Electric Resources

Today, more than a million customers in Washington state depend on PSE for safe, reliable, and affordable electric services. That number will grow over the next 20 years, despite the current economic slowdown, and this growth, combined with expiring resource contracts and the retirement of aging facilities, will drive electric resource need in coming years.

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I. Electric Resource Need

At this time, three factors are driving PSE's electric resource need over the 20-year planning horizon:

- expiring and retiring contracts and resources
- load growth due to increasing numbers of customers
- renewable portfolio standards

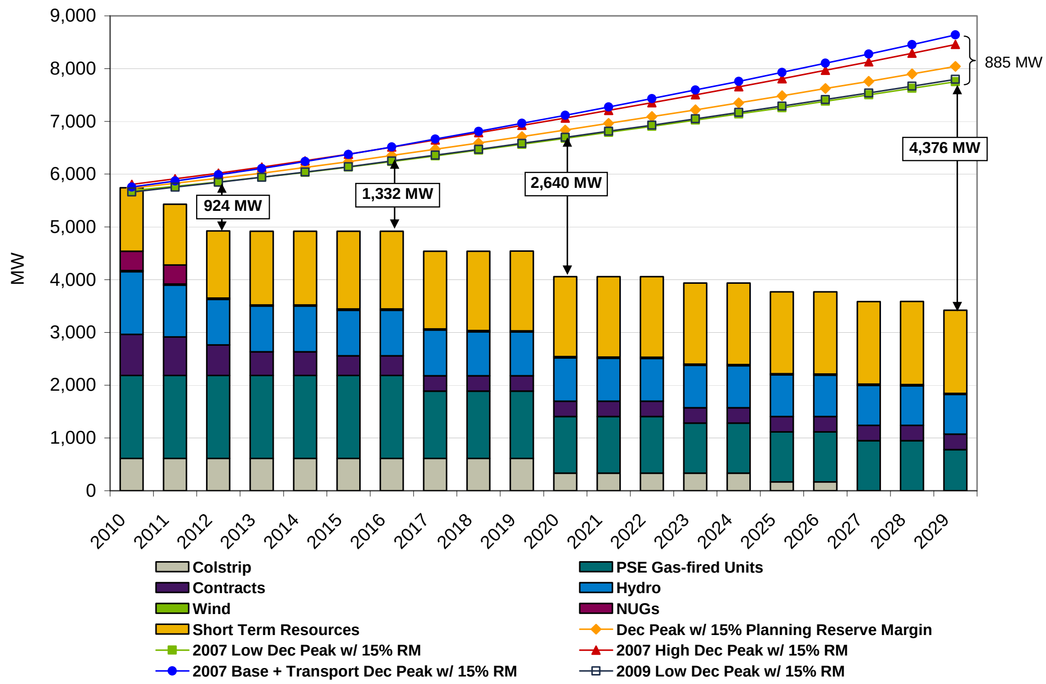
As a winter peaking utility, PSE experiences the highest demand for electricity when the weather is coldest and our customers' need for heating is greatest. This is the peak need we must prepare to meet; above that, we must also maintain sufficient reserves to minimize the risk of not serving load.

Figure 5-1 shows PSE's electric peak capacity resource need. It compares the forecasted load during the highest-demand hour of the year (across a range of load forecasts) to the peak capacity of existing PSE resources and contracts.

The top lines on the chart represent the peak load forecast. This includes a forecast of the customer base over time, and an estimate of how much power would be used at: (a) a temperature of 23^{o} Fahrenheit, (b) a normal winter peak, and (c) a 15% planning margin. The 15% planning reserve margin translates to a 5% loss of load probability, a standard reliability metric used in the electric industry. A discussion of how the planning reserve margin was calculated can be found in Appendix I, Electric Analysis.

PSE's adoption of regional operating reserve requirements ensures that we are prepared to manage unplanned outages should they occur. We follow a standard developed by the Western Electricity Coordinating Council (WECC) that calls for the greater of the largest single contingency or 7% of name plate for thermal units plus 5% of name plate for hydroelectric units. Half of the reserve requirement must be instantaneously available (also known as spinning reserves); the rest can be carried as supplemental reserves.

Figure 5-1
Electric Peak Capacity Resource Need
Comparison of Projected Peak Loads with Resources Available, 2009-2028



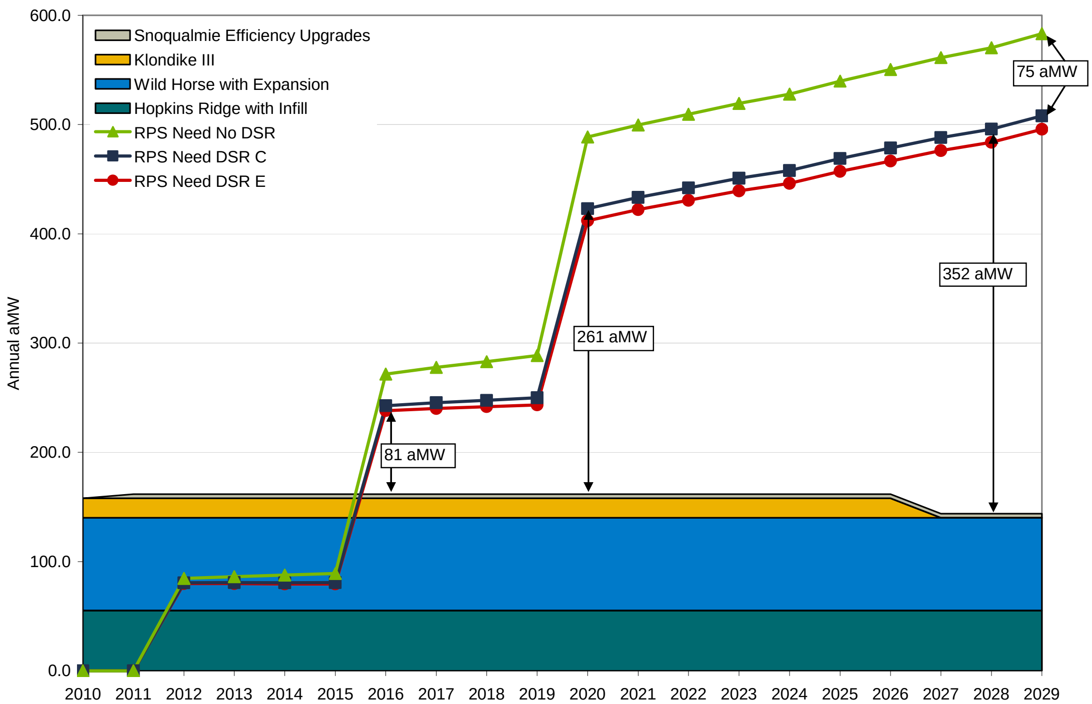
It is important to note that expiring and retiring resources contribute more to future resource need than load growth does. Figure 5-2 shows that by 2029 PSE will need to replace 2,322 MW of resources in addition to meeting an increase in load growth of 2,010 MW, based on the 2007 Low demand forecast. If demand growth reaches the 2007 Base Case forecast, an additional 290 MW will be required. Even if loads remained at today's levels, the amount of resources "falling off" – due to contracts expiring or because generating equipment reached the end of its useful life – means PSE would still need more than 800 MW of resources by 2012.

Figure 5-2
Drivers of Electric Resource Need:
Expiring Resources Compared to Demand Growth

	2012	2016	2020	2029
Need from Expiring Resources	819	825	1,685	2,322
Need Due to 2009 Low Growth Load	105	507	955	2,054
Total Need (MW)	924	1,332	2,640	4,376

In addition to capacity need, PSE must also meet the renewable portfolio standard (RPS) required by Initiative 937. I-937 mandates that PSE meet 3% of load with renewable resources by 2012, 9% by 2016, and 15% by 2020. RPS need is calculated after reducing annual load by the amount of demand-side resources (DSR) achieved. Figure 5-3, shows how RPS need varies depending on the amount of DSR a portfolio includes. Higher levels of DSR reduce renewable needs, but by 2029, even the highest DSR levels still result in the need for an additional 352 aMW of renewable energy to fulfill requirements.

Figure 5-3
RPS Need with Different DSR Levels



II. Existing Resources

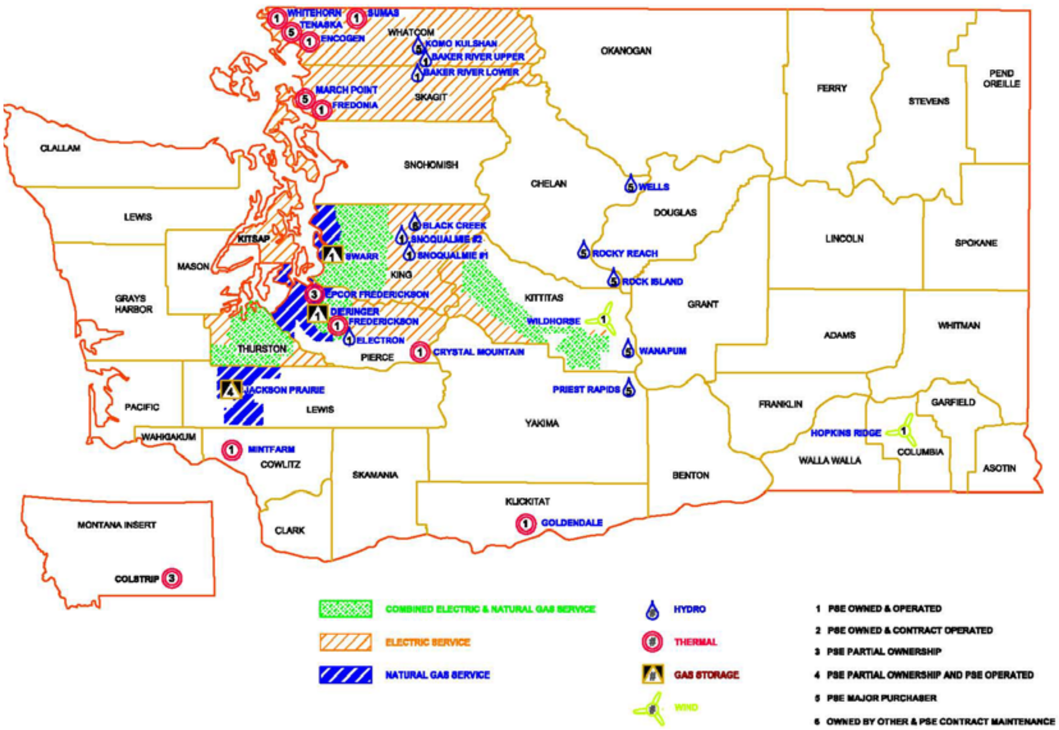
Discussion of PSE's existing electric resources is divided into three parts.

- **Supply-side resources.** These include power generated by PSE-owned and contracted facilities, primarily hydroelectric power, coal-fired plants, natural gas-fueled turbines, and wind resources.
- **Demand-side resources.** These contributions to the resource pool are generated on the customer side of the meter, primarily through energy efficiency programs.
- **Green Power and small-scale renewables.** PSE offers two renewable energy programs, one for customers who want additional renewable energy, and one for customers who produce power from small-scale renewables.

