

Electric Resources

PSE provides electric services to more than a million customers in Washington state. Over the next 20 years those numbers will grow. That growth, combined with expiring resource contracts, means we will face substantial electric resource needs in coming years. This chapter reviews PSE's existing electric resources and the alternatives available to us. It outlines the methodology we used to analyze those alternatives, and it summarizes the key findings from the quantitative analysis. The chapter is divided into five sections.

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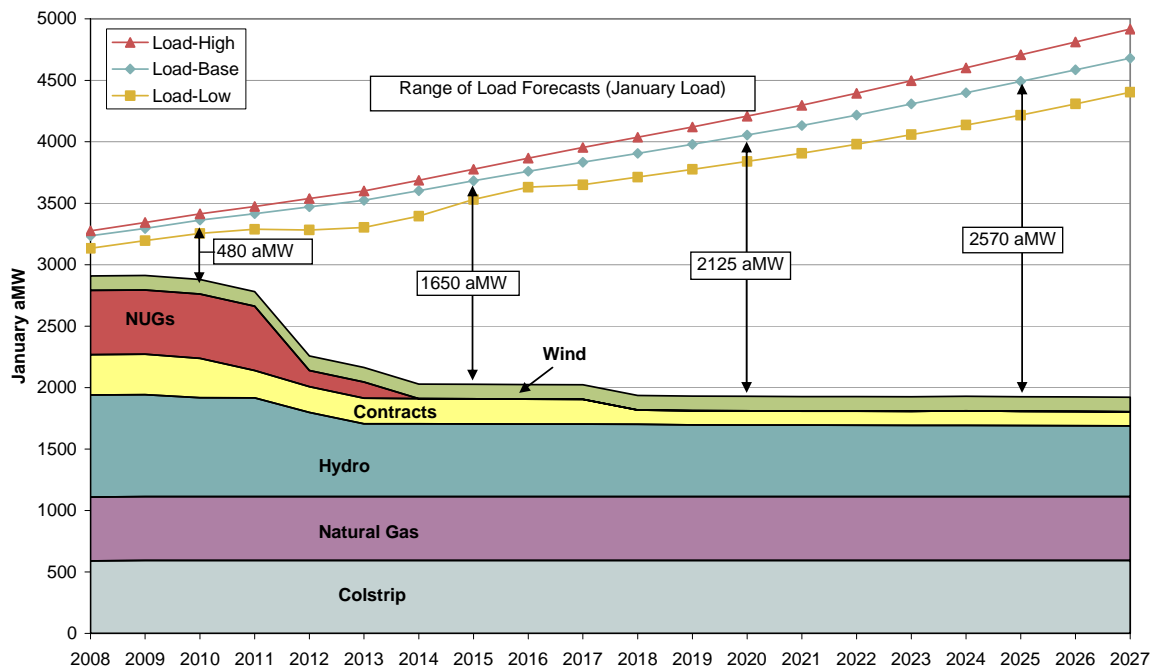
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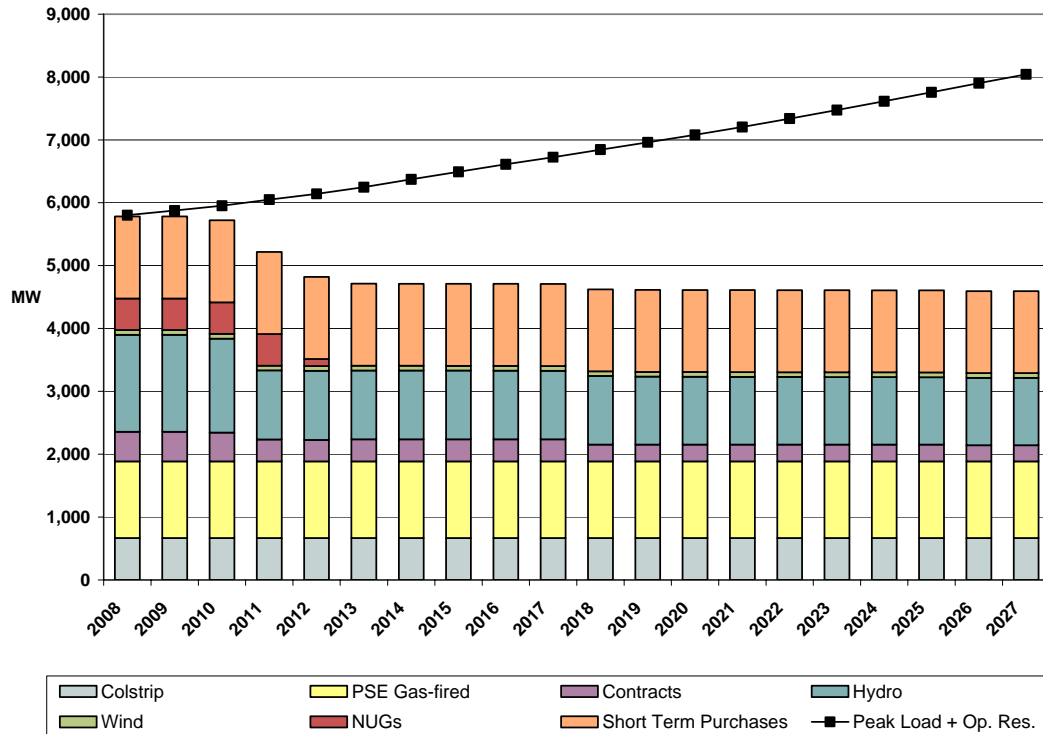
I. Electric Resource Need

The combination of economic growth and expiring supply contracts means that PSE faces large electric resource needs in the years ahead. To meet the projected base load demand of our customers, we will need to acquire nearly 700 aMW of electric resources by 2011, more than 1,600 aMW by 2015, and 2,570 aMW by 2027, as Figure 5-1 below illustrates. This is the equivalent of adding enough electricity to power the city of Seattle for the next 20 years.

**Figure 5-1
Electric Baseload Resource Need:
Comparison of Projected Loads and Existing Resources, 2008-2027**



**Figure 5-2
Electric Peak Capacity Resource Need:
Comparison of Projected Peak Loads with Existing Resources, 2008-2027**



As the number of PSE customers increases each year, so do our peak load and base load energy demand. Figure 5-2 compares the forecasted load during the highest demand hour of the year to the peak capacity of existing resources and contracts. PSE is a winter peaking utility whose peaks are driven by temperature-dependent heating loads. The peak load forecast, therefore, includes both a forecast of the customer base and an estimate of how much power would be used at a temperature of 13 degrees Fahrenheit. The 13°F represents a one in 20 year occurrence (5% exceedence probability) based on the 30 year historical data of minimum temperatures during the on-peak hours.

Electric resources are constrained by regional operating reserve requirements that, in effect, raise the peak resource requirement to take into account possible forced outages. The Western Electricity Coordinating Council (WECC) identifies this standard as the greater of the largest single contingency or 7% for thermal units plus 5% for hydro units.

Half of the reserve requirement must be provided as spinning (instantaneously available) reserves with the balance being carried as supplemental reserves.

Differences between Long-term and Short-term Peak Capacity Planning

Figure 5-2 describes long-term peak capacity needs, but it does not fully describe PSE's near-term capacity situation due to the different methods used to assess and address peak capacity.

During the past several winters PSE has met peak needs that are beyond the capacity of existing resources with a combination of short-term market product alternatives that have been more cost-effective than acquiring new generation. These include call options, energy exchanges, and the acquisition of additional cross-Cascades transmission capacity.

Long-term peak resource needs are plotted over the 20-year planning horizon using the December peak-load forecast compared to the existing resources available to meet those needs. Short-term peak needs planning is performed annually, and uses monthly estimates of peak loads and capacity for the winter period (November through February). Short-term planning also considers the transmission capacity of each transmission link the Company owns or leases, and the current marketplace conditions for day-ahead and month-ahead purchases.

Differences between the two methods result in observable differences in resource need estimates. For example, peak loads may be forecast to increase by 65 MW per year over the next 20 years, but only 50 MW for the coming December.

Extending the short-term methodology to cover long-term assessments of peak need is not practical. The transmission issues and short-term market conditions that inform near-term analyses are not possible to quantify over the long term in any meaningful way.

II. Existing Resources

This discussion of PSE's existing electric resources is divided into four parts.

- **Supply-side resources** encompass power generated by PSE-owned and contracted facilities, primarily hydropower, coal-fired plants, natural gas fueled turbines, and wind.
- **Demand-side resources** are contributions to the resource pool that are generated on the customer side of the meter, primarily through energy efficiency programs.
- **Green Power and small-scale renewables** discusses PSE's two customer renewable energy programs, one for customers who want additional renewable energy and one for customers producing power from small-scale renewables.
- **Regional transmission resources** describes the transmission system available to PSE to transport power to and across our service territory (as opposed to the local power distribution system owned and operated by PSE, which is discussed in Chapter 7).

A. Supply-side Resources

PSE’s portfolio of supply-side generation resources is diversified both geographically and by fuel type (see Figure 5-3). Most of our gas-fueled resources are in western Washington, while the major hydroelectric contracted resources are in central Washington, outside our service area. The wind facilities are located in central and eastern Washington and the Colstrip coal facility is in eastern Montana.

**Figure 5-3
Map of Supply-side Resources**

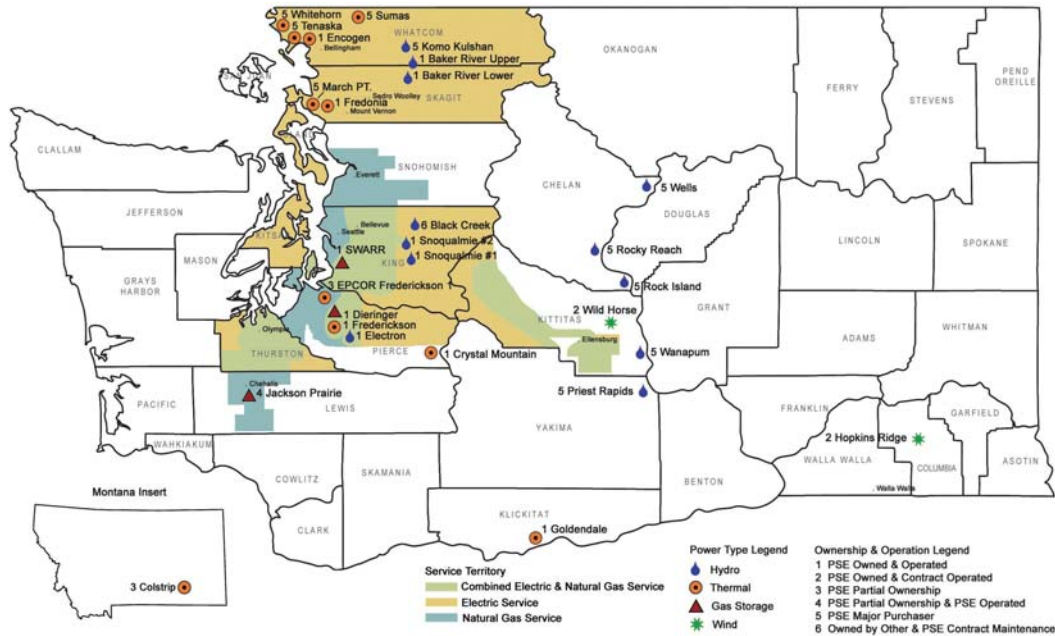


Figure 5-4
Expected Supply-side Resources for 2008

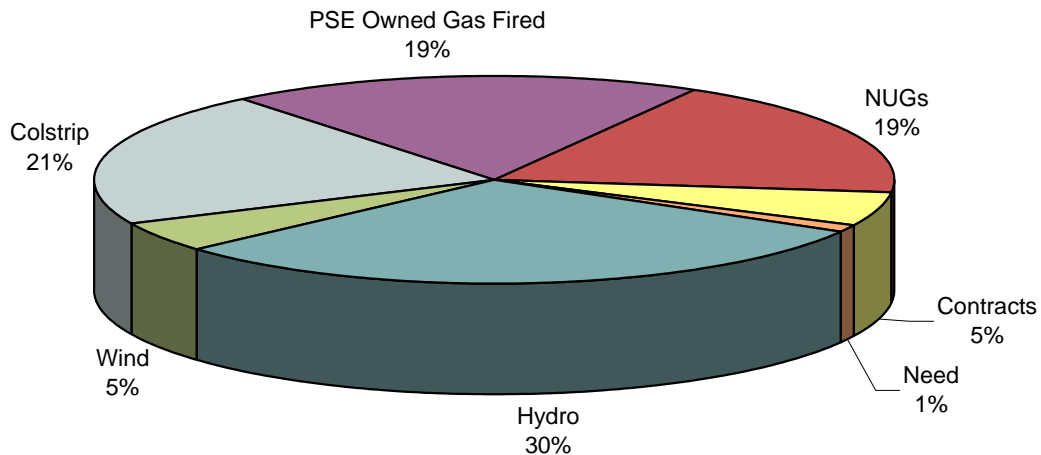


Figure 5-4 shows our supply-side sources annual availability of energy for 2008 under average (50-year) hydroelectric conditions. This figure shows the percent of annual electric resource base load need in 2008 based off of the annual load forecast. Hydroelectricity, which provides the largest supply percentage, includes both owned projects and long-term purchase contracts with mid-Columbia public utility districts (PUDs). Our share of the coal-fueled Colstrip plant makes up the next largest portion. Natural gas resources include nonutility generator (NUG) contracts, plus simple-cycle and combined-cycle combustion turbine plants that we both own and lease. Our Hopkins Ridge and Wild Horse wind-powered facilities provide 5% of our energy supply.

