Electric Resources

Contents

Section one of this appendix is designed to provide additional information about PSE's existing fleet of electric resources. Section two offers context related to a variety of electric resource alternatives, including a brief technology summary, information about the viability and availability of each resource for PSE, and estimated ranges for anticipated capital and operating costs.

1. Existing Resources

- **Supply-side resources.** These include power generated by PSE-owned and contracted facilities, primarily hydroelectric power and power from coal-fired plants, natural gas-fueled turbines, and wind-powered 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 to support additional development of renewable energy through voluntary bill payments, and one for customers who produce their own power from small-scale renewables.

A. Supply-side Resources

Hydroelectricity

While operating restrictions to protect endangered species limit the operational flexibility of hydroelectric resources, these generating assets remain valuable because of their ability to track customer load, and because of their lower cost relative to other power resources. High precipitation levels generally allow more power to be generated, while low-water years produce less power. During low-water years, the utility must rely on other, more expensive self-generated power or market sources to meet load. The analysis conducted for this IRP accounts for both seasonality and year-to-year variations in hydroelectric generation. PSE owns hydroelectric projects in Western Washington and has long-term purchased-power 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.

Figure D-1
Hydroelectric Resources

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

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

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 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-'99, 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 PSE to generate an estimated 300,000 MWh per year.

Electron Hydroelectric Project. Located about 25 miles southeast of Tacoma in the western foothills of Mount Rainier, this facility has a 16 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 PUDs, 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 29.89 percent 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 percent 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. PSE 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 at Wanapum in November 2009. PSE receives a combined share of power from both projects; this share declines over time as the PUDs' loads increase. The new agreements with Grant County PUD will continue through the term of any new FERC license, which is through April 4, 2052.

White River Project. In January 2004, PSE stopped generating electricity at White River because relicensing and environmental expenses would have driven power costs well above available alternatives. The utility subsequently sold the Lake Tapps reservoir to the Cascade Water Alliance. The lake will be used to support a new regional source of drinking water.

Coal

The coal-fueled generating plants located in Colstrip, Mont., provide low-cost, baseload energy to PSE. PSE owns a 50 percent share in Colstrip 1 & 2, and a 25 percent share in Colstrip 3 & 4.

Gas-fired Combined-cycle Combustion Turbines (CCCTs)

PSE has five CCCT resources with a combined nameplate capacity of 975 MW. 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.

PSE's CCCT fleet includes **Mint Farm** in Cowlitz County, **Frederickson 1** in Pierce County, **Goldendale** in Klickitat County, and **Encogen** and **Sumas** in Whatcom County. We also own 49.85 percent 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. **Hopkins Ridge**, located in Columbia County, Wash., 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 273 MW and came online in December 2006 (The facility originally had a 229 MW capacity, but was expanded by 44 MW in 2010.) Combined, the two projects produce 127 aMW of electrical capacity,[1] and have provided over 2.3 million MWh of electrical energy. 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 (for example, Columbia County launched a new health clinic).

PSE's wind portfolio includes a power-purchase agreement with Iberdrola Renewables for a 50 MW share of electricity generated at the **Klondike III** wind farm in Sherman County, Ore. The wind farm has 125 turbines with a project capacity of 224 MW total. This agreement remains in effect until November 2026.

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[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).*

PSE also began construction of **Lower Snake River Phase I** in spring 2010, a 343 MW wind farm located in Garfield County, Wash. The project is scheduled to be completed by mid 2012.

Figure D-2 presents details about the company's coal, CCCT, and wind resources.

Figure D-2
Coal, CCCT and Wind Resources

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

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

Gas-fired Simple-cycle Combustion Turbines

PSE's 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 operating reserve requirements. The company displaces these resources 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**, located south of Seattle in east Pierce County, is comprised of two combustion turbine units with a combined nameplate capacity of 149 MW. Details are shown in Figure D-3 below.

Figure D-3
Simple-cycle Combustion Turbines

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

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

Other Long-term Contracts

Long-term contracts consist of agreements with independent producers and other utilities to supply electricity to PSE. Fuel sources include hydropower, gas, waste products, and system deliveries without a designated supply resource. These contracts are summarized in Figure D-4. Short-term contracts negotiated by PSE's energy trading group are not included in this listing.

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 percent 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.

Powerex Purchase for Point Roberts. Powerex delivers electric power to PSE's retail customers in Point Roberts, Wash. The Point Roberts load, which is physically isolated from PSE's 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.

BPA Baker Replacement. Under a 20-year agreement signed with the U.S. Army Corps of Engineers (COE) 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, PSE receives 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 PSE exchanges 300 MW of seasonal 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. PSE's 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 PSE's 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 PSE provides rather than receives, so it is a negative number (-56 MW for 2010).

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 D-4
Long-term Contracts for Electric Power Generation

TYPE	NAME	POWER TYPE	CONTRACT EXPIRATION	NAMEPLATE CAPACITY (MW)[1]
NUG	Tenaska	Thermal	12/31/2011	245
NUG	March Point I	Thermal	12/31/2011	80
NUG	March Point II	Thermal	12/31/2011	62
Total NUG				**387**
Other Contracts	BPA- WNP-3 Exchange	System	6/30/2017	82
Other Contracts	Powerex/Pt.Roberts	System	9/30/2014	8
Other Contracts	BPA Baker Replacement	Hydro	10/1/2029	7
Other Contracts	PG&E Seasonal Exchange-PSE	Thermal	Ongoing*	300
Other Contracts	Canadian EA	Hydro	09/15/2024	-58
Other Contracts	Powerex	System	02/29/2012	150
Other Contracts	Shell Energy	System	03/31/2013	50
Other Contracts	RBS Sempra Commodities	System	03/31/2013	75
Other Contracts	Barclays Bank	System	02/28/2015	75
Total Other				**689**
Independent Producers	Twin Falls	Hydro	3/8/2025	20
Independent Producers	Koma Kulshan	Hydro	3/31/2037	14
Independent Producers	North Wasco	Hydro	12/31/2012	5
Independent Producers	Nooksack Hydro	Hydro-QF	01/01/2014	2.5
Independent Producers	Weeks Falls	Hydro	12/1/2022	4.6

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

1 Nameplate capacity reflects PSE share only.

B. 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 PSE embraces and encourages 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 2008 and 2010, the number of subscribers increased from 21,509 to 29,398, and the number of megawatt-hours purchased increased from 291,167 to 314,893.

To supply green power, the program purchases renewable energy credits (RECs) from a variety of sources. The primary supplies are the Bonneville Environmental Foundation (BEF), a nonprofit environmental organization in Portland, Ore.; Acciona Energy, a broker of national wind RECs; and 3Degrees, a REC broker based out of San Francisco. These suppliers provide PSE's Green Power Program with a portfolio of resources including wind, biomass, low-impact hydropower, biogas and biomass. In addition, the Green Power Program purchases RECs directly from small, local producers in order to support the development of new small renewable resources. Examples include the Vander Haak Dairy (now FPE Renewables), Farm Power Rexville, Farm Power Lynden, Qualco Energy, and the Nooksack Hydro Facility.

The Green Power Program has also provided grant funding for several solar demonstration projects. For example, in 2009, the Green Power Program provided a $20,000 grant to the Vashon Island Community, which has the highest rate of participation of any community in our service territory. The grant was leveraged by additional community funds and in-kind support for the installation of two separate solar PV projects, each approximately two kW in size, and located on non-profit facilities. In addition, the Green Power Program awarded a $25,000 grant to the Council of Governments on Whidbey Island after a successful Green Power Challenge, where the

Island residents increased participation in the program by 50 percent during 2009. The funds will be used toward a community solar project at Greenbank Farm. Finally, the program provided a $20,000 grant to Phase IV of the Ellensburg Community Solar Project, which is looking at the difference in output from thin-film vs. crystalline silicon PV modules. The Green Power Program is receiving the RECs generated from PSE's share of that project.

