X. ELECTRIC ANALYSIS AND RESULTS

This chapter describes the analytical process and assumptions PSE used to develop its long-term electric resource strategy for the 20-year planning period. It begins with a discussion of the analytical methodology and planning standard used in the electric planning process. This is followed by an overview of generic new generation alternatives. Next, PSE presents the five power price forecasts created using the AURORA model, which correspond to each of six scenarios analyzed in this least cost planning process (two scenarios use the same power price forecast). Section D describes the benefits of scenario analysis, including brief summaries about each of the six scenarios and the use of probabilistic analysis. A summary table is provided to outline the key assumptions for each scenario. Section E offers a detailed discussion of electric generation and energy efficiency portfolios. The chapter concludes with quantitative findings and the identification of the theoretical "best" portfolio.

A. Electric Methodology

The Least Cost Plan process establishes a methodology for evaluating resource portfolios. This methodology is used both in the generic least cost planning process and for evaluating specific resource acquisition opportunities. The following section describes the electric planning process.

Analysis Process Objectives

PSE strives to continually improve its least cost planning analytic process. The main analytic objectives of this Least Cost Plan are to:

- Reflect lessons and results of the 2004 resource acquisition process.
- Develop an analytical approach to properly assess the impacts of key uncertainties.
- Test major resource portfolio options.
- Facilitate open, well-documented decision-making that includes both quantitative and qualitative factors.
- Integrate energy supply resources and demand-side management in the analytic process.
- Identify the least-cost mix of supply resources and demand-side resources.

Analytical Process Stages

In order to achieve the Company's least cost planning objectives, PSE developed a deliberate and thorough analytical approach. In keeping with the overall goal to develop an executable plan, PSE's analytical approach addresses major industry uncertainties and key lessons from the 2004 resource acquisition process. The process followed these stages:

1.	Examine planning environment and identify key industry trends and drivers
2.	Design analytical approach
3.	Develop major input assumptions and forecasts
4.	Determine PSE's need for new resources
5.	Develop scenarios to evaluate key elements of uncertainty
6.	Construct portfolios to analyze major resource options
7.	Analyze supply resource portfolios
8.	Analyze energy efficiency and fuel conversion potential
9.	Identify final resource portfolio

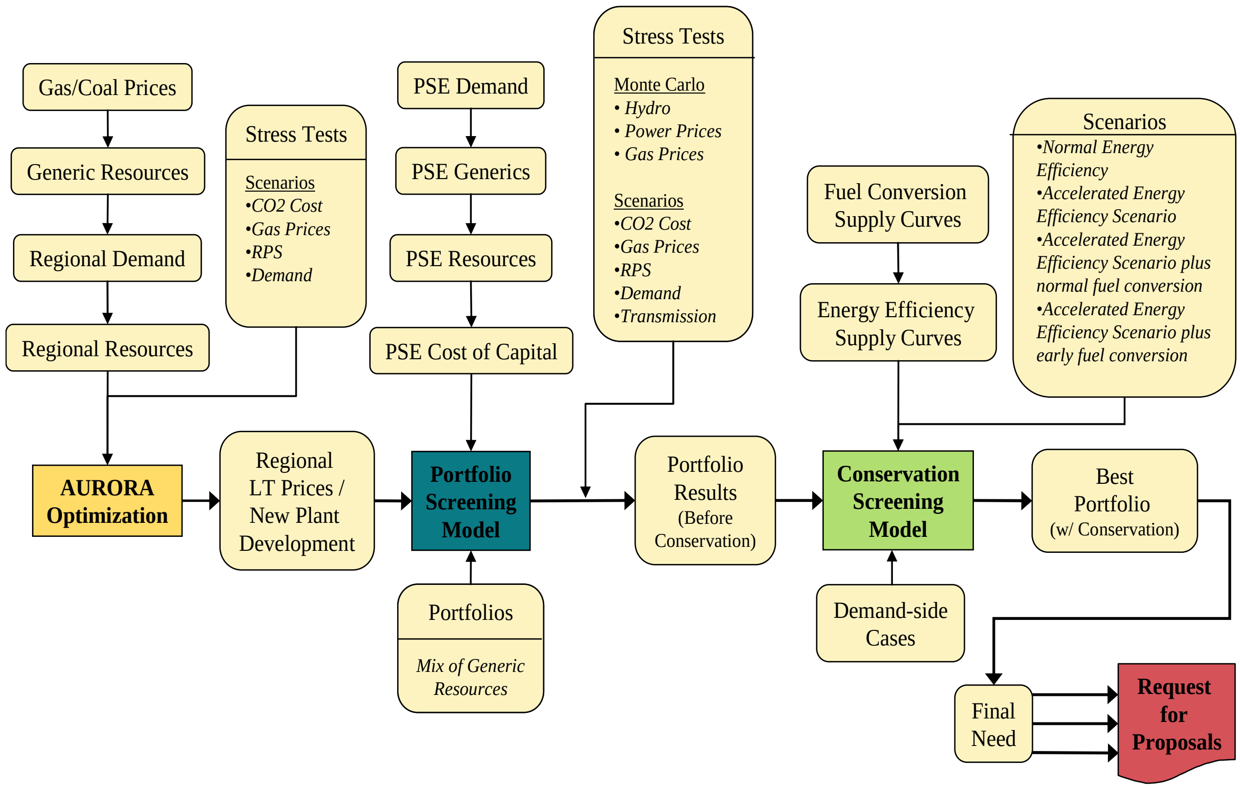
Stage 1- Examine Planning Environment and Identify Key Industry Trends and Drivers. Chapter VIII includes an expansive discussion of the planning environment and key issues. These key issues introduce uncertainty, and they impact the cost and availability of resources.