Hydroelectricity

Hydroelectric plants deliver approximately 32% of our annual energy generation or 810 aMW (aMW is the average number of megawatt-hours [MWh] over a specified time period; for example, 295,650 MWh generated over the course of one year is equivalent to 810 aMW, or 295,650 divided by 8,760 hours, which is the number of hours in a year). Hydro resources are very valuable because they can follow load (such as the mid-Columbia resources) and their cost is generally low compared to other sources of generation power. PSE owns hydro projects in western Washington and has long-term contracts with three PUDs that own large dams on the Columbia River in central

Washington. We also contract with smaller hydro generators. High precipitation levels generally allow more power to be generated; low-water years produce less power, so we must rely on more expensive self-generated or market sources to meet the load. This IRP analysis accounts for both seasonality and year-to-year variations in hydro production.

**Figure 5-5
Existing Hydro 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 and Electron	PSE	100	68	n/a
Total PSE-Owned			258	
Wells	Douglas Co. PUD	29.9	251	3/31/18
Rocky Reach	Chelan Co. PUD	38.9	493	11/1/11
Rock Island I & II	Chelan Co. PUD	50.0	272	6/7/12
Priest Rapids	Grant Co. PUD	4.31	39	Will tie to new FERC license
Wanapum	Grant Co. PUD	10.8	106	Will tie to new FERC license
Mid-Columbia Total			1420	
Total Hydro			1678	

*Nameplate capacity reflects PSE's share only.

Baker River Hydroelectric Project. 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. PSE initiated relicensing for the Baker River Hydroelectric Project in March 2000, in advance of the existing license's expiration in 2006. A Settlement Agreement representing the consensus of 23 stakeholders was recommended to the FERC in 2004. All parties (federal and state resource agencies, three Native American tribes, Skagit County, several nongovernmental organizations and PSE) supported a 45-year license. We anticipate that, in 2007, FERC will issue a new license authorizing PSE to generate 707,600 MWh (average annual output) for a term of 30-45 years.

Snoqualmie Falls Hydroelectric Project. 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, making this a reliable and cost-effective resource. 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, the outcome of which cannot now be determined.

Mid Columbia Long-Term Purchased Power Contracts. PSE purchases a percentage of the output of five hydroelectric projects located on the middle stem of the Columbia River in Central Washington pursuant to long-term purchase power agreements with three PUDs (see Figure 5-5). In exchange, we pay the PUDs its proportionate share of operating expenses for the 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 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 will be in effect upon termination of the current agreements in 2011 and 2012, and will 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 applied to Priest Rapids in November 2005 and will apply to Wanapum beginning November 2009. After that date, PSE will receive a combined share of power from both projects, which declines over time as the PUDs' loads increase. PSE's share of the Wanapum Development will remain at 10.8% until November 2009 and will be adjusted 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.

Wanapum and Priest Rapids Developments. PSE signed new contracts for a share of the electricity produced at these facilities in 2001. The terms applied to Priest Rapids as of November 1, 2005 and will apply to Wanapum beginning November 1, 2009. After that date we will receive a combined share of power from both projects rather than individual shares of each project.

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 about 22% of our overall energy needs. PSE owns a 50% share in Colstrip 1 & 2, and a 25% share in Colstrip 3 & 4. The four coal-fired units are restoring their rated capacities by installing higher-efficiency turbine components by 2008. At that time, our share of the Colstrip output will total 566 aMW, an increase of 28 aMW. 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)

CCCTs improve output efficiency by generating additional energy from the heat produced by the original power-producing cycle of a simple-cycle combustion turbine. The nameplate capacity of our three CCCT resources is 570 MW. The **Goldendale** facility, in southern Washington, is our newest acquisition. Purchased in February 2007, it has a nameplate capacity of 277 MW. **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

The two wind projects described here represent PSE's first ownership of utility-scale renewable energy, and supply 5% of our energy portfolio. So far we are the only Northwest utility to solely own and operate large wind-power facilities. **Hopkins Ridge**, located in Columbia County began generating energy in November 2005. **Wild Horse**, located in Kittitas County near Ellensburg, came online in December 2006. Combined, the two projects produce 125 aMW. 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, these projects have increased the tax base, allowing local government to provide additional services (e.g., a new health clinic in Columbia County). Figure 5-6 presents details about our coal, CCCT, and wind resources.

**Figure 5-6
Existing Coal, CCCT, and Wind Resources**

POWER TYPE	UNITS	PSE OWNERSHIP	NAMEPLATE CAPACITY (MW)*
Coal	Colstrip 1 & 2	50%	310
Coal	Colstrip 3 & 4	25%	370
Total Coal			680
CCCT	Goldendale	100%	277
CCCT	Encogen	100%	170
CCCT	Frederickson	49.85%	133
Total CCCT			570
Wind	Hopkins Ridge	100%	149
Wind	Wild Horse	100%	229
Total Wind			378

*Nameplate capacity reflects PSE's share only.

Gas-fired Simple-cycle Combustion Turbines

Our four simple-cycle combustion turbine plants contribute a total of 606 MW of capacity. Details are shown in Figure 5-7. They provide important peaking capability, although they typically operate only a few days each year. These resources are not used for baseload energy when lower cost energy purchases are available, but were designed to provide winter peaking capacity and peak energy when market conditions warrant. A long-term financing lease for **Fredonia 3 & 4** expires in 2011. Our lease for **Whitehorn 2 & 3** expires in 2009, and we have executed an agreement to purchase the units when the lease ends.

**Figure 5-7
Existing Simple-cycle Combustion Turbines**

NAME	PSE OWNERSHIP	NAMEPLATE CAPACITY (MW)
Fredonia 1 & 2	100%	202
Fredonia 3 & 4	100%	110
Whitehorn 2 & 3	Leased	147
Frederickson	Leased	147
Total		606

*Nameplate capacity reflects PSE's share only.

Non-Utility 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. All three are located in Skagit and Whatcom counties, in the northern part of our service area. The combined nameplate capacity of these plants is 523 MW.

Tenaska Cogeneration. In 1991 we contracted to purchase the 224 aMW output, beginning in April 1994, from Tenaska Washington Partners, L.P., which owns and operates the project near Ferndale, Washington. 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. We thus became 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 term of this agreement ends December 31, 2011.

Sumas Energy Cogeneration. In 1989 we contracted to purchase 133 aMW from Sumas Cogeneration Company, L.P., which owns and operates this project located in Sumas, Washington. Under its terms, this agreement ends April 16, 2013.

March Point Phases I & II. We have contracts through December 31, 2011 to purchase the full output of March Point Phase I & II from the March Point Cogeneration Company, which owns and operates these facilities. The plants are located at the Shell refinery in Anacortes, Washington and deliver a combined 145 aMW.

Other Long-term Contracts

Long-term contracts, which range in capacity up to 300 MW, consist of agreements with independent producers and other utilities. Fuel sources include hydro, gas, waste products, and system deliveries without a designated supply resource. Independent producers provided approximately 42 aMW, and utilities contributed approximately 110 aMW in 2006. This does not include short-term contracts (less than one year) negotiated by our energy trading group. These are summarized below in Figure 5-8.

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 BPA resulting from its action to halt construction on nuclear project WNP-3, in which we had a 5% interest. Under the agreement, in effect until June 2017, PSE receives power 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 2006 this amounted to 44 aMW during the months January through April, November and December. The agreement provides for PSE to provide exchange energy from PSE combustion turbines, at PSE's cost, to BPA, if requested, during the months of January through April and September through December.

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, then delivery passed to Snohomish County PUD.

Powerex Purchase for Point Roberts. Powerex delivers electric power to our retail customers in Point Roberts, Washington. 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 2007. PSE is currently in the process of renegotiating an extension with Powerex.

BPA Baker Replacement. Under a letter of intent signed with the U.S. 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 the 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. We provide power to PG&E

in June through September, and PG&E provides power to us November through February. (PSE is a winter-peaking utility, while PG&E is a summer-peaking utility.)

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 in 2006).

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

TYPE	NAME	TYPE	CONTRACT EXPIRATION	NAMEPLATE CAPACITY (MW)**
NUG	Tenaska		12/31/2011	245
NUG	Sumas		04/16/2013	133
NUG	March Point I		12/31/2011	80
NUG	March Point II		12/31/2011	65
Total NUG				523
Other Contracts	Northwestern Energy Company	Colstrip	12/29/2010	97
Other Contracts	BPA- WNP-3 Exchange	Various	6/30/2017	102
Other Contracts	Conservation Credit - SnoPUD	Hydro	2/28/2010	18
Other Contracts	Powerex/Pt.Roberts	Hydro	9/30/2007	3
Other Contracts	BPA Baker Replacement	Hydro	10/1/2007	7
Other Contracts	PG&E Seasonal Exchange-PSE	Thermal	Ongoing*	300
Other Contracts	Canadian EA	Hydro	12/31/2025	-58
Total Other				469
Independent Producers	Spokane Municipal Solid Waste	Biomass-QF	11/15/2011	18

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TYPE	NAME	TYPE	CONTRACT EXPIRATION	NAMEPLATE CAPACITY (MW)**
Independent Producers	Twin Falls	Hydro	3/8/2025	14
Independent Producers	Koma Kulshan	Hydro	3/1/2037	11
Independent Producers	North Wasco	Hydro-QF	12/31/2012	5
Independent Producers	ORMAT	Heat Recovery	11/01/2028	5
Independent Producers	Nooksack Hydro	Hydro	11/30/2008*	3
Independent Producers	Puyallup Energy Recovery Co.(PERC)	Biomass-QF	4/18/2009	2
Independent Producers	Weeks Falls	Hydro	12/1/2022	3
Independent Producers	Hutchison Creek	Hydro-QF	9/30/2016	1
Independent Producers	Kingdom Energy-Sygitowicz	Hydro-QF	2/2/2014	0
Independent Producers	Port Townsend Paper	Hydro-QF	12/31/2008	0
Total Independent				62

*May be terminated with issuance of 5-year notice.

**Nameplate capacity reflects PSE's share only.

B. Demand-side Resources

Demand-side resources are generated or saved on the customer side of the meter. Energy efficiency, our primary demand-side resource, makes up a meaningful and increasing portion of PSE's energy portfolio. We have long supported cost-effective energy conservation. Between 1985 and 2005, these measures produced savings that gained approximately 310 aMW on an investment of \$462 million. This is roughly equal to the annual output from our share of Colstrip 3 & 4--equivalent to the electricity used by about 230,000 homes. During the 2004-2005 tariff period, electric energy efficiency programs contributed 19.6 aMW to our resource needs, more than the annual amount of power supplied from our largest long-term contract with an independent producer, saving enough energy to power 30,000 homes.

In our April 2005 Least Cost Plan Update, PSE presented an extensive analysis of energy efficiency savings potential and its contribution to the Company's electric portfolio. In collaboration with key external stakeholders represented by the Conservation Resource Advisory Group (CRAG) and Least Cost Plan Advisory Group (LCPAG), these results were used to develop energy efficiency program targets for 2006 and 2007. A two-year stretch goal for energy savings of approximately 40 aMW by the end of 2007 was adopted. In addition, PSE also issued requests for proposals (RFPs) to acquire new electric and gas efficiency resources.

PSE's energy efficiency programs are designed to serve all customers—including residential, low-income, commercial, and industrial. Energy savings targets and the programs to achieve those targets are established every two years. The 2004-2005 biennial program period concluded at the end of 2005; current programs operate January 1, 2006 through December 31, 2007. A high-level summary is included in Figure 5-9.

PSE funds the majority of our electric energy efficiency programs using electric "Rider" funds collected from all customers. A portion of the funding takes place through arrangements with BPA to provide conservation and renewable discount (C&RD) credits. As with supply-side resources, we evaluate energy efficiency programs for their cost-effectiveness and suitability within a lowest reasonable cost strategy.

Current Electric Energy Efficiency Programs

The **Commercial and Industrial Retrofit Program** offers expert assistance and grants to help existing commercial and industrial customers use electric 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 2005, producing 5.27 aMW at a cost of \$7,686,733. The retrofit program accounted for 32% of all electric savings in 2005. In 2006, the program savings declined, but it was again the dominant contributor to commercial program savings, contributing 4.74 aMW at a cost of \$9,672,363 and comprising 25% of all electric energy efficiency savings.

The **Energy Efficient Lighting Program** offers instant rebates for residential customers and builders who purchase Energy Star fixtures and compact fluorescent light bulbs. This program generated the greatest energy savings gains on the residential side in 2005, producing 2.65 aMW at a cost of \$1,306,655. It accounted for 16% of all electric savings in 2005. In 2006, rebates for CFL Fixtures, Energy Star™ Washing Machines and Dishwashers, Refrigerator Decommissioning, and Energy Star™ Manufactured Homes combined for a savings of 6.6 aMW at a cost of \$7,236,082. This very successful program accounted for 35% of all electric energy efficiency savings.

