.65	40.61
2029	43.54	49.55	40.21	32.06	27.32	27.08	38.56	43.66	47.25	44.02	52.58	51.50	41.44
2030	44.70	50.29	40.46	32.75	27.55	27.18	39.43	43.88	47.69	44.13	52.48	51.54	41.84
2031	45.84	51.43	41.85	34.39	28.47	29.32	40.43	44.44	49.02	45.08	53.51	53.02	43.07

B. Electric Demand-Side Screening Results

The results in the following tables were part of the bundles provided by Cadmus Group. See Appendix K for a discussion of Cadmus' methodology and analysis.

Figure I-15

Annual Energy Savings (aMW)

Bundles A through H includes Energy Efficiency, Fuel Conversion, Distributed Generation, and Distribution Efficiency

	Bundle									
	A	B	C	D	E	F	G	H	DE	EISA
2012	27.5	32.5	36.4	38.0	39.0	40.8	41.6	50.1	1.1	4.1
2013	56.1	67.0	74.9	78.1	80.3	83.9	85.5	102.9	2.2	11.9
2014	82.7	100.1	112.2	117.1	120.6	126.1	128.5	155.1	3.4	22.6
2015	107.8	132.7	149.0	155.7	160.8	168.2	171.5	207.6	4.5	31.7
2016	132.2	165.5	186.1	194.6	201.9	211.3	215.4	261.4	5.7	39.6
2017	155.2	197.4	222.3	232.6	242.5	253.8	258.8	314.6	7.2	46.1
2018	178.9	230.6	260.1	272.2	284.7	298.0	303.9	369.8	8.8	51.8
2019	203.1	266.0	300.8	315.0	330.1	345.5	352.3	428.6	10.3	56.5
2020	227.8	298.3	338.6	354.9	372.8	390.3	398.0	485.4	12.0	77.6
2021	251.3	328.5	374.1	392.4	412.9	432.5	441.1	539.1	13.6	95.3
2022	258.5	339.0	386.3	405.3	427.5	447.5	456.2	557.7	15.7	111.1
2023	265.9	349.7	398.7	418.4	442.3	462.7	471.6	576.8	17.9	125.1
2024	274.2	361.8	412.8	433.4	459.1	480.1	489.1	598.2	20.1	137.6
2025	280.7	371.4	424.1	445.4	472.7	494.0	503.2	616.0	22.3	147.3
2026	288.3	382.4	437.0	459.0	488.2	509.9	519.2	636.6	24.6	155.7
2027	295.7	393.2	449.7	472.4	503.1	525.3	534.8	656.6	27.0	162.7
2028	304.1	405.1	463.5	487.0	519.1	541.9	551.5	678.1	29.6	169.6
2029	311.1	415.2	475.5	499.7	532.7	555.9	565.7	696.3	31.9	174.9
2030	319.1	426.8	489.0	514.1	548.0	571.7	581.6	716.9	34.4	180.3
2031	327.0	438.2	502.3	528.2	563.0	587.2	597.3	737.2	36.8	185.5

Figure I-16

Total December Peak Reduction (MW)

Bundles A through H includes Energy Efficiency, Fuel Conversion, Distributed Generation, Distribution Efficiency, and Demand Response

	Bundle										
	A	B	C	D	E	F	G	H	DE	EISA	DR
2012	37	49	56	59	61	63	64	77	2	5	10
2013	75	99	115	120	124	128	130	157	4	16	20
2014	110	149	172	180	186	192	195	237	5	30	30
2015	144	197	228	240	248	256	260	317	7	42	49
2016	176	246	286	300	312	322	327	400	9	52	50
2017	206	294	342	359	375	387	392	482	11	61	51
2018	237	342	398	419	437	451	458	564	14	68	75
2019	268	392	457	482	504	520	527	649	16	74	90
2020	300	439	514	542	567	586	594	734	19	102	127
2021	319	467	549	578	607	626	635	787	21	121	144
2022	342	501	589	621	652	673	683	847	25	146	162
2023	350	513	604	637	670	692	701	872	28	165	165
2024	358	525	617	651	685	708	717	894	32	181	169
2025	367	539	634	668	705	727	737	921	35	194	172
2026	377	554	652	688	726	749	759	952	39	205	175
2027	388	570	672	709	749	773	783	986	43	215	179
2028	397	584	688	726	767	792	802	1013	46	223	182
2029	405	597	704	742	785	810	820	1039	50	231	185
2030	414	610	720	759	803	829	839	1065	55	238	189
2031	424	626	738	779	823	850	860	1096	58	245	193

The DSR December peak reduction is based on the average of the very heavy load hours (VHLH). The VHLH method takes the average of the five-hour morning peak from hour ending 7 a.m. to hour ending 11 a.m. and the five-hour evening peak from hour ending 6 p.m. to hour ending 10 p.m. Monday through Friday.