A. Supply-side Resources

PSE's portfolio of supply-side generation resources is diversified geographically and by fuel type (see Figure 5-4). Most of our gas-fueled resources are in western Washington. The major hydroelectric contracted resources are in central Washington, outside our service area. Our wind facilities are located in central and eastern Washington. Coal-fired generation is located in eastern Montana.

Figure 5-2
Location of Supply-side Resources



Hydroelectricity

PSE's hydroelectric resources are expected to be capable of producing enough energy to meet approximately 30% of our load in 2010. Hydroelectric resources are valuable because of their ability to follow load and their lower cost relative to other resources. PSE owns hydroelectric projects in western Washington and has long-term contracts with three Public Utility Districts (PUDs) that own and operate large dams on the Columbia River in central Washington. In addition, we contract with smaller hydroelectric generators. High precipitation levels generally allow more power to be generated; low-water years produce less power. During low-water years, we must rely on more expensive self-generated power or market sources to meet the load. The analysis conducted for this IRP accounts for both seasonality and year-to-year variations in hydroelectric generation.

Figure 5-5
Hydroelectric Resources (2008)

PLANT	OWNER	PSE SHARE %	NAMEPLATE CAPACITY (MW)*	EXPIRATION DATE
Upper Baker River	PSE	100	105	n/a
Lower Baker River	PSE	100	85	n/a
Snoqualmie Falls	PSE	100	46	n/a
Electron	PSE	100	22	n/a
Total PSE-Owned			**258**	
Wells	Douglas Co. PUD	29.9	251	3/31/18
Rocky Reach	Chelan Co. PUD	38.9	497	11/1/11
Rock Island I & II	Chelan Co. PUD	50.0	285	6/7/12
Wanapum	Grant Co. PUD	.64**	6	Will tie to new FERC license
Priest Rapids	Grant Co. PUD	.64**	6	Will tie to new FERC license
Mid-Columbia Total			**1045**	
Total Hydro			**1303**	

*Nameplate capacity reflects PSE share only.
**Based on Grant Co. PUD current load forecast for 2010; our share will be reduced to this level.

Baker River Hydroelectric Project. This facility is located in Washington's north Cascade Mountains. It consists of two dams and is the largest of PSE's three hydroelectric power facilities. The project includes a modern fish-enhancement system with a floating surface collector designed to safely capture juvenile salmon in Baker Lake for downstream transport around both dams. In addition to generating electricity, the project provides public access for recreation and significant flood-control storage for people and property in the Skagit Valley. Hydroelectric projects require a license from the Federal Energy Regulatory Commission (FERC) for construction and operation. These licenses normally are for periods of 30 to 50 years and then they must be renewed. In October 2008, after a lengthy renewal process, FERC issued a new 50-year license allowing PSE to generate 707,600 MWh (average annual output) from the Baker River project.

Snoqualmie Falls Hydroelectric Project. Located east of Seattle on the Cascade Mountains' western slope, the Snoqualmie Falls Hydroelectric Project consists of a small diversion dam just upstream from Snoqualmie Falls and two powerhouses. The first powerhouse, which is encased in bedrock 270 feet beneath the surface, was the world's first completely underground power plant. Built in 1898, it was also the Northwest's first large hydroelectric power plant. FERC issued PSE a 40-year license for the Snoqualmie Falls Hydroelectric Project in 2004. The terms and conditions of the license allow us to generate an estimated 300,000 MWh per year. The 2004 license requires significant enhancements to both the upper and lower power plants and the diversion dam, and to a number of public amenities such as parks. The new license is being challenged in federal court, and the outcome cannot be predicted at this time.

Electron Hydroelectric Project. Located about 25 miles southeast of Tacoma in the western foothills of Mount Rainier, this facility has a 22.5 MW generating capacity. Completed in 1904, the project draws water from the Puyallup River and funnels it to the power plant via a 10-mile span of wooden flume that runs through the winding river valley.

Mid Columbia Long-term Purchased Power Contracts. Under long-term purchased power agreements with three Public Utility Districts, PSE purchases a percentage of the output of five hydroelectric projects located on the Columbia River in Central Washington (see Figure 5-5). PSE pays the PUDs a proportionate share of the operating expenses for these hydroelectric projects. The agreement with Douglas County PUD for the purchase of 29.9% of the output of the Wells project expires in 2018. PSE executed a new 20-year agreement with Chelan County PUD for the purchase of 25% of the output of the Rocky Reach and Rock Island projects. The new agreements take effect upon termination of the current agreements in 2011 and 2012 and extend through October 2031. We also executed new agreements with Grant County PUD for a share of the output of the Wanapum and Priest Rapids developments. The terms of the agreements took effect at Priest Rapids in November 2005 and will apply to Wanapum beginning in November 2009. After that, PSE will receive a combined share of power from both projects; this share declines over time as the PUDs’ loads increase. PSE’s share of the Wanapum Development remains at 10.8% until November 2009 and adjusts annually thereafter. Our share of the Priest Rapids Development declined to 4.3% in 2007. The new agreements with Grant County PUD will continue through the term of any new FERC license to be obtained by the PUD.

White River Project. In January 2004, we stopped generating electricity at White River because relicensing and environmental expenses would have driven power costs well above available alternatives. We have arrangements with third parties to cover most ongoing postretirement costs, and we are working with interested groups to preserve the Lake Tapps reservoir for regional recreation and municipal water supply.

Coal

The coal-fueled generating plants located in Colstrip, Montana, provide important baseload energy to PSE, and are expected to be capable of producing enough energy to meet about 22% of our load in 2010. PSE owns a 50% share in Colstrip 1 & 2, and a 25% share in Colstrip 3 & 4. We also receive additional energy from Colstrip under a contract with NorthWestern Energy, which expires at the end of 2010.

Gas-fired Combined-cycle Combustion Turbines (CCCTs)

With the addition of Mint Farm, PSE now has five CCCT resources with a combined nameplate capacity of 975 MW. In 2010 PSE's CCCTs are expected to be capable of producing enough energy to serve 34% of our load. In a CCCT, 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.

Mint Farm, in Cowlitz County at Longview, Wash., is our newest acquisition. Purchased in December 2008, it came online in January 2008 and has a nameplate capacity of 305 MW. PSE's CCCT fleet also includes **Frederickson 1** in Pierce County, **Goldendale** in Klickitat County, and **Encogen** and **Sumas** in Whatcom County. Encogen, our natural gas–fired cogeneration facility in Bellingham, Washington, provides steam to the adjacent Georgia-Pacific mill. To facilitate economic dispatch of the plant, an auxiliary boiler installed in August 2005 provides steam to the mill when market conditions warrant it. We also own 49.85% of **Frederickson 1**, a combined-cycle plant operated by EPCOR.

Wind Energy

PSE is the largest utility owner and operator of wind-power facilities in the Northwest. The two wind projects described here are expected to produce enough energy to serve approximately 5% of our overall load in 2010. **Hopkins Ridge**, located in Columbia County, has a nameplate capacity of 157 MW and began commercial operation in November 2005. **Wild Horse**, located in Kittitas County near Ellensburg, has a nameplate capacity of 229 MW and came online in December 2006. Combined, the two projects produce 127 aMW of electrical capacity,[1] and have provided over 2.3 million MWh of electrical energy to PSE customers. Both projects have contributed to their respective local economies by providing permanent family-wage jobs, local supply and services procurement, and payment of production royalties to local landowners. In addition, they have increased county tax bases, enabling local government to provide additional services (e.g.,Columbia County launched a new health clinic). Figure 5-6 presents details about our coal, CCCT, and wind resources.

PSE's portfolio also includes a power purchase agreement for approximately 50 MW of electricity generated at the **Klondike III** wind farm in Sherman County, Ore. This agreement remains in effect until November 2027.

Figure 5-6
Coal, CCCT and Wind Resources

POWER TYPE	UNITS	PSE OWNERSHIP	NAMEPLATE CAPACITY (MW)*
Coal	Colstrip 1 & 2	50%	307
Coal	Colstrip 3 & 4	25%	370
Total Coal			**677**
CCCT	Encogen	100%	159
CCCT	Frederickson 1**	49.85%	129
CCCT	Goldendale	100%	261
CCCT	Mint Farm	100%	305
CCCT	Sumas	100%	121
Total CCCT			**975**
Wind	Hopkins Ridge	100%	157
Wind	Wild Horse	100%	229
Wind	Klondike 3	n/a	50
Total Wind			**436**

*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).
**Frederickson 1 CCCT unit is co-owned with EPCOR.

[1] The average number of megawatt-hours (MWh) over a specified time period; for example, 295,650 MWh generated over the course of one year equals 810 aMW (295,650/8,760 hours).

Gas-fired Simple-cycle Combustion Turbines

Our four simple-cycle combustion turbine plants contribute a total of 606 MW of capacity. Although they typically operate only a few days each year, they provide important peaking capability and help us meet reserve requirements. We do not use these resources for baseload energy when lower-cost energy is available for purchase. The **Fredonia** facility is located near Mount Vernon, about 75 miles north of Seattle in Skagit County. In February 2009 PSE purchased **Whitehorn** units 2 & 3 in northwestern Whatcom County. The **Frederickson Generating Station** is a leased facility located south of Seattle in the Port of Tacoma comprised of two combustion turbine units with a combined nameplate capacity of 149 MW. Details are shown in Figure 5-7 below.

Figure 5-7
Simple-cycle Combustion Turbines

NAME	PSE OWNERSHIP	NAMEPLATE CAPACITY (MW)*
Fredonia 1 & 2	100%	208
Fredonia 3 & 4	100%	108
Whitehorn 2 & 3	100%	149
Frederickson	Leased	149
Total		**606**

* 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).

Nonutility Generators (NUGs)

Our NUG supply consists of cogeneration plants that use natural gas to supply electricity to us and steam to industrial “hosts” for their production processes. Both are located in Skagit and Whatcom counties, in the northern part of our service area. Their combined nameplate capacity is 387 MW.

Tenaska Cogeneration. Tenaska Washington Partners, L.P. owns and operates this project near Ferndale, WA. In 1991, PSE contracted to purchase 245 MW beginning in April 1994. We later bought out the project’s existing long-term gas supply contracts, which contained fixed and escalating gas prices well above then current and projected future market prices. This made us the principal natural gas supplier to the project, and power purchase prices under the Tenaska contract were revised to reflect market-based gas prices. This agreement ends December 31, 2011.

March Point Phases I & II. We have contracts through December 31, 2011 to purchase the full output of March Point Phases I & II from the March Point Cogeneration Company, which owns and operates these facilities. The plants are located at the Shell refinery in Anacortes, Wash., and deliver a combined 142 MW.

Other Long-term Contracts

Long-term contracts, which range in capacity up to 300 MW, 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 in Figure 5-6. Short-term contracts negotiated by our energy trading group are not included in this listing.