**Figure 5-9
Annual Energy Efficiency Program Summary, 2005 & 2006
(\$millions, except MWh)**

Tariff + C&RD Programs	2004 - 2005 Actual	'04-'05 2-Year Bdgt./Goal	'04/'05 Actual vs. '04/'05 % Total	2006 Actual	'06-'07 2-Year Bdgt./Goal	'06 vs. '06/'07 % Total
Electric Program Costs*	\$50.4	\$52.2	104%	\$28.7	\$63.9	44.9%
Megawatt Hour Savings	344,606	343,080	100%	166,254	350,628	47.4%

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

The year 2005 marked the end of a conservation tariff period spanning 2004 and 2005 that continued ongoing programs. Figure 5-9 shows 2004-2005 performance compared to two-year budget and savings goals for electric energy efficiency programs.

During 2004-2005, our electric energy efficiency programs saved a total of 39.3 aMW of electricity at a cost of \$50.4 million. We surpassed our two-year savings goals while operating at a cost that was under budget. In 2006, electric energy efficiency programs saved 18.9 aMW of electricity at a cost of \$28.7 million. It is also notable that, on average, costs of acquiring energy efficiency increased by approximately 16% from 2005 to 2006, although energy savings declined slightly.

In November 2005, we issued an “all-comers” RFP for energy efficiency resources to be added in 2006-2007. 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. The results of that RFP process did not identify any significant new opportunities for additional electric energy efficiency. Of the 18 proposals received, 12 involved electric energy efficiency. One program, a multifamily weatherization direct installation program was selected.

C. Green Power and Small-scale Renewables

More PSE customers are participating in PSE’s customer renewable energy programs each year. The Green Power Program serves customers who want additional renewable energy, and the Customer Renewables Program serves customers who generate renewable energy on a small scale. Our customers find the Green Power and Customer Renewables programs to have value as well as social benefits. We embrace their use.

Green Power

PSE launched its Green Power program in 2001, after passage of a law requiring Washington state’s 16 largest electric utilities to allow customers to voluntarily purchase retail electric energy from qualified renewable energy resources (i.e., green power). Since then, the program has grown significantly—increasing to 17,426 subscribers who purchased 131,742 MWh in 2006 from 4,850 subscribers who purchased 8,563 MWh in 2002. (See Figure 5-11 for year-by-year totals.) The National Renewable Energy Laboratory recognized PSE as one of the top 10 utilities for Renewable Energy Sales and Total Number of Green Power Participants in 2005.

To supply green power, the Green Power Program purchases renewable energy credits, called green tags, from a variety of sources. The primary supplier is the Bonneville

Environmental Foundation (BEF), a nonprofit environmental organization in Portland, Oregon, which provides a portfolio of resources including wind, solar and biomass. The Green Power Program also purchases green tags directly from producers to support the development of new small renewable resources.

Figure 5-10 lists the resources constituting the Green Power portfolio.

**Figure 5-10
Green Power Portfolio**

Name	Resource	Location
Condon	Wind	Condon, OR
Stateline	Wind	Walla Walla, WA
Klondike	Wind	Sherman Co., OR
Klondike II	Wind	Sherman Co., OR
Nine Canyon	Wind	Kennewick, WA
Nine Canyon II	Wind	Kennewick, WA
Tillamook WTE	Bio	Tillamook, OR
Dry Creek LFG	Bio	Medford, OR
White Creek	Wind	Klickitat Co. WA
Small Solar	Solar	Various, OR, WA
Vander Haak	Bio	Lynden, WA
Grays Harbor Paper	Bio	Hoquiam, WA

Customers can purchase green power in 160 kWh blocks for \$2 per block with a two-block minimum. In 2005, the Green Power Program introduced a large-volume green power rate, and also initiated several programs to increase business participation and encourage small-scale renewable energy projects within our region. The Green Power Program supports new resources by entering into agreements to purchase the green tags from these projects. The Customer Renewables Program has also directly paid for all or part of the installation of new solar demonstration projects, including a 1 kilowatt system on the Capitol building in Olympia and another solar project at the International Brotherhood of Electrical Workers office.

The large-volume green power rate—0.6 cent per kWh for customers who purchase more than 1,000,000 kWh annually—attracted seven customers by the end of its first year,

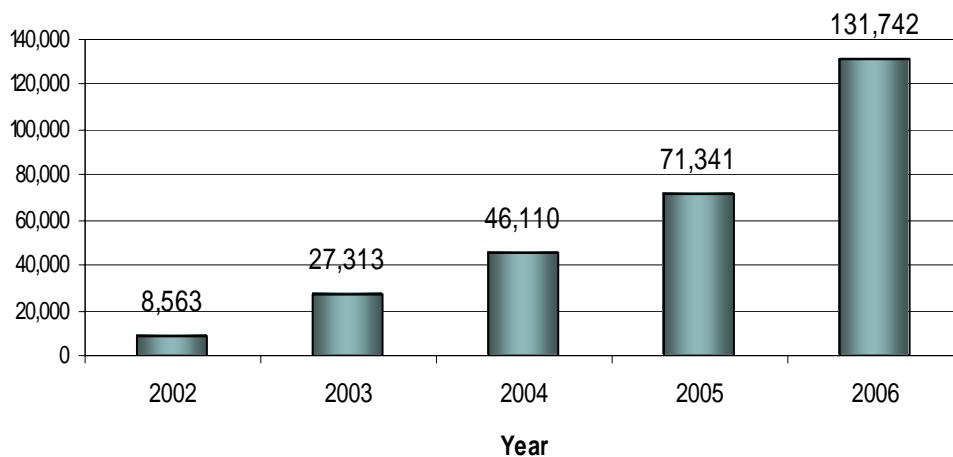
including PSE's corporate offices in Bellevue. Two of these customers, Western Washington University and The Evergreen State University, use the program for 100% of their electric energy. Three more large-volume customers joined the program in 2006.

Expanded efforts to increase participation have included exploring broader marketing techniques and projects. We entered into partnerships with Made in Washington stores, PCC Natural Markets, and Grounds for Change for residential campaigns, conducted direct mail campaigns, and advertised in business journals to reach the business and commercial communities. We also launched a formal recognition program for our large customers to support their actions.

Of our 17,426 Green Power subscribers at the end of 2006, 16,994 were residential customers and 432 were business customers. Cities with the most Green Power participants include Olympia with 2,120, Bellingham with 1,826, Bellevue with 1,009 and Kirkland with 817.

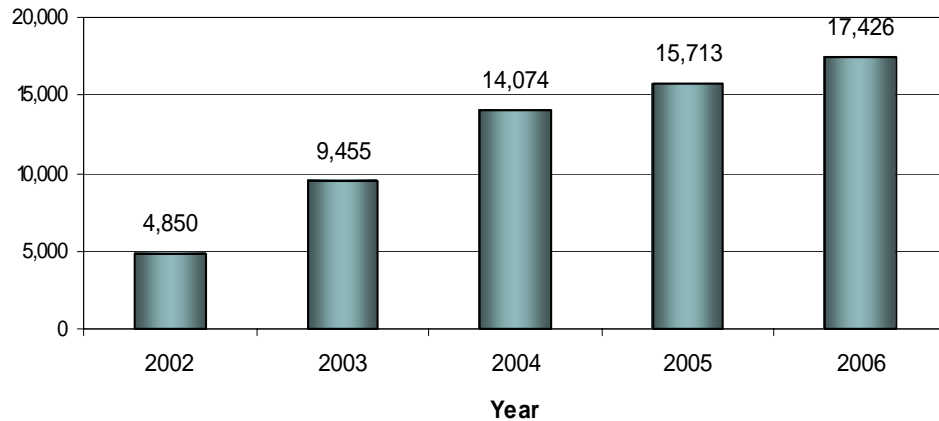
2006 marked the expiration of a three-year agreement with BEF for the purchase of green tags, which provided PSE with some surety on tag pricing and flexibility in adding small-scale resources to the program. In 2006, PSE issued an RFP for green tags, which resulted in a new three-year agreement, also with BEF.

**Figure 5-11
Green Power Kilowatt-Hours Sold, 2002-2006**



In 2006, the average purchase under Schedule 135 was 300 KWH per month. The average 2006 large volume purchase under Schedule 136 was 67,100 KWH per month. Figure 5-12 illustrates the number of subscribers by year.

**Figure 5-12
Green Power Subscribers, 2002-2006**

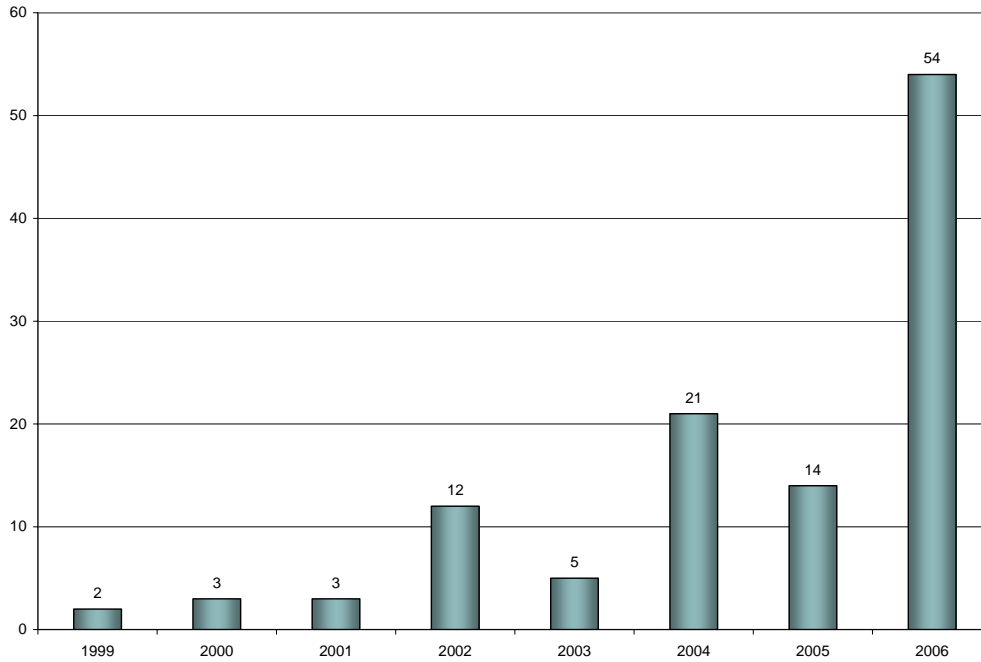


Customer Renewables Programs

PSE's net metering program, in place since 1999, provides a way for customers who generate their own renewable electricity to offset the electricity provided by PSE. The amount of electricity generated by the customer is subtracted from the amount of electricity provided by PSE, and the net difference is what the customer pays on a monthly basis. If the customer generates more electricity than PSE supplies, a KWh credit is carried over to the next month. The "banked" energy can be carried over until every April 30, when the account must be reset to zero according to state law.

Customer interest in small-scale renewables has increased significantly over the past three years, as Figure 5-13 below shows. In 2006, PSE added more than 50 new net metered customers for a total of 114.

Figure 5-13
Net Metered Customers Added per Year 1999-2006



The Customer Renewables Program also doubled the aggregate interconnected kilowatt capacity. The vast majority of systems are solar photovoltaic (PV) installations with an average generating capacity of 3.03 kW. Combined with our net metered small-scale hydroelectric generators and wind turbines, the overall average generating capacity of all net metered systems is 3.12 kW.

Figure 5-14
Net Metered Systems by Technology

Average System Capacity (kW)	Count	Technology	Aggregate Generating Capacity (kW)
3.97	3	Hybrid; solar/wind	11.91
5.67	3	Micro hydro	17.01
3.03	108	Solar array	327.24
Total	114		356.16

These small-scale renewable systems are distributed over a wide area of our service territory.

**Figure 5-15
Net Metered Systems by County**

County	Number of Net Meters
Whatcom	22
King	23
Jefferson	21
Skagit	15
Island	13
Kitsap	9
Thurston	9
Kittitas	1
Pierce	1

In June 2006, the interconnection capacity allowed under PSE's Net Metering Schedule 150 was increased to 100 kW, and the banking of accumulated kWh was extended to April 30 of the year after they were accumulated. Current initiatives include the following:

Residential Solar Rebate Program. The Customer Renewables residential solar rebate program began in 2004 in response to a 2003 rate case stipulation. Interconnected solar PV residential customers receive rebates of \$525 to \$600 per kilowatt of installed capacity; 44 customers took advantage of this program in 2006. The rebate rates are currently adjusted by county solar production factors within our service area.

Renewable Energy Advantage Program. In October 2006, 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 three 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 2006, the Customer Renewables Program had enrolled 54 of our 81 eligible customers, and the first annual incentive payments were made. The tariff governing REAP, Schedule 151, along with its related agreement, was approved by the WUTC on October 6, 2006.

D. Regional Transmission Resources

PSE transports power from its origination point to our service area over the regional transmission grid through contracts with various transmission providers. This regional system is separate from the PSE-owned local delivery system through which we distribute power to customers (see Chapter 7, Delivery System Planning).

Physical and contractual limitations and lack of coordination within the regional transmission system severely constrain PSE's ability to promptly acquire generation outside our service territory. Of particular concern are the following.

- Transmission capacity constraints to the I-5 corridor
- A transmission planning process that is not well aligned with the resource acquisition process
- Multi-jurisdictional siting and permitting issues
- Diminished role of "rolled-in" ratemaking and funding, in favor of marginal cost pricing marginal user up-front funding

Unless these market structure and institutional factors are addressed in a timely manner, PSE will be challenged to acquire resources such as wind from the Columbia Gorge, gas plants within the state of Washington, coal plants from Montana, Wyoming, or Nevada, geothermal power from Idaho and Oregon, and hydroelectric power or biomass from British Columbia.