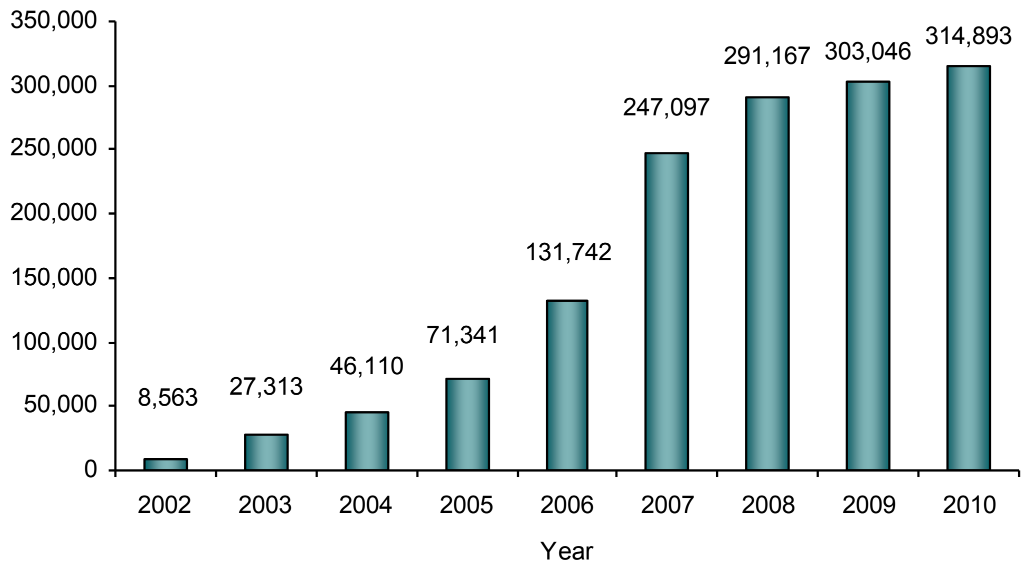
Increased pressure on west coast REC pricing, due to expanding compliance requirements, means the Green Power Program is now purchasing the majority of RECs for our large volume customers (those purchasing a minimum of 1,000,000 kWh a year under our large volume tariff) from outside the WECC region. Over 90 percent of the large volume portfolio will come from wind RECs generated in the mid-west. If prices continue to rise, PSE may also consider purchasing a small percentage of our standard portfolio wind RECs from outside of the WECC region.

Rates. The standard rate for green power is $0.0125 per 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, this option adjusts the amount of the customer's monthly green power purchase to match their monthly electric usage.

The large-volume green power rate—0.6 cent per kWh for customers who purchase more than 1,000,000 kWh annually—has attracted 25 customers since it was introduced in 2005.

In 2008, PSE agreed to increase participation in the Green Power Program to 5 percent of all electric customers by the end of 2013. To help achieve that goal, PSE contracted with 3Degrees, a third party REC marketer. 3Degrees has developed and refined education and outreach techniques while working with other utility partners across the country. Since their contract was initiated with PSE in January 2009, customer growth has increased by 20 percent and 14 percent in 2009 and 2010, respectively. As of December 31, 2010, nearly 3 percent of electric customers are participating in the program.

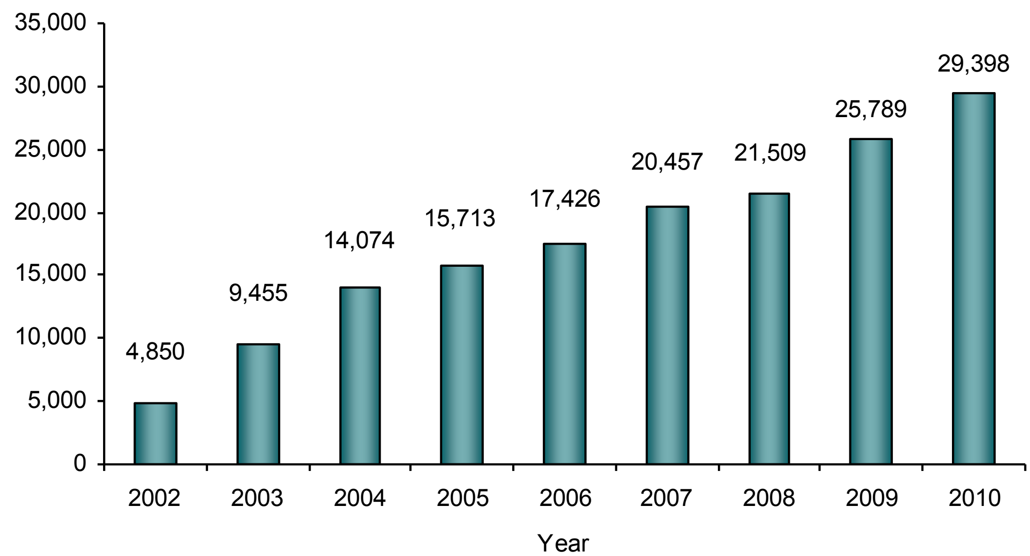
Figure D-5
Green Power Kilowatt-Hours Sold, 2002-2010



In 2010, the average residential customer purchase was 704 kWh per month, and the average commercial customer purchase was 2,305 kWh. The average 2010 large-volume purchase, by account, under Schedule 136 was 29,480 kWh per month.

Figure D-6 illustrates the number of subscribers by year. Of our 29,398 Green Power subscribers at the end of 2010, 28,524 were residential customers, 541 accounts were commercial accounts, and 333 accounts were assigned under the large volume commercial agreement. Cities with the most residential and commercial participants include Olympia with 3,633, Bellingham with 3,563, Bellevue with 1,869, Kirkland with 1,266, and Bainbridge Island with 1,073. Vashon Island has the highest percentage of participants, with over 12 percent of customers enrolled.

Figure D-6
Green Power Subscribers, 2002-2010

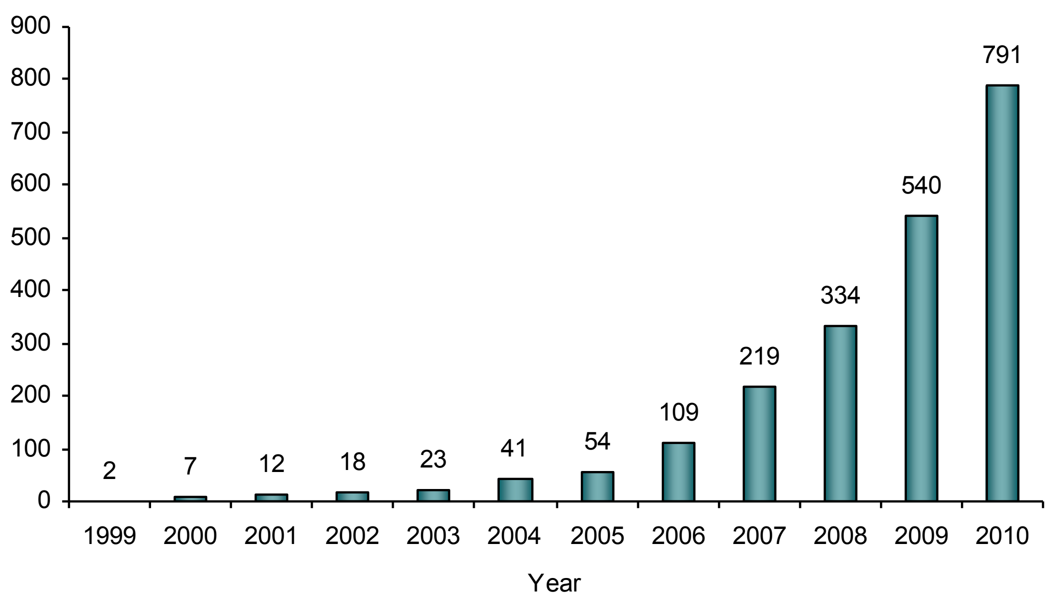


Customer Renewables Programs

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 is 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 ten years, as Figure D-7 shows. For 2010, PSE added 251 new net metered customers for a total of 791.

Figure D-7
Net Metered Customers Total Per Year, 1999-2010



The vast majority of customer systems (95 percent) are solar photovoltaic (PV) installations with an average generating capacity of 4.3 kW, but there are also small-scale hydroelectric generators and wind turbines. These small-scale renewable systems are distributed over a wide area of PSE's service territory. The average generating capacity of all net metered systems is 4.2 kW. Overall, the program was capable of producing more than 3.3 MW of nameplate capacity at the end of 2010.

