

# Planning Environment

A high degree of uncertainty exists in the energy marketplace today for utility planners. New laws and regulations are being adopted, driven by concern about environmental impacts. Their final shape is still in flux, and their full implications are not yet fully understood. The cost of adding new resources is rising as overall demand for energy increases; in particular, demand for renewable resources and energy efficiency is rising. Regional transmission constraints continue to pose challenges, and so does integrating intermittent renewables such as wind. Here we describe the landscape in which we must make long-term resource decisions to meet the growing needs of our customers.

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## I. Changing Environmental Regulations

Changing environmental regulations in three areas are significantly influencing the options PSE has for meeting the needs of our customers. These are:

- Renewable Portfolio Standards
- Greenhouse Gas Emissions
- Mercury Emissions

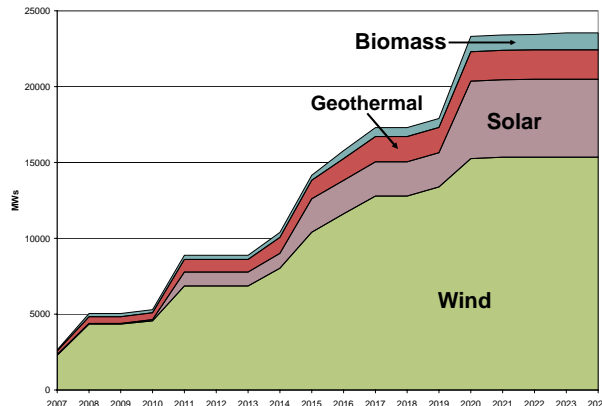
Additional information on climate change, greenhouse gas emissions, and potential legislation may be found in Appendix C, along with a brief discussion of mercury emissions and related regulations. Here, we focus on the implications those regulations have on the marketplace in which we must operate.

### A. Increasing Reliance on Renewable Portfolio Standards

Twenty-two states have passed legislation imposing a Renewable Portfolio Standard (RPS) on electric generation. As this IRP is being completed, Oregon is considering an RPS, and a Federal RPS is also a distinct possibility. These targets will significantly boost the renewable components of the regional generation base, and change the mix of generation technologies built over the next two decades. Figure 2-1 illustrates the magnitude of the additions required. Assuming that each state's RPS target will be met as currently written, nearly 30,000 MW of renewable generation will need to be added in the Western Electric Coordinating Council (WECC) over the next 20 years. The price and value of renewable alternatives will increase as a result, since there are finite limits on how many resources are feasible to develop in each state.

In the Pacific Northwest, wind is the primary renewable capable of generating utility-scale power. To meet the new requirements, Washington and Oregon together will have to add 10,500 MW of wind power by 2025. This means bringing four 150 MW wind farms online in the region every year from 2009 to 2025—enough to cover