This section discusses constraints affecting use of the regional transmission grid, including PSE's current situation, the processes for adding new transmission capacity, current efforts to address regional transmission issues, and transmission needs related specifically to this IRP.

Current Situation

For the most part, PSE's owned and operated transmission system of 115 kV and 230 kV facilities have been developed to move power to customers. We do not have significant excess transmission capacity either across our service area or outside our service area. To bring power to our service area, PSE has typically contracted for transmission from the BPA.

Our local transmission system also interconnects with several utilities including BPA, Seattle City Light, Snohomish PUD, Tacoma Power, British Columbia Transmission Corporation, Chelan County PUD, Douglas County PUD, Grant County PUD and with purchasers of the Centralia project. Most of the interconnections are west of the Cascades.

Numerous developments have created pervasive congestion on the grid.

- Current load patterns are significantly different than those that existed when the grid was designed.
- Resource operations patterns have changed with the entrance of market participants other than utilities and the construction of new gas-fired generating sources, whose actual operation is market-driven and highly variable.
- Loads are growing more rapidly than transmission capability.
- The transmission industry is in the middle of considerable change, and with the recent 2005 Energy Policy Act (EPA) and the efforts of regional utilities to form ColumbiaGrid, it is unclear what the final Northwest transmission structure will look like.
- Almost all wind resources are located east of the Cascade Mountains in transmission-constrained areas.

Recent development of gas-fired generation and other intermittent resources like wind has made operation of the transmission system more challenging. The number of market transactions has also grown significantly, increasing the complexity of system operations and transmission system use. Consequently, the grid is now being utilized at near-full capability, and any forced outage or critical maintenance often places the grid in a “de-rated” condition.

New generation opportunities in PSE’s service area may be limited to natural gas projects and small-scale renewables as a result of these conditions. In order to diversify with coal or wind resources, PSE must look mostly to the east. However, bringing this new generation to PSE loads will require new transmission construction and possible construction of west-side gas-fired resources to provide wind integration services and other ancillary services needed to comply with new FERC/NERC system security requirements. Figure 5-16 lists the path constraints that directly affect PSE’s ability to import new generation.

Figure 5-16
List of Transmission Path Constraints Affecting PSE's Ability to Import

Transmission Path	Where Constrained
Along I-5 corridor	South of Allston
West through the Columbia River Gorge	McNary Slatt
Across the Cascades	Washington Oregon
From Montana to the NW	In Montana west of Garrison

New Generation

At present, generation planning and transmission planning are not performed in an integrated manner. BPA's current transmission system improvements are designed primarily to meet and maintain its current obligations, including an obligation to support load growth where contractually committed. Its policies with regard to new construction do not mesh well with the roughly 2-year cycles utilities follow for resource planning, integrated resource planning, resource acquisition, and RFPs. Without a specific request for service from the generation developer, BPA will not consider new upgrades, and its current policies require 100% advance funding in return for transmission credits for the entire cost of network upgrades. These policies make developers and utilities wary.

In 2005, BPA attempted to fund the McNary–John Day upgrade with advance funding, requiring the requesting parties to pre-pay the cost of the project. However, the project did not proceed due to lack of commitments to participate from BPA's power business line and interested parties, who are stuck in the permitting process and the processes of competitively acquiring a power purchase agreement.

BPA is reviewing its transmission services with the intention of addressing the limitations that current policies create. The organization is developing an evaluation and decision-making framework to address financing, contract value of anticipated future uses of facilities, future regional needs, risk assessment, and public process. PSE is hopeful that the new framework will be developed by the end of April 2007 and result in a transmission plan-of-service likely to have a high value to the region. Meanwhile, PSE continues to work closely with BPA to find a transmission solution for each new generation project. Nevertheless, the availability and cost of transmission will continue to be key factors in PSE's decision-making process for acquiring new resources.

Acquiring Long-Term Firm Transmission

The Northwest does not currently have a single regional body to coordinate transmission requests. Under current FERC rules, transmission providers sell long-term firm transmission through their Open Access Same-time Information System (OASIS). Resource developers must identify and apply to individual transmission providers to arrange for transportation of power.

Requesting transmission is a cumbersome process that involves multiple steps and the possibility of one or more lengthy studies. Completion of the process can take anywhere from a few months to several years.

If the new transmission requires service from multiple providers, the customer must make requests with each provider. Since the review processes may not match (e.g. one provider can offer immediate service while the other requires facility upgrades), the transmission customer may face the decision to sign up for one section of the transmission before securing rights for the entire route. In Order 890, FERC has taken a step toward fixing this problem. FERC requires transmission providers to work together to develop standards that will allow for coordination of these multiple requests.

Developers of new energy resources must be able to prove that they can bring their generation to load, or lenders will not finance their efforts. Lenders require proof of adequate transmission capacity at a reasonable price, or a clear and predictable process for developing and pricing new transmission. As a result of these requirements, the request queues for key existing transmission routes become overloaded with applications of varying certainty. After the developer has worked through the process and is offered a service agreement, the agreement must be executed, and significant payments made regardless of the resource project status, or the developers risks losing its place in the queue.

BPA and other transmission providers require customers to front the costs of network upgrades prior to undertaking the work. Once upgrades have been built, the transmission provider must recover the cost. Under current Long-term Generation Interconnection Agreements, the customer receives credits under the provider's tariff rate until the total amount credited equals the total amount fronted by the customer. Under this model, PSE—the customer—pays for transmission facilities without receiving the asset benefits of ownership. This model also makes transmission upgrades essentially participant-

funded without regard to the regional value created for all transmission network users—for example, enhanced off-system sales for legacy transmission customers.

Developing and Siting New Transmission

The processes involved in developing and siting new transmission are distinct from those used by transmission providers, but no less complex.

The Energy Policy Act of 2005, discussed in more detail in the Regional Transmission Resources Appendix, authorizes the Secretary of Energy to designate “national interest electric transmission corridors.” Several western corridors have been identified, but the actual siting authority granted to FERC under the Act is yet to be defined and is limited, requiring the FERC to wait for states or regional groups to complete their analysis. For the time being, most transmission projects will continue to be sited under the current process.

The physical reality of electricity flow over long distance lines is that as generation flows to load, the energy crosses several flow paths (cut-planes) and multiple states. Because transmission facility siting lies with each state, lines crossing more than one state (coal and wind, for example) involve multiple, independent, and often disjointed state processes. In order to qualify for a new transmission contract, each of the affected paths must have sufficient available transmission capacity (ATC).

Again, no central permitting or siting authority exists, although some states have centralized authorities. To construct new transmission, developers must be prepared to work with multiple jurisdictions, observe differing processes for each jurisdiction at each level of government (local, state, and federal), anticipate local issues, and work around the absence of central siting or permitting authorities.

Early assessment of environmental conditions determines the level of permitting necessary to gain regulatory approval. Common regulatory permits at federal and state levels include SEPA/NEPA, Endangered Species (biological assessments), Army Corps of Engineers section 404 and 10 permits, Department of Fish/Wildlife HPA and the Department of Ecology NPDES. At the city or county level, common permitting needs are conditional use permits for shorelines, clearing and grading, critical area review, and right-of-way use.

In addition to these permits, consideration must be made as to whether tribal lands will be affected by proposed transmission line siting, necessitating land-use negotiations. Additionally, the company could be required to enter into long-term franchise agreements with local municipalities that are granting operating rights for facilities located in their rights-of-way.

Public involvement is a necessary ingredient in the planning and development phases of transmission projects. This involves informing, consulting, and involving affected and concerned stakeholders in many of the transmission provider's decisions. To compound the challenge, transmission projects usually offer regional system improvements but limited direct local benefits.

Routing of transmission lines can also require the use of corridors other than those available via municipal, county, or state rights-of-way in many cases. In these instances, easements from individual property owners are required. Because negotiation of these rights can become contentious and ultimately result in condemnation, careful consideration is critical. The use of condemnation can prove costly from a cost/schedule perspective and create community ill will.

Long-Term Regional Transmission Structure

The Northwest continues to function without a regional transmission organization, and without workable processes to align generation and transmission development and investment. Since the advent of open access transmission rules in 1996, regional entities have made a number of attempts to form regional transmission organizations such as IndeGO, RTO West, Grid West, Transmission Issues Group (TIG) and ColumbiaGrid. A summary history of these organizations and efforts is included in the Regional Transmission Resources Appendix.

Since PSE's 2005 LCP publication, Grid West and TIG have ceased operation, concluding that the organizations would not work. However, in light of the genuine need to resolve the region's transmission problems, a variety of interested regional parties have come together to form a new organization, ColumbiaGrid, to address critical transmission-related issues and search for solutions.

ColumbiaGrid

ColumbiaGrid is a nonprofit, Washington state membership corporation formed on March 31, 2006, to improve the operational efficiency, reliability, and planned expansion of the Northwest transmission grid. An independent board of directors was elected August 1, 2006. The board's term began on August 17, and they selected a president and chief executive officer effective December 11, 2006.

ColumbiaGrid will be given substantive responsibilities pursuant to a series of functional agreements with members and other qualified non-member parties. These agreements are being developed in a public process with broad participation. Work has been based on elements of BPA's October 2005 Integration Proposal, which combined elements of Grid West and TIG efforts.

The public process focuses on the design and implementation of near-term services and the design of additional longer-term responsibilities. Near-term services include transmission planning and expansion, reliability, and a common OASIS queue. Longer-term services may include adopting a regional flow-based analytical approach, long-term reliability initiatives, and regional transmission services. A Draft Planning and Expansion Functional Agreement was released on October 25, 2006, for public review and comment. The agreement was offered for signature on January 17, 2007 and was filed with the FERC on February 2, 2007.

The current Members of ColumbiaGrid are Avista Corp., BPA, Chelan County PUD, Grant County PUD, PSE, Seattle City Light, and Tacoma Power. All Northwest control area operators are welcome to join ColumbiaGrid as members.

Ultimately, in spite of all of the effort that has gone into the development of a regional transmission structure, the future of ColumbiaGrid is unknown, and the ability of ColumbiaGrid to assure the construction of transmission for commercial purposes does not exist. In short, there are still no comprehensive transmission solutions visible on the horizon.

Role and Limitations of BPA

Since no regional entity has yet been established, BPA continues to be the only entity in the Northwest with the geographic scope and siting authority needed to approach

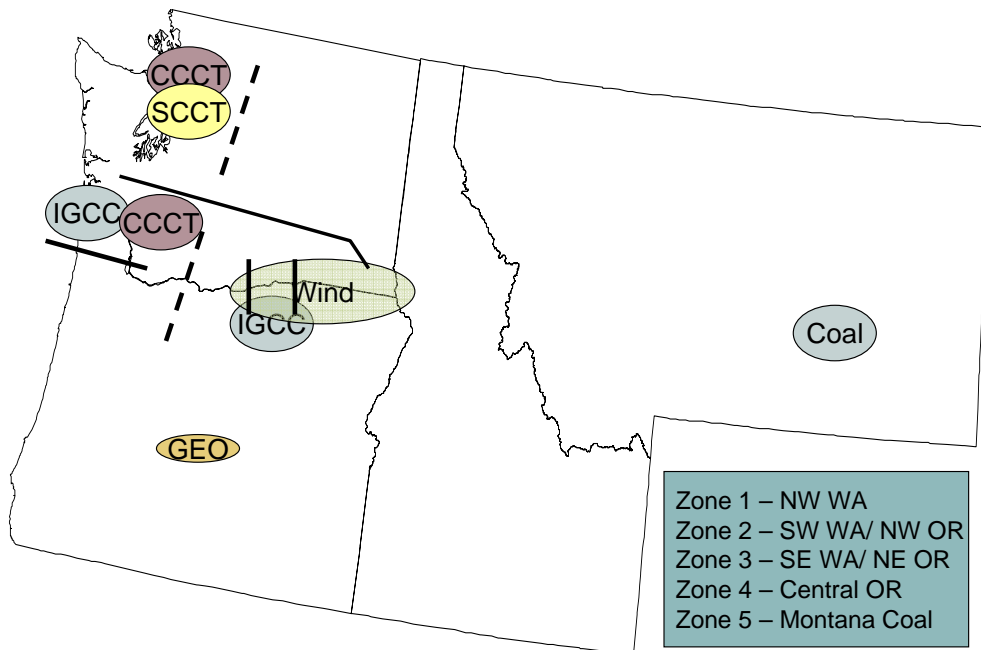
building regional transmission. However, BPA does not currently have the borrowing authority to undertake major regional transmission expansion. BPA's scope is also limited by law and policy. Without BPA involvement, a major transmission solution will be difficult to organize.

In its 2006 Programs in Review process, BPA discussed its financial situation. The agency has a total of \$4.45 billion in borrowing authority for all BPA projects, both power and transmission. It continues to seek mechanisms to extend its borrowing authority, including third party financing and creative debt management programs. Based on current projections, BPA expects its borrowing authority to extend to approximately 2013. BPA's existing capital plan includes capital dollars for reliability, NERC, WECC, environmental, and other compliance requirements; integration of new generating resources; congestion management; and the people and processes necessary to accomplish these projects. No money is targeted for economic transmission construction projects at this time.

Transmission Needs for New Resources

The map below shows the resource zones identified for location of possible resources in the 2007 IRP process.