Figure D-8
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/hydro	1	1.02	1.02
Hybrid: solar/wind	4	3.76	15.06
Micro hydro	4	4.63	18.50
Solar array	747	4.30	3215.22
Wind turbine	35	2.72	95.10
Total Number of Systems	**791**	**Total Capacity of All Systems**	**3344.90**

Figure D-9
Net Metered Systems by County

County	Number of Net Meters
Whatcom	98
King	221
Jefferson	91
Skagit	85
Island	75
Kitsap	90
Thurston	78
Kittitas	26
Pierce	27

Renewable Energy Cost Recovery. In 2005, PSE launched Production Metering 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 hydroelectric customers are not eligible under the current law). Annual amounts range from 12 cents to $1.08 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 2010, PSE had paid $283,000 to 641 customers eligible for production payments. The PSE tariff governing Production Metering is Schedule 151.

2. Electric Resource Alternatives

This section is designed to provide a brief overview of technology alternatives for electric power generation. It encompasses mature technologies, but emphasis is placed on new methods of power generation with near- and mid-term commercial viability.

All data has been gathered from public sources except where noted, and in these instances is non-sensitive PSE data. It should be noted that many data sources are the manufacturers themselves, who may provide optimistic availability, cost, and production figures.

A. Biomass

Technology Summary

Biomass in this context refers to the burning of woody biomass in boilers. Most existing biomass in the Northwest is tied to steam hosts (aka ‘cogeneration’ or ‘combined heat and power’), most typically in the timber, pulp, and paper industries. This dynamic has limited the size of power available for export to date. With the extension of the ITC and Treasury Cash Grant to biomass projects of various types, PSE has observed a bout of activity in biomass generation development plans, both for cogeneration and standalone facilities. The typical plant size we have observed is 25 MW, but plants up to 50 MW are being proposed. One major advantage to biomass plants is that they provide firm capacity and can operate as a base load resource and do not impose generation variability on the grid, unlike wind and solar.

Commercial Availability

This technology is commercially available. Greenfield development of a new biomass facility would require approximately five years and consist of the following activities: two and a half years for development and permitting; one year for major equipment lead-time; and one year for construction.

Cost and Performance Assumptions

Cost and performance assumptions derive mainly from PSE's experience in reviewing recent biomass proposals and input from The Shaw Group (engineering, construction, and technology consultants). Plant output is not significantly affected by temperature and is assumed to be the same in winter as throughout the year, and the typical size was chosen to be 25 MW. The plant heat rates are approximately 13,420 but can vary depending on fuel moisture content. The typical expected capacity factor for a biomass plant is approximately 90 percent. Assuming two weeks pear year of routine maintenance, the implied forced outage rate is approximately 6.3 percent. It would be typical for a biomass plant to operate at base load to cover fixed costs under a PPA, but it should be noted that biomass plants are technically capable of being turned down during off-peak hours, or turned off entirely during periods of low market demand and pricing. Emissions assumptions are based on a mix of proposals and from estimates by The Shaw Group. The greatest source of uncertainty is whether CO_2 emissions will be considered fully or even partially carbon-neutral by the EPA.

All development and capital costs, and fixed and variable O&M are based on preliminary estimates provided by The Shaw Group, and assumed to be for a plant that would be constructed in Washington with estimated accuracy of +/- 20 percent. Fixed O&M is substantially higher than wind facilities or combustion turbines due to the high number of staff required to operate the plant and a large amount of maintenance that needs to be performed to keep the various systems (fuel storage, handling, combustion, ash removal, etc.) operating. Fuel cost estimates are the most difficult to forecast given that centralized markets do not exist. Pricing is primarily dependent on bilateral agreements, and can be both highly regionally specific and highly volatile. The expected fuel price is based on historical pricing at the Pt. Townsend mill from 2000 to 2009.

The majority of the plants that have been proposed in this region would interconnect with BPA. As such, the generic biomass plant is assumed to interconnect with BPA and incur the typical thermal wheeling rate.

B. Coal

Technology Summary

Coal is the fuel used to produce a significant portion of the electricity generated in the United States. Most coal-fired electric generating plants combust the coal in a boiler to produce steam which drives a turbine-generator. There are a small number of U.S. coal-fueled power plants which gasify coal to produce a synthetic gas that is used to fuel a combustion turbine. Coal gasification is still in a state of development and all currently operating plants are demonstration projects built with federal grants or other government subsidies.

Of the fuels commonly used to produce electricity, coal produces the most greenhouse gases (GHGs) per MWh of electricity. Technologies for reducing or capturing some of the GHGs produced are currently in the research and development phase. A report recently released by the National Energy Technology Laboratory of the U.S. Department of Energy indicates it may take 20 years for carbon capture and storage (CCS) technology for power generating plants to become commercially available.

Commercial Availability

RCW 80.80 sets a generation performance standard for electric generating plants and prohibits Washington utilities from building plants or entering into long-term electricity purchase contracts from units that emit more that 1100 pounds of GHGs per MWh. With currently available technology, coal-fired generating plants produce GHGs, primarily carbon dioxide, at a level two or more times greater than the performance standard. This regulation makes it unlawful for PSE to build a new coal-fired power plant or enter a long-term purchase agreement to buy electricity produced by coal unless the plant includes CCS technology to reduce GHG emissions to a level below the RCW 80.80 standard. The status of CCS development makes it impossible to accurately estimate the cost of electricity from a coal-fired generating plant that meets these requirements.

There are no new coal-fired power plants under construction or development in the Pacific Northwest, and the owner of one of the three existing coal-fired plants in the region has announced plans to shut down the plant in 2020.

Cost and Performance Assumptions

No technologies are currently commercially available to allow a coal-fired generating plant to meet the requirements of RCW 80.80. Likewise, there are no accurate estimates of either the cost or performance for a coal-fired generating unit that would meet those requirements.

C. Fuel Cells

Technology Summary

Fuel cells combine fuel, typically carbon based, and oxygen to create electricity, water, and potentially other byproducts through a chemical process. The benefit of fuel cells over traditional combustion technologies is that they have high conversion efficiencies from fuel to electricity, on the order of 25 percent to 60 percent, which can be boosted higher using heat recovery and reuse. Fuel cells operate or are being developed at scales from several hundred watts, such as those to power portable electric equipment, up through several MW to power equipment, buildings, or provide backup power. Some of the largest differentiators amongst the types of fuel cells are the materials used as a membrane to separate fuels, the electrode and electrolyte materials, the operating temperature, and the scale of the fuel cells. There are five major types of fuel cells (Department of Energy, Fuel Cell Technologies Program).

Figure D-10

Comparison of Fuel Cell Technologies

Fuel Cell Type	Common Electrolyte	Operating Temp	Typical Stack Size	Efficiency	Applications	Advantages	Disadvantages
Polymer Electrolyte Membrane (PEM)	*Perfluoro sulfonic acid*	*50-100° C 122-212° F*	*<1 kW - 100 kW*	*60% transport-tation* *35% stationary*	• Backup power • Portable power • Distributed generation • Transportation • Specialty vehicles	• Solid electrolyte reduces corrosion & electrolyte management problems • Low temperature • Quick start-up	• Expensive catalysts • Sensitive to fuel impurities
Alkaline (AFC)	*Aqueous solution of potassium hydroxide soaked in a matrix*	*90-100° C 194-212°F*	*10-100 kW*	*60%*	• Military • Space	• Cathode reaction faster in alkaline electrolyte leads to high performance • Low cost components	• Sensitive to CO_2 in fuel and air • Electrolyte management
Phosphoric Acid (PAFC)	*Phosphoric acid soaked in a matrix*	*150-200°C 302-392° F*	*400 kW 100 kW Module*	*40%*	• Distributed generation	• Higher temperature enables CHP • Increased tolerance to fuel impurities	• Pt catalyst • Long start up time • S sensitivity
Molten Carbonate (MCFC)	*Solution of lithium, sodium, and/or potassium carbonates, soaked in a matrix*	*600-700° C 1112-1292° F*	*300 kW – 3 MW* *300 kW module*	*60%*	• Electric utility • Distributed generation	• High efficiency • Fuel flexibility • Can use for a variety of catalysts • Suitable for CHP	• High temperature corrosion and breakdown of cell components • Long start up time • Low power density
Solid Oxide (SOFC)	*Yttria stabilized zirconia*	*700-1000° C 1202-1832° F*	*1 kW-2 MW*	*60%*	• Auxiliary power • Electric utility • Distributed generation	• High efficiency • Fuel flexibility • Can use a variety of catalysts • Solid electrolyte • Suitable for CHP & CHHP • Hybrid/GT cycle	• High temperature corrosion and breakdown of cell components • HT operation requires long start up time and limits shutdowns

Commercial Availability

Fuel cells have been growing in both number and scale, but are not yet operating at a gross generation scale. The largest fuel cell project underway in the United States is a 4.5 MW project being built in Connecticut, at a cost of over $5,000/kW. In some states, incentives are serving to drive fuel cell pricing to be competitive with retail electric prices, especially where additional value can be captured from waste heat. Washington does not currently have any incentives specific to fuel cells.