**Figure 2-1. RPS Additions in WECC – Total**

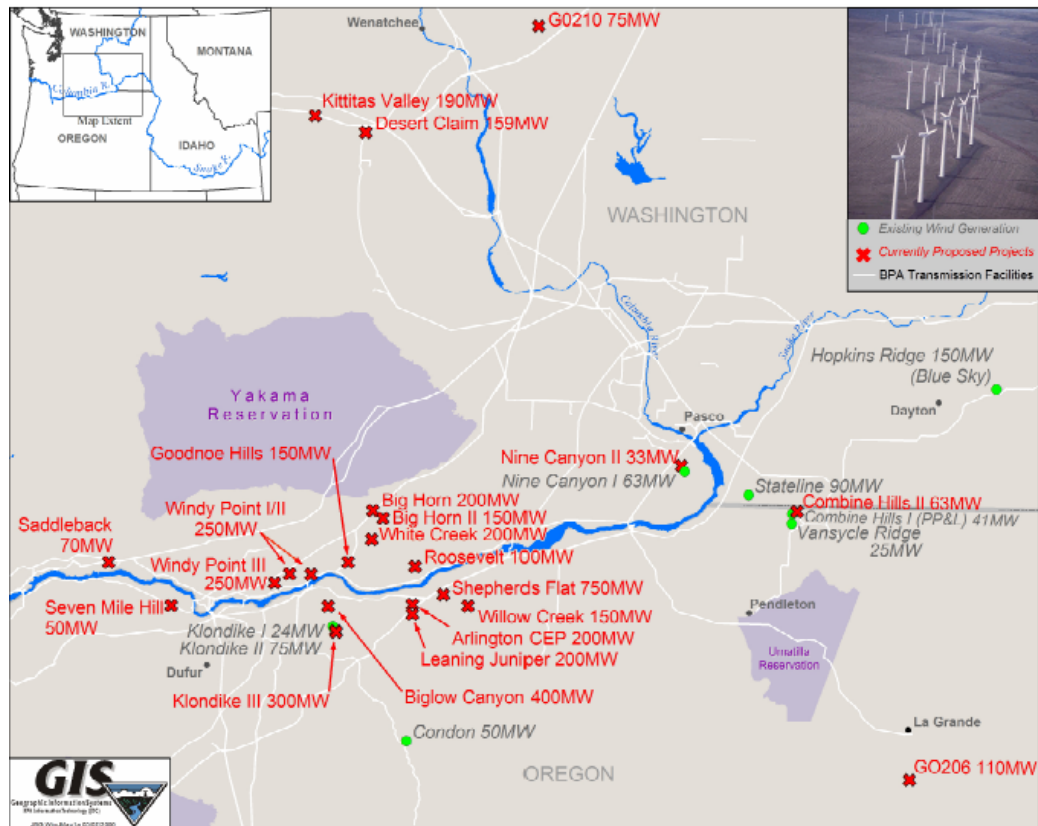


90% of the surface area of Puget Sound. The total amount developed in the region may turn out to be even larger if California seeks to develop wind here to meet its need for renewable resources.

Precisely forecasting the amount of wind generation that will actually be constructed is difficult because Washington's RPS includes a complex financial cap. This cap may limit the quantity of wind and other renewable resources that utilities are required to acquire; whether the Oregon law will include similar caps is not yet clear.

The current and proposed wind projects that would interconnect with BPA's transmission facilities are shown in Figure 2-2 below. They total approximately 4000 MW—less than half of the requirements set forth by the Washington and proposed Oregon laws.

**Figure 2-2**  
**Current and Proposed Wind Project Interconnections to BPA Transmission Facilities**



The field is crowded and will only become more so. Identifying enough locations for commercial wind development to satisfy RPS requirements will create increasing pressure in the marketplace. Demand for generators, developers, and skilled labor will also increase.

### *Summary of Washington's Renewable Portfolio Standard*

Initiative 937 (the Energy Security Act) is Washington's Renewable Portfolio Standard. It was passed by voters in late 2006. The new law requires the state's electric utilities to meet the following targets:

- 3% of load from qualifying renewables by 2012;
- 9% of load from qualifying renewables by 2016;
- 15% of load from qualifying renewables by 2020;
- Penalty: \$50/MWh for every MWh that a utility falls short;
- Cost Cap: total incremental renewable cost at 4% annual revenue requirement.

### *Regional and Neighboring States' Policy Activities*

The actions of regional and neighboring states affect the energy markets in which we participate. In particular, California's actions have an enormous impact on renewable resources throughout the WECC region due to their early and aggressive policies and the sheer size of their markets. They have advanced a number of policy changes to support more renewable development.

Recently, FERC approved changes sought by the California Independent System Operator (CAISO) that altered the way certain transmission projects are financed in the state. The changes allow implementation of a "hybrid financing method" for smaller generators that will make it easier for them to access smaller projects. Previously, developers were responsible for the cost of building the transmission trunk lines that connected their new generation systems to the main grid; smaller renewable developers faced serious obstacles in obtaining the large amounts of financing required for transmission construction. Under the new model, utilities will now pay for trunk line construction and be reimbursed after connecting the additional smaller, renewable projects.

In considering CAISO's proposals, FERC acknowledged that renewable developers cannot generally locate their projects near favorable transmission lines, but instead must locate them where those renewable resources are available (such as windy or sunny spots).

### ***RPS Impacts on Demand-side Resources***

RPS and related policies will also increase pressure on demand-side resources in the marketplace, since most RPSs include demand-side as well as renewables requirements. This IRP calls for a significant increase in demand-side resources, and estimates expenditures of \$2 billion for such resources over the 20-year planning horizon. In California, investor-owned utilities have budgeted to spend that amount *in the next two years alone* on energy efficiency.<sup>1</sup> The people who have the experience and skill to implement effective demand-side programs will be highly sought after as the region seeks to meet its goals.

### ***B. State & Local Initiatives to Limit Green House Gas Emissions***

Federal policy has yet to be set on climate change, but state and local initiatives to limit GHG emissions date back to June 2002, when Massachusetts adopted a 10% reduction of CO<sub>2</sub> for the state's coal-fired plants. These regulations took effect on January 1, 2006, and New Hampshire soon followed suit.

A cooperative effort among seven Northeastern states known as the Regional Greenhouse Gas Initiative (RGGI) mandates that electric utilities in the participating states reduce their emissions. The agreement caps power plant GHG emissions at 2005 levels from 2009 through 2014, then reduces them an additional 10% by 2019. Maryland will join RGGI in 2007. Together, these eight states account for one-eighth of the U.S. population and approximately 8% of the country's power generation.

State initiatives have also gained momentum in the West. Washington, Oregon, and California have proposed a number of emission reduction projects under the umbrella known as the West Coast Governors Global Warming Initiative. Currently, both Oregon

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<sup>1</sup> California Public Utilities Commission Energy Efficiency California's Highest-Priority Resource, June 2006.

and Washington require new power plants to offset a certain portion of their anticipated CO<sub>2</sub> emissions. Similarly, the California Public Utility Commission (CPUC) requires that a "carbon adder" (an estimate of the cost of complying with future carbon emission limits) be used by the state's utilities when comparing the costs of alternative generation during their resource planning processes.