Figure I-17

Annual Costs (Thousands $)

Bundles A through E includes Energy Efficiency, Fuel Conversion, Distributed Generation, Distribution Efficiency, and Demand Response

	Bundle										
	A	B	C	D	E	F	G	H	DE	EISA	DR
2012	$29,160	$58,001	$85,232	$100,108	$110,522	$130,716	$140,619	$612,534	$1,184	$0	$8,839
2013	$30,105	$62,458	$90,733	$106,239	$116,837	$137,504	$147,585	$640,565	$1,184	$0	$9,680
2014	$30,862	$66,407	$95,589	$111,582	$122,339	$143,429	$153,652	$664,289	$1,184	$0	$10,078
2015	$31,268	$70,914	$100,770	$117,167	$128,088	$149,599	$159,941	$686,937	$1,184	$0	$17,698
2016	$31,813	$76,031	$106,677	$123,416	$134,511	$156,456	$166,898	$709,821	$1,184	$0	$4,301
2017	$32,306	$79,869	$111,280	$128,286	$139,563	$161,942	$172,466	$731,104	$2,002	$0	$4,376
2018	$32,754	$82,686	$114,798	$132,004	$143,464	$166,272	$176,851	$750,660	$2,002	$0	$30,166
2019	$33,657	$94,223	$132,473	$151,449	$163,334	$187,145	$198,361	$795,614	$2,002	$0	$11,651
2020	$34,186	$73,849	$113,370	$132,735	$144,891	$169,237	$180,610	$793,174	$2,002	$0	$42,737
2021	$34,449	$73,202	$112,554	$132,044	$144,407	$168,841	$180,192	$806,499	$2,002	$0	$16,283
2022	$9,940	$29,082	$43,407	$49,621	$52,157	$57,244	$59,308	$279,141	$2,537	$0	$18,112
2023	$10,200	$29,183	$43,824	$50,086	$52,843	$58,079	$60,182	$292,652	$2,537	$0	$14,714
2024	$10,486	$29,412	$44,391	$50,747	$53,732	$59,134	$61,279	$307,334	$2,537	$0	$14,953
2025	$10,714	$29,635	$44,895	$51,382	$54,480	$60,015	$62,194	$318,708	$2,537	$0	$15,192
2026	$10,966	$29,946	$45,486	$52,146	$55,351	$61,031	$63,243	$330,688	$2,537	$0	$15,434
2027	$11,240	$30,358	$46,162	$53,037	$56,341	$62,178	$64,422	$342,605	$2,678	$0	$15,679
2028	$11,468	$30,896	$46,937	$54,064	$57,455	$63,446	$65,714	$352,867	$2,678	$0	$15,923
2029	$11,736	$31,631	$47,923	$55,357	$58,840	$65,032	$67,335	$364,341	$2,678	$0	$16,194
2030	$12,002	$32,627	$49,111	$56,875	$60,431	$66,813	$69,139	$375,724	$2,678	$0	$16,459
2031	$12,278	$33,502	$50,112	$58,245	$61,863	$68,444	$70,788	$387,273	$2,678	$0	$16,730

C. Electric Integrated Portfolio Results

This chart summarizes the expected costs of the different portfolios.