Cost and Performance Assumptions

Fuel cell costs are estimated to be at least $5,000/kW, and some projects appear to be as high as $10,000/ kW before subsidies.

Fuel cell performance is very reliable, provided that feedstocks are kept clean of impurities. Fuel cells are in relatively common use as a backup power source in many telecommunications and data center applications, which require very high reliability. In addition, fuel cells are starting to be used for commercial combined heat and power applications, though most are in states with significant programs or subsidies for fuel cell deployment.

D. Geothermal

Technology Summary

Geothermal generation technologies use steam trapped in the earth, or generate steam using heat from the earth and a circulating fluid system. Geothermal energy production falls into four major types.

Dry Steam Plants utilize hydrothermal steam from the earth directly in turbines. This was the first type of geothermal power generation technology, but is limited by the number of sites that offer very hot (greater than 235 degrees Celsius) hydrothermal fluids that are predominantly steam.[2]

[2] *Renewable Energy Policy Project,* http://repp.org/geothermal/geothermal_brief_power_technologyandgeneration.html

Flash Steam Plants operate similarly to dry steam plants but use low pressure tanks to vaporize hydrothermal liquids into steam. Like dry steam plants, this technology is best suited to high temperature geothermal sources (greater than 182 degrees Celsius).[3]

Binary Cycle Power Plants can use lower temperature (107 degrees Celsius to 182 degrees Celsius) hydrothermal fluids to transfer energy through a heat exchanger to a fluid with a lower boiling point. This system is completely closed-loop, without even steam emissions. The majority of new geothermal installations are likely to be binary cycle systems due to emissions and the greater number of potential sites.[4]

The United States, Japan, England, France, Germany and Belgium are testing Enhanced Geothermal or "hot dry rock" technologies.[5] These systems involve the drilling of deep wells into hot dry or nearly dry rock formations and injecting water to develop the hydrothermal working fluid. The heated water is then extracted and used for generation. There are small operating facilities in Germany and France, and several commercial facilities are under development in Australia. The U.S. Department of Energy has funded a test project in the United States.

Commercial Availability

Currently, approximately 3,086 MW of geothermal generating capacity is online in the United States, with 97 percent of that capacity in California or Nevada[6]. The only operating geothermal plants in the Northwest are the 0.28 MW plant in Klamath Falls, Ore., and the 15.8 MW Raft River plant in Idaho.

The Northwest has been subject to considerable exploration activity over the past several years, with at least 700 MW in some stage of development[7]. Most of this is very early development, and may or may not have obtained site access and drilled exploratory wells. Most projects have not yet proven their output, though several are in testing at this time. Currently, three projects in the Northwest, a total of approximately 70 MW in capacity, are reported to be under construction, Neal Hot Springs and Crump Geyser in Oregon, and an expansion of the Raft River project in Idaho.

[3] *EERE,* http://www1.eere.energy.gov/geothermal/gerthermal_basics.html
[4] *Ibid*
[5] *Geothermal Education Office, 2000,* http://geothermal.marin.org/pwrheat.html
[6] *Geothermal Energy Association*
[7] *U.S. Geothermal Power and Production Update, April 2010.*

Other Northwest projects are planned in Oregon and Idaho, but are further behind in development and would take at least four years before commercial operation, if the resources prove viable.

Cost and Performance Assumptions

Geothermal plants typically run with high uptime, often exceeding 85 percent. However, plants sometimes do not reach their full output capacity due to lower than anticipated production from the geothermal resource. This issue affected the largest geothermal complex in the United States, the Geysers projects in California, due to resource depletion, but has been improved in recent years because of additional water recycling.

Geothermal energy plants are capital intensive, with estimated capital costs of approximately $3,650/kW (U.S. Department of Energy, 2008) for traditional geothermal steam plants. Other large scale technologies, including binary plants, are similar in cost. Overall, site specific factors including resource size, depth, and temperature can significantly affect costs. Generally, operating costs are relatively low due to a zero fuel cost, but this can vary due to site conditions as well.

E. Natural Gas – Combined Cycle Combustion Turbine (CCCT)

Technology Summary

Combined-cycle combustion turbine power plants consist of one or more combustion turbine generators equipped with heat recovery steam generators that capture heat from the CT exhaust. This otherwise wasted heat is then used to produce additional electricity via a steam turbine generator. Many plants also feature ‘duct firing’ which can produce additional capacity from the steam turbine generator, although at less efficiency than the primary unit. CCCT plants currently entering service can convert about 50 percent (HHV) 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 a popular power generation resource for well over a decade.

Commercial Availability

This technology is commercially available. Greenfield development of this type of plant would require approximately five years and consist of the following activities: two years for development and permitting; two years for major equipment lead-time; and one year for construction. PSE does not take the risk of contracting for major equipment before permits are in hand. Private developers, on the other hand, are often willing to take that risk and can accelerate the development timeframe by about one year.

Cost and Performance Assumptions

Cost and performance assumptions were provided to PSE by the engineering consulting firm (EC) as described above. Winter capacity (MW) is based on the average January temperature at Sea-Tac Airport and the heat rate is based on ISO conditions, which are similar to typical annual average temperatures for this region. The heat rate (both primary and duct firing) is degraded by 2 percent to simulate degradation typically experienced between major maintenance events.

The capital cost estimate is provided by the EC as previously described. The EPC cost is supported by a preliminary cost estimate provided June 30, 2010. EPC costs are developed to approximately +/- 20 percent. Owner’s Costs were estimated using the EC’s recommended 40 percent of EPC adder.

Non-fuel O&M costs were also estimated by the EC as previously described. PSE provided projected operating characteristics of 55 percent primary unit and 10 percent duct fire capacity factor and 100 primary unit starts per year. The EC assumed 21.25 FTE’s would be needed, and PSE increased the estimated overhead to reflect PSE’s standard overhead adder. To be consistent with trade floor dispatch and with AURORA modeling practices at PSE, the team allocated major maintenance as a fixed expense instead of a variable cost as provided by EC.

Natural gas supply is assumed to be firm year round and based on projected Northwest Pipeline firm rates. The unit is assumed to be connected to the PSE transmission system and as such does not incur any direct transmission cost, but the capacity contribution to peak load should be reduced by 7 percent to account for reserves.

F. Natural Gas – Simple Cycle Resources

The principal simple-cycle technologies for 'peaking' applications consist of 'frame' CTs, aeroderivative (aero) CTs, and reciprocating (recip) engines. Frame CTs are also known as 'industrial' or 'heavy-duty' CTs, and are generally larger in capacity and feature frames, bearings, and blading of heavier construction. In 2010, PSE performed a review of typical cost and performance characteristics across these technology categories and determined that frame and aero CTs are the best fit economically for the Pacific Northwest market and PSE's needs.

1 - Frame Combustion Turbine

Technology Summary

Conventional frame CTs are a mature technology. Our generic frame CT is based on a typical modern F-class machine in the 200 MW range. It can be fueled by natural gas, distillate, or a combination of fuels (dual fuel). Typical turbine units have efficiencies in the range of 15 percent to 35 percent (HHV) at full load. These units are typically less flexible than their aero and recip counterparts, meaning they cannot reduce output beyond about 50 percent to 60 percent, have slower ramp rates on the order of 15 MW/min, and though some can start in ten minutes, the output achieved in ten minutes is typically not baseload.