NorthWestern Energy Company. This 20-year, unit-specific, purchased power contract is tied to Colstrip Unit 4. The contract, which expires in 2010, specifies capacity payments for each year, subject to reductions if specific performance is not achieved.

BPA – WNP-3 Bonneville Exchange Power. This is a system-delivery, not a unit-specific, purchased power contract. The agreement resulted from PSE claims against the Bonneville Power Administration (BPA) regarding its action to halt construction on nuclear project WNP-3, in which PSE had a 5% interest. Under the agreement, in effect until June 2017, PSE receives power during the winter months from BPA according to a formula based on the average equivalent annual availability and cost factors of four surrogate nuclear plants similar in design to WNP-3. In exchange, PSE provides power to BPA from its combustion turbines, if requested, except during the month of May.

BPA Snohomish Conservation Contract. This agreement, which runs through February 2010, is a system-delivery, not a unit-specific, purchased power contract. Snohomish County PUD, Mason County PUD, and Lewis County PUD installed conservation measures in their service areas. PSE receives an amount of power equal to the amount saved over the expected 20-year life of the measures. BPA delivered this power through 2001; after that, delivery passed to Snohomish County PUD.

Powerex Purchase for Point Roberts. Powerex delivers electric power to our retail customers in Point Roberts, Wash. The Point Roberts load, which is physically isolated from our transmission system, connects to British Columbia Hydro’s electric distribution facilities. We pay a fixed price for the energy during the term of the contract. This agreement ends in September 2009, and PSE has begun discussions with Powerex to extend service.

BPA Baker Replacement. Under a letter of intent signed with the US Army Corps of Engineers (COE) for a 20-year agreement, PSE provides flood control for the Skagit River Valley. Early in the flood control period, we draft water from the Baker Reservoir at the request of the COE. Then, during periods of high precipitation and runoff between October 15 and March 1, we store water in the Upper Baker Reservoir and release it in a controlled manner to reduce downstream flooding. In return, we receive power from BPA from November through February; this compensates for the lower generating capability caused by reduced head due to the early drafting at the plant during the flood control months.

Pacific Gas & Electric Company (PG&E) Seasonal Exchange. Each calendar year we exchange 300 MW of capacity, together with 413,000 MWh of energy, on a one-for-one basis under this system-delivery purchased power contract. PSE is a winter-peaking utility and PG&E is a summer-peaking utility, so we provide power to PG&E from June through September, and PG&E provides power to us November through February.

Canadian Entitlement Return. Under a treaty between the United States and Canada, one-half of the firm power benefits produced by additional storage capability on the Columbia River in Canada accrue to Canada. Our benefits and obligations from this storage are based on the percentage of our participation in the Columbia River projects. Agreements with the Mid Columbia PUDs specify our share of the obligation to return one-half of the firm power benefits to Canada until the expiration of the PUD contracts or 2024, whichever occurs first. This is energy that we provide rather than receive, so it is a negative number (-58 MW for 2009).

Powerex. Under the terms of this contract, Powerex delivers power to PSE on peak hours during the winter months of December through February until 2012. Peak hours are defined as Monday through Saturday, hour ending 7:00 to hour ending 22:00.

Credit Suisse. This contract replaces a preexisting contract with an alternate counterparty. This is a system delivery, not a unit-specific, purchased power contract. Under the terms of this agreement, Credit Suisse delivers 50 MW per hour of around-the-clock electric power through the end of March 2013.

RBS Sempra Commodities. This is a system-delivery, not a unit-specific, purchased power contract, which provides seasonally shaped power to PSE. RBS Sempra agrees to deliver 75 MW per hour during the months of July through March, and 25 MW per hour during the months of April through June until the end of the contract term. This contract terminates on March 31, 2013.

Barclays Bank. Under this agreement, which runs through February 2015, Barclays delivers around-the-clock power to PSE during the winter months of November through February. This is a system-delivery of 75 MW per hour, not a unit-specific, purchased power contract.

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

TYPE	NAME	TYPE	CONTRACT EXPIRATION	NAMEPLATE CAPACITY (MW)*
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	Northwestern Energy Company	Colstrip	12/29/2010	97
Other Contracts	BPA- WNP-3 Exchange	System	6/30/2017	82
Other Contracts	Conservation Credit - SnoPUD	Hydro	2/28/2010	18
Other Contracts	Powerex/Pt.Roberts	Hydro	9/30/2009	3
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	12/31/2025	-58
Other Contracts	Powerex	System	02/29/2012	150
Other Contracts	Credit Suisse	System	03/31/2013	50
Other Contracts	RBS Sempra Commodities	System	03/31/2013	75

TYPE	NAME	TYPE	CONTRACT EXPIRATION	NAMEPLATE CAPACITY (MW)*
Other Contracts	Barclays Bank	System	02/28/2015	75
Total Other				**799**
Independent Producers	Spokane Municipal Solid Waste	Biomass-QF	11/15/2011	18
Independent Producers	Twin Falls	Hydro	3/8/2025	20
Independent Producers	Koma Kulshan	Hydro	3/1/2037	14
Independent Producers	North Wasco	Hydro	12/31/2012	5
Independent Producers	Nooksack Hydro	Hydro-QF	01/01/2014	1.5
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	2/2/2014	<1
Independent Producers	Port Townsend Paper	Hydro-QF	06/30/09	<1
Total Independent				**64**

*Nameplate capacity reflects PSE share only.

B. Demand-side Resources

Demand-side resources are 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 2006-2007 tariff period, the 44.4 aMW contributed by these programs amounted to more than a year's worth of power supplied by our March Point 2 contract, or enough energy to power more than 33,000 homes. Between 1985 and 2007, gains of 299 aMW have accumulated on an investment of $528 million – more than the annual output from our share of Colstrip 1 & 2 and equivalent to the electricity used by about 225,000 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.

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 2006-2007 biennial program period concluded at the end of 2007; current programs operate January 1, 2008 through December 31, 2009. The majority of electric energy efficiency programs are funded using electric "rider" funds collected from all customers.

For the 2008-2009 period, a two-year target of approximately 53.3 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 **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 produced the greatest gain in energy savings of all PSE efficiency programs in 2007, producing 7 aMW at a cost of $11 million; it accounted for 27% of all electric savings in 2007. Program savings declined in 2008, but at 19% they still represented the largest portion of all electric energy efficiency programs: 6 aMW was contributed at a cost of $13 million.

The **Energy Efficient Lighting Programs** offer instant rebates for residential customers and builders who purchase Energy Star fixtures and compact fluorescent light bulbs. These programs generated the greatest energy savings gains on the residential side in 2007, producing 10 aMW at a cost of $7 million and accounting for 32% of all electric savings. In 2008, program savings increased, and again it was the dominant contributor, saving 12 aMW at a cost of $8 million. This represented 38% of all electric energy efficiency savings.

Figure 5-9
Annual Energy Efficiency Program Summary, 2006-2008
(Dollars in millions, except MWh)

Tariff + C&RD Programs	2006 - 2007 Actual	'06-'07 2-Year Budget./Goal	'06/'07 Actual vs. '06/'07 % Total	2008 Actual	'08-'09 2-Year Budget./Goal	'08 vs. '08/'09 % Total
Electric Program Costs*	$ 65,455,248	$ 67,450,175	97.0%	$ 53,172,241	$ 123,250,000	43.1%
Megawatt Hour Savings	388,563	357,706	108.6%	273,555	467,195	58.6%

*Does not include low-income weatherization O&M funding of $300 thousand per year.

Figure 5-9 shows performance compared to two-year budget and savings goals for the biennial 2006-2007 electric energy efficiency programs, and records 2008 progress against 2008-2009 budget and savings goals.

During 2006-2007, electric energy efficiency programs saved a total of 44.4 aMW of electricity at a cost of $66 million. We surpassed two-year savings goals while operating at a cost that was under budget. In 2008, these programs saved 31 aMW of electricity at a cost of $53 million. The average cost for acquiring energy efficiency increased from 2007 to 2008 by approximately 51%, while energy savings increased by 23%.

RFPs. In 2007 and 2008 PSE issued four RFPs for energy efficiency and demand-response pilots. We issued two energy efficiency RFPs for resources to be added in 2008-2009. The first, issued in June 2007, targeted specific program areas; the second was an "all-comers" energy efficiency RFP open to all program areas. The RFP process is used to seek out and fill untapped market segments or add under-utilized energy efficiency technologies to complement our ongoing efforts. No significant new opportunities for additional electric energy efficiency were identified. Of the 39 proposals received for both RFPs, four were awarded contracts.

Similarly, PSE issued two demand-response RFPs during 2007 and 2008. The first was a commercial sector pilot issued in August 2007; two proposals were received and one contract was awarded. A second RFP, for the residential sector, was issued in November 2008; nine proposals were received, and one has been selected.

C. Green Power and Small-scale Renewables

PSE's customer renewable energy programs continue to grow. The **Green Power Program** serves customers who want additional renewable energy, and the **Customer Renewables Program** serves those who generate renewable energy on a small scale. Our customers find value as well as social benefits in the programs, and we embrace and encourage their use.

Green Power

PSE's Green Power Program, launched in 2001, allows customers to voluntarily purchase retail electric energy from qualified renewable energy resources. Every year since 2005, the National Renewable Energy Laboratory has recognized PSE as one of the top 10 utilities for Renewable Energy Sales and Total Number of Green Power Participants. Between 2006 and 2008, the number of subscribers increased from 17,426 to 21,509, and the number of megawatt-hours purchased increased from 131,742 to 291,167.

To supply green power, the program purchases renewable energy credits (RECs), also called green tags, from a variety of sources. The primary supplier is the Bonneville Environmental Foundation (BEF), a nonprofit environmental organization in Portland, Ore., which provides a portfolio of resources including wind, solar, and biomass. In addition, the Green Power Program purchases RECs directly from producers in order to support the development of new small renewable resources. Examples include the Vander Haak Dairy, Grays Harbor Paper, and the Nooksack Hydro Facility. The program has also been working with two methane digester developers – Farm Power LLC, and Qualco Energy – to finalize the purchase of RECs from their projects upon completion in 2009. In recognition of the high level of program participation in Bellingham, the Green Power Program has also funded solar demonstration projects at the Bellingham Environmental Learning Center, the Depot Market Square, and Western Washington University's Student Union.

2009 marks the expiration of a three-year agreement with BEF for the purchase of RECs, which has provided PSE with some surety on REC pricing and flexibility in adding small-scale resources to the program. Increased pressure on west coast renewables, due to expanding compliance requirements, means the Green Power Program will consider including some RECs from outside the WECC region when it issues an RFP for a new REC agreement this year.

Figure 5-10 lists the resources that make up PSE’s Green Power portfolio.