**Figure 5-17
Resource Zones for the 2007 IRP**



Zone 1 (NW WA) indicates CCCT and SCCT plants in northwest Washington

Zone 2 (SW WA/NW OR) shows CCCT and IGCC plants in southwest Washington and northwest Oregon

Zone 3 (SE WA/NE OR) shows the Washington/Oregon boundary having wind resource in the Columbia Gorge and an IGCC plant around the Wallula area

Zone 4 (Central OR) shows geothermal resource in central Oregon

Zone 5 (Montana Coal) shows the Montana coal resource around the Colstrip area

For the purpose of modeling in this IRP, PSE has assumed that a regional transmission organization will not be established in time to facilitate transmission expansions that can be reflected in system-wide wheeling rates. PSE will continue to look for ways to work

with BPA and other potential transmission providers to acquire the transmission needed for our resource additions.

Figure 5-18 table below shows PSE cost estimates for transmission upgrades related to the resources shown in the five zones above.

**Figure 5-18
Cost Estimates for Transmission Upgrades Related to 2007 IRP
(\$Millions)**

	Wind	GEO	Biomass	CCCT	SCCT	IGCC	Coal
Zone 1			0	0	0		
Zone 2			4	26		63	
Zone 3	16					62	
Zone 4		0					
Zone 5						374	374

Resource	Size (MW)
Wind	150
GEO	30
Biomass	40
CCCT	250
SCCT	150
IGCC	600
Coal	600

In order for us to continue to provide reliable power at a reasonable cost, we must take several steps to ensure that new energy supply can reach the Company's loads.

Short term. In the near term, PSE must focus on resources that are either located on the PSE system, already have transmission on the BPA system, or that exist where BPA is considering upgrades.

Long term. Based on a detailed analysis of BPA's current ATC availability, PSE anticipates that West of McNary and I-5 corridor transmission paths will need to be upgraded first. Both will require 500 kV line construction (i.e., McNary – John Day and Paul – Troutdale). PSE must continue to participate in regional efforts and actively work with BPA to create a stable, long-lasting transmission structure.

Other actions PSE should consider include:

- Retaining existing contract transmission rights
- Working with BPA to establish its new evaluation and decision-making framework—to determine the most effective paths to facilitate the integration of new generation and to create a feasible financing structure
- Investing to upgrade PSE-owned transmission paths

With the recent passage of the Washington State Renewable Portfolio Standard, I-937, there is increased urgency for PSE and other utilities in Washington to actively acquire and build renewable resources. Until new regional transmission lines are built, PSE might even rely on short-term transmission to transmit wind resources from the Columbia Gorge to our service territory.

III. Electric Resource Alternatives

The demand- and supply-side resource options considered for this IRP were informed by 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). The resources discussed in this section are the ones most relevant to this IRP. A comprehensive list of alternatives and detailed information on their current development status is included in Appendix D, Electric Resource Alternatives.

Resource Alternatives Are Limited

Few commercially viable resources are available at this time; only four are currently capable of producing generation in quantities large enough to impact the significant need we face over the 20-year planning horizon. These are demand-side resources, wind, natural gas, and coal. Only two—coal and gas—produce baseload generation which can be counted on to provide energy at virtually any time. However, coal and gas also come with significant risks, which are explored in further detail below. Limited biomass and geothermal generation is possible; however, our experience in the marketplace indicates that such opportunities are few in number, small in scale and face challenging development issues.

Many technologies have not yet proven to be commercially viable—that is, able to economically generate power on a scale large enough to make meaningful contributions to meeting utility needs.

Tidal and wave. Technologies harnessing tidal and wave power to produce energy are still largely research and development efforts. 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 in the Northwest is not a current reality. While there has been much speculation about the potential for tidal and wave energy in the Puget Sound area, the initial estimates for energy generation at each location must be studied and validated during the preliminary permit process. Moreover, the extent and duration of associated cultural, recreational and environmental studies remains to be determined, and these studies may prove to be a significant hurdle for the

successful commercial application of these technologies. We will continue to monitor the development of these resources.

Solar. While approaching commercial status in other parts of the United States, solar power is still emerging as a utility-scale resource in Washington state. PSE recently announced plans to develop a solar demonstration project at our Wild Horse wind facility. In addition to providing a small amount of renewable energy, the project affords us the opportunity to explore the potential benefits and challenges of solar generation in our state while encouraging local solar development.

Nuclear. Despite claims of pre-approved Nuclear Regulatory Commission designs, nuclear power faces considerable challenges. Development and construction costs are so much higher than the next highest base load resource option as to be prohibitive to all but a handful of the largest capitalized utilities. Additionally, permitting, public perception, and waste disposal pose substantial risks.

Hydro. There are few new hydroelectric generating opportunities in the region, and none without significant environmental and permitting risk. Furthermore, hydro is not included as an *eligible renewable resource* under Washington's renewable portfolio standard and therefore cannot be applied toward the fulfillment of our requirement. Further, recent federal court decisions seem to raise risks for existing large hydro projects.

Geothermal. There are few proven geothermal resources in our region. Because these resources are located outside Washington state (primarily in Idaho and Oregon), they face long-haul transmission issues to bring power from the point of generation to PSE's service territory.

Biomass. In addition to opportunity and generation output limitations, biomass is subject to fuel supply and fuel management risks.

B. Commercially Viable Resource Alternatives

Demand-side Resources

Demand-side resources include energy efficiency, fuel conversion, and distributed generation. All these alternatives enable 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.

Wind

The RPS established by Washington state requires that an increasing portion of renewable resources make up the portfolio of the largest utility providers. For our region, renewables means wind. This is because wind is the primary eligible renewable resource, as defined by the RPS, that is capable of producing utility-scale generation. At the same time, renewable portfolio standards are being adopted in Oregon, California, and other states across the country, a reality that is expected to increase overall demand for wind resources throughout the region and the nation. As a result, competition for experienced wind developers, viable sites, and component parts is expected to be robust.

Wind is also an intermittent resource, meaning that we cannot be certain the wind will be blowing when our customers most need the power. Because of this, stand-by base load resources must be available to "fill the gaps." Further, integrating an intermittent generation source into the transmission system poses challenges of its own. For a detailed discussion of wind integration issues, refer to the Wind Integration Studies Appendix.

Finally, remote-location wind projects face long-haul transmission issues, resulting from increased demand on an already-constrained system. Many of these constraints are described in part D of Section II of this chapter.

Natural Gas

Natural gas fired generation has several benefits. First, a gas fired-generator can be located within our service territory, which avoids the costly transmission investments required for east-side resources. Gas-fired resources are dispatchable, meaning they can be turned on when needed to meet loads, unlike an intermittent resource like wind or run-of-the-river hydro. Different kinds of gas-fired generators also have varying degrees of ability to ramp up and down quickly in response to variations in loads and variations in wind generation. Gas plants are also 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. Also, natural gas resources have significantly lower emissions than coal resources.

However, natural gas resources do have drawbacks. There are concerns about long-term natural gas 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 are also of concern, as are long-term price risks and short-term market price volatility.

Coal

Coal is one of two viable commercially available base load resources in the Northwest capable of providing enough generation to reliably meet our growing long-term need. It offers a plentiful, low cost, stable fuel source, and valuable resource diversity. On the other hand, coal faces substantial risks related to cost, regulatory issues, long-haul transmission, and permitting and development. Further, with mercury emissions and twice the CO₂ emissions of natural gas, conventional coal poses potential risks to health and human welfare and the environment.

Since the 2005 resource plan was developed, market, regulatory, and legislative conditions have changed significantly regarding coal. Activity at both federal and state

levels suggests that cost consequences for the emission of CO₂ are likely in the future. Conditions have even changed since modeling began in October 2006 for this plan, with adoption of a new law that bans new coal resources without carbon sequestration. Mercury emission standards are also becoming more stringent. Overall, the estimated cost of permitting, constructing, and operating coal plants has increased enormously, and the commercial viability of coal resources has grown more uncertain.

Carbon sequestration is a key technology to managing coal risks. Unfortunately, permanent deep well geological sequestration of CO₂ is not a proven technology, nor is there a reliable estimate of when such technology may become commercially viable. Further, there is no regulatory framework in place to address the risks associated with siting and permitting carbon sequestration projects, CO₂ transportation, injection and storage.

Developing a regulatory framework for carbon capture and sequestration (CCS) will be challenging. The Pacific Northwest Utilities Conference Committee's publication *PNUCC Principles for Global Climate Change Legislation*, dated February 28, 2007, includes the following list of key questions that need to be addressed.

- Immunity from potentially applicable criminal and civil environmental penalties
- Property rights, including the passage of title to CO₂ (including to the government) during transportation, injection and storage
- Government mandated caps on long-term CO₂ liability, insurance coverage for short-term CO₂ liability
- Licensing of CO₂ transportation and storage operators, intellectual property rights related to CCS, and monitoring of CO₂ storage facilities

Ultimately, the cost risks associated with impending future environmental regulations will continue to be significant unless CO₂ can be sequestered. Likewise, cost risks associated with sequestration-related liability uncertainties will continue to be significant until uniform legal standards are developed to address them.

C. Commercially available capacity resources

Capacity resources supply physical electric power, or shave peak loads, at times of peak hourly demand. Alternatives are limited because the physical requirement to serve customers necessitates either a generator located on the west side of the Cascades or a firm transmission contract to transmit power from other geographical locations.

Demand Response

These 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. The acquisition of demand response resources may be based on reliability considerations, or economic or market objectives.

Call Options

The buyer of a call option pays an up-front premium to the seller in exchange for the right to take power at a specified time and price. Call options are generally purchased with less than a one year term due to the steep increases in prices resulting from long range price volatility and time value of money. PSE's experience is that these call options are a relatively expensive tool to meet peak load. In addition, the derivative nature of these contracts requires mark to market accounting. Additionally, to be most valuable to PSE, a call option is either purchased from a supplier on the west side of the Cascades or purchased along with firm transmission.

Gas Tolling Contract

The buyer of a gas tolling contract pays a fixed monthly amount based on the output capacity in exchange for the right to deliver and convert natural gas to electric power at a contract stated heat rate. In addition to the fixed capacity payment, the buyer pays a variable charge for each MWh of energy produced. Gas tolling contracts can be

purchased at a range of heat rates. The lower heat rates are usually from combined cycle combustion turbines and the higher heat rates are from simple cycle combustion turbines. Tolling contracts are frequently available with terms of one to five years, and occasionally offered with longer terms. The gas tolling contract is sometimes referred to as a heat rate call option because of the right to take power by running the physical turbine once the market price of power and gas indicate that the gas tolling contract is economical. The gas tolling contract was used in this IRP to supply capacity in the years prior to 2014.

Natural Gas - Simple Cycle Combustion Turbines

One of the benefits of simple cycle combustion turbines is that they can be built in ten months or less. Moreover, they can be brought online quickly to serve peak need. While a simple cycle unit can be brought online more quickly than a combined cycle unit, which is what makes them more attractive from a capacity perspective, 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 Fuel - Reciprocating Engine Generation

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.

IV. Electric Analytic Methodology

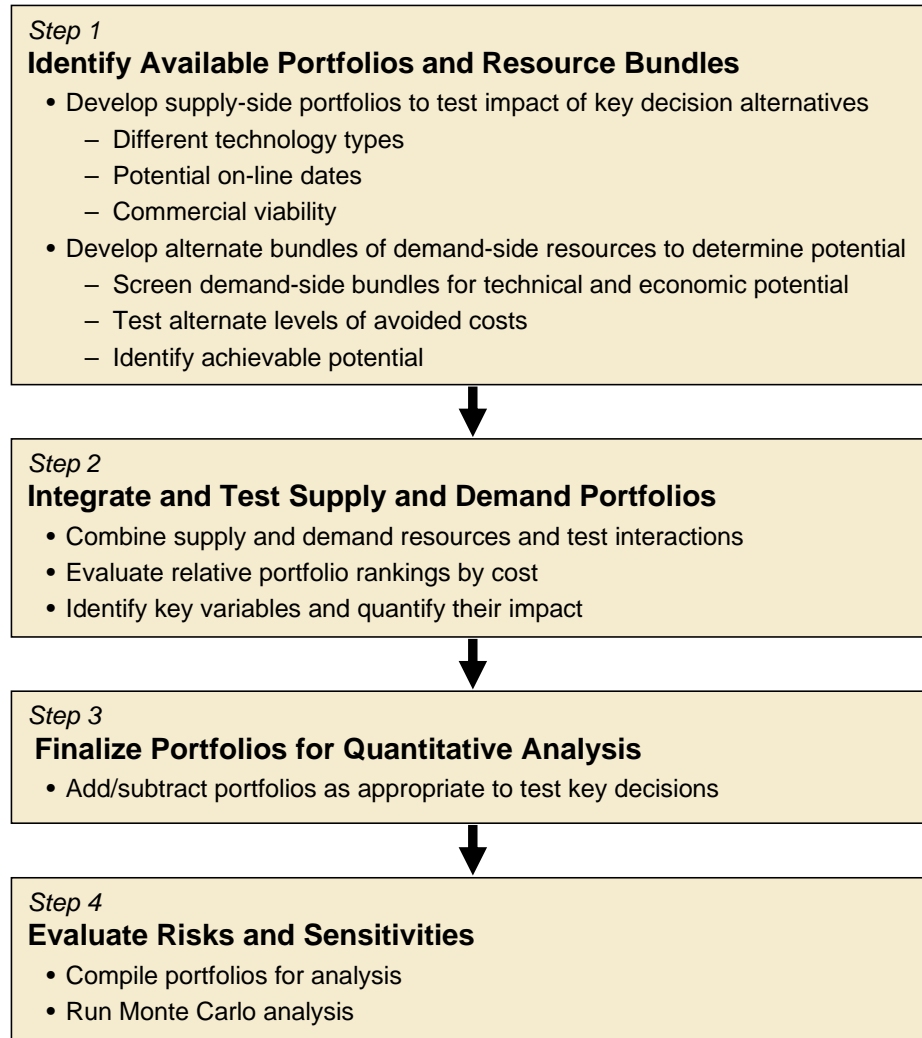
This section describes the quantitative analysis of electric demand- and supply-side alternatives. It explains how hypothetical portfolios were created to test a variety of key planning questions, and how these portfolios were evaluated under a wide range of potential scenarios. The resulting analysis allowed us to quantify how sensitive some of our conclusions 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 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 is the impact if carbon sequestration technology cannot be proven commercially viable?
- What if PSE decides not to build any more coal generation?
- What is the impact of adopting IGCC technology earlier in the planning horizon rather than later?
- What if reliance on renewable energy alternatives is significantly increased?
- What is the carbon intensity under different planning assumptions?