California was the first state to reach beyond the energy sector in order to reduce GHG emissions. In July 2002, the state enacted legislation requiring motor vehicles to reduce GHG emissions. In 2005, Governor Schwarzenegger signed an executive order committing the state to a program with goals to reach 2000 emission levels by 2010 and 1990 levels by 2020. Most notable is the California legislature's passage of AB 32 in August 2006. AB 32 establishes an economy-wide CO<sub>2</sub> cap that commits the state to reducing greenhouse gas emissions from all sources combined to 1990 levels by 2020. Specific measures are not mandated, but the bill directs the California Air Resources Board to develop regulations to achieve the required emissions reductions.

The passage of AB 32 in California and the limits set forth in the RGGI states mean that *approximately one-quarter of the U.S. population is now subject to state GHG emission limits.*

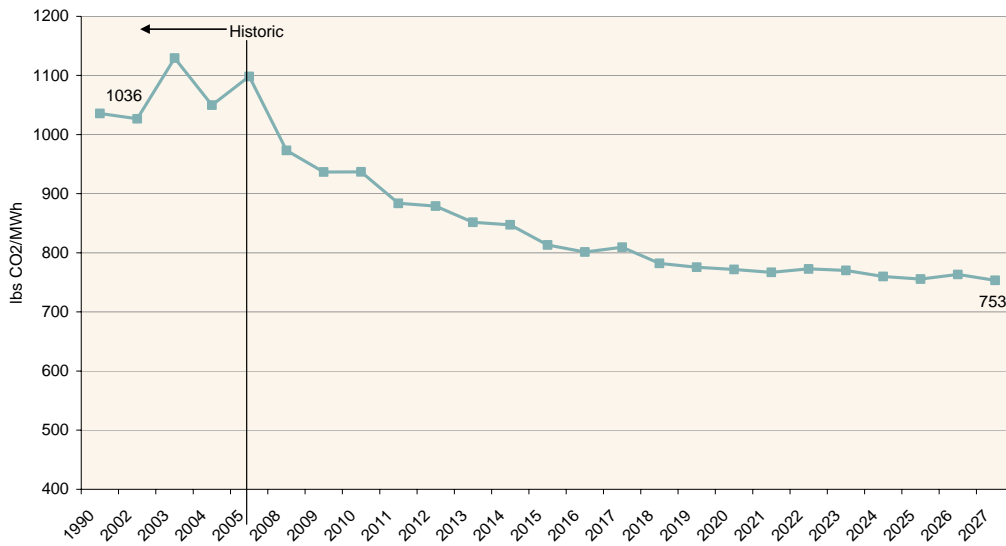
Local jurisdictions in the Pacific Northwest have also been developing their own climate policies, and Seattle has been one of the leading cities in this effort. In 2005, Mayor Greg Nickels launched the U.S. Mayors Climate Protection Agreement, which has enlisted over 330 municipalities in an agreement to reduce GHG emissions from their communities by 7% from 1990 levels, by 2012. Mayor Nickels also created the "Green Ribbon Commission on Climate Protection," which recommended ways for Seattle to achieve the 7% goal. King County announced this year that it joined the Chicago Climate Exchange.

In May 2007, after our analysis for this IRP was completed, Washington state adopted a new law regulating GHG emissions (Senate Bill 6001). The law has two key components that affect electric utilities. The first component is a set of guidelines pertaining to *emission rates* for CO<sub>2</sub> from new electric sources (whether owned or contracted). These guidelines state that any newly added electric resources must emit no more than 1,100 pounds of CO<sub>2</sub> per MWh. The second component sets goals to reduce *total* GHG *emissions* in the state to 1990 levels by 2020, 75% of 1990 levels by 2035, and 50% of 1990 levels by 2050.

The distinction between emission rates (carbon intensity) and total emissions is important to understand. “Carbon intensity” measures the amount of CO<sub>2</sub> produced per Megawatt hour of energy generated. “Total emissions” is the sum of *all* CO<sub>2</sub> produced by *all* of the energy that is generated. Even if carbon intensity is successfully reduced, total emissions may increase if greater overall energy production is required.

The carbon intensity of PSE’s resource portfolio is anticipated to decline significantly in the future under this IRP, as illustrated in Figure 2-3 below. Our carbon intensity falls to 753 lbs/MWh in 2027 from 1990 levels of 1,036 lbs/MWh. This means that PSE’s carbon footprint will decline by 27% over the planning horizon.