Figure I-18

Revenue Requirements with Expected Inputs for the Scenario

Scenario	20-yr NPV Expected Cost ($Millions)						Expected Portfolio Cost $/MWh
	Expected Portfolio Cost	Net Purchases/ (Sales)	DSR Rev. Req.	Generic Rev. Req.	Variable Cost of Existing	REC Revenue	
Base	$13,365	$5,207	$1,262	$3,913	$3,035	($52)	$46.72
Base + CO2	$15,928	$5,210	$1,262	$4,647	$4,861	($51)	$55.68
Low Growth	$9,826	$2,283	$1,262	$3,282	$3,057	($56)	$36.17
High Growth	$18,582	$7,435	$1,262	$5,900	$4,057	($71)	$61.66
Very Low Gas	$10,870	$2,016	$767	$5,076	$3,061	($50)	$37.70
Very High Gas	$16,455	$6,749	$1,262	$4,605	$3,917	($78)	$57.51
Green World	$21,065	$6,847	$1,513	$5,412	$7,534	($242)	$77.54
PTC Sensitivity							
Base + PTC/ITC Extension 2013	$13,331	$5,025	$1,262	$4,102	$3,035	($94)	$46.60
Base + PTC/ITC Extension 2016	$13,271	$5,044	$1,262	$4,018	$3,035	($88)	$46.39
Base + PTC/ITC Extension 2020	$13,241	$5,120	$1,262	$3,896	$3,035	($72)	$46.29
Base + PTC/ITC Extension 2031	$13,236	$5,175	$1,262	$3,823	$3,035	($59)	$46.27
Risk Sensitivity							
Base + Fixed Gas Transport	$14,103	$5,195	$1,262	$4,664	$3,035	($53)	$49.30
Base + No Peakers	$14,539	$2,796	$1,262	$7,507	$3,035	($60)	$50.83
Base + Thermal Mix	$14,259	$3,130	$1,262	$6,702	$3,035	($50)	$49.85
Base + No DSR	$16,071	$6,842	$0	$6,239	$3,035	($45)	$56.18

Figure I-19

Revenue Requirement with Input Simulations – 1000 Trials

20-yr NPV Portfolio Cost ($Millions)	Risk Simulation - 1000 Trials			
	Base	Base + Thermal Mix	Base + No Peaker	Base + No DSR
Expected	$13,365	$14,259	$14,539	$16,071
Minimum	$9,235	$9,699	$9,993	$10,592
1st Quartile (P25)	$12,402	$13,218	$13,428	$14,987
Mean	$13,349	$14,209	$14,448	$16,045
Median	$13,122	$14,062	$14,346	$15,794
3rd Quartile (P75)	$13,712	$14,746	$15,021	$16,474
TVar90	$17,902	$18,411	$18,525	$21,433
Maximum	$20,508	$21,168	$21,348	$24,237
Standard Deviation	$1,850	$1,801	$1,787	$2,182
Annual Volatility	18.1%	17.4%	17.1%	18.5%

Figure I-20

Base

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	68	10
2013	-	-	-	-	-	75	10
2014	-	1,065	-	-	-	78	10
2015	-	-	-	-	-	76	19
2016	-	-	-	-	-	76	1
2017	-	-	-	-	500	74	1
2018	-	-	-	-	-	73	23
2019	-	-	-	-	-	75	16
2020	-	213	300	25	-	94	36
2021	-	-	-	-	-	66	17
2022	-	-	-	-	-	69	18
2023	-	213	-	-	-	40	3
2024	-	213	-	-	-	35	3
2025	-	-	-	-	-	36	3
2026	-	-	-	-	-	36	3
2027	-	213	100	-	-	36	3
2028	-	-	-	-	-	30	3
2029	-	213	-	25	-	29	4
2030	-	213	-	-	-	29	4
2031	-	-	-	-	-	31	4
Total	0	2343	400	50	500	1126	193

Figure I-21
Base + CO_2

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	68	10
2013	-	-	-	-	-	75	10
2014	-	1,065	-	-	-	78	10
2015	-	-	-	-	-	76	19
2016	-	-	-	-	-	76	1
2017	-	-	-	-	500	74	1
2018	-	-	-	-	-	73	23
2019	-	-	-	-	-	75	16
2020	-	213	300	-	-	94	36
2021	-	-	-	-	-	66	17
2022	-	-	-	-	-	69	18
2023	-	213	-	-	-	40	3
2024	-	213	-	-	-	35	3
2025	-	-	-	-	-	36	3
2026	-	-	100	-	-	36	3
2027	-	213	-	-	-	36	3
2028	-	-	-	-	-	30	3
2029	-	426	100	-	-	29	4
2030	-	-	-	-	-	29	4
2031	-	-	-	-	-	31	4
Total	0	2343	500	0	500	1126	193

Figure I-22
Low Growth

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	68	10
2013	-	-	-	-	-	75	10
2014	-	852	-	-	-	78	10
2015	-	-	-	25	-	76	19
2016	-	-	-	25	-	76	1
2017	-	-	-	-	500	74	1
2018	-	-	-	-	-	73	23
2019	-	-	-	-	-	75	16
2020	-	-	200	-	-	94	36
2021	-	-	-	-	-	66	17
2022	-	-	-	-	-	69	18
2023	-	213	-	-	-	40	3
2024	-	-	-	-	-	35	3
2025	-	-	100	-	-	36	3
2026	-	213	-	-	-	36	3
2027	-	-	-	-	-	36	3
2028	-	213	-	-	-	30	3
2029	-	-	-	-	-	29	4
2030	-	-	-	-	-	29	4
2031	-	-	-	-	-	31	4
Total	0	1491	300	50	500	1126	193