Commercial Availability

This CT is commercially available. Greenfield development of this type of plant would require approximately four years and consist of the following activities: two years for development and permitting; one and a half years for major equipment lead-time; and a half year for construction. Again, PSE does not take the risk of contracting for major equipment before permits are in hand. Private developers, on the other hand, are often willing to take that risk and can accelerate the development timeframe by about one year.

Cost and Performance Assumptions

Again, cost and performance assumptions were provided to PSE by a respected EC firm retained by PSE. The EC models performance and emissions characteristics under various ambient conditions and plant output levels. Winter capacity (MW) is based on the average January temperature at Sea-Tac Airport and the heat rate is based on ISO conditions, which are similar to typical annual average temperatures for this region. The heat rate is degraded by 2 percent to simulate degradation typically experienced between major maintenance events.

The capital cost estimate provided by the EC is composed of the Engineer, Procure, and Construct (EPC) cost and 'Owner's Costs' components. The EPC cost is supported by a definitive cost estimate provided June 15, 2010. EPC costs are developed to approximately +/- 15 percent accuracy and are based on national and international vendors for major equipment and take into consideration information on local labor rates and productivity. The capital cost includes an estimate for a 1 million gallon oil storage tank, land, containment berm, forwarding equipment, etc.

Owner's Costs (OC) such as development, permitting, engineering, site preparation, public relations, legal, construction management, O&M staff training, spares, acceptance testing, contingency, and AFUDC were estimated using the EC's recommended 40 percent of EPC adder. According to the EC, owner's costs are typically about 40 percent[8] of the EPC cost.

Non-fuel O&M costs were estimated by the EC using a proprietary model which estimates a levelized cost for routine and major maintenance, labor, other maintenance items, and consumables. These rates are levelized based on PSE-provided operating characteristics of 8 percent capacity factor and 85 starts per year. Staffing levels and rates are determined by PSE and assume staffing levels for a new standalone facility. To be consistent with trade floor dispatch and with AURORA modeling practices at PSE, the team allocated major maintenance as a fixed expense instead of a variable cost as provided by EC.

Natural gas supply is assumed to be interruptible and based on estimate of gas transport rates available in the capacity release market. Fixed O&M includes an estimate for the cost of distillate fuel backup for approximately 48 hours per year when natural gas supply may be curtailed. The unit is assumed to be connected to the PSE transmission system and as such does not incur any direct transmission cost, but the capacity contribution to peak load should be reduced by 7 percent to account for reserves.

[8] *The EC notes that owner's costs vary widely (30-70% of EPC), primarily depending on the site, technology, and the developer's cost of capital.*

2 – Aeroderivative Combustion Turbine

Technology Summary

Aeroderivative (aero) combustion turbines are a mature technology but new features and designs are continually being introduced. This generic resource is based on a relatively new design that features an intercooler following the compressor and which improves overall efficiency and hot weather power output. It can be fueled by natural gas, oil, or a combination of fuels (dual fuel). Typical aero units have efficiencies in the range of 25 percent to 38 percent (HHV) at full load. Aero units are typically more flexible than their frame counterparts and many can reduce output to nearly 30 percent. Most can start and achieve full output in less than ten minutes and start multiple times per day without maintenance penalties. Ramp rates range from 50 to 90 MW/min. Another key difference between aero and frame units is size. Aero CTs are typically smaller in size, from 40 to 100 MW each. This small scale allows for modularity and reducing shaft risk, but also tends to reduce economies of scale.

Commercial Availability

This technology is commercially available. Greenfield development of this type of plant would require approximately four years and consist of the following activities: two years for development and permitting; one and a half years for major equipment lead-time; and a half year for construction. PSE does not take the risk of contracting for major equipment before permits are in hand. Private developers, on the other hand, are often willing to take that risk and can accelerate the development timeframe by about one year.

Cost and Performance Assumptions

Cost and performance assumptions were provided to PSE by the EC previously mentioned. The EC models performance and emissions characteristics under different ambient conditions and at various output levels. Winter capacity (MW) is based on the average January temperature at Sea-Tac Airport and the heat rate is based on ISO conditions, which are similar to typical annual average temperatures for this region. The heat rate is degraded by 2 percent to simulate degradation typically experienced between major maintenance events.

The capital cost estimate was provided by the EC using the methodology previously described. The EPC cost is supported by a preliminary cost estimate provided January

14, 2010. This EPC cost was developed to approximately +/- 20 percent accuracy based on their in-house proprietary database of recently obtained budgetary quotes for other recent projects, adjusted for current market pricing conditions, escalation factors, and local labor rates and productivity. The capital cost includes an estimate for a 1 million gallon oil storage tank, land, containment berm, forwarding equip, etc. Owner's Costs were estimated using the EC's recommended 40 percent of EPC adder.

Non-fuel O&M costs were estimated by the EC as previously described. PSE provided an operating profile estimate of 18 percent capacity factor and 130 starts per year. Staffing levels and rates are determined by PSE and assume staffing levels for a new standalone facility. To be consistent with trade floor dispatch and with AURORA modeling practices at PSE, the team allocated major maintenance as a fixed expense instead of a variable cost as provided by BV.

Natural gas supply is assumed to be interruptible and based on an estimate of gas transport rates available in the capacity release market. Fixed O&M includes an estimate for the cost of distillate fuel backup for approximately 48 hours per year when natural gas supply may be curtailed. The unit is assumed to be connected to the PSE transmission system and as such does not incur any direct transmission cost, but the capacity contribution to peak load should be reduced by 7 percent to account for reserves.

G. Nuclear

Technology Summary

The thermal cycle

Like other types of thermal generating resources (coal-, oil-, and gas-fired), nuclear power plants produce electricity by boiling water into steam at elevated temperature and pressure. The thermal energy of the steam is converted to mechanical energy in a steam turbine driving an electrical generator to produce electricity. Instead of burning fossil fuels, the nuclear power plant uses solid ceramic pellets of uranium, developing heat in a process called "fission" or the splitting of uranium atoms in a nuclear reactor.

The fission reaction

Nuclear fuel consists of two types of uranium, U-238 and U-235. The atomic nucleus of uranium is composed of 92 protons and 143 neutrons. When split, the uranium nuclei break up, releasing high energy neutrons and heat. As these neutrons impact other uranium atoms, those atomic nuclei also split, releasing neutrons of their own, along with additional heat. These neutrons in turn strike other atoms, splitting them and triggering other such collisions in a chain reaction. When that happens, a self-sustaining fission reaction has begun.

To control the nuclear fission reaction, control rods are inserted into the reactor vessel that absorb neutrons without contributing to the fission reaction. These control rods may be inserted or withdrawn to varying degrees, slowing or accelerating the reaction.

Commercial Availability

The nuclear fleet

Today, there are 104 nuclear plants operating in the United States, the largest of which is Palo Verde in Arizona, whose three nuclear reactors together produce 3,942 MW[9]. The performance of the 104 U.S. nuclear plants has been excellent, with a combined energy output of 799 million MWh in 2009[10]. The total number of kWh produced by the reactors has steadily increased over the last five years. The fleet-averaged capacity factor since 2003 has been maintained at about 90 percent[11]. Approximately two-thirds of U.S. nuclear plants are pressurized water designs while the remaining one-third are boiling water designs.

Worldwide, there are 65[12] nuclear plants under construction, including in China (27), Russian Federation (11), India (5), Korea (5), Bulgaria (2), Taiwan (2), Ukraine (2), Japan (2), Argentina (1), Finland (1), France (1), Iran (1), Pakistan (1), and the United States (1). The lone U.S. plant is Watts Bar 2, located in Tennessee, with an electric capacity of 1,177 MW and a scheduled date for commercial operation of the year 2013. Initial site work is well under way at two additional plants, Vogtle in Georgia and Virgil C. Summer in South Carolina.