Overview of Approach and Methodology

Electric analytic methodology followed the four basic steps illustrated in Figure 5-19. A detailed technical discussion of these models and methods is included in Appendix I, Electric Analysis.

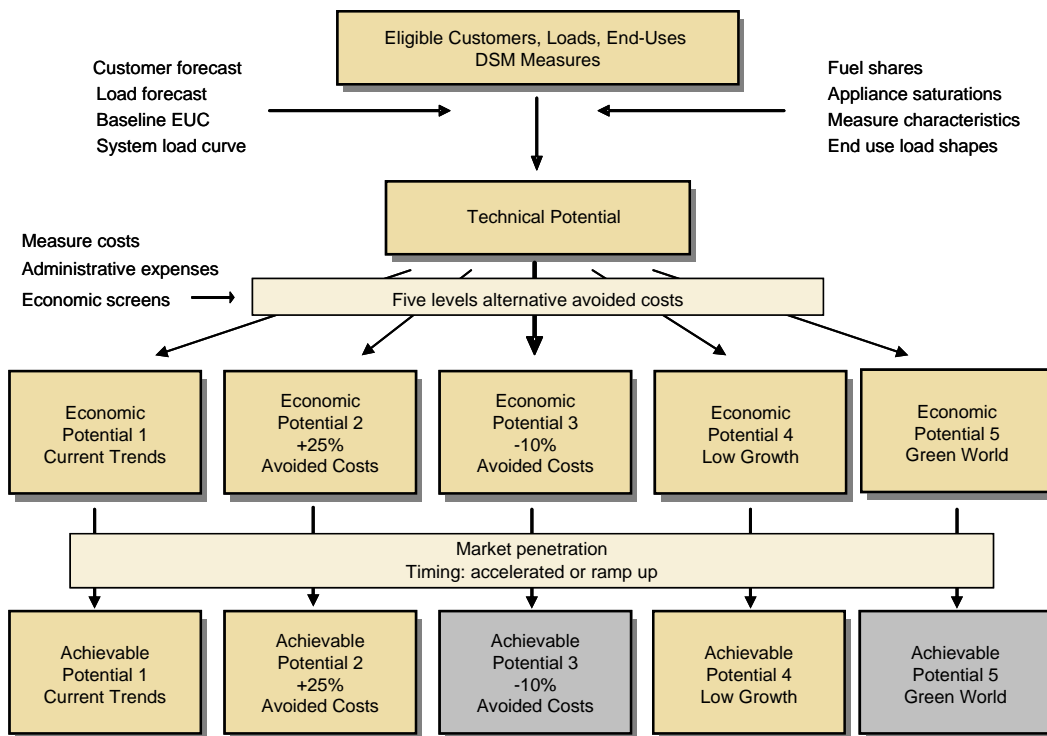
Figure 5-19
Methodology Used to Analyze Demand- and Supply-side Portfolios



Step 1: Identify Available Resource Alternatives

Demand-side resources were first evaluated, and then combined into various bundles for integration with supply-side resource combinations. For PSE, demand-side resource alternatives include energy efficiency, fuel conversion, distributed generation, and demand response. Each involves different technologies, load impacts, and markets. To evaluate their unique characteristics and potential, we applied three distinct yet related screens. These three screens—for technical potential, economic potential, and achievable savings—are widely used in utility resource planning, consistent with the Northwest Power Planning and Conservation Council methodology, and with evaluation of energy efficiency resource potentials in general. After individual evaluation, demand-side resources were combined into bundles for further analysis. A more in-depth discussion of the demand-side resource evaluation and the development of the bundles used in our analysis process is provided in Appendix K.

**Figure 5-20
General Methodology for Assessing Demand-Side Resource Potential**



The first screen, for technical potential, assumed that all energy efficiency resource opportunities could be captured regardless of costs or market barriers. It produced an end-use forecast assuming “frozen” end-use efficiencies, and then calibrated it to PSE’s system load forecast. We then generated a second forecast that included all technically feasible demand-side measures. Technical energy efficiency resource potentials were then calculated as the difference between the forecasts.

The second screen, for economic potential, included only measures deemed to be cost effective based on a total resource cost test. Five levels of avoided costs were tested. The Current Trends, Green World, and Low Growth scenario electric price projections were used (with a planning adjustment), and in addition, we tested 10% below the adjusted Current Trends price projection and 25% above the adjusted Current Trends price projection. This wide range enabled us to test for behavior responses at different levels of avoided costs. This screening step resulted in five preliminary bundles containing different amounts of energy efficiency resources, and different estimated savings potentials for each level of avoided costs.

Finally, we screened out any resources not considered achievable. Establishing achievable potential largely relied on customer response to PSE’s past energy programs, the experience of other utilities offering similar programs, and review of the Northwest Power Planning and Conservation Council’s most recent energy efficiency potential assessment. For this IRP we assumed that economic electric energy efficiency potentials of 85% and 65% in existing buildings and new construction markets, respectively, are likely to be achievable over the planning period. The achievable potential was distributed over the planning period based on technical and market considerations.

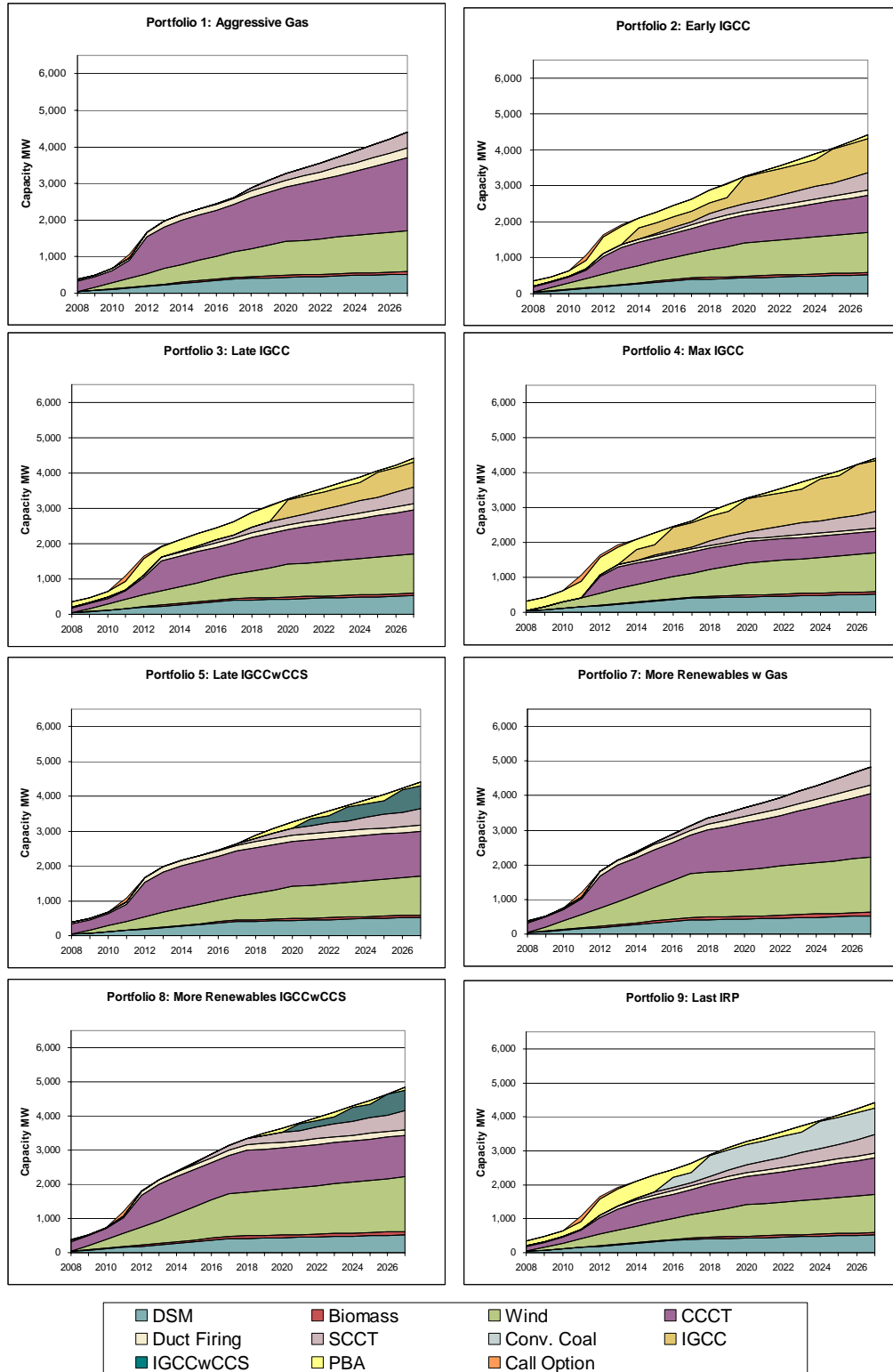
These three screens confirmed that the range of potential results was bounded by “bookends” representing the highest and lowest avoided costs (25% higher and 14% lower than the 2005 LCP). This allowed us to streamline our analysis by eliminating demand-side bundles 3 and 5 from our integrated analysis since all quantitative results from these two portfolios would be contained between the bookends.

Combinations of supply alternatives were constructed to provide analytical comparison groups composed of different renewable and thermal technologies. For example, combinations were constructed to test IGCC attractiveness with and without carbon sequestration, or to test heavy reliance on natural gas, or the aggressive use of renewables to meet future load requirements.

Step 2: Define and Test Integrated Portfolios

Each of the original eight supply combinations was matched with each of the three demand-side bundles, creating 24 integrated portfolios. Each of these 24 portfolios was then evaluated under each of the six planning scenarios, resulting in 144 portfolio-scenario combinations. On the next page, Figure 5-21 displays the capacity MW additions for the eight portfolios. More detailed information can be found in the Electric Analysis appendix.

Figure 5-21
Eight Initial Integrated Portfolios



Demand-side Bundle 1 (Current Trends) was based on the 2005 LCP estimate of avoided costs of \$89.92 per MWh. Bundles 2 and 4 had higher and lower avoided costs. These were included to test whether they affected the cost rankings of the integrated portfolios. Our analysis of the 24 integrated portfolios across scenarios indicated that the relative rankings were essentially the same for all the energy efficiency portfolios. That is, the attractiveness of each portfolio basically did not shift depending on whether avoided costs equaled the 2005 LCP estimates, or were higher or lower. In the two cases that energy efficiency bundles affected relative rankings, the difference was so slight—less than 1/100 of 1%—it could be attributed to a rounding error. The relative rankings of all of the 144 portfolio-scenario combinations are shown in Figure 5-22.

Since rankings were unaffected by the level of energy efficiency resources, the final analyses focused on just one energy efficiency bundle. This further streamlined the analysis without affecting the quantitative conclusions. Demand-side Bundle 1 (Current Trends) was used in all subsequent analyses.