Figure I-23
High Growth

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	68	10
2013	-	-	-	-	-	75	10
2014	-	1,065	-	25	-	78	10
2015	-	213	-	25	-	76	19
2016	-	-	-	25	-	76	1
2017	-	-	-	-	500	74	1
2018	-	-	-	-	-	73	23
2019	-	-	-	25	-	75	16
2020	-	213	200	-	-	94	36
2021	-	213	-	-	-	66	17
2022	-	-	200	-	-	69	18
2023	-	213	-	-	-	40	3
2024	-	213	-	-	-	35	3
2025	-	-	-	-	-	36	3
2026	-	213	-	-	-	36	3
2027	-	213	-	-	-	36	3
2028	-	-	-	-	-	30	3
2029	-	426	-	-	-	29	4
2030	-	213	-	-	-	29	4
2031	-	-	-	-	-	31	4
Total	0	3195	400	100	500	1126	193

Figure I-24
Green World

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	70	10
2013	-	-	-	-	-	77	10
2014	-	852	-	-	-	80	10
2015	-	-	500	-	-	78	19
2016	-	-	500	-	-	78	1
2017	-	-	-	-	500	76	1
2018	-	-	-	-	-	75	23
2019	-	-	-	-	-	77	16
2020	-	-	-	-	-	96	36
2021	-	-	-	-	-	67	17
2022	-	-	-	-	-	71	18
2023	-	213	-	-	-	40	3
2024	-	-	-	-	-	36	3
2025	-	-	-	-	-	37	3
2026	-	213	-	-	-	37	3
2027	-	-	-	-	-	36	3
2028	-	-	-	-	-	31	3
2029	-	213	-	-	-	30	4
2030	-	-	-	-	-	30	4
2031	-	-	-	-	-	32	4
Total	0	1491	1000	0	500	1153	193

Figure I-25
Very Low Gas

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	56	10
2013	-	-	-	-	-	63	10
2014	-	1,065	-	-	-	65	10
2015	-	-	-	-	-	62	19
2016	-	213	-	-	-	61	1
2017	-	-	-	-	500	59	1
2018	-	-	-	-	-	58	23
2019	-	-	-	-	-	59	16
2020	-	213	300	-	-	77	36
2021	-	-	100	-	-	54	17
2022	-	-	-	-	-	58	18
2023	-	213	-	-	-	35	3
2024	-	213	-	-	-	31	3
2025	-	-	-	-	-	31	3
2026	-	-	-	-	-	30	3
2027	-	213	100	-	-	29	3
2028	-	-	-	-	-	25	3
2029	-	426	-	-	-	25	4
2030	-	-	100	-	-	25	4
2031	-	-	-	-	-	26	4
Total	0	2556	600	0	500	929	193

Figure I-26
Very High Gas

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	68	10
2013	-	-	-	-	-	75	10
2014	-	1,065	-	25	-	78	10
2015	-	-	-	25	-	76	19
2016	-	-	-	25	-	76	1
2017	-	-	-	-	500	74	1
2018	-	-	-	25	-	73	23
2019	-	-	-	-	-	75	16
2020	-	213	100	-	-	94	36
2021	-	-	200	-	-	66	17
2022	-	-	-	-	-	69	18
2023	-	213	-	-	-	40	3
2024	-	-	-	-	-	35	3
2025	-	213	-	-	-	36	3
2026	-	-	-	-	-	36	3
2027	-	213	-	-	-	36	3
2028	-	-	-	-	-	30	3
2029	-	213	-	-	-	29	4
2030	-	213	-	-	-	29	4
2031	-	-	-	-	-	31	4
Total	0	2343	300	100	500	1126	193

Figure I-27

Base + Fixed Gas Transport

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	68	10
2013	-	-	-	-	-	75	10
2014	-	1,065	-	-	-	78	10
2015	-	-	-	-	-	76	19
2016	-	-	-	-	-	76	1
2017	-	-	-	-	500	74	1
2018	-	-	-	-	-	73	23
2019	-	-	-	-	-	75	16
2020	-	213	300	-	-	94	36
2021	-	-	-	-	-	66	17
2022	-	-	-	-	-	69	18
2023	-	213	-	25	-	40	3
2024	-	-	-	25	-	35	3
2025	-	213	-	25	-	36	3
2026	-	-	-	-	-	36	3
2027	-	213	-	-	-	36	3
2028	-	-	-	-	-	30	3
2029	-	426	100	-	-	29	4
2030	-	-	-	-	-	29	4
2031	-	-	-	-	-	31	4
Total	0	2343	400	75	500	1126	193