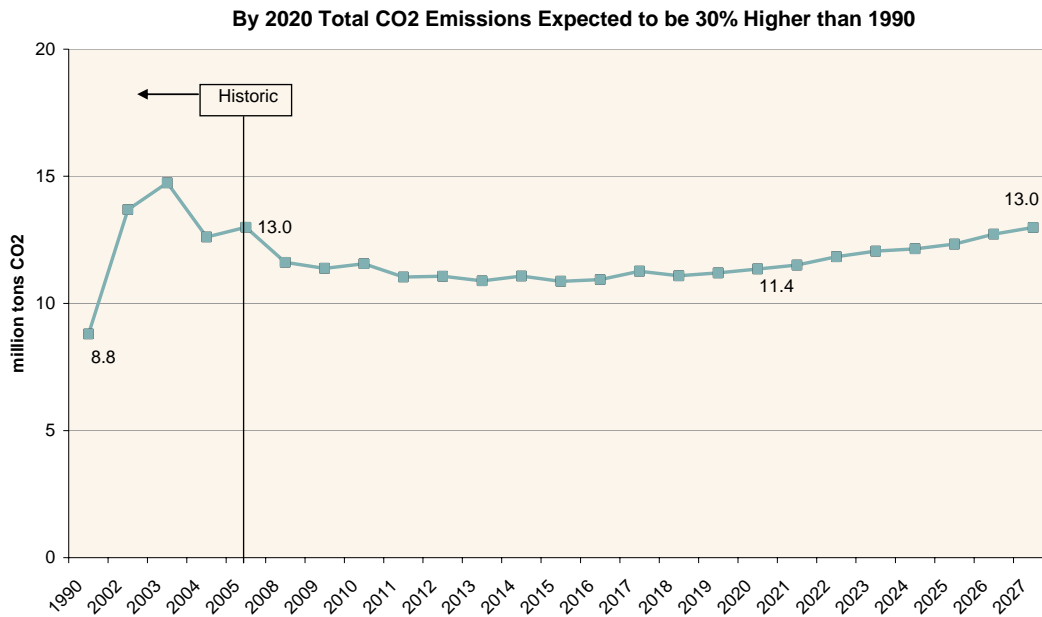
**Figure 2-3**  
**PSE Carbon Dioxide Emission Rates Declining by 27% from 1990 Levels**



By the end of the 20 year planning horizon, the Lowest Reasonable Cost portfolio will reduce the CO<sub>2</sub> footprint passed on to our customers by 27% relative to 1990 carbon emission intensity levels.

However, while PSE’s carbon footprint is declining, we also anticipate that the total number of customers—and thus the total amount of electricity we produce—will continue to grow. So even though the CO<sub>2</sub> emissions we produce per Megawatt hour will decline substantially, our total CO<sub>2</sub> emissions will increase. Figure 2-4 shows the total emissions we expect over the same time period. By 2020, total emissions are expected to be 30% higher than 1990 levels.

**Figure 2-4  
PSE Carbon Dioxide Total Emissions**



The comparison of emission rates with total emissions shown above illustrates the importance of using emission rates for single-sector GHG regulation. Senate Bill 6001 identifies the transportation sector as the largest emitter of GHG in Washington state. There is an emerging risk that in the future, emissions from the transportation sector will be shifted to electric utilities through the use of plug-in electric hybrid vehicles. We have not performed an assessment of whether such a shift would increase or decrease total GHG emissions in Washington in this IRP, nor have we otherwise examined the potential impacts of plug-in vehicles. We will investigate the issue for our 2009 IRP. If PSE's load does increase as a result of plug-in hybrids, it would be even more unlikely that we could get back to 1990 total CO<sub>2</sub> emission levels, though we may be able to meet the emission rate cap of 1,100 lbs of CO<sub>2</sub>/MWh.

**C. Mercury Regulations**

The Clean Air Mercury Rule (CAMR) enacted by the Environmental Protection Agency (EPA) in May 2005 permanently caps and reduces mercury emissions from coal-fired power plants. State and environmental group lawsuits are seeking to overturn the CAMR program in favor of stricter control requirements and limits on trading emissions (a



mechanism that gives utilities a certain level of flexibility to comply with the cap). States, however, are moving beyond EPA in regulating mercury emissions from power plants. So far, sixteen have enacted or are working to enact programs more stringent than EPA.

In Idaho, coal-fired power plants will effectively be banned from the state under a mandate announced in August 2006 by Gov. Risch. Risch's executive order directs the state Department of Environmental Quality (DEQ) to initiate rulemaking with an eye toward opting out of CAMR. If approved by at least one house of the 2007 Legislature, the new DEQ rule will preclude any developer of coal-fired power plants from buying mercury emission credits from elsewhere and using them to operate in Idaho. With no coal-burning power plants currently in the state, Idaho's mercury emission budget is zero.

Oregon has also adopted a stricter standard than CAMR. In December 2006, the Oregon Environmental Quality Commission (DEQ) adopted a rule that limits mercury from new coal-fired power plants and mandates installation of mercury control technology by the state's only existing coal-fired plant. The Boardman plant, in eastern Oregon, is expected to reduce mercury emissions by 90% by July 1, 2012.