[9] *Source: Nuclear Energy Institute – Resources & Stats*
[10] *Source: World Nuclear Association – Nuclear Power in the U.S. – December 2010*
[11] *Source:* http://www.nrc.gov/reading-rm/doc-collections/huregs/staff/sr1350/v19/sr1350v19.pdf
[12] *Source: European Nuclear Society - Nuclear power plants, world-wide – January 2011*

Select U.S. nuclear construction update[13]

- Watts Bar 2

While the focus is on new technology, The Tennessee Valley Authority (TVA) undertook a detailed feasibility study which led to its decision in 2007 to complete unit 2 of its Watts Bar nuclear power plant. The 1,177 MWe reactor is expected to come on line in 2013 at a cost of about $2.5 billion. Construction was suspended in 1985 at 80 percent completion, and resumed in October 2007 under a still-valid permit. It is progressing on time and within budget. Its twin, unit 1, started operation in 1996. Completing Watts Bar 2 utilizes an existing asset, thus saving time and cost relative to alternatives for new baseload capacity. It was expected to provide power at 4.4 ¢/kWh, which is 20 percent to 25 percent less than coal-fired or new nuclear alternatives, and 43 percent less than natural gas.

- South Texas Project 3 & 4

This is to be a merchant plant with two 1,356 MWe Advanced Boiling Water Reactors. NRG Energy already operates two reactors at the site, and works are under way preparing for the new units. With Toshiba, NRG is part of Nuclear Innovation North America (NINA), which awarded the EPC contract to The Shaw Group and Toshiba America Nuclear Energy in November 2010. The construction and operating license (COL) review by the Nuclear Regulatory Commission (NRC) is expected to be completed in the first half of 2012, and the units are expected on line in 2016 and 2017. One reactor pressure vessel was ordered from IHI in May 2010.

- Vogtle 3 & 4

Site works are largely complete in preparation for two 1,200 MWe Westinghouse AP1000 reactors. Some of the reactor steelwork is on site. In April 2008, Georgia Power signed an EPC contract with Westinghouse and The Shaw Group consortium. Southern Nuclear has been awarded government loan guarantees, the COL review by the NRC is due to be complete early in 2011, and a license is expected mid 2012. The units are expected on line in 2016 and 2017.

- Summer 2 & 3

Site works are well advanced for two 1,200 MWe Westinghouse AP1000 reactors. In May 2008, South Carolina Electricity & Gas and Santee Cooper signed an EPC contract with

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[13] *Source: World Nuclear Association - Nuclear Power in the USA – December 2010*

Westinghouse and The Shaw Group consortium. The total cost of $9.8 billion includes forecast inflation and owners' costs for site preparation, contingencies and project financing. The COL review by the NRC is due to be completed early in 2011 and the units are expected to enter commercial operation in 2016 and 2019.

Policy Considerations

The Energy Policy Act of 2005 provided financial incentives for the construction of advanced nuclear plants. The incentives include a 2.1 ¢/kWh tax credit for the first 6,000 MWe of capacity in the first eight years of operation, and federal loan guarantees for the project cost. After putting this program in place in 2008, the Department of Energy (DOE) received 19 applications for 14 plants involving 21 reactors. The total amount of guarantees requested is $122 billion, but only $18.5 billion has been authorized for the program. In light of the interest shown, industry has asked that the limit on total guarantees be raised to $100 billion. There are three other regulatory initiatives which enhance the prospects for building new nuclear plants. First is the streamlined design certification process, second is provision for early site permits (ESPs), and third is the combined construction and operating license process. All have some costs shared by the DOE.

Following the requirements of the Nuclear Waste Policy Act, the DOE submitted a license application for the Yucca Mountain repository in 2008. Congress mandated and is providing the funding for the NRC to complete a license review. The Obama administration has stated that Yucca Mountain is no longer an option for nuclear waste disposal. There is no plan for high-level wastes, but the administration has committed to a comprehensive review of waste management. In conclusion, the progress on high-level waste disposal has not been positive.

Cost and Performance Assumptions

There is little hard data from recent U.S. nuclear developments from which reasonable cost estimates can be made. The construction costs track record for nuclear plants completed in the United States during the 1980s and early 1990s was certainly poor. Actual costs were far higher than had been projected and construction schedules experienced long delays, which, together with increases in interest rates at the time, resulted in high financing charges. Changing regulatory requirements also contributed to project cost increases, and in some instances, the public controversy over nuclear power contributed to some of the construction delays and cost overruns.

The plants in Korea and Japan remain on schedule. However, the construction and scheduling experiences of other plants such as the one in Finland are not encouraging. Whether the lessons-learned from the past have been adequately considered in the permitting, design, cost estimating, and construction of future nuclear plants remains to be seen. These factors will have a significant impact on the risk facing investors and/or utilities financing new projects. For this reason, the most recent update to the Massachusetts Institute of Technology “Future of Nuclear Power” report applied a 2.2 percent higher weighted cost of capital to the construction of a new nuclear plant as a risk premium compared to the construction of a new coal or new natural gas facility.

Figure D-11
Cost and Performance of New Central Station Electricity Generating Technologies[14]

Technology	Online Year	Size (MW)	Lead Time (Years)	Overnight Cost in 2009 (2008 $/kW)	Variable O&M ($2008 Mills/kWh)	Fixed O&M ($2008/kW)	Heat Rate in 2009 (Btu/kWh)
Scrubbed Coal	2013	600	4	2,223	4.69	28.15	9,200
Integrated Coal Gasification (IGCC)	2013	550	4	2,569	2.99	39.53	8,765
IGCC with Carbon Sequestration	2016	380	4	3,776	4.54	47.15	10,781
Conv Gas/Oil Combined Cycle	2012	250	3	984	2.11	12.76	7,196
Adv Gas/Oil Combined Cycle	2012	400	3	968	2.04	11.96	6,752
ADVCC W/ Carbon Sequestration	2016	400	3	1,932	3.01	20.35	8,613
Conv Cobustion Turbine	2011	160	2	685	3.65	12.38	10,788
Adv Combustion Turbine	2011	230	2	648	3.24	10.77	9,289
Fuel Cells	2012	10	3	5,478	49	5.78	7,930
Advanced Nuclear	2016	1350	6	3,820	0.51	92.04	10,488
Distributed Generation - Base	2012	2	3	1,400	7.28	16.39	9,050
Distributed Generation - Peak	2011	1	2	1,681	7.28	16.39	10,069
Biomass	2013	80	4	3,849	6.86	65.89	9,451
Geothermal	2010	50	4	1,749	0	168.33	32,969
MSW - Landfill	2010	30	3	2,599	0.01	116.8	13,648

[14] *Source: U. S. Energy Information Administration/Assumptions to the Annual Energy Outlook 2010*

Technology	Online Year	Size (MW)	Lead Time (Years)	Overnight Cost in 2009 (2008 $/kW)	Variable O&M ($2008 Mills/kWh)	Fixed O&M ($2008/kW)	Heat Rate in 2009 (Btu/kWh)
Gas							
Conventional Hydro power	2013	500	4	2,291	2.49	13.93	9,884
Wind Onshore	2009	50	3	1,966	0	30.98	9,884
Wind Offshore	2013	100	4	3,937	0	86.92	9,884
Solar Thermal	2012	100	3	5,132	0	58.05	9,884
Solar Photovoltaic	2011	5	2	6,171	0	11.94	9,884

In 2009 Moody's wrote: "From a credit perspective, the risks of building new nuclear generation are hard to ignore, entailing significantly higher business and operating risk profiles, with construction risk, huge capital costs, and continual shifts in national energy policy. Moody's is considering taking a more negative view for those issuers seeking to build new nuclear power plants. The longer-term value proposition appears intact, and, once operating, nuclear plants are viewed favorably due to their economics and no-carbon emission footprint. Historically, however, most nuclear-building utilities suffered a ratings downgrade - and sometimes several - while building these facilities."[15]

As indicated in Table 1, the capital cost of developing a new nuclear power plant is higher than most conventional and renewable technologies. It carries significant technology, credit, permitting, policy, and waste disposal risks. Its high cost and high uncertainty make nuclear technology an undue risk for PSE at this time. As Moody's explains in its report, nuclear power represents a "bet-the-farm risk" to companies pursuing development. PSE will continue to follow emerging trends in this technology, and may include it in future resource plans if evolving national policies and the technological maturity of newer designs sufficiently reduce project risks and cost uncertainty for our customers.

[15] *Source: Moody's Global Infrastructure Finance – New Nuclear Generation: Ratings Pressure Increasing - June 2009*

H. Solar Energy

Technology Summary

Solar energy uses the light and radiation from the sun to directly generate electricity with photovoltaics, or to capture the heat energy of the sun for either heating water or for creating steam to drive electric generating turbines.