Figure 5-10
Green Power Portfolio

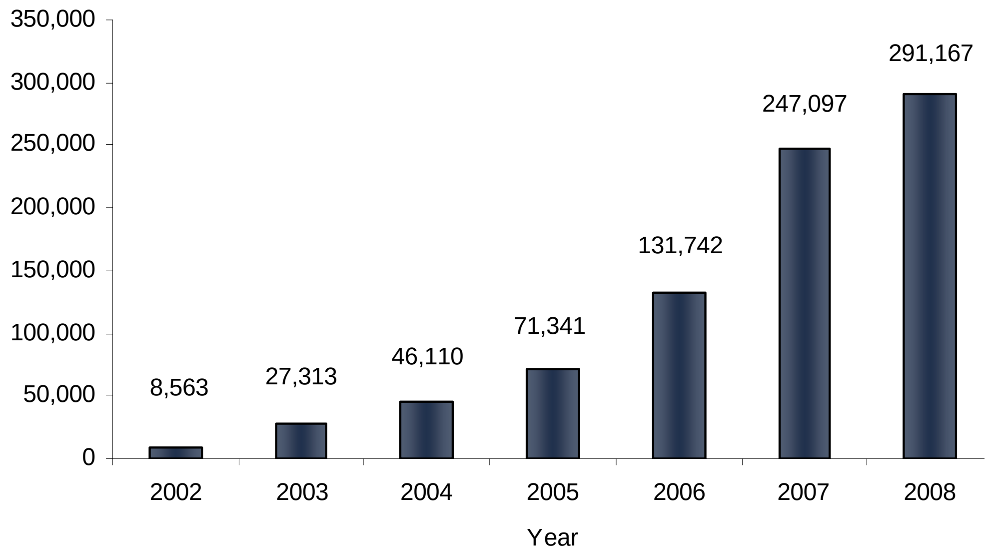
Name	Resource	Location
Condon	Wind	Condon, OR
Stateline	Wind	Walla Walla, WA
White Creek	Wind	Klickitat Co., WA
Klondike II	Wind	Sherman Co., OR
Nine Canyon	Wind	Kennewick, WA
Nine Canyon II	Wind	Kennewick, WA
Wolverine Creek	Wind	Bingham, ID
H.W, Hill LFG	Bio	Klickitat Co., WA
Edgeley/Kulm	Wind	Edgeley, ND
Small Solar	Solar	Various, OR, WA
Vander Haak	Bio	Lynden, WA
Grays Harbor Paper	Bio	Hoquiam, WA
Nooksack Hydro Facility	Low-Impact Hydro	Nooksack, WA

Rates. The standard rate for green power is $0.0125/kWh. Customers can purchase 160 kWh blocks for $2 per block with a two-block minimum, or they can choose to participate in the “100% Green Power Option.” Introduced in 2007, the 100% option adjusts the amount of the customer’s monthly green power purchase to match their monthly electric usage. In 2007, the Green Power Program reduced rates from $0.02 per kWh to the $0.0125 per kWh.

The large-volume green power rate—0.6 cent per kWh for customers who purchase more than 1,000,000 kWh annually—has attracted 20 customers since it was introduced in 2005. Large-volume customers who are covering 100% of their electric use include Evergreen State University, the City of Bellingham, the City of Lacey, Whatcom County, the LOTT Alliance, Whatcom Transportation Authority, King County Road Services Division, and Partners Crackers.

In 2008, the Green Power Program issued an RFP for a third-party marketer to help increase participation. As a result, PSE signed a three-year contract with 3Degrees; together we established a goal of increasing residential customer participation from 2% of total to 4% by December 31, 2011. 3Degrees has developed and refined education and outreach techniques while working with other utility partners across the country.

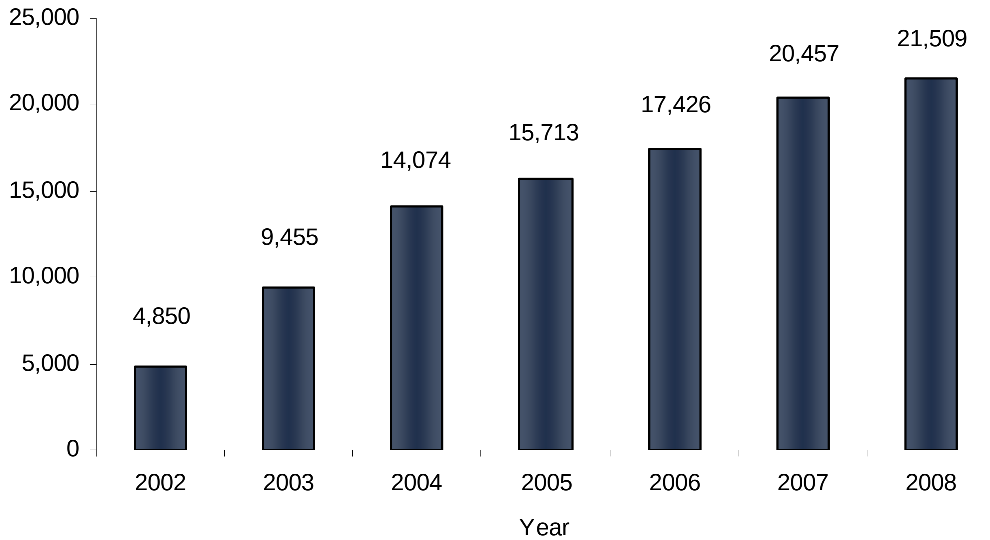
Figure 5-11
Green Power Kilowatt-Hours Sold, 2002-2008



In 2008, the average residential customer purchase was 557 kWh per month and the average commercial customer purchase was 1,989 kWh. The average 2008 large-volume purchase, by account, under Schedule 136 was 28,690 kWh per month.

Figure 5-12 illustrates the number of subscribers by year. Of our 21,509 Green Power subscribers at the end of 2008, 20,619 were residential customers and 890 accounts were business customers. Cities with the most residential and commercial participants include Bellingham with 2,965, Olympia with 2,410, Bellevue with 1,223, and Kirkland with 970.

Figure 5-12
Green Power Subscribers, 2002-2008



Customer Renewables Programs

PSE's net metering program, which began in 1999, provides a way for customers who generate their own renewable electricity to offset the electricity provided by PSE. The amount of electricity that the customer generates and sends back to the grid is subtracted from the amount of electricity provided by PSE, and the net difference is what the customer pays on a monthly basis. A kWh credit is carried over to the next month if the customer generates more electricity than PSE supplies over the course of a month. The "banked" energy can be carried over until every April 30, when the account must reset to zero according to state law. The interconnection capacity allowed under net metering is 100 kW.

Customer interest in small-scale renewables has increased significantly over the past four years, as Figure 5-13 shows. In 2008, PSE added 117 new net metered customers for a total of 335.

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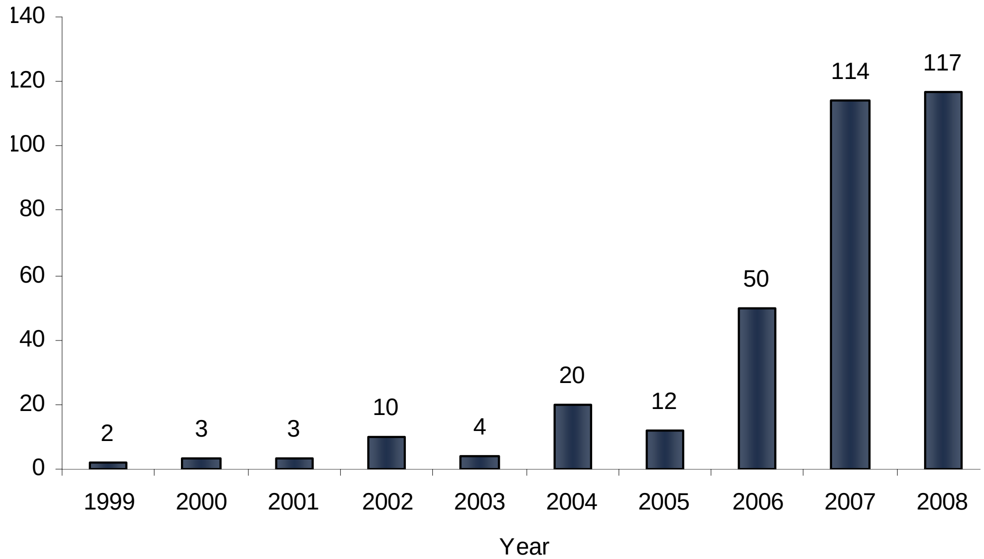
Figure 5-13
Net Metered Customers Added per Year 1999-2008



The vast majority of customer systems are solar photovoltaic (PV) installations with an average generating capacity of 3.6 kW, but there are also small-scale hydroelectric generators and wind turbines. These small-scale renewable systems are distributed over a wide area of our service territory. The average generating capacity of all net metered systems is also 3.6 kW. Overall, the program was capable of producing more than 1.2 MW of nameplate capacity at the beginning of 2009.

Figure 5-14
Interconnected System Capacity by Type of System

System Type	Number of Systems	Average Capacity per System Type (kW)	Sum of all Systems by Type (kW)
Hybrid; solar/wind	3	3.98	11.95
Micro hydro	4	4.63	18.50
Solar array	318	3.61	1148.01
Wind turbine	10	2.91	29.10
Total Number of Systems	**335**	**Total Capacity of All Systems**	**1207.56**

Figure 5-15
Net Metered Systems by County

County	Number of Net Meters
Whatcom	46
King	68
Jefferson	60
Skagit	43
Island	28
Kitsap	42
Thurston	32
Kittitas	6
Pierce	10

Renewable Energy Advantage Program. In 2005, PSE launched a Renewable Energy Advantage Program (REAP) in response to WAC 458-20-273. The program is voluntary for Washington state utilities, but we embraced the opportunity to participate because we have such a large and committed group of interconnected customers. Payments are made to interconnected electric customers who own and operate eligible renewable energy systems including solar PV, wind, or anaerobic digesters (the four micro hydro customers are not eligible under the current law). Annual amounts range from 15 cents to 18 cents per kWh produced by their system. PSE receives a state tax credit equal to the aggregate incentive payments made to customers. By the end of 2008, the Renewable Energy Advantage Program had enrolled 300 of our 331 eligible customers for production payments. The tariff governing REAP is Schedule 151.

III. Electric Resource Alternatives

Even though dozens of electric resource alternatives are discussed in the press and on the internet today—from wiregrass-fueled biomass generators to fuel cells and tidal technology—very few are capable of generating "utility scale" power. This chapter presents an overview of the most relevant possible additions to PSE's portfolio, it is a brief discussion of what resources were modeled and not modeled in the analysis. A comprehensive list of alternatives, and detailed information on their current development status, is included in Appendix F, Electric Resource Alternatives.

Our consideration of both demand- and supply-side options is informed by PSE's active participation in the marketplace, our close observation of developing market trends, and information obtained from a variety of public resources such as the Northwest Power and Conservation Council (NPCC) and the Energy Information Administration (EIA).

Thermal Resources

Coal

It is hard to consider new coal plants a "commercially viable" resource in today's market. While Washington state's emissions standard (RCW 80.80) does not currently prohibit importing new coal power from out of state, it appears unrealistic to think that a new coal plant could be constructed anywhere in the Western US, even if a developer or utility wanted to build one.