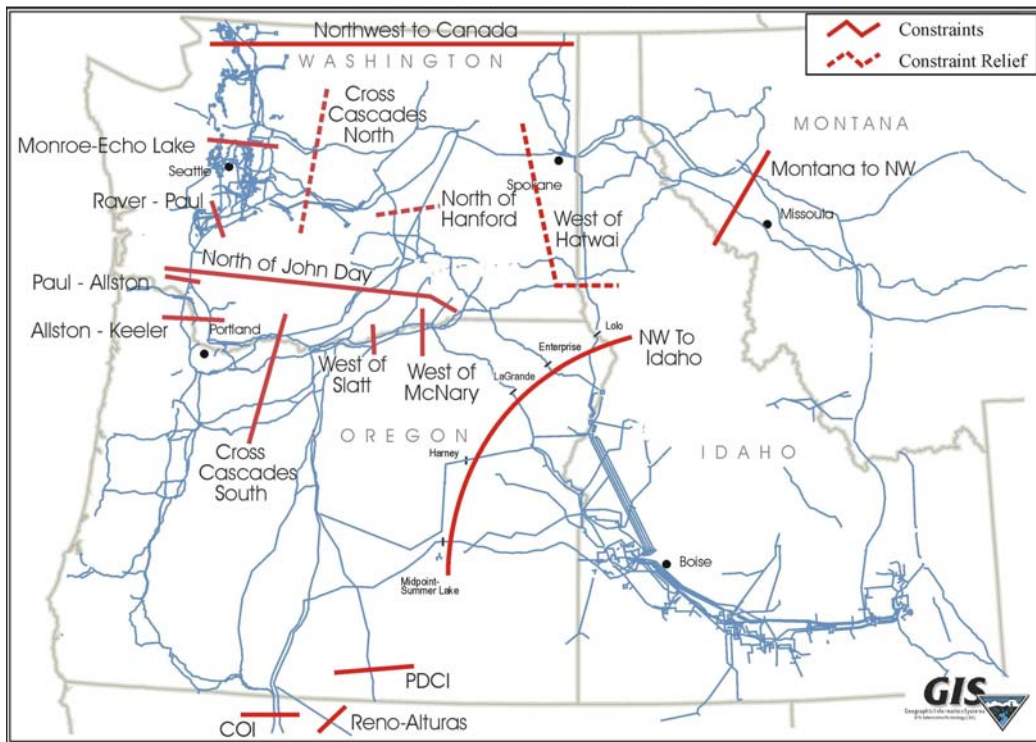
In October 2006, the Montana Board of Environmental Review approved a regulation to limit mercury emissions from coal-fired power plants. This, too, is more stringent than CAMR. Adopted with a 5-1 vote, the administrative rule (ARM 17.8.771) takes a two-tiered approach. It allows power plants burning lower-quality lignite coal to release more emissions than plants burning cleaner sub-bituminous coal. The new rule will cut mercury emissions by approximately 80%, and includes a cap-and-trade provision to help power plants meet their emissions-reductions targets. It also includes alternative emissions limits for plants that have tried to meet the new standards but have demonstrated that they cannot.

The Washington Department of Ecology (Ecology) is also drafting a mercury rule that is far more stringent than CAMR. The proposed standards would prohibit coal-based generators from participating in the national mercury emissions cap-and-trade program after 2012, effectively ending the future growth of clean coal in the state. The preliminary proposal would allow the continued operation of Transalta's existing pulverized coal facility in Centralia and might allow development of another 600 MW integrated gasification combined cycle (IGCC) facility, but would prohibit additional coal generation in Washington. Ecology isn't sure if opting out of the cap-and-trade program is the way to go; however, the agency is concerned about such a program creating mercury hotspots. Ecology has not been able to provide any information regarding studies about mercury sources in the state and their impacts to the local and regional environment, but is steadfast on this rulemaking.

## II. Regional Transmission Constraints

PSE transports power from its origination point to our service territory over the regional transmission grid through contracts with various transmission providers. Physical and contractual limitations and lack of coordination within the regional transmission systems challenge PSE's ability to import resources from outside our service territory. The major constraints upon the regional transmission system are shown in Figure 2-5.

**Figure 2-5**  
**2005 Northwest Transmission Constraints**



The intermittent nature of wind creates additional operating challenges for an electrical system. PSE has experienced wind resources that go from zero wind to full capacity and back down to zero within an hour. Variations of this magnitude create short-term operational issues, generally referred to as “wind integration,” which is described more fully in the Wind Integration Appendix.

Over the next three years, as much as 2,400 MW of wind power is expected to come online in the Northwest region, for a total of nearly 3,800 MW by 2009. The Northwest Power and Conservation Council's Fifth Northwest Electric Power and Conservation Plan includes up to 6,000 MW of developable and potentially cost-effective wind power. This number represents only a portion of the 10,500 MW of renewable generation that we expect will be needed in Washington and Oregon. The Fifth Plan also calls for the development of a wind confirmation plan to resolve uncertainties surrounding wind power development.

The Northwest Wind Integration Action Plan was developed by many of the region's utility, regulatory, consumer, and environmental organizations and produced significant findings regarding the ability of the Northwest to accommodate future wind power development. The effort also identified issues that need to be resolved for wind power to achieve its full potential. The Action Plan made 16 recommendations intended to help resolve these issues. Of particular importance are actions addressing challenges associated with transmission marketing, planning, and expansion, and the limited market for control area services. A final action calls for the formation of a Northwest Wind Integration Forum to facilitate implementation of the Action Plan.