- Photovoltaics are semiconductors which generate direct electric currents. These are then run through an inverter to create alternating current. Photovoltaics have been in use for decades, but only recently have started to grow significantly as costs of production have dropped. Most photovoltaics are based on silicon imprinted with electric contacts, much like computer chips, but other technologies, notably several chemistries of thin-film photovoltaics, have gained substantial market share. Thin film photovoltaics offer lower costs of production, but have lower efficiencies (3 percent to 12 percent efficiency) than silicon based photovoltaics (12 percent to 20 percent efficiency), requiring greater areas for the same amount of electric generation. All technologies of photovoltaics have significant ongoing research efforts, which have been increasing sunlight to electricity conversion efficiencies and decreasing costs. Photovoltaics are generally installed in arrays ranging from a few watts for sensor or communication applications, up through hundreds of MW for bulk power generation.
- Concentrating photovoltaics use lenses to focus the sun's light onto specialty high-efficiency photovoltaics, creating higher amounts of generation for the given area. Because of the use of concentrating lenses, these technologies must be more precisely oriented towards the sun.
- Solar thermal plants focus the direct irradiance of the sun to generate enough heat to produce steam, which in turn drives a conventional turbine generator. Two general types are in use or development today, trough-based plants and tower-based plants. Trough plants use horizontally mounted parabolic mirrors or Fresnel mirrors to focus the sun onto a horizontal pipe that carries water or a heat transfer fluid. Tower plants use a field of mirrors that focus sunlight onto a central receiver. A heat transfer fluid is used to collect the heat and transfer it to make steam.

As of late 2010, there were approximately 1,780 MW of installed photovoltaics in the United States, and 400 MW of operating solar thermal plants.

Commercial Availability

Currently, renewable portfolio standards (RPS) are the driver behind most solar development in the United States, as well as generous state and federal incentives. As of the end of 2009, Washington had only 5.2 MW of solar equipment installed, Idaho 0.2 MW, and Oregon 14 MW. Collectively, these amount to approximately a 2.5 aMW output over a year. Oregon is experiencing growth in solar development because the state's RPS requires the installation of about 20 MW of solar photovoltaics, and because of the state's Business Energy Tax Credit. In comparison, California had over 750 MW installed photovoltaics as of the end of 2009, and approximately 300 MW of solar thermal plants.

With less sunlight than other areas of the country, and incentive structures that limit development of smaller systems, photovoltaic development has been slow here in the Northwest. Likewise, concentrating PV and Concentrating Solar Thermal systems have not been developed, again because of the Northwest's relatively low percentage of direct sunlight, which these systems require for generation.

Cost and Performance Assumptions

PSE has had a positive experience with the performance of our 500 kW Wild Horse Solar Demonstration Project, which has outperformed its pre-construction production estimates. PV systems in Western Washington are expected to have capacity factors of approximately 10 percent to 11 percent, while those in Eastern Washington could achieve capacity factors as high as 18 percent.

Since PSE built the Wild Horse Solar Demonstration Project in 2007, costs have declined considerably, reaching national averages of approximately $6.50/ Watt-dc for residential systems, $5.75/ Watt-dc for commercial systems, and $4.00/ Watt-dc for utility scale systems (Solar Electric Industry Association, 2010). PSE's calculations of the lowest levelized cost for utility-scale solar systems have ranged from $0.18 - $0.25/kWh, significantly exceeding costs for other renewable energy sources, such as wind.

Solar thermal plants have proven reliable over time, with the SEGS plants in California operating since the 1980s. While the limited number of recent developments makes it difficult to estimate current costs, best known current costs are shown below.

Figure D-12
Solar Facility Cost Estimates

Technology	Capital Cost ($/kW)	Levelized Cost ($/MWh)	Typical Installation Size (kW)	Expected Life (years)
Solar Thermal Trough[16]	$4,950	$220	25-50,000	20

I. Waste-to-Energy Technologies

Technology Summary

Converting wastes to energy is a means of capturing the inherent energy locked into wastes. Generally, these plants take several forms:

- Waste Combustion Facilities. These facilities combust waste in a boiler, and use the heat to generate steam for a steam turbine to use in electric generation. This is a well established technology, with 86 plants operating in the United States, representing 2,500 MW in generating capacity.
- Waste Thermal Processing facilities (includes Gasification/Pyrolisis/Reverse Polymerization). These facilities add energy to waste and control the oxygen available to break down the waste into components without combusting it. Typically, a syngas is generated, which can be combusted for heat or to produce electricity. A number of pilot facilities once operated in the United States, but only a few remain today.
- Landfill Gas and Municipal Wastewater Treatment Facilities. Most landfills in the United States collect methane from the decomposition of wastes in the landfill. Many larger municipal wastewater plants also operate anaerobic systems to produce gas from their organic solids. Both of these processes produce a low quality gas with approximately half the methane content of natural gas. This low quality gas can be collected and scrubbed to remove impurities or improve the heat quality of the gas. The gas can then be used to fuel a boiler for heat recovery, or a turbine or reciprocating engine to generate electricity. Approximately 553 U.S. landfills generate electricity today, with a combined capacity of 1,831 MW.

[16] *Based on Nevada Solar One and Solar Tres announced capital costs*

Commercial Availability

Under Washington's RPS, landfill gas does qualify as a renewable energy resource, but municipal solid waste does not. Under revisions to the RPS, the definitions of wastes and biomass would be clarified to allow some new wastes, such as food wastes, to qualify as renewable energy sources.

Currently, several waste-to-energy facilities are operating in or near PSE's electric service area. There are two landfills using landfill gas for electric generation in Washington state, with a combined output of approximately 12.4 MW. The largest landfill in PSE's service territory, the Cedar Hills landfill, currently purifies its gas to meet natural gas quality, then sells that gas to PSE rather than using it to generate electricity. There are two waste combustion facilities operating in the Northwest: the 13.1 MW Covanta facility in Brooks, Ore., and the 26 MW Spokane Waste to Energy Facility. The Spokane facility currently holds a Purchased Power Agreement (PPA) with PSE. The only waste thermal processing facility known in the Northwest is a test facility operated by InEnTec in Richland, Wash. Several wastewater treatment plants in PSE's electric service area use gas from their digestion processes to generate electricity, but this is typically not enough to offset facility electric use and would therefore not be available for PSE to meet resource needs.

No waste-to-energy facilities are currently planned or under construction in the Northwest.

Cost and Performance Assumptions

While there were 87 waste combustion facilities and 553 landfill gas-to-energy facilities operating in the United States by the end of 2010, relatively few have been built in recent years, making reliable cost data difficult to obtain. The U.S. Department of Energy estimates that landfill gas projects cost approximately $2,400/kW in capital costs. Waste Combustion projects are similar to biomass projects, which have a construction cost of approximately $3,400/kW.

In general, waste-to-energy facilities are highly reliable, as they've used proven generation technologies and gained considerable operating experience over the past 30 years. Some variation of output from landfill gas facilities and municipal wastewater plants is expected due to uncontrollable variations in gas production. For waste combustion facilities, output is typically more stable, as the amount of input waste and heat content can be controlled.

J. Water-based Generation – Wave and Tidal

Technology Summary

The natural movement of water is used to generate energy through the flow of tides, or the rise and fall of waves.

Tidal generation technologies use rotors which are spun by tidal flow, which in turn turns a generator. Two major plant layouts exist: barrages, which use artificial or natural dam structures to accelerate flow through a small area; and in-stream turbines, which are placed in natural channels. Currently, the largest operating tidal generation facility in the world is the Rance Tidal Power barrage system in France, which has a generating capacity of approximately 240 MW. In-stream turbines up to 1.2 MW in size have been tested in Canada, Scotland, and South Korea.

Wave generation technologies use the rise and fall of waves to drive hydraulic systems, which in turn fuel generators. Technologies tested include floating devices, such as the Pelamis, and bottom mounted devices such as the Oyster. The largest wave power plant in the world was the 2.25 MW Agucadoura Wave Farm off the coast of Portugal, which opened in 2008. It has since been shut down because of the developer's financial difficulties. Significant testing has occurred off of Scotland, and developments are underway in Scotland, Australia, and England.