Though the coal resources that are already part of PSE's portfolio offer valuable resource diversity and a low-cost, stable fuel source, existing plants are no longer capable of providing enough generation to meet growing long-term need reliably. Adding more coal would expose us to a number of substantial risks.

- Activity at state and federal levels suggest that the potential cost of mitigating the level of CO_2 emissions produced by coal-fired plants may reduce the economic advantage of lower fuel costs.
- Carbon capture and sequestration technologies – key to managing coal risks – have not been proven, and there is no reliable estimate of when commercial viability may be achieved.
- The cost of permitting, constructing, and operating new coal plants has increased enormously.

- The regulatory framework needed to address siting and permitting for sequestration projects has only just begun.

Natural Gas

Natural gas-fired generation has several benefits.

- Proximity: A gas-fired generator can be located within or adjacent to our service territory, which avoids potential costly transmission investments required for long distance resources.
- Timeliness: Gas-fired resources are dispatchable, meaning they can be turned on when needed to meet loads, unlike intermittent resources such as wind and run-of-the-river hydropower.
- Versatility: Different kinds of gas-fired generators have varying degrees of ability to ramp up and down quickly in response to variations in loads and variations in wind generation.
- Scalability: Gas plants are more scalable and less capital intensive than coal plants and thus avoid some of the long-lead risks associated with the development of remote coal mines and coal plants.
- Environmental burden: Natural gas resources produce significantly lower emissions than coal resources (approximately half the CO_2).

However, natural gas resources do have drawbacks. There are concerns about long-term availability, especially as the region becomes increasingly dependent on natural gas for generation fuel. Lack of diversity in supply basins and lack of diversity in gas transportation alternatives also create concern, as do long-term price risks and short-term market price volatility.

Natural Gas-fired Combined-cycle Combustion Turbines (CCCTs). Combined-cycle combustion turbine power plants consist of one or more gas turbine generators equipped with heat recovery steam generators that capture heat from the gas turbine exhaust. This otherwise wasted heat is then used to produce more electricity via a steam turbine generator. 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 air emissions, CCCTs have been the resource of choice for power generation for well over a decade.

Natural Gas-fired Simple-cycle Combustion Turbines. One of the benefits of simple-cycle combustion turbines is that they can be built in ten months or less. They can also be brought online quickly to serve peak need. While simple-cycle units can be brought online more quickly than combined-cycle units, simple cycles are less efficient and have higher heat rates than combined cycles, rendering them more expensive to run. Additionally, these units have relatively high capital costs, and are subject to significant risks related to rising gas costs, and fuel supply and delivery diversity issues.

Natural Gas Fueled Reciprocating Engines. Like simple-cycle combustion turbines, reciprocating engines can be built in ten months or less, and 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 less efficient than simple-cycle combustion turbines, but the small size of the units allows a better match with peak loads thus increasing operating flexibility relative to the simple-cycle combustion turbine.

Renewable Resources

Most renewable technologies are not yet commercially viable – that is, they are not able to economically generate power on a scale large enough to make meaningful contributions to meeting utility-scale needs. Brief overviews of resources modeled in this IRP appear below. A more comprehensive list with a fuller discussion of their development status appears in Appendix F, Electric Resource Alternatives.

Solar. Solar has seen significant growth internationally, driven by subsidies in select markets, notably Germany, Spain, France, and California. This has led to improved manufacturing and installation technologies, which has in turn driven down costs. Improved understanding and comfort with the technology has improved financing conditions. Though the recent economic downturn has led to some scaling back of solar expansion plans, overall, the market is expected to continue to grow. PSE began to develop the Wild Horse Solar Facility in 2007, and continues to collect data from this facility to evaluate equipment performance and fit with our resource portfolio. We will continue to explore different financial structures and technologies for solar development in the northwest, including concentrating solar with thermal storage.

Geothermal. Proven geothermal resources in the northwest are generally clustered in Oregon and Idaho, and so would require transmission to bring power to PSE's service territory. Several new developments are moving forward with test wells in Oregon, and more are proposed for Oregon and Idaho. In addition to traditional geothermal technologies, the Department of Energy has restarted funding for Enhanced Geothermal Research. PSE will continue to monitor technology developments in geothermal, as well as entertain proposals for geothermal projects and power.

Biomass. Most existing biomass in the northwest is tied to steam hosts, typically in the timber, pulp, and paper industries. This has limited the size of available power to export to date, and exposed biomass projects to fuel supply and fuel management risks. Some new models of biomass sourcing are emerging, with some companies exporting biomass specifically for power generation and new longer-term supply contracts being considered. PSE will continue to seek biomass projects with stable fuel sources and high reliability.

Wind. The Renewable Portfolio Standard (RPS) established in Washington state by Initiative 937 requires that an increasing portion of renewable resources make up the portfolio of the largest utility providers. While the RPS contemplates several distinct types of renewable resources, wind energy is the primary producer in our region due to its technical maturity, reasonable lifecycle cost, acceptance in various regulatory jurisdictions, and large "utility" scale compared to other technologies. Renewable portfolio standards are being adopted in Oregon, California, and other states across the country, increasing overall demand for wind resources throughout the region and the nation. As a result, we expect competition for experienced wind developers, viable sites, and wind turbine equipment to continue to be robust.

Wind is also a variable generating resource, meaning that daily and hourly power generation patterns may not correlate well with customer demand. Because of this, more flexible baseload resources must be available to "fill the gaps." Further, integrating a variable generation resource into the transmission system also poses challenges. For a detailed discussion of wind integration issues, refer to Appendix H, Wind Integration Studies.

Finally, remotely located wind projects may face long-haul transmission constraints resulting from increased demand on a near fully subscribed system. Many of these constraints are covered in Appendix G, Regional Transmission Resources.

Demand-side Resources

Demand-side resources include energy efficiency, fuel conversion, and distributed generation. Each of these alternatives enables us to make less energy do the same amount of work.

Energy efficiency is defined as a technology that demonstrates the same performance for a given task as competing technologies, but requires less energy to accomplish the task. Energy efficiency resources count toward meeting our energy efficiency requirement under the state's renewable portfolio standard (RPS).

Fuel conversion takes place when a customer switches from electricity to natural gas, particularly in the case of space and water heating. Electrical savings are gained from the reduction in electrical energy use.

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

Demand Response is 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. The acquisition of demand response resources may be based on reliability considerations or economic or market objectives.

Short-term Resource Alternatives

In order to effectively balance the power supply portfolio, PSE actively engages in short-term energy markets including balance of the month, cash, and real time markets. We actively monitor energy supply, capacity requirements, and merchant transmission availability, and we engage in short-term market transactions that meet reliability, economic, and compliance obligations as necessary. In the recent past, PSE has focused on managing short-term positions with tools such as temporal exchanges, ancillary energy products, and energy products with various points of physical delivery.

Resources Not Modeled

Nuclear. Development and construction costs for nuclear power plants are so much higher than the next highest baseload resource 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.

Tidal and wave. PSE has been a supporter of two northwest ocean energy studies (one tidal assessment and one wave demonstration project) because we believe that tidal and wave resources merit further attention and monitoring; however, commercial production of such resources is not possible at this time. Also, additional work is necessary to clarify permitting processes, evaluate environmental impacts, and develop generation technologies. We will continue to monitor the development of these resources in the northwest and internationally.

Hydroelectric. There are few new hydroelectric generating opportunities in the region, and none without significant environmental and permitting risk. Further, recent federal court decisions seem to raise risks for existing large hydroelectric projects. (Hydroelectric power may not be counted toward fulfilling RPS requirements in Washington state.)

IV. Electric 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 us 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 we posed were the following:

- How might economic conditions and load growth affect resource decisions?
- 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?
- Would different power plant costs in the future significantly impact our resource decisions?
- How might future carbon regulation affect the relative value of resource alternatives?
- What carbon emissions are produced by portfolios under different scenarios?

Electric analytic methodology followed the three basic steps illustrated in Figure 5-16. A detailed technical discussion of these models and methods is included in Appendix I, Electric Analysis.

Figure 5-16
Methodology Used to Create and Evaluate Portfolios

Step 1. Identify Available Resources

Identify Supply-side Resources
- Technology Types
- Online Dates
- Commercial Viability

Identify Demand-side Resources
- Identify Technical Potential
- Screen Technical Potential for Achievable Potential
- Create DSR Bundles from Achievable Potential

Step 2. Create Optimal, Integrated Portfolios for Each Scenario

Create Supply-side Only Portfolios (Strategist)

Select Lowest Cost Portfolio by Scenario (Strategist)

Integrate DSR Bundles into Portfolio (Strategist)

Select Lowest Cost Combination of Supply- and Demand-side Resources as Optimal Portfolio by Scenario

Step 3. Evaluate Costs and Risks

Evaluate Risks with Monte Carlo analysis

Evaluate and Identify Costs with Financial Model (PSM II)

Step 1: Identify Available Resources

First, all resources that are available to fill unmet need were identified.

Supply-side resources included coal-fired generation, natural gas-fired generation, wind, solar, geothermal, and biomass. Their selection is described in Section III of this chapter.

Selection of demand-side resources followed the process illustrated in Figure 5-17. First, each demand-side measure was screened for technical potential. This step assumed that all opportunities could be captured regardless of cost or market barriers, so that the full spectrum of technologies, load impacts, and markets could be surveyed.

A second screen eliminated any resources not considered achievable. 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 Planning and Conservation Council's most recent energy efficiency potential assessment. (For this IRP, we assumed economic electric energy efficiency potentials of 85% in existing buildings and 65% in new construction.)

The remaining measures were considered to have "achievable technical potential." These were combined into bundles based on levelized cost for inclusion in the optimization analysis conducted in Step 2. (A detailed discussion of demand-side resource evaluation and the development of DSR bundles can be found in Appendix L, Demand-side Resource Analysis.)