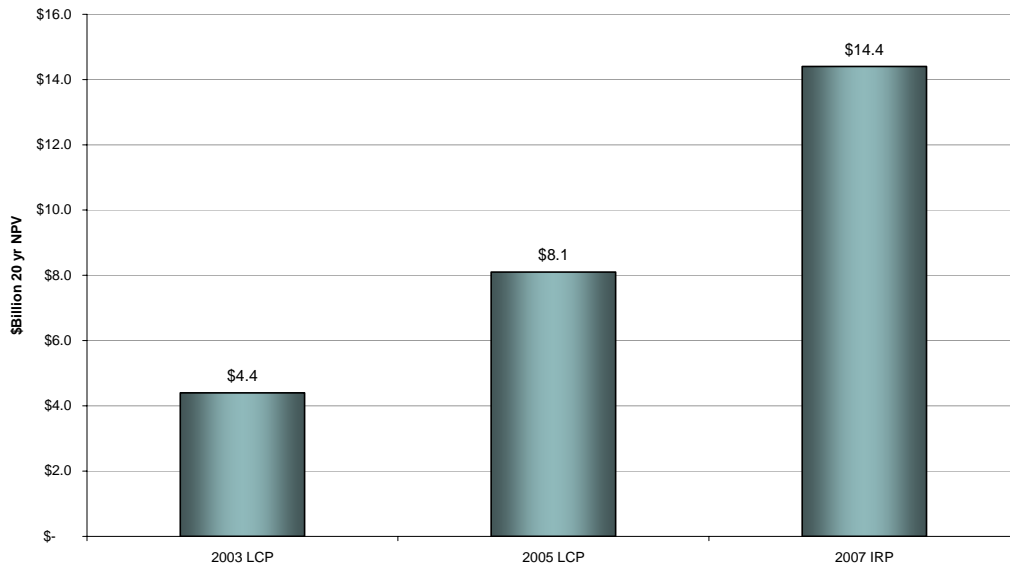
### III. Resource Costs and Availability

In recent years the cost of adding new generation has risen sharply throughout the country and particularly here in the Northwest. PSE has a unique insight into these market trends since we have been active in the market through a series of solicitations and acquisitions over the past five years. A number of factors are influencing these cost trends.

#### A. Portfolio Cost Increase

Overall, PSE's long-term portfolio cost estimates have been increasing significantly over time. Figure 2-6 illustrates that our incremental portfolio cost has more than tripled since the 2003 LCP.<sup>2</sup> These figures compare the 20-year net present value of the portfolios for the 2003 and 2005 LCPs with the 2007 IRP.

**Figure 2-6  
Comparison of Incremental Portfolio Costs**



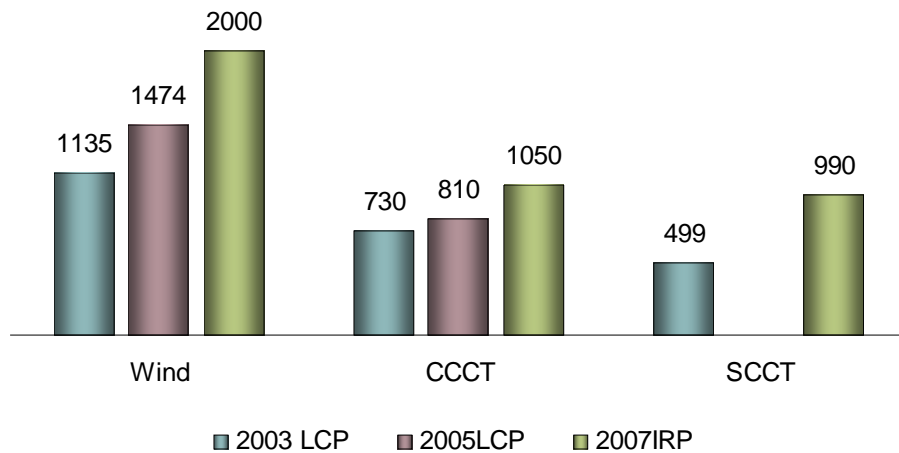
Long-term portfolio cost has more than tripled since 2003 LCP. Key drivers:  
 -Capital costs up by 44 - 76% depending on resource;  
 -Gas prices up 85%

<sup>2</sup> Incremental portfolio cost here is measured as the variable costs associated with existing resources plus the fixed and variable costs of new resources.

**B. Resource Cost Trends from Recent Market Solicitations**

The cost of electric generation resources of all types has increased significantly over the past four years. PSE has experienced these shifting resource costs first-hand. The following chart illustrates the range of costs we experienced during the 2003 and 2005 RFP cycles.

**Figure 2-7  
Resource Cost Trends by Technology (\$2007)**



We have also experienced another sign of increasing pressure on the marketplace. During the 2005 RFP process, several renewable projects were withdrawn or scaled down by developers as a direct result of RPS requirements initiated by other states.