Stage 2- Design Analytical Approach. PSE elected to analyze the key issues using a scenario approach. This approach was selected because of the magnitude of the key issues and because many of the uncertainties are independent (i.e. availability of transmission is not dependent upon gas prices or greenhouse gas regulation). Since each of the scenarios represents a unique future, PSE developed a consistent set of input data for each.

Each scenario was analyzed using electric market simulation models. PSE uses three primary models for least cost planning. The AURORA model analyzes the western power market to produce hourly electricity price forecasts. The Portfolio Screening Model (PSM) tests portfolios to evaluate PSE's long-term incremental portfolio costs. Finally, the Conservation Screening Model (CSM) tests demand-side resource cases to determine the most cost effective level for a given generation portfolio. Appendix C provides more detail about the electric models.

Exhibit X-1 shows the integration of the major process stages and models.

Exhibit X-1
Analytic Process for Least Cost Planning



Stage 3- Development of Major Input Assumptions and Forecasts. The AURORA model and the PSM require inputs for demand, fuel prices, power prices (PSM only), existing and new resource costs, and operational characteristics. The input assumptions to the models are both regional and specific to PSE. PSE used Cambridge Energy Research Associates' (CERA) natural gas price forecasts from December 2004 for this Least Cost Plan. Chapter V discusses the gas price forecasts in detail. Generic plant costs and operational characteristics were developed from analysis of EIA data, resource acquisition bids, and other data sources. Chapter VI describes the methodology PSE uses for load forecasting.

Stage 4- Determination of PSE's Need for New Resources. For its 2003 Least Cost Plan, PSE performed extensive analyses on eight planning levels to meet energy and capacity need. The final result of the analyses was the selection of the level "B2" planning standard – energy resources to meet the average energy need for the highest winter month and peak resources to meet capacity needs at 16ºF. This planning standard was chosen as a result of cost and risk tradeoffs (see Chapters XI and XII of the 2003 Least Cost Plan). The definition of need determined in 2003 is still applicable and has, therefore, been used by PSE for the current Least Cost Plan.

Using this definition, PSE compared its forecast load requirements against existing resources to determine the need for acquisitions.

Stage 5- Development of Scenarios to Evaluate Key Elements of Uncertainty. Scenarios were developed with a consistent set of assumptions for transmission costs, carbon costs, renewable portfolio standards (RPS), gas prices, electric prices, and electric demand to evaluate key issues of uncertainty that affect PSE resource acquisition decisions. Scenarios were first run in AURORA to produce a scenario-specific forecast of regional electric market prices.

The use of scenarios allows PSE to quantify the uncertainty resulting from the key issues. Examining how portfolios perform across a range of scenarios provides insight into how resources perform under different conditions over 20 years.

Stage 6- Construction of Portfolio to Analyze Major Resource Options. A portfolio is a distinct set of generic resources over the planning period. For the Least Cost Plan, PSE creates a variety of portfolios with different mixes of coal, natural gas, renewables, and other resources. These portfolios include generic plants with known costs and operational characteristics. Each portfolio is analyzed against the scenarios, using the PSM.

Stage 7- Analyze and Select Least Cost Portfolio of Supply Resources. PSE employs the PSM to evaluate resource portfolios. PSM calculates the economic dispatch for existing and potential new PSE resources against hourly power prices from AURORA scenarios. The model derives a comparative incremental cost to customers for a particular resource portfolio by combining the variable cost of dispatch from the existing dispatchable fleet, the cost of net market purchases, and the revenue requirement for the new resource portfolio. The 20-year present value of these costs discounted at PSE's cost of capital is referred to as the portfolio cost (expressed in millions of dollars).