Figure 5-17
General Methodology for Assessing Demand-side Resource Potential

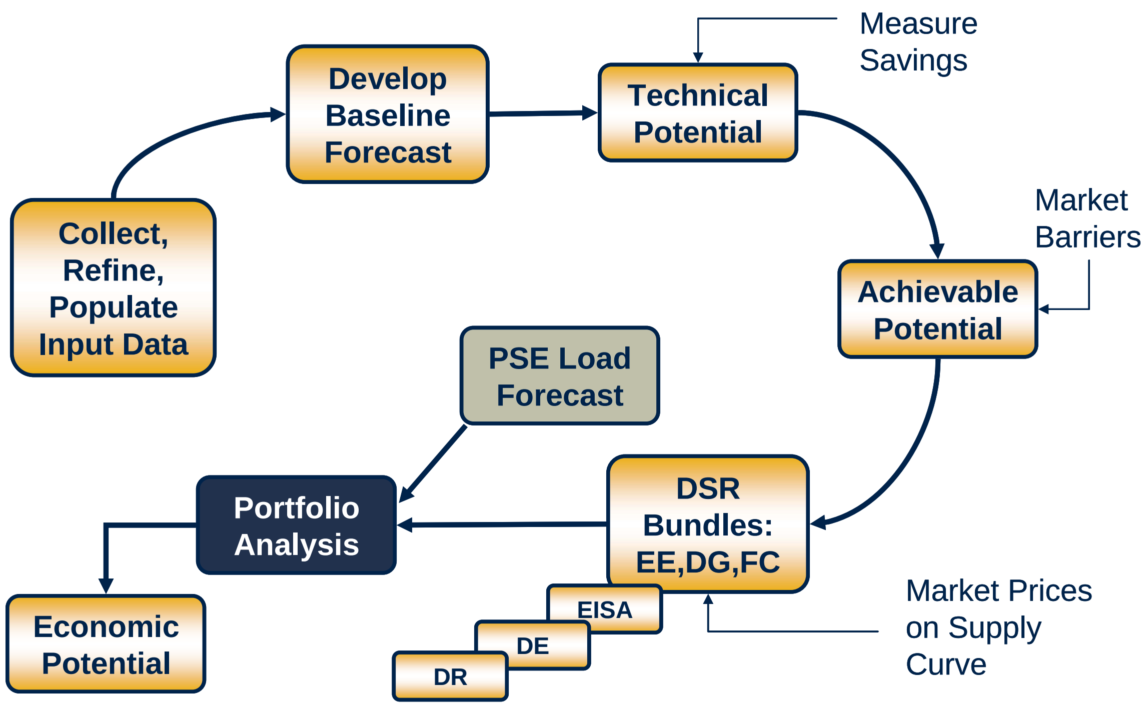
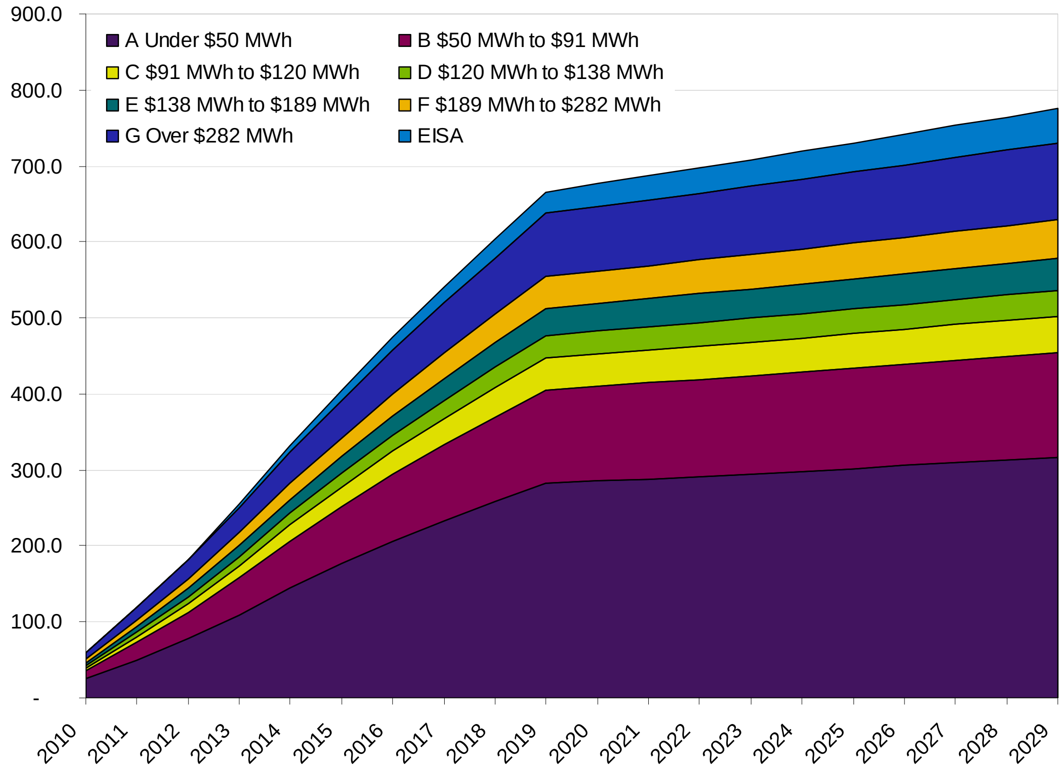


Fig 5-18 shows the achievable potential of all DSR bundles tested in the IRP. The effect of these bundles is to reduce load, so the costs of achieving the savings are added to the cost of the electric portfolios.

5-18
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 Strategist portfolio optimization model to combine 11 supply-side resources with 5 demand-side bundles. This is a general description of the process; for a detailed description of Strategist, see Appendix I, Electric Analysis.

- First, each scenario was combined with all available supply-side resources in the Strategist model.
- Strategist then produced all possible supply-side-only resource combinations capable of filling the resource need defined in that scenario.
- Next, these No-DSR portfolios were ranked in order of cost.
- The lowest-cost, No-DSR portfolio became the starting point for integrating demand-side resources.
- Finally, DSR bundles were added to the lowest-cost, No-DSR portfolio one by one until they no longer reduced portfolio cost.

The results in Figure 5-19 show how DSR bundle C completes the optimal, integrated portfolio for the 2007 Business As Usual scenario.

5-19
Selection of DSR Bundle for 2007 Business as Usual Portfolio

Scenario	No DSR	DSR A	DSR B	DSR C	DSR D	DSR E
2007 Business as Usual	27.35	23.94	23.17	22.95	23.04	

DSR A < No DSR test DSR B	DSR B < DSR A test DSR C	DSR C < DSR B test DSR D	DSR D > DSR C DSR C “optimal”

For comparison purposes, PSE also constructed one portfolio to the specifications of the B2 Energy Standard adopted in 2003. Resource planning conditions have changed significantly since that time, and we wanted test whether this energy standard still reduced cost and risk. It did not.

Figures 5-20, 5-21, and 5-22 display the MW additions for the 11 optimal portfolios in 2015, 2020, and 2029. See Appendix I, Electric Analysis, for more detailed information.

Figure 5-20
2015 Resource Builds by Scenario (Cumulative Additions by Name Plate)

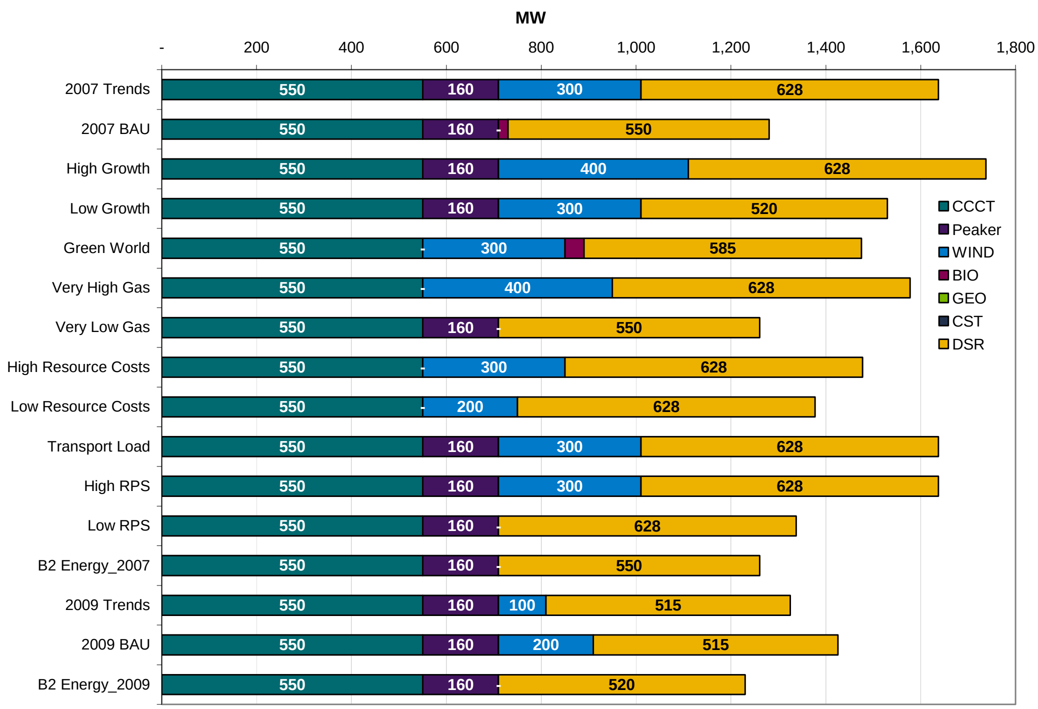


Figure 5-21
2020 Resource Builds by Scenario (Cumulative Additions by Name Plate)

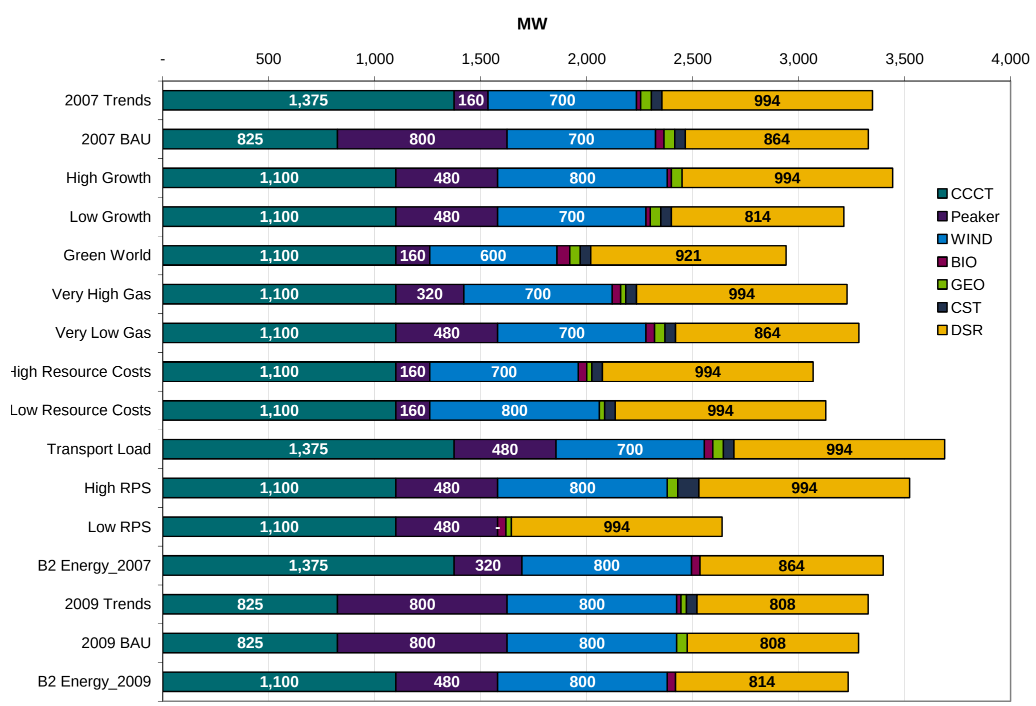
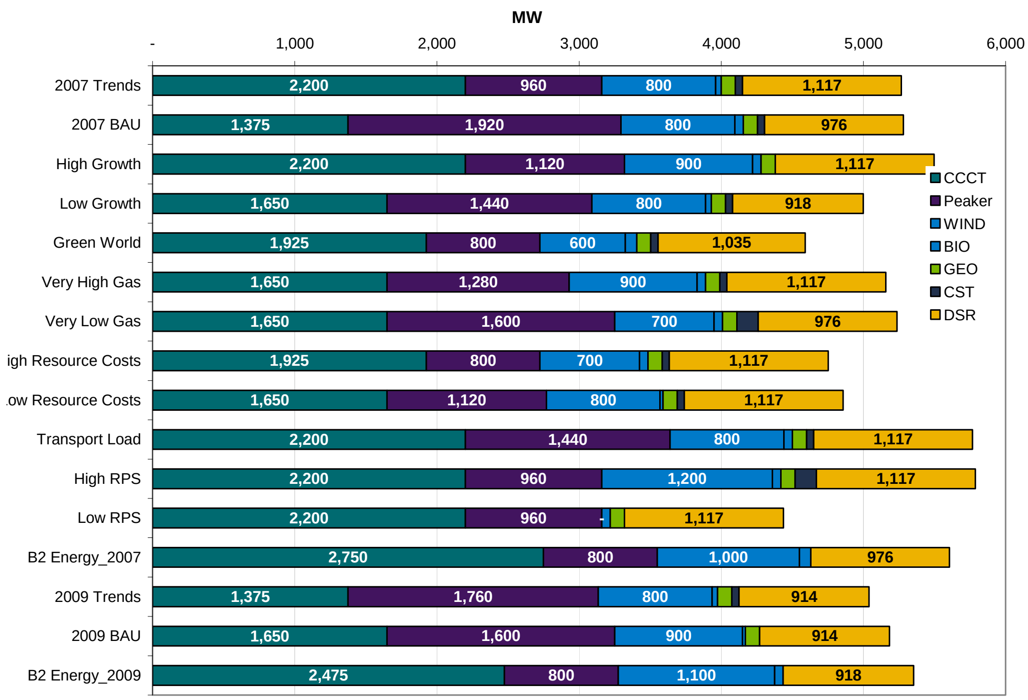