**C. Global Demand for Generation Resources**

The demand for energy resources is increasingly tied into an integrated global market, and high growth in certain regions is having a ripple effect in other regions. At this time, strong economic growth in China and India, and other growing economies in Asia, is having a pronounced effect on global prices for raw commodities, energy, and equipment and services related to construction of new generation facilities. Figure 2-8 illustrates the magnitude of that growth in terms of impacts on electricity consumed, based on data from

the Department of Energy's, Energy Information Administration.<sup>3</sup> The figure shows that annual *growth* in electricity consumption in developing Asian economies is expected to nearly equal the *total* electricity consumed in the Northwest Power Pool

Data from the Energy Information Administration indicates that China, India, and other developing Asian economies will be adding the equivalent of more than 60% of the entire WECC load in generation every year. In other words, Asia is expected to build the equivalent of a new WECC-sized generation system every two years.

**Figure 2-8**  
**Annual Growth in Asia Nearly Equals Total Northwest Consumption**  
**(kWh in Billions)**

	2010	2015	2020	2025
<b>Non-OECD Asia Electric Consumption:</b>	4,713	5,896	7,154	8,513
<b>Period-to-Period Change:</b>		1,183	1,258	1,359
<b>Average Annual Growth:</b>		237	252	272
<b>Northwest U.S. Consumption:</b>	259	274	299	319

To a certain extent, the economic growth in Asian markets is simply displacing economic growth that might have occurred in Europe, Latin America, or other regions in previous years. However, the impact on the energy markets is somewhat unique because of the fact that China and India are growing from a minimal base into significant energy markets in an extremely rapid time frame. They now represent such a large economic opportunity for sectors such as clean coal technology, nuclear power, substation equipment, and wind turbine development, that the engineering, manufacturing and logistical capabilities of the world's largest OEMs are focusing heavily on these markets. As a result, other geographic regions are experiencing delays in manufacturing queues and delivery cycles that make it difficult to obtain equipment, and they are also experiencing upward pressure on prices.

On a macro level, these pressures will continue for both equipment and key engineering skills, and they will continue to affect PSE.

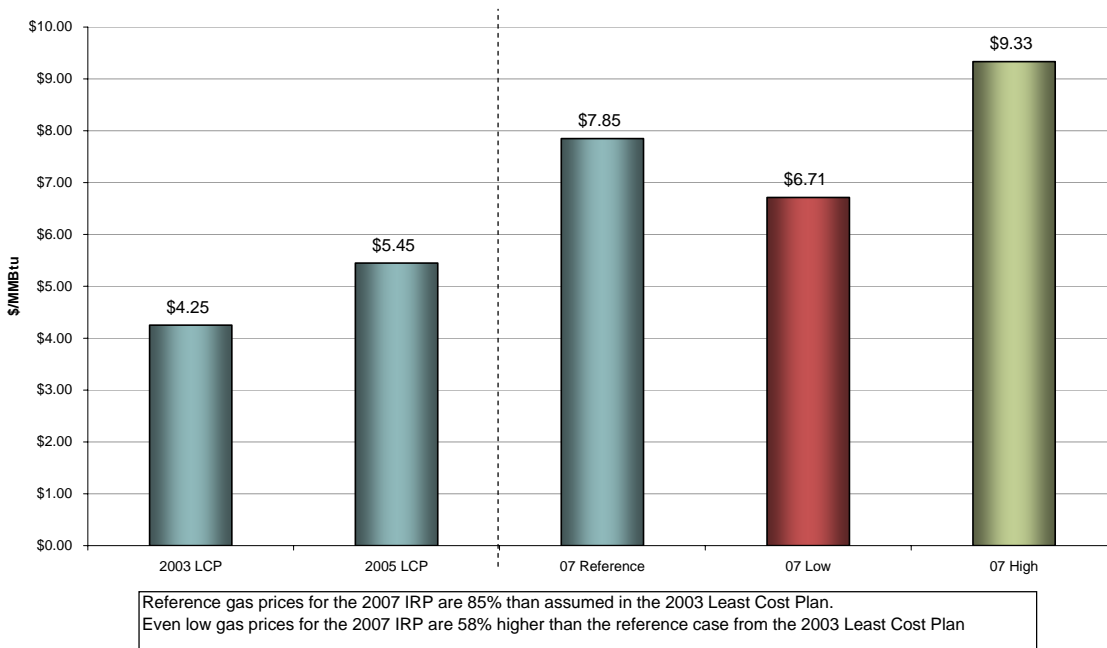
<sup>3</sup> International Data: [http://www.eia.doe.gov/oiaf/ieo/excel/ieoreftab\\_9.xls](http://www.eia.doe.gov/oiaf/ieo/excel/ieoreftab_9.xls)

U.S. Data: [http://www.eia.doe.gov/oiaf/aeo/supplement/suptab\\_72.xls](http://www.eia.doe.gov/oiaf/aeo/supplement/suptab_72.xls)

**D. Gas Prices**

Growing demand and increasing production costs have contributed to increases in natural gas prices. Since the 2003 LCP, gas prices have increased 85%. Even the low gas prices modeled in the 2007 IRP are 58% higher than reference case assumptions for the 2003 LCP.