Figure I-28

Base + No Peaker

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	71	10
2013	-	-	-	-	-	78	10
2014	1,002	-	-	-	-	81	10
2015	-	-	-	25	-	79	19
2016	-	-	-	25	-	79	1
2017	-	-	-	-	500	77	1
2018	-	-	-	-	-	76	23
2019	-	-	-	-	-	78	16
2020	334	-	300	-	-	97	36
2021	-	-	-	-	-	68	17
2022	-	-	-	-	-	71	18
2023	334	-	-	-	-	40	3
2024	-	-	-	-	-	36	3
2025	-	-	-	-	-	37	3
2026	334	-	-	-	-	37	3
2027	-	-	100	-	-	36	3
2028	-	-	-	-	-	31	3
2029	334	-	-	-	-	30	4
2030	-	-	-	-	-	30	4
2031	-	-	-	-	-	32	4
Total	2338	0	400	50	500	1163	193

Figure I-29

Base + Thermal Mix

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	68	10
2013	-	-	-	-	-	75	10
2014	668	426	-	-	-	78	10
2015	-	-	-	-	-	76	19
2016	-	-	-	-	-	76	1
2017	334	213	-	-	-	74	1
2018	-	-	-	-	-	73	23
2019	-	-	-	-	-	75	16
2020	-	213	300	-	-	94	36
2021	-	-	-	-	-	66	17
2022	334	-	-	-	-	69	18
2023	-	-	-	-	-	40	3
2024	-	-	-	-	-	35	3
2025	-	-	-	25	-	36	3
2026	-	213	-	-	-	36	3
2027	-	-	100	-	-	36	3
2028	-	-	-	-	-	30	3
2029	-	-	-	25	500	29	4
2030	-	-	-	-	-	29	4
2031	-	-	-	-	-	31	4
Total	1336	1065	400	50	500	1126	193

Figure I-30

Base + PTC/ITC Extension 2013

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	68	10
2013	-	-	300	-	-	75	10
2014	-	1,065	-	-	-	78	10
2015	-	-	-	-	-	76	19
2016	-	-	-	-	-	76	1
2017	-	-	-	-	500	74	1
2018	-	-	-	-	-	73	23
2019	-	-	-	-	-	75	16
2020	-	213	-	-	-	94	36
2021	-	-	-	-	-	66	17
2022	-	-	-	-	-	69	18
2023	-	213	-	-	-	40	3
2024	-	213	-	-	-	35	3
2025	-	-	-	-	-	36	3
2026	-	-	100	-	-	36	3
2027	-	213	-	-	-	36	3
2028	-	-	-	-	-	30	3
2029	-	426	100	-	-	29	4
2030	-	-	-	25	-	29	4
2031	-	-	-	-	-	31	4
Total	0	2343	500	25	500	1126	193

Figure I-31

Base + PTC/ITC Extension 2016

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	68	10
2013	-	-	-	-	-	75	10
2014	-	1,065	-	-	-	78	10
2015	-	-	-	-	-	76	19
2016	-	-	400	-	-	76	1
2017	-	-	-	-	500	74	1
2018	-	-	-	-	-	73	23
2019	-	-	-	-	-	75	16
2020	-	213	-	-	-	94	36
2021	-	-	-	-	-	66	17
2022	-	-	-	-	-	69	18
2023	-	213	-	-	-	40	3
2024	-	213	-	-	-	35	3
2025	-	-	-	-	-	36	3
2026	-	-	-	-	-	36	3
2027	-	213	-	-	-	36	3
2028	-	-	-	-	-	30	3
2029	-	426	-	25	-	29	4
2030	-	-	-	-	-	29	4
2031	-	-	100	-	-	31	4
Total	0	2343	500	25	500	1126	193