Figure 5-22
2029 Resource Builds by Scenario (Cumulative Additions by Name Plate)



Step 3: Evaluate Costs and Risks

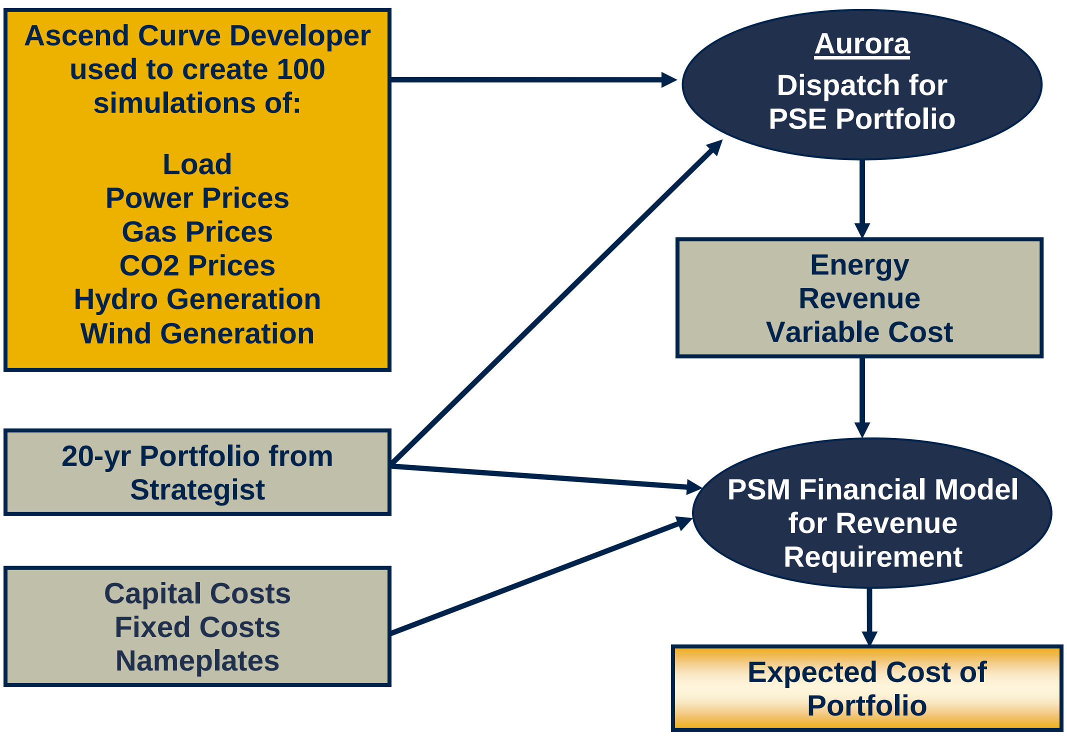
Once the optimal portfolio for each scenario was identified, PSE conducted Monte Carlo analysis on the 2007 Trends and 2007 Business As Usual Portfolios, and used the PSM II process illustrated in Figure 5-23, below, to calculate the revenue requirements for all portfolios.

Ascend Curve Developer was used to create 100 simulations of input variables for the 2007 Trends scenario and 100 simulations for the 2007 BAU scenario. These variables, along with the optimal portfolios for the two scenarios, were loaded and dispatched in AURORA. The dispatch results were then loaded into the PSM financial model, and PSM calculated revenue requirements. This allowed us to fully understand risks associated with differing gas prices, power prices, and weather conditions that affect loads, and hydro and wind generation levels.

In addition, static analysis was used to test the 2007 Trends Portfolio and 2007 Business As Usual Portfolio in the other six scenarios. These results enabled us to examine how they performed against each other under different conditions, and how they performed against the optimal portfolio for that scenario.

The key quantitative results and insights from this analysis are described in Section V of this chapter. For detailed results, go to Appendix I, Electric Analysis.

Figure 5-23
PSM II Analysis Process



V. 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. The data generated by the analysis are presented in the Appendix I, Electric Analysis; detailed descriptions of each portfolio also appear there.

1. Portfolio costs are tightly grouped together.

When different portfolios are tested in the same scenario, their costs are tightly grouped. Figure 5-24 illustrates this result. When we tested the portfolios for 2007 Trends, 2007 BAU, and 2009 Trends in the 2007 Trends scenario, their costs differed by only about 1%. When we tested the same portfolios in the 2009 Trends scenario, the absolute portfolio costs changed, but differences between them remained very small. This tells us that portfolio costs are being driven by scenario assumptions; resource mix has little influence.

Figure 5-24
Relative Portfolio Costs in 2007 and 2009 Scenarios

Portfolio Costs in Millions	2007 Trends Scenario	2009 Trends Scenario
Optimal 2007 Trends Portfolio	$ 23,319	$ 20,243
Optimal 2007 BAU Portfolio	$ 23,469	$ 20,194
Optimal 2009 Trends Portfolio	$ 23,124	$ 20,377

2. Portfolio risk depends on scenario assumptions, not resource builds.

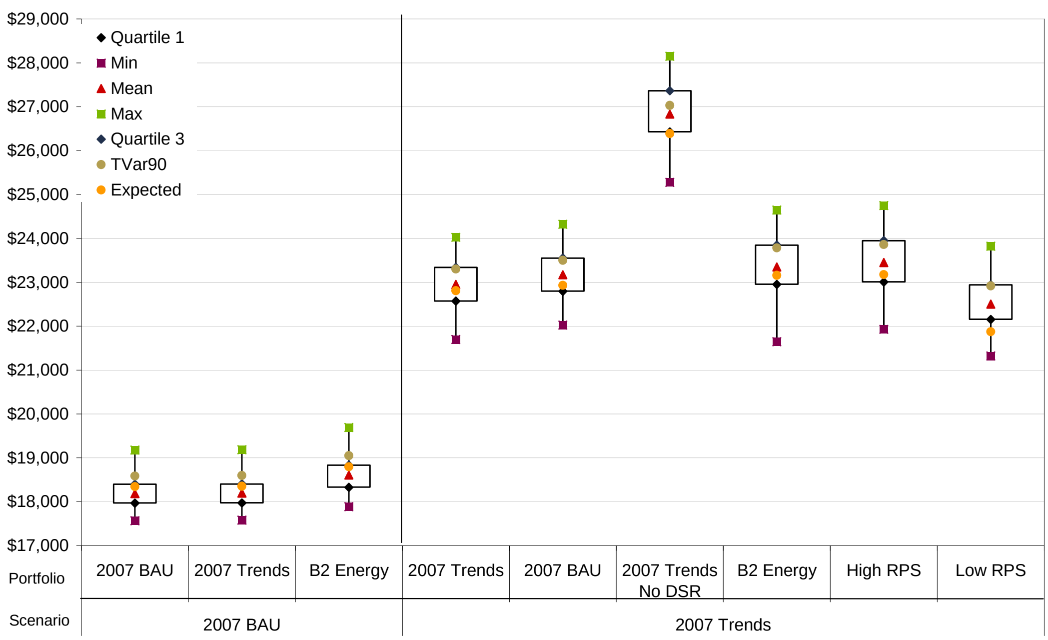
Figure 5-25 shows box plots that represent the range of cost results produced by several portfolios in both the 2007 Trends and 2007 BAU scenarios. Within each scenario, the portfolio ranges are quite compact. The magnitude of expected costs changes dramatically, however, when the scenario changes. It is notable that increasing the amount of renewable resources built within a portfolio, as in the High RPS Portfolio, actually increases cost risk; conversely, decreasing the amount of renewables, as in the Low RPS Portfolio, actually decreases cost and risk.