To compare scenario results, the portfolio cost is divided by the load to express values in dollars per megawatt hour. The unit cost makes relative comparisons of outcomes when scenario load levels vary. It is important to note that the portfolio cost does not equal total power costs because it does not include the capital or fixed operating costs for PSE's existing resources.

For each of the six scenarios, the developed generic resource portfolios are run through PSM. PSM supports Monte Carlo variation of hydro production, gas prices, and electric market prices. Model results without Monte Carlo variation (static mode) provide a point estimate of the incremental portfolio cost. From the static results, PSE can identify the best portfolio within a given scenario and compare portfolios across all scenarios. Model results with Monte Carlo variation (dynamic mode) provide an expected value and a range of outcomes. The Monte Carlo analysis identifies incremental portfolio cost estimates within a 90 percent confidence interval and creates a risk measure based upon the average of the 10 percent worst outcomes. The objective is to identify the least cost portfolio considering both cost and risk. PSE is most concerned with the risk of higher costs for its customers.

With uncertainty around many of the key variables, a single portfolio may not always be the lowest cost and lowest risk. The goal is to find a portfolio that performs well across the range of futures, and to identify areas of uncertainty that have the greatest impact on portfolio selection.

Stage 8- Analyze Energy Efficiency and Fuel Conversion Potential. After the generating resource portfolio is selected, the Conservation Screening Model (CSM) is used to determine the best level of demand-side resource. Thousands of demand resource portfolios with energy efficiency and fuel conversion are tested in the CSM. It builds on the PSM and integrates demand-side resource to find the level of conservation that produces the lowest portfolio cost.

Stage 9- Identification of Final Resource Portfolio. The integrated result of portfolio and conservation modeling is the theoretical best resource portfolio.

B. New Generation Alternatives

New Resource Choices

There are numerous technically feasible generating technologies available to PSE as new resources. The resources modeled in the PSM represent generic resources that could reasonably be included in PSE's portfolio. Supply-side resources include combined cycle combustion turbines (CCCTs) fueled by gas; thermal plants fueled by coal; renewable energy, including wind and biomass; power bridging agreements and a winter call option contract to cover winter peak energy needs. Demand-side resources include numerous individual energy efficiency measures that were bundled into 17 supply curves; and residential fuel conversion where, for example, electric heaters are replaced with gas-fueled heaters.

One previously modeled resource was seasonally shared to provide PSE with winter energy without further increasing summer length. From the 2003-04 competitive resource acquisition process, it appears that the market potential for a shared resource is unlikely. Therefore, a seasonally shared resource is not considered in this plan as a generic resource. PSE recognizes that there is value in a seasonally shaped resource, and that one may be procured in a future acquisition process.

PSE has used information obtained from the request for proposal (RFP) and resource acquisition processes to inform the PSM. As a result, the Company was able to define a set of resources that included the relative cost of new resources. A primary source for information was the U.S. Department of Energy's Energy Information Agency's (EIA) table of "Cost and Performance Characteristics of New Central Station Electricity Generating Technologies" from the Annual Energy Outlook, 2004. The EIA provides basic information about plant characteristics at the national level, such as plant capacity, heat rates, capital costs, variable costs and fixed costs. This information was augmented with cost data gleaned from the recent resource acquisition process for capital costs, power transmission development and gas fuel transportation, among others.

Fuel prices for the gas turbines are based upon the CERA forecast and are discussed extensively in Chapter V. PSE considers a generic gas turbine to be located along the I-5 corridor, hence the CERA Sumas hub price needs to be increased to account for a pipeline commodity charge, fuel use, and tax. Coal prices were based upon an RFP response as well as PSE's knowledge of Powder River Basin coal where the company's Colstrip plant is located. The prices take into account market prices, heat content of the coal, and transportation costs.

Gas-Fueled Combustion Turbines (CCCTs)

The I-5 corridor of Puget Sound has numerous CCCTs in place along the Northwest Pipeline. PSE owns some CCCTs in this region and has contracts for the output of others. A new generic plant of 400 MW capacity could be an expansion of an existing simple-cycle combustion turbine site; the expansion, upgrade or development of a cogeneration facility; or a greenfield location.

For modeling, the site is assumed to be in PSE's service territory and includes costs that would be applicable to any new development. The gas fuel cost starts with the Sumas hub price from CERA, then adds a fixed cost for firm delivery on Northwest Pipeline and a commodity charge, fuel usage, and tax. Since the facility is local, the gas plant cost assumes no new transmission lines need to be built; however, there is a fixed electric transmission charge for connecting in the PSE control area, as well as a small variable charge. The capital cost for a plant built in Washington is slightly higher, taking into account the CO_2 charge (WAC 173-407) which is calculated as an upfront cost, not a pay-as-you-produce fee.