Figure I-32

Base + PTC/ITC Extension 2020

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	68	10
2013	-	-	-	-	-	75	10
2014	-	1,065	-	-	-	78	10
2015	-	-	-	-	-	76	19
2016	-	-	-	-	-	76	1
2017	-	-	-	-	500	74	1
2018	-	-	-	-	-	73	23
2019	-	-	-	-	-	75	16
2020	-	213	500	-	-	94	36
2021	-	-	-	-	-	66	17
2022	-	-	-	-	-	69	18
2023	-	213	-	-	-	40	3
2024	-	213	-	-	-	35	3
2025	-	-	-	-	-	36	3
2026	-	-	-	-	-	36	3
2027	-	213	-	-	-	36	3
2028	-	-	-	-	-	30	3
2029	-	426	-	-	-	29	4
2030	-	-	-	25	-	29	4
2031	-	-	-	-	-	31	4
Total	0	2343	500	25	500	1126	193

Figure I-33
Base + PTC/ITC Extension 2031

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	68	10
2013	-	-	-	-	-	75	10
2014	-	1,065	-	-	-	78	10
2015	-	-	-	-	-	76	19
2016	-	-	-	-	-	76	1
2017	-	-	-	-	500	74	1
2018	-	-	-	-	-	73	23
2019	-	-	-	-	-	75	16
2020	-	213	300	25	-	94	36
2021	-	-	-	-	-	66	17
2022	-	-	100	-	-	69	18
2023	-	213	-	-	-	40	3
2024	-	213	-	-	-	35	3
2025	-	-	-	-	-	36	3
2026	-	-	-	-	-	36	3
2027	-	213	-	-	-	36	3
2028	-	-	-	-	-	30	3
2029	-	213	-	25	-	29	4
2030	-	213	-	-	-	29	4
2031	-	-	-	-	-	31	4
Total	0	2343	400	50	500	1126	193

Figure I-34
Base + No DSR

	CCGT	Peaker	Wind	Biomass	Transmission	DSR	DR
2012	-	-	-	-	-	-	-
2013	-	-	-	-	-	-	-
2014	-	1,278	-	-	-	-	-
2015	-	213	-	-	-	-	-
2016	-	-	-	-	-	-	-
2017	-	-	-	-	500	-	-
2018	-	213	-	-	-	-	-
2019	-	213	-	-	-	-	-
2020	-	213	400	25	-	-	-
2021	-	213	-	25	-	-	-
2022	-	-	-	25	-	-	-
2023	-	213	-	-	-	-	-
2024	-	213	100	-	-	-	-
2025	-	-	-	-	-	-	-
2026	-	213	-	-	-	-	-
2027	-	213	100	-	-	-	-
2028	-	-	-	-	-	-	-
2029	-	426	100	-	-	-	-
2030	-	-	-	-	-	-	-
2031	-	213	-	-	-	-	-
Total	0	3834	700	75	500	0	0

D. Incremental Cost of Renewable Resources to meet RCW 19.285 Incremental Cost Alternative Compliance

1. Overview

According to RCW 19.285, certain electric utilities in Washington must meet 15 percent of their retail electric load with eligible renewable resources by the calendar year 2020. The annual target for the calendar year 2012 is 3 percent of retail electric load. However, if the incremental cost of those renewable resources compared to an equivalent non-renewable is greater than 4 percent of its revenue requirement, then a utility will be considered in compliance with the annual renewable energy target in RCW 19.285. “The incremental cost of an eligible renewable resource is calculated as the difference between the levelized delivered cost of the eligible renewable resource, regardless of ownership, compared to the levelized delivered cost of an equivalent amount of reasonably available substitute resource that do not qualify as eligible renewable resources”[3] (equivalent non-renewable).

2. Analytic Framework

This analysis compares the revenue requirement cost of each renewable resource with the projected market value and capacity value at the time of the renewable acquisition. This, “contemporaneous” with the decision-making aspect of PSE’s approach, is important. Utilities should be able to assess whether they will exceed the cost cap before an acquisition, without having to worry about ex-post adjustments that could change compliance status. The analytical framework here reflects a close approximation of the portfolio analysis used by PSE in resource planning, as well as in the evaluation of bids received in response to the company’s Request for Proposals (RFP).