Figure 5-25

Effects of Scenario Assumptions on Portfolio Costs

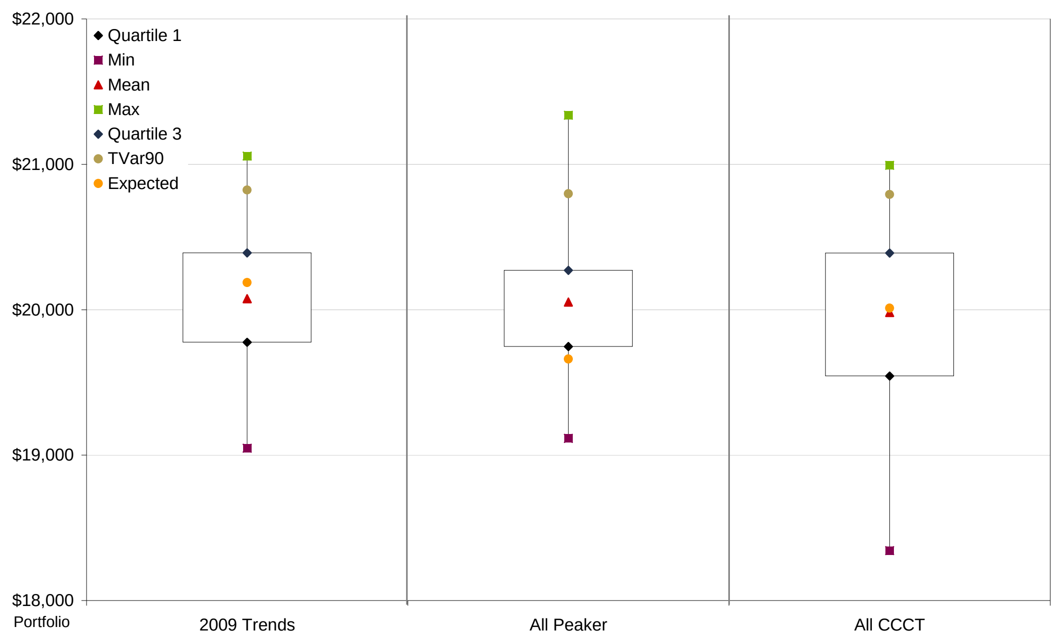
Cost Ranges for Select Portfolios in 2007 Trends and 2007 BAU Scenarios

(Expected Cost for 100 Simulations, $ in Millions)



PSE also designed two extreme portfolios to test how the balance of thermal builds affects cost and risk. Both portfolios built the same level of DSR and renewable generation; the remaining resource need was met by building only peaking plants for Portfolio A and only CCCT plants for Portfolio B. These were compared to each other and to the 2009 Trends Portfolio in the 2009 Trends scenario. Figure 5-24 shows that in this scenario, expected costs and Tail Var 90 costs for the three portfolios are tightly grouped. The results tell us that the balance of peakers to CCCT resources built in a portfolio has very little effect on expected costs or risk.

Figure 5-26
Balance of Thermal Builds and Portfolio Cost and Risk
Comparison of All-CCCT and All-peaker Portfolios in the 2009 Trends Scenario
(Expected Portfolio Cost for 100 Simulations, $ in Millions)



3. RPS requirements drive renewable builds.

The amount of renewable resources to include in portfolios is driven solely by RPS requirements; no other factor introduces renewables as a lowest reasonable cost resource. Figure 5-29 shows the results of portfolio comparisons performed to test how changes in CO_2 costs, RPS requirements, load growth, and demand-side resources would affect wind additions to the portfolios. Except for very high load growth, which increased the need for all resources, no variable increased wind additions except higher RPS requirements.

Figure 5-27
The Effect of Variables on Wind Additions in 2029

Variable	Portfolio's to Compare	Effects of Change
Change in CO_2 Costs	2007 Trends Portfolio vs. 2007 BAU Portfolio	Increased CO_2 costs did not add wind to the portfolio
Change in RPS Requirement	2007 Trends Portfolio vs. High RPS vs. Low RPS	More or less wind added depending on the direction of RPS change
Change in Load	2009 Trends (low demand) vs. 2007 Trends (mid demand) vs. High Growth (high demand)	No significant change in wind builds until High Growth is reached, then 100 MW added
Change in DSR	No-DSR 2007 Trends Portfolio vs. 2007 Trends Portfolio	Adding the optimal amount of DSR in 2007 Trends reduced the amount of wind built

4. Emissions are declining.

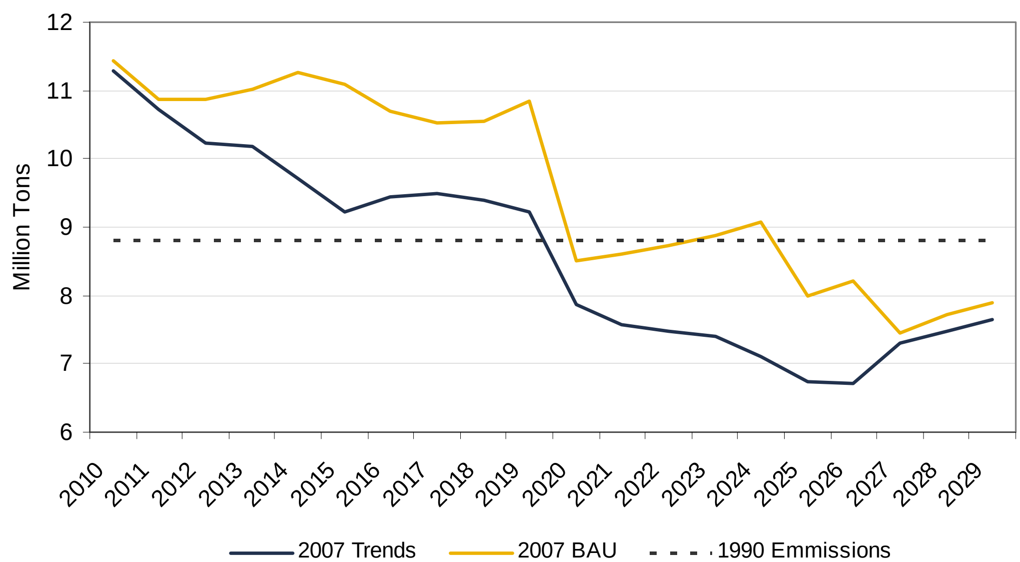
Relative to current levels, CO_2 emissions are falling throughout the study period. All portfolio emissions fall below 1990 levels of 8.8 million tons per year by the end of the study period except for the No-DSR portfolios. CO_2 costs influence the timing of reductions, but the assumed retirement of our coal-fired generation at the Colstrip facility has the biggest effect on all.

Figure 5-26 compares the annual emissions of the 2007 Trends portfolio with the 2007 BAU portfolio. Essentially this is a comparison of portfolios with and without CO_2 costs, (2007 Trends includes CO_2 costs of $37 per ton in 2012 that rise to $130 per ton by 2029; 2007 BAU includes a negligible $0.32 per ton.) Even the 2007 BAU portfolio, with nearly no emissions costs, falls below 1990 levels in 2020. The 2007 Trends portfolio emits less total CO_2 over the study period, but by 2029, thanks to the retirement of Colstrip, the difference between the two is only about 0.25 million tons per year. By the end of the planning period then, the BAU portfolio is producing roughly the same amount of emissions as a portfolio that carried an additional $4.9 billion of CO_2 costs over the 20 year study period. The cost per ton to go from 2007 BAU emission levels to 2007 Trends emissions levels is $532 per ton.

Emissions profiles for select portfolios can be found in Appendix I, Electric Analysis.

Figure 5-28

Annual Emission Rates for 2007 BAU and 2007 Trends Portfolios



5. Cost-effective DSR is the only way to reduce cost and risk.

Demand-side resources are the only resource that reduces both cost and risk in portfolios, because they reduce need. All other resources -- including renewables – expose the portfolio to the risks inherent in the power and gas markets. A portfolio heavy in wind builds must rely on market power purchases to balance wind variability, for instance, and a portfolio's thermal resources are subject gas price volatility. Figure 5-29 shows the expected cost and risk ranges for the No-DSR 2007 Trends Portfolio and the optimal 2007 Trends Portfolio, which includes 1,117 MW of DSR by 2029.

The amount of cost-effective conservation varies from scenario to scenario. Moving from a No-DSR portfolio to one that includes DSR Bundle A produces the most savings; after that, savings accumulate incrementally. All scenarios identified at DSR Bundle B to be cost effective, but Bundles C, D, and E became cost effective only when certain scenario assumptions were present. Figure 5-30 shows how portfolio costs change as incremental bundles of DSR are added. Going from No-DSR to Bundle A in 2007 Trends reduces costs by 12.13%, going to Bundle B reduces costs by 3.08%, by the time we add bundle the savings are only .2% of portfolio costs.

Figure 5-29

Effect of DSR on Portfolio Cost and Risk

Comparison of Expected Costs and Cost Ranges for No-DSR and Optimal 2007 Trends Portfolios

(Expected Portfolio Cost for 100 Simulations, $ in Millions)

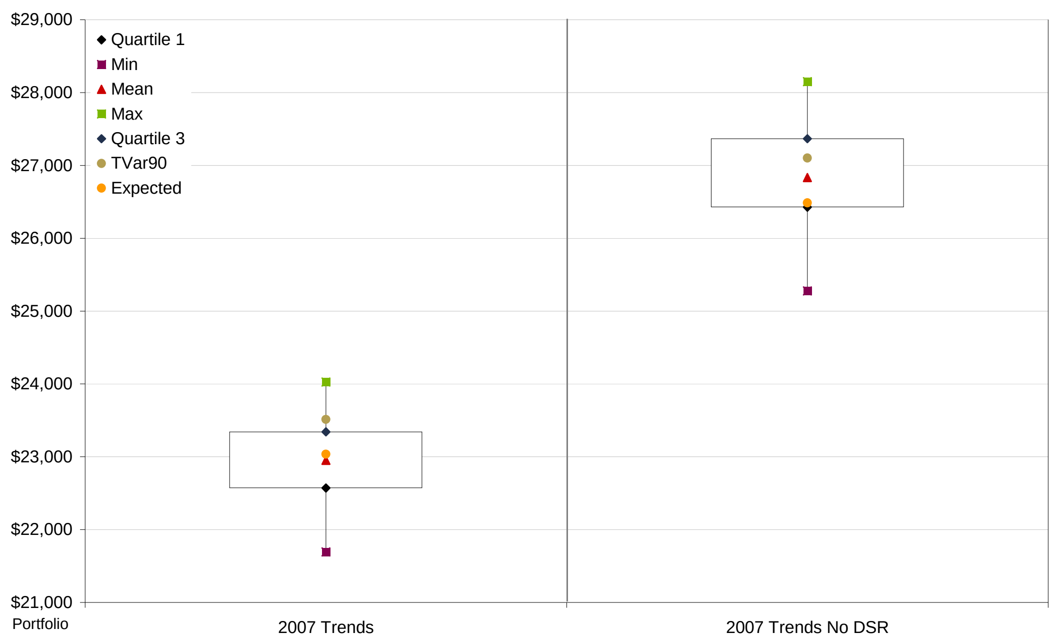


Figure 5-30

Percentage Change in Portfolio costs by DSR Bundle in Different Scenarios

Scenario	No DSR to A	A to B	B to C	C to D	D to E
2007 Trends	-12.13%	-3.08%	-0.48%	-0.79%	-0.20%
Green World	-10.64%	-1.25%	-2.89%	-0.36%	1.30%
2007 Business As Usual	-12.47%	-3.22%	-0.95%	0.39%	
Low Growth	-11.58%	-2.57%	0.32%		
High Growth	-10.32%	-3.40%	-0.65%	-0.42%	-0.84%
Very High Gas	-11.94%	-3.27%	-0.64%	-0.63%	-0.78%
Very Low Gas	-10.24%	-2.93%	-1.01%	0.69%	
2007 Trends_ High Resource Cost	-11.29%	-3.74%	-1.25%	-0.68%	-2.14%
2007 Trends_ Low Resource Cost	-10.61%	-3.50%	-1.42%	-0.24%	-1.39%
2007 Trends_ Transport Load	-11.01%	-3.72%	-1.15%	-0.31%	-2.85%
2009 Trends	-12.07%	-3.28%	2.60%	-4.78%	2.89%
2009 Business As Usual	-13.60%	-2.39%	-0.70%		