Figure 5-22
Relative Rankings of 144 Portfolio-Scenario Combinations
(24 portfolios across 6 scenarios)

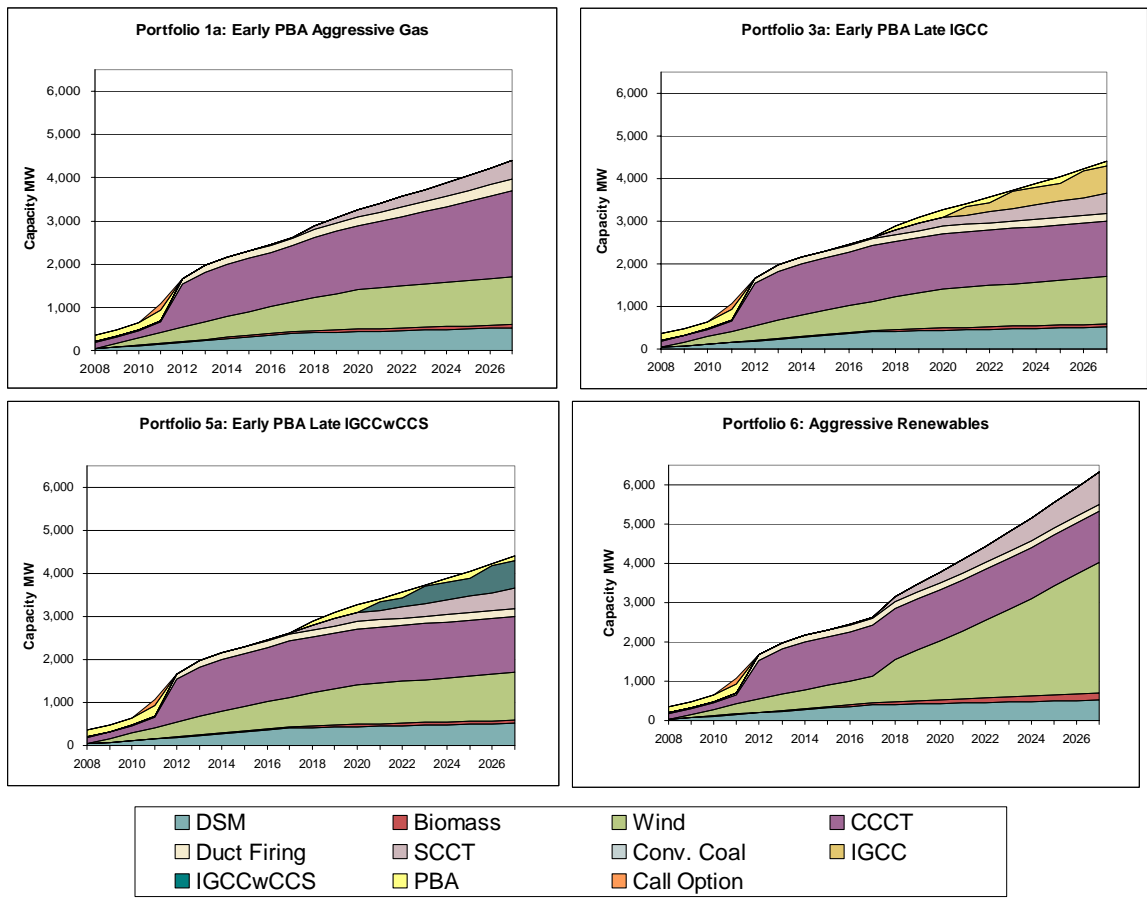
	1	2	3	4	5	7	8	9
	Aggressive Gas	Early IGCC	Late IGCC	Max IGCC	Late IGCCwCCS	More Renew w Gas	More Renew w IGCCwCCS	Last IRP Portfolio
Current Trends								
Low Growth DSM	2	3	1	4	6	7	8	5
Current Trends DSM	2	3	1	4	5	7	8	6
CT + 25% DSM	2	3	1	4	6	7	8	5
Green World								
Low Growth DSM	2	7	5	8	1	4	3	6
Current Trends DSM	2	7	5	8	1	4	3	6
CT + 25% DSM	2	7	5	8	1	4	3	6
Low Growth								
Low Growth DSM	1	5	2	8	4	3	7	6
Current Trends DSM	1	5	2	8	4	3	7	6
CT + 25% DSM	1	5	2	8	4	3	7	6
Robust Growth								
Low Growth DSM	6	2	3	1	5	8	7	4
Current Trends DSM	6	2	3	1	5	8	7	4
CT + 25% DSM	6	2	3	1	5	8	7	4
Technology Improvement								
Low Growth DSM	5	3	2	1	4	7	8	6
Current Trends DSM	5	3	2	1	4	7	8	6
CT + 25% DSM	5	3	2	1	4	7	8	6
Escalating Costs								
Low Growth DSM	1	4	2	6	3	7	8	5
Current Trends DSM	1	4	2	7	3	6	8	5
CT + 25% DSM	1	4	2	7	3	6	8	5

Lowest Cost Portfolio
2nd Lowest Cost Portfolio

Step 3: Finalize Portfolios for Quantitative Analysis

Examining the integrated portfolios raised a number of additional analytical questions that led us to construct four new supply portfolios as modifications of some of the original portfolios. These new portfolios have an “a” following the number to indicate an adjusted portfolio. These changes were made primarily to create equivalent comparisons of portfolios with the same amount of power bridging agreements (PBAs) in the early years. This allowed us to isolate the impacts of adding wind, gas, and IGCC with and without CCS over a comparable time horizon without having the results influenced by different levels of PBAs. The 12 final supply portfolios used in the analysis were able to provide a quantitative comparison of costs of all portfolios that contained equivalent amounts of PBAs in early years. The four new portfolios, along with their resource additions by year, are shown in Figure 5-23.

**Figure 5-23
Four Additional Integrated Portfolios**



Step 4: Complete Portfolio Analysis

After adding the four new portfolios, we tested them under all six scenarios. This enabled us to rank the 12 portfolios in each future. To fully understand risks associated with using expected gas prices, power prices, average hydro generation levels, and expected wind generation levels, we evaluated these variables using Monte Carlo analysis as we did in the 2003 and 2005 LCPs. The Monte Carlo analysis performed 100 iterations on each of the 12 integrated portfolio combinations for the Current Trends scenario. This provided quantitative backup for the risk evaluations. As we learned in the 2005 LCP and in subsequent RFP analyses, since the input variables and their probability distributions are the same for all portfolios (based on historical data), it is only necessary to perform the Monte Carlo analysis for one scenario to provide the analytic insight to support the risk assessment.

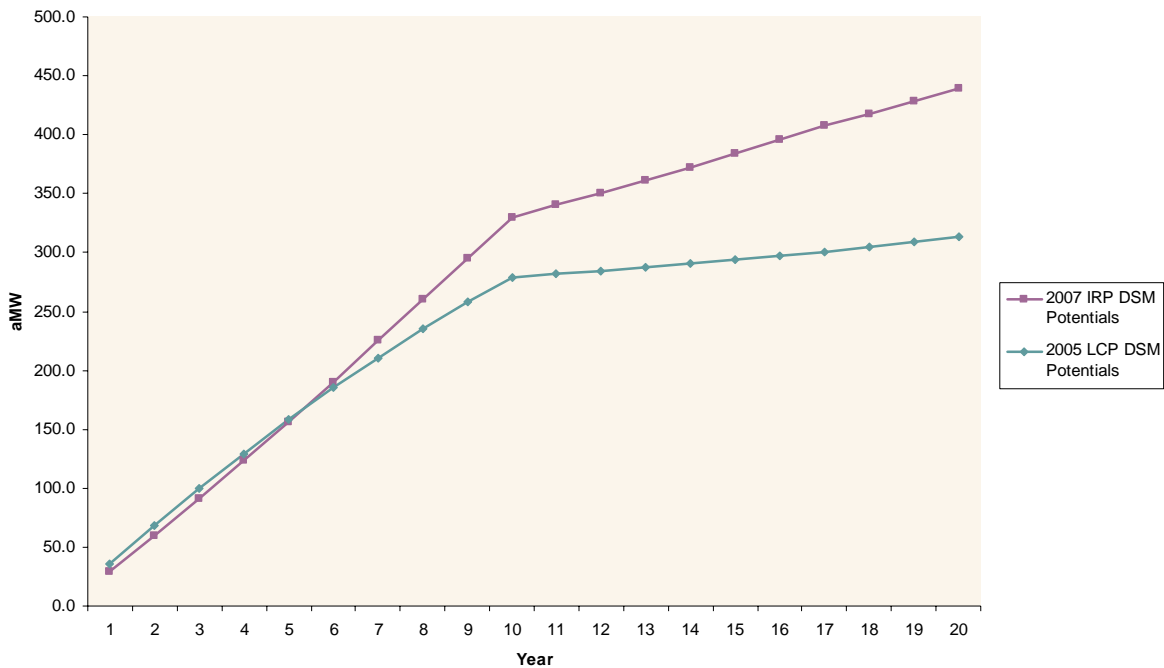
V. Quantitative Results and Insights

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 Electric Analysis appendix.

Key General Findings

1. Demand-side programs are projected to increase by approximately 40% over the last LCP. At their current level, these programs are not significantly affected by changes in assumed avoided costs.

Figure 5-24
2005 versus 2007 Demand-side Potentials



The demand-side resources in this plan represent an aggressive pursuit of cost-effective energy efficiency, fuel conversion, distributed generation, and demand response. The amount of cost-effective achievable demand-side resources is 40% greater than it was in

the 2005 plan (Figure 5-24). Demand-side resources contribute 329 aMW to meeting the Company’s energy need by 2017, and 438 aMW by 2027.

Near-term, the 2007 IRP guidance also represents a significant increase in energy efficiency resource acquisition for PSE. In the 2004-2005 biennial program cycle, PSE achieved 39 aMW of electric efficiency savings. For 2006-2007, the two-year target is 40 aMW. This guidance suggests a level of 56 aMW of meter-level savings for 2008-2009, an increase of 40% over current levels (Figure 5-25). This reflects higher levels of avoided costs and market penetration across all portfolios and scenarios.

Figure 5-25
Energy Efficiency Potential: Historical vs. Projected Short-term

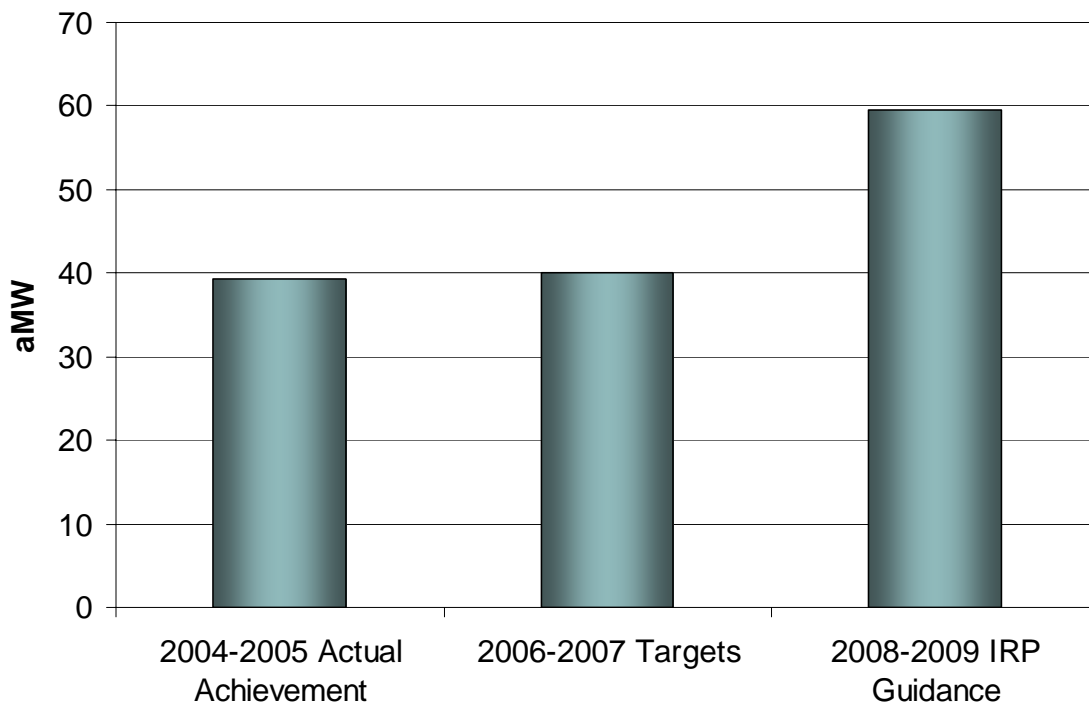
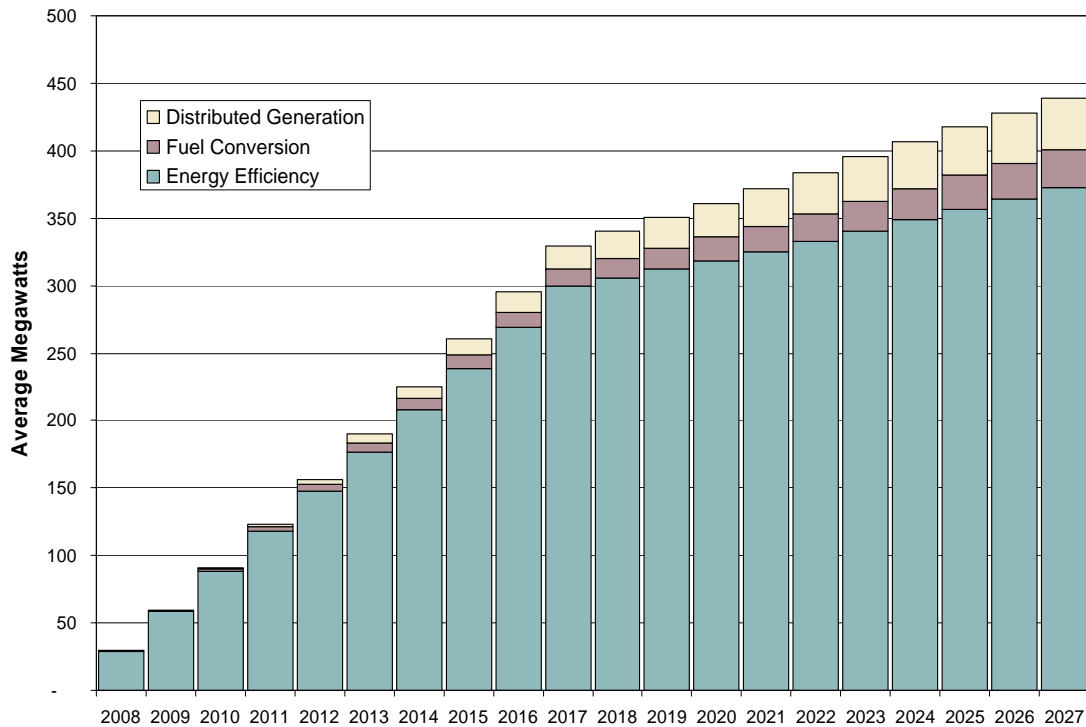


Figure 5-26 shows the breakdown of energy savings from demand-side resources by type of resource. Energy efficiency is by far the largest component at 372 aMW by 2027, with 299 aMW of that potential occurring by 2017, as all discretionary energy savings opportunities are accelerated into the first 10 years of the planning period. Fuel conversion and distributed generation resources account for 28 aMW and 38 aMW respectively by 2027. These are ramped in over time, reflecting the need to gain experience with customer acceptance and program design since they are new and

untested resources for PSE. Fuel conversion also results in increased gas consumption of about 1.2 million decatherms, as part of the cost of gaining 28 aMW of electric savings. The 20-year achievable potential from demand response is 130 MW of peak capacity reduction.