[3] *RCW 19.285.050 (1) (a) (b)*

3. Resources that meet RCW 19.285 definition of Eligible Renewable Resource

Figure I-35

Resources that meet RCW 19.285 definition of Eligible Renewable Resource

	Nameplate (MW)	Annual Energy (aMW)	Commercial Online Date	Market Price/ Peaker Assumptions	Capacity Credit Assumption
Hopkins Ridge	149.4	53.3	Dec 2005	2004 RFP	20%
Wild Horse	228.6	73.4	Dec 2006	2006 RFP	17.2%
Klondike III	50	18.0	Dec 2007	2006 RFP	15.6%
Hopkins Infill	7.2	2.4	Dec 2007	2007 IRP	20%
Wild Horse Expansion	44	10.5	Dec 2009	2007 IRP	15%
Lower Snake River I	342.7	102.5	Apr 2012	2010 Trends	5%
Snoqualmie Upgrades	6.1	3.9	Mar 2013	2009 Trends	95%
Lower Baker Upgrades	30	12.5	May 2013	2011 IRP Base	95%
Generic Wind 2020	300	89.7	Jan 2020	2011 IRP Base	1.8%
Generic Wind 2027	100	29.9	Jan 2027	2011 IRP Base	1.8%
Generic Biomass 2020	25	21.25	Jan 2020	2011 IRP Base	93%
Generic Biomass 2029	25	21.25	Jan 2029	2011 IRP Base	93%

4. Equivalent Non-Renewable

The incremental cost of a renewable resource is defined as the difference between the levelized cost of the renewable resource compared to an equivalent non-renewable resource. An equivalent non-renewable is an energy resource that does not meet the definition of a renewable resource in RCW 19.285, but is equal to a renewable resource on an energy and capacity basis. For the purpose of this analysis, the cost of an equivalent non-renewable resource has three components:

1. Capacity Cost: There are two parts of capacity cost: First is the capacity in MW. This would be nameplate for a firm resource like biomass, or the assumed capacity of a wind plant. Second is the $/kW cost, which we assumed to be equal to the cost of a peaker.
2. Energy Cost: This was calculated by taking the hourly generation shape of the resource, multiplied by the market price in each hour. This is the equivalent cost of purchasing the equivalent energy on the market.

3. Imputed Debt: The law states the non-renewable must be an "equivalent amount," which includes a time dimension. If PSE entered into a long-term contract for energy, there would be an element of imputed debt. Therefore, it is included in this analysis as a cost for the non-renewable equivalent.

For example, Hopkins Ridge produces 466,900 MWh annually. The equivalent non renewable is to purchase 466,900 MWh from the Mid-C market and then build a 30 MW (149.4*20 percent = 30) peaker plant for capacity only. With the example, the cost comparison includes the hourly Mid-C price plus the cost of building a peaker, plus the cost of the imputed debt. The total revenue requirement (fixed and variable costs) of the non-renewable is the cost stream—including end-effects—discounted back to the first year. That net present value is then levelized over the life of the comparison renewable resource.

5. Cost of Renewable Resource

Levelized cost of the renewable resource is more direct. It is based on the preforma financial analysis performed at the time of the acquisition. The stream of revenue requirement (all fixed and variable costs, including integration costs) are discounted back to the first year—again, including end effects. That net present value is then levelized out over the life of the resource/contract. The levelized cost of the renewable resource is then compared with the levelized cost of the equivalent non-renewable resource to calculate the incremental cost.

6. Example

The following is a detailed example of how PSE calculated the incremental cost of Wild Horse. It is important to note that PSE's approach uses information contemporaneous with the decision making process, so this analysis will not reflect updated assumptions for capacity, capital cost, or integration costs, etc.

Eligible Renewable: Wild Horse Wind Facility
Capacity Contribution Assumption: 228.6 * 17.2% = 39 MW

1. Calculate Wild Horse Revenue Requirement

Figure I-36 is a sample of the annual revenue requirement calculations for the first few years of Wild Horse, along with the NPV of revenue requirement.

Figure I-36
Calculation of Wild Horse Revenue Requirement

($ Millions)	20-yr NPV	2007	2008	…	2025
Gross Plant		384	384	…	384
Accumulative depreciation (Avg.)		(10)	(29)	…	(355)
Accumulative deferred tax (EOP)		(20)	(56)	…	(7)
Rate base		354	299	…	22
After tax WACC		7.01%	7.01%	…	7.01%
After tax return		25	21	…	2
Grossed up return		38	32	…	2
PTC grossed up		(20)	(20)	…	-
Expenses		16	16	…	22
Book depreciation		19	19	…	19
Revenue required	370.9	53	48	…	44
End effects	4.6				
Total revenue requirement	375				

2. Calculate Revenue Requirement for Equivalent non-renewable: Peaker Capacity

Capacity = 39 MW

Capital Cost of Capacity: $462/KW

Figure I-37
Calculation of Peaker Revenue Requirement

($ Millions)	20-yr NPV	2007	2008	…	2025
Gross Plant		18	18	…	18
Accumulative depreciation (Avg.)		(0)	(1)	…	(10)
Accumulative deferred tax (EOP)		(0)	(0)	…	(3)
Rate base		18	17	…	5
After tax WACC		7.01%	7.01%	…	7.01%
After tax return		1	1	…	0
Grossed up return		2	2	…	0
Expenses		1	1	…	2
Book depreciation		1	1	…	1
Revenue required	32	4	4	…	3
End effects	2				
Total revenue requirement	34				

3. Calculate Revenue Requirement for Equivalent non-renewable: Energy

Energy: 642,814 MWh

For the Market purchase, we used the hourly power prices from the 2006 RFP plus a transmission adder of $1.65/MWh in 2007 and escalated at 2.5 percent.