**Figure 2-9  
Comparison of 20-year Levelized Gas Prices**



We foresee increased reliance on natural gas as a fuel for electric generation, which will add to the upward pressure on overall portfolio costs. While current supplies and infrastructure are ample to meet existing and near-term needs, increased reliance on gas for electric generation (as well as continued growth of demand from gas sales customers) will require a significant increase in gas supplies, delivery pipelines, and storage facilities.

While cost-effective alternatives for expanding gas supplies are available, evaluating and acquiring the alternatives best suited to our needs while minimizing gas costs will continue to be a challenge. As our gas use increases, it will be important to maintain supply diversity. By making sure we establish and maintain effective connections with a variety of supply basins, we increase our ability to take advantage of price opportunities when and where they occur.



Imported liquefied natural gas (LNG) is expected to play a growing part in the continental and regional energy picture. The U.S. Energy Information Administration (EIA) projects LNG imports must increase from under one trillion cubic feet (Tcf) in 2004 to more than six Tcf by 2025 to meet projected continental demand. Recent technological developments and streamlined production, as well as higher prices in North America, have made the cost of LNG imports more competitive. More than 40 new terminals have been proposed to regulators, including four in Oregon and two in British Columbia. A regional LNG import facility would increase the diversity of PSE's gas supply portfolio as well as reduce our dependence on the gas pipeline network.

LNG importation, however, faces a host of hurdles including shipping and safety concerns, financing of import facilities, suitable location for terminals, and regulatory approval and permitting.

### ***E. Long-Lead Resource Development Issues***

"Long-lead" resources are those that take several years to engineer, site, and construct. Coal resources are the obvious—but not only—example. Most new, out-of-territory development projects fall into this category because of the length of time it takes to construct transmission facilities. High-head hydroelectricity from Alaska or British Columbia, geothermal power from eastern Idaho, and wind from Montana or Wyoming could all be described as long-lead resources.

Long-lead resources are subject to several risks that must be borne by the developer, or in some cases, by the utility sponsor. Siting and permitting can cost millions of dollars and take several years. Negotiation and development of long-haul transmission lines can take as long as 10 years. Direct construction can require up to four years for a coal plant, or two years for a gas plant. During all this time, capital must be expended, and interest costs continue to accumulate.

Electric utilities have historically undertaken such long-lead projects because they operated under a "regulatory compact" that helped to reassure them that prudently incurred expenditures would be recovered in the rate base. In the current planning environment, however, the size of the investments at risk are much larger and the potential exposure to different environmental scenarios is much less predictable than in the past. In addition, some long-lead alternatives now present the possibility of total success or total failure, with no spectrum of outcomes in between and huge amounts of

money at stake. Commit to clean coal in hopes that carbon capture and sequestration will prove technically and commercially viable by the time siting and transmission issues have been fully negotiated—and if it does, you win. If it doesn't—or if environmental regulations change significantly—you lose big. In this high stakes planning environment, it becomes almost impossible for a utility to prudently make long-lead judgments until either technology or regulatory risks become more certain.

#### *IV. Financial Considerations*

In the course of developing our resource strategy, PSE considers how the selected resource portfolio and individual resources impact our incremental power costs and risk. The impact on our financial strength and credit are further evaluated during development of the annual strategic financial plan, and also when a specific resource is considered for purchase or contract. The following considerations and assumptions were used during this IRP analysis. For an in-depth discussion of the financial considerations that affect and influence resource acquisitions, see Appendix F.

- For evaluation of generic resources, both PPA contracts and natural gas fuel were priced at spot market without a risk management adder. This issue will be re-examined as we evaluate specific resource acquisitions.
- If the future coal market more closely resembles the natural gas market model, credit could become an issue for coal-fueled IGCC resources. This IRP does not include a credit adder for coal fuel.
- PSE could have a large capital need for resources concentrated over a few years prior to the time that NUG contracts expire in 2011-2012. While capital limitations during this time were not specifically analyzed in this IRP, we will need to examine the timing of replacement acquisitions to determine whether we have the financial strength to support rapid-owned resource additions.
- The timing of regulatory recovery is not explicitly modeled in the IRP, but this may become a consideration for specific resource acquisitions. For long-lead resources, and possibly transmission, PSE may need to pursue recovery of costs for construction work in progress. Short-term retail rate changes are another potential concern.
- Short-term power bridging agreements (PBAs) are used in this IRP to cover need until long-lead resources become available. PBAs may also be used to stagger resource additions to moderate the year-to-year financing requirements of owned resources. For the generic power bridging agreements analyzed in the portfolios, we computed an equity offset cost adder to account for the effect of imputed debt. A similar approach will be applied when evaluating specific power purchase agreements during the resource acquisition process.

## *V. Conclusion*

The current planning environment for PSE is one that combines increasing uncertainty at a time when costs are also increasing, and the impact of being right or wrong is significant. Managing these challenges represents a significant opportunity for PSE to leverage its experience, insight, and personnel in a way that satisfies our customers, regulators and other stakeholders.