Figure 5-26
Cumulative Annual Energy from Electric Demand-side Resources



Over the range of avoided cost scenarios considered, the difference between the highest and lowest cases was 60 aMW over 20 years. Compared to the Current Trends scenario used in the final portfolio analysis, the Current Trends +25% scenario yielded an additional 26 aMW, while the low growth scenario reduced the potential by 35 aMW. Figure 5-27 illustrates the 60 aMW range of achievable potentials between the avoided costs “bookends.”

For the range of avoided costs considered, the achievable energy efficiency supply curve is a near vertical slope. Thus, changes in avoided costs did not significantly impact the potential for energy efficiency resources. Figure 5-28 shows the shape of the demand-side resource supply curve.

Figure 5-27
Range of Achievable Demand-side Potentials

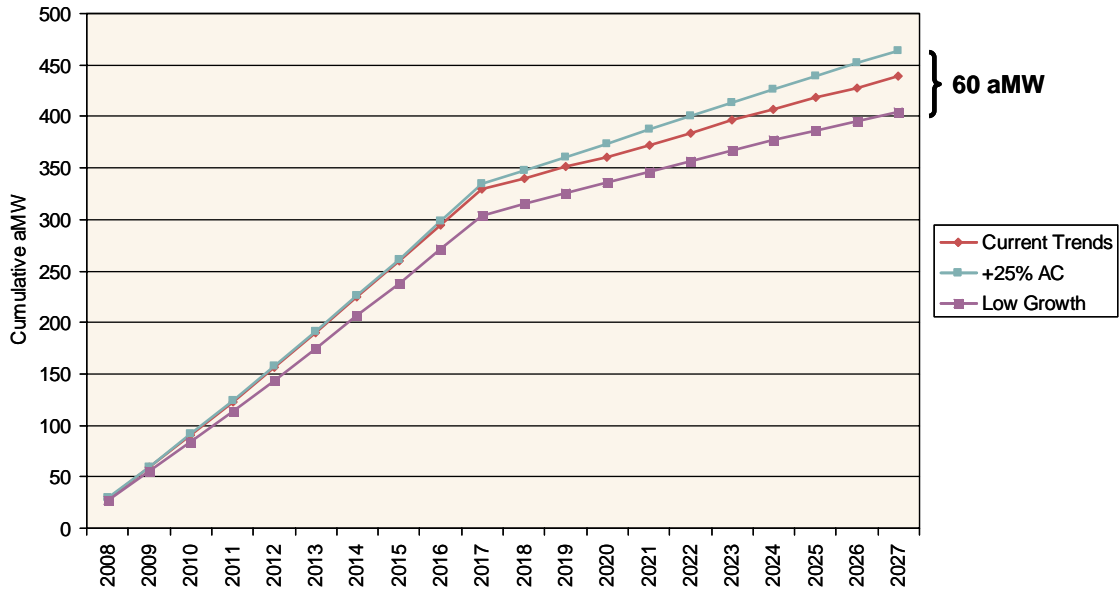
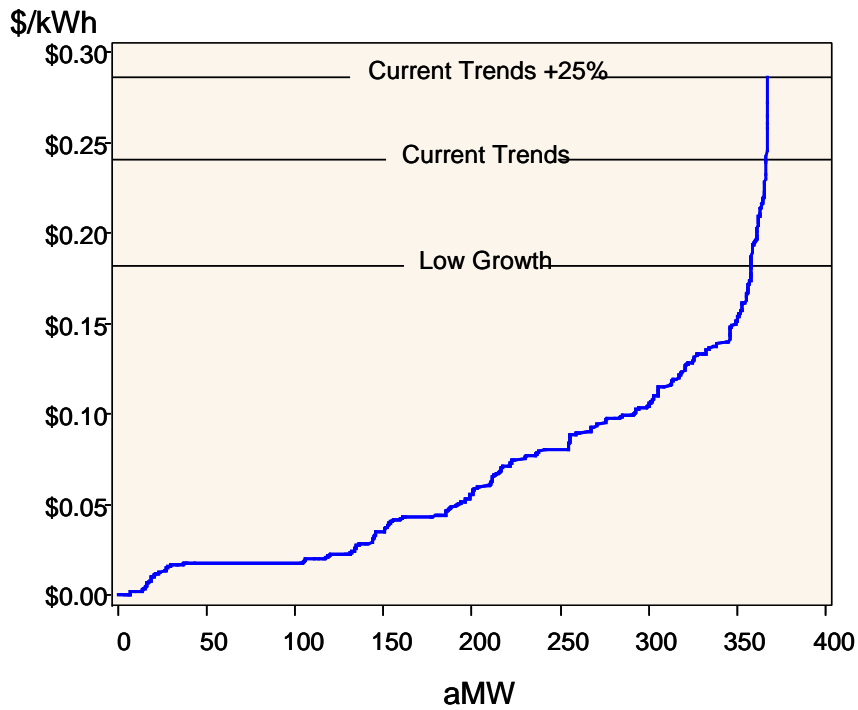


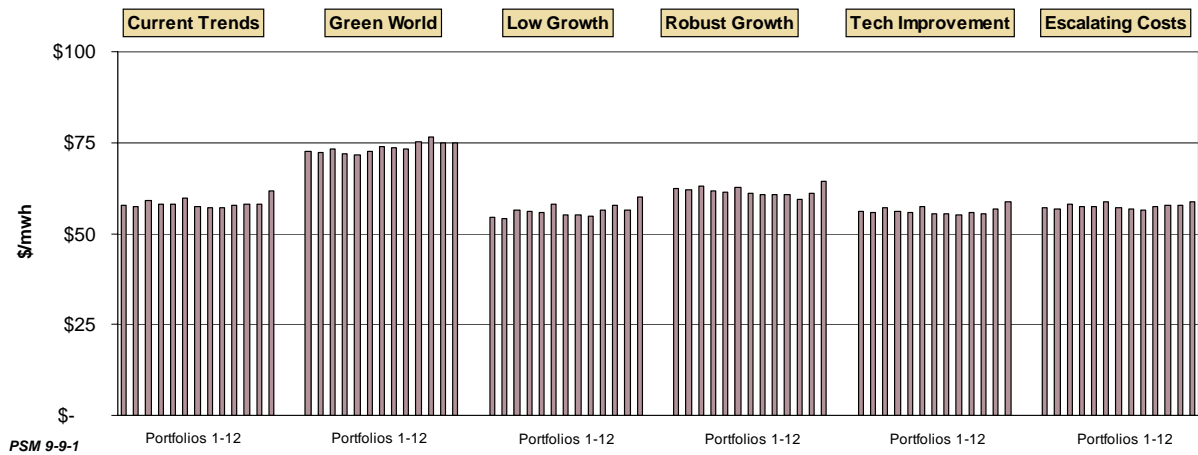
Figure 5-28
Supply Curve of Demand-side Potential



2. Total costs for all portfolios are very tightly grouped together.

The quantitative analysis found that cost differences between individual portfolios are small, so conclusions about which portfolio is best or second best must consider that the magnitude differentiating the “winner” is relatively small. There are two primary reasons for this tight grouping: (1) the differences in incremental portfolio additions are small compared to the larger relative size of the existing portfolio; and (2) most differences between portfolios involve choices occurring in the later half of the planning horizon. Due to discounting the out-year effects, this results in fairly small quantitative differences. The incremental cost per MWh for the different portfolios is shown in Figure 5-29.

Figure 5-29
Cost Differences between Portfolio-Scenario Combinations



3. The preferred portfolio varies considerably from scenario to scenario.

Figure 5-30 ranks the 12 portfolios in each of the six scenarios. These rankings demonstrate that in scenarios where gas prices are relatively high, portfolios with IGCC look better. In cases where natural gas prices are relatively lower, gas portfolios are better. When high environmental costs are added to high gas prices, as in the Green World scenario, the IGCC with carbon sequestration portfolio is preferred because it has the lowest emissions, low fuel prices, and stable supplies. If CCS is not available, however, aggressive gas portfolios would be the preferred choice.

**Figure 5-30
Relative Rankings of 12 Portfolio-Scenario Combinations**

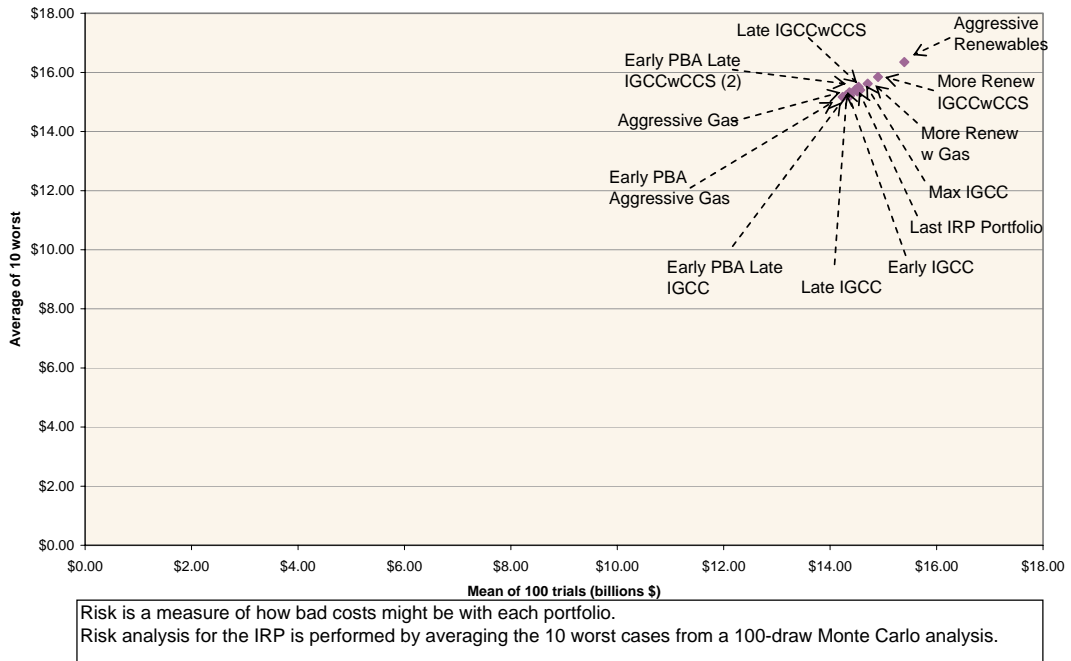
	1	1a	2	3	3a	4	5	5a	6	7	8	9
	Aggressive Gas	Early PBA Aggressive Gas	Early IGCC	Late IGCC	Early PBA Late IGCC	Max IGCC	Late IGCC w CCS	Early PBA Late IGCC w CCS	Aggressive Renew	More Renew w Gas	More Renew IGCC w CCS	Last IRP Portfolio
Current Trends	4	3	5	2	1	6	8	7	12	10	11	9
Green World	4	3	11	8	7	12	2	1	9	6	5	10
Low Growth	2	1	8	4	3	10	6	5	12	7	11	9
Robust Growth	9	8	2	4	3	1	7	6	12	11	10	5
Technology Improvement	8	5	4	3	1	2	7	6	12	10	11	9
Escalating Costs	3	2	7	4	1	9	6	5	12	10	11	8

Lowest Cost Portfolio
2nd Lowest Cost Portfolio

4. The worst portfolio outcomes are tightly grouped.

Figure 5-31 compares the cost-to-risk tradeoff of the different portfolios within the context of the Current Trends scenario. This graph plots the mean of the 100 trials from Monte Carlo and the average of the 10 worst trials (similar to the expected portfolio costs in finding 2). The risk results are tightly grouped.

**Figure 5-31
Comparison of Cost/Risk Tradeoff
between Portfolios in the Current Trends Scenario**



5. Annual volatility is dependent on fuel source.

The following chart shows that portfolios with more gas have more annual volatility, and portfolios with coal have less annual volatility. This is not surprising because the cost of coal fuel is relatively stable whereas gas prices are more variable. The addition of wind plants does not reduce volatility significantly, because more gas plants are needed to fill in for capacity need.

**Figure 5-32
Comparison of Cost/Volatility Tradeoff between Portfolios in the Current Trends Scenario**