Coal

The generic coal plant for the model represents a new scrubbed mine-mouth facility in Montana with a capacity of 600 MW and a heat rate of 9,274 Btu/kWh. The coal comes from the Powder River Basin, which is the least expensive source area identified by the EIA. PSE's coal price reflects both the current market and some conveyance from mine to plant.

Unfortunately, there is currently no firm transmission available to bring power from Montana to the Puget Sound area. The cost of building new transmission facilities by generation participants to overcome constraints between Montana and PSE has been estimated by PSE to be over $1 billion. PSE anticipates that such facilities would not be available until 2016. Alternatively, there is the possibility of a regional transmission solution with system-wide rates, with availability in 2013 at the earliest. In all cases, the analysis assumes coal-fueled energy is not available until new transmission is constructed.

The low cost of coal makes it an attractive resource. The largest coal plant cost risks are potential carbon and greenhouse gas emissions restrictions and their associated costs, and the availability or construction of transmission. Two of the scenarios, Current Momentum and Green World, apply specific charges to CO_2 output.

Wind

Because PSE is directly involved with two wind projects in Washington state, the generic resource costs reflect recent direct experience. As discussed in the transmission section, PSE estimates that the Company may be able to double its wind generating capacity (from 5 percent to 10 percent of load) without further transmission upgrades. To get to 15 percent of load (under a renewable portfolio standard, for example) would require transmission upgrades with a large fixed cost. Because wind energy output is not dispatchable, day-ahead and hour-ahead integration costs are particularly important to wind power generation. As additional wind energy is added to a system, the integration cost increases. Currently the estimated integration cost is in the $4/MWh range (for more information, refer to Appendix D).

Before new transmission is completed, the fixed operations and maintenance (O&M) charge of $50/KW/yr is based on new developments and includes both fixed O&M as well as fixed transmission costs. When new transmission is considered, the fixed O&M is the sum of the new transmission fixed charge and the fixed O&M from EIA. EIA uses a plant capacity of 50 MW, while PSE uses 150 MW (which is large enough to provide economies of scale). PSE uses a capital cost 14 percent higher than EIA based on knowledge of costs for this region. One of the risks associated with wind plants involves obtaining an accurate estimate of the wind energy production, as there is little historical data. The second risk is that the federal tax credit is currently necessary to make these plants economic. In the model, the tax credit is reduced over the 20-year period to zero.

Biomass

A renewable energy alternative to wind is biomass using either wood waste or agriculture waste. PSE received some biomass energy bids in the all-source RFP, and is currently involved in a small biomass project at a dairy. The energy is created by burning methane gas in any of a number of turbine configurations. Collecting and producing methane gas from biomass is currently very expensive and an important area for improvement. For modeling, PSE includes biomass as an alternative because of the transmission limitations of wind projects. Although the capital cost is higher for biomass than for wind, it is offset by a much higher capacity factor (85 percent for biomass with a flat shape vs. 35 percent for wind with a highly variable shape). The risks involved in a biomass plant include the cost and continued availability of fuel.

Power Bridging Agreements

PSE is using the term “power bridging agreements” (PBAs) to designate power purchase agreements that bridge the period until long-lead resources or transmission can be developed. The load-resource balance shows that there is an immediate need for resources that continues to grow over time. The resources PSE models may not be immediately available or may require new transmission before becoming viable. The PBAs allow PSE to bridge the need before the resource is online. The PBAs also allow PSE to directly test delaying a resource. PBAs in the model are priced at a 5 percent premium for credit and liquidity costs over the market price forecast and include an appropriate transmission charge.

Winter Call Options

For modeling purposes, PSE has moved away from filling excess capacity need with simple-cycle peaker units, as this does not accurately reflect PSE operations. In planning for winter peak needs, PSE adopts a balanced approach that includes the use of existing simple-cycle gas peaking resources; contracts for seasonal firm power; call options that cover the months of November, December, January and February; and short-term market transactions. For modeling, PSE uses call options as a reasonable proxy for peak planning. The cost of the call option is a function of the spread between peak and off-peak prices using the AURORA Business as Usual (BAU) price forecast. In the model, the call premium is $14.60 per KW-season and escalates at 2.5 percent per year. The capacity option can be called when the market heat rate is greater than 12 MMBtu/MWh. The market heat rate and call premium were developed based on actual PSE purchases in previous peaking seasons.

Resource Options Not Modeled

For the purposes of testing generic portfolios in the Portfolio Screening Model, PSE only considered proven technologies with more certain costs and operational characteristics. PSE considered but did not analyze emerging technologies for which the costs are less certain because it would not provide an accurate cost tradeoff analysis.

PSE currently supports renewable energy including solar technology, wave technology and geothermal power with direct financial contributions or advice and regional participation. As of this time, all three of these technologies cannot cost-effectively be considered for utility-scale planning. PSE currently