Commercial Availability

Currently, only one tidal power site is under development in the Northwest, Snohomish PUD's Admiralty Inlet site. Plans call for the installation of two to three test turbines, producing a total of 1 MW by 2013. Snohomish PUD also holds preliminary permits for developments of other sites in Puget Sound, though Admiralty Inlet is by far the largest. Tacoma Power considered development in the Tacoma Narrows, but ultimately abandoned the project. A small system has been tested off Vancouver Island, B.C, but no further development is planned at this time.

Several sites have been tested for wave power in the Northwest. Currently, the furthest along in development is off of Reedsport, Ore. Current plans are for 10 buoy-type floating tidal power generators, with a combined capacity of 1.5 MW. Past tests included a floating buoy-type generator tested off of the Oregon coast.

In general, the limiting factors in development of wave and tidal power projects have been long permitting timelines and relatively little experience with siting and the generation technologies. Permitting processes for tidal power projects are overseen by FERC, and also have state stakeholders. After permits are obtained, studies of the site water resource and aquatic habitat must be made prior to installation of test equipment. This process, from initial permit application until equipment installation, can take two to three years.

Even after the resource is proven, few technologies have more than a few years of in-water operational experience and limited production volumes, so costs remain high and longevity of equipment uncertain.

Cost and Performance Assumptions

Tidal and wave generation technologies are very early in development, making cost estimates difficult. Most developers have not produced more than one full scale device, and some have not yet reached that point. The best known cost estimates for development at scale are shown below. These are subject to considerable uncertainty, as they assume a certain scale-up in the respective industries, with the attending decrease in costs.

Figure D-13
Tacoma Narrows Tidal Plant Cost Estimates

Capital Cost ($/kW)	Levelized Cost ($/MWh)	Commercial Installation Size (kW)	Expected Life (years)	Typical Capacity Factor
$2,300 / kW	$112	16,000	20	35 %

Source: Electric Power Research Institute, EPRI

Figure D-14
Wave Energy Plant Cost Estimates

Capital Cost ($/kW)	Levelized Cost ($/MWh)	Commercial Installation Size (kW)	Expected Life (years)	Typical Capacity Factor
$3,375 – 6,747/ kW	$150-240/MWh	90,000	20	40 %

Sources: UK Carbon Trust, EPRI

K. Wind Energy – Off-shore Resources

Technology Summary

Offshore wind generation uses versions of horizontal axis wind turbines specifically designed for use in marine environments. Approximately 2,300 MW are currently in operation, mostly in the North Sea and Baltic Sea. Existing installations have mainly been via driven pile foundations in water depths of less than 30 meters, though some gravity foundations exist and a number of new designs are under development for tripod platforms and floating platforms. One floating platform wind turbine is currently in operation off Norway.

Commercial Availability

Currently, within the United States no offshore wind projects are under development on the West Coast (U.S. Offcoast Wind Collective - http://www.usowc.org/). Most U.S. projects have been proposed for the East Coast and Great Lakes region. The nearest proposed project to PSE's service territory is the Naikun Offshore Wind Project in British Columbia. This project has not received development permits or secured a power purchase agreement at this time.

Cost and Performance Assumptions

Due to the higher winds offshore, offshore wind is expected to operate at higher capacity factors than onshore wind projects, helping decrease prices. However, costs of marine construction considerably exceed those of on-shore construction. As no projects have been developed in the United States at this time, costs of offshore wind development are not well known, but are estimated to be at least $4,000/kW (Large Scale Offshore Wind Power in the United States, Opportunities and Barriers, 2010).

L. Wind Energy – On-shore Resources

Technology Summary

Wind turbine generator technology is mature and the dominant form of new renewable energy generation in the Pacific Northwest. While the basic concept of a wind turbine has generally remained constant over the last several decades, the technology is continuously evolving, yielding larger towers, wider rotor diameters, greater nameplate capacity, and increased wind capture. New commercially available machines are pushing into the 2.0 to 3.0 MW range with hub heights of 80 to 100 meters and blade diameters topping out around 100 meters. These changes have come about largely in response to the development of premium high wind resource sites that were close to existing transmission. The current generation of turbines is pushing the physical limits of existing transportation infrastructure. In addition, if nameplate capacity and turbine size continue to increase, the industry must explore creative solutions, such as concrete tower foundations poured on site.

Commercial Availability

This resource is commercially available, and the market for turbines appears to be in favor of buyers at the moment. Greenfield development of a new wind facility would require approximately five to as many as ten years, and consist of the following activities, at a minimum: three years for development and permitting; one year for major equipment lead-time; and one year for construction.

Cost and Performance Assumptions

Assumptions, unless noted otherwise, are based on actual and anticipated figures from the Lower Snake River Wind Project (LSRWP), Phase II. These assumptions are based on known and best available information at the time of this writing.

Capital Cost

Development Rights: PSE purchased the LSRWP Development Rights from RES Development in December 2008 and August 2009. With the Development Rights purchase, PSE acquired all the work completed to date, including: real property and lease agreements, BPA prepayments, project studies, project agreements, wind resource assessment reports, project permits, met masts; and other assets. LSRWP, Phase II carries a portion of the total asset purchase price, allocated based on the value of the assets at the time of the Development Rights purchase.

Development Costs: This category encompasses incremental costs incurred to develop all phases of LSRWP subsequent to the purchase of Development Rights. Like the Development Rights, the Development Costs benefit the development of all phases and are allocated based on the relative value of the assets at the time of purchase. Examples of costs included here are: ongoing real estate work, permitting, wind resource assessments, legal costs, communications / advertising, telecommunications and PSE labor and expenses.

Interconnection Costs: In addition to the prepaid transmission expense discussed in the following section, the Bonneville Power Administration (BPA) identified specific communications equipment that PSE must install in our project substation(s) in order for LSRWP, Phase II to interconnect into the BPA Substation.

Prepaid Transmission Expense: LSRWP will interconnect to the new BPA Central Ferry Substation. BPA requires PSE to prefund the Central Ferry Substation, which BPA will refund to PSE through credits based upon contracted monthly point-to-point expenses each LSRWP Phase will incur to transmit power across BPA's transmission system to PSE's territory. Items to note: First, the prepaid amount is allocated to each phase of LSRWP based on the relative value of the assets at the time of purchase. Second, while these expenditures are included in the development and construction budget, these expenditures are not depreciable assets that PSE can place into rate base and are therefore excluded from generic capital cost assumptions.

Wind Turbine Generators: This category includes one or more informal quotes from the three different turbine suppliers that participated in the LSRWP, Phase I bidding process: Siemens, Vestas, and General Electric. Scope typically includes manufacture, port delivery, commissioning, and some form of substantial and/or final completion. However, each vendor quote included scope nuances that are reflected in increased or decreased balance of plant (BOP) costs (e.g. Siemens' scope included turbine erection resulting in lower BOP costs).

Balance of Plant: Work inclusive of project substations, the turbine foundations, the collection system, the roads and the operations and maintenance building. Generally the BOP work will serve to "wrap" or fully complete the wind project. This estimate is based upon PSE's past experience in dealing with RES.

Construction Management: The category includes costs associated with managerial oversight of the construction phase, ongoing real estate work, required environmental assessments, wind resource monitoring, power performance testing, engineering work for roads, collector systems and substations, internal overhead, and construction insurance.

Other relevant costs included in this estimate include project communications equipment, credit for test power, turbine service and maintenance service prior to COD, PSE radio equipment, sales tax (100 percent exempt from sales tax through June 30, 2011), contingency, and AFUDC (rate of return of 8.1 percent for book purposes).

Generic Wind Turbine Generator O&M Costs

Operating costs are based on LSRWP, Phase I vendor pricing and predicted escalation rates. These costs were considered scalable for the different sized projects.

Generic Wind Turbine Generator Transmission Costs

Twenty-year cost estimates were generated based on historical and current tariff information supplied by BPA. These estimates were then escalated to take into account projected inflation.

Long-haul Wind Resources

PSE received several offers for long-haul wind resources sited in Montana during our 2010 RFP process. The overall economics of these resources were unfavorable when compared to PSE's other renewable alternatives due to the high cost of the transmission required to bring the power to PSE's service territory. Additionally, all of these resources were located outside of the Northwest boundary. This presents challenges related to Washington's RPS, which requires that such resources be delivered to Washington state on a "real-time" basis to qualify as renewable under the standard.