Month	Day	Hour	20-yr NPV	2007	…	2025
1	1	1		49 MW * $59/MW = $2891	…	49 MW * $61/MW = $2989
1	1	2		92 MW * $60/MW = $5520	…	92 MW * $63/MW = $5796
…	….	…		…	…	…
12	31	24		13 MW * $59/MW = $767	…	13 MW * $65/MW = $845
($Millions)						
Cost of Market				36	…	41
Imputed Debt				1	…	0
Total Revenue Requirement			285	37	…	41

Figure I-38

Calculation of Energy Revenue Requirement

4. Incremental Cost

The table below is the total cost of Wild Horse less the cost of the peaker and less the cost of the market purchases for the total 20-year incremental cost difference of the renewable to an equivalent non-renewable.

Figure I-39

20-yr Incremental Cost of Wild Horse

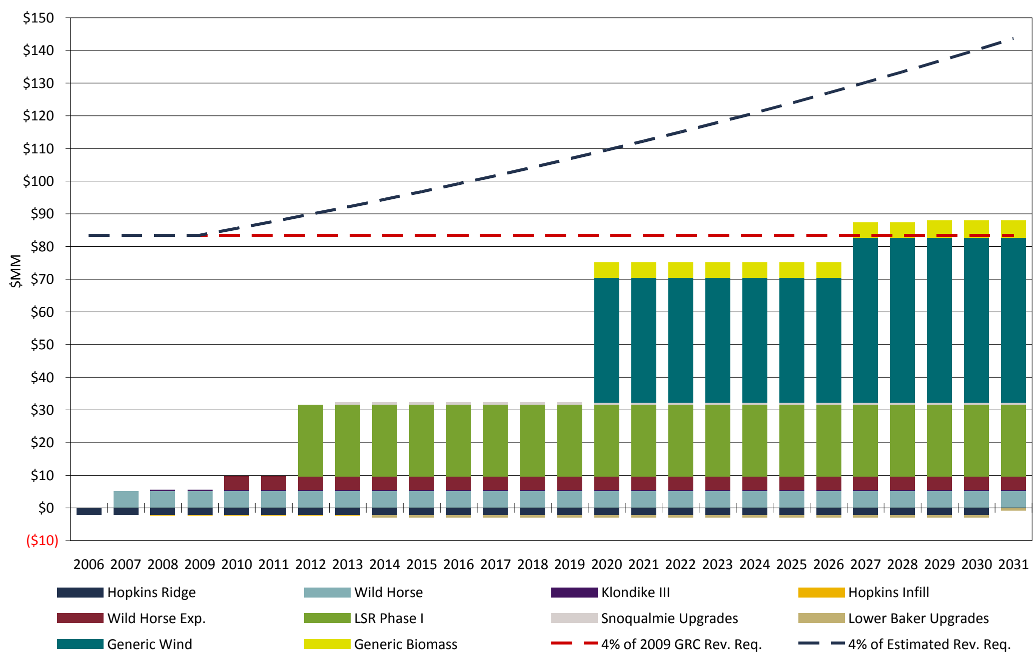
($ Millions)	20-yr NPV
Wild Horse	375
Peaker	34
Market	285
20-yr Incremental Cost of Wild Horse	56

We chose to spread the incremental cost over 25 years since that is the depreciable life of a wind project used by PSE. The payment of $56 Million over 25 years comes to $5.2 Million/Year using the 7.01 percent discount rate.

7. Summary Results

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

Figure I-40
Equivalent Non-renewable 20-year Levelized Cost Difference Compared to 4 Percent of 2009 GRC Revenue Requirement



As the chart reveals, even if the company's revenue requirement were to stay the same for the next 10 years, PSE would still not hit the 4 percent requirement. The estimated revenue requirement uses a 2.5 percent assumed escalation from the 2009 General Rate Case revenue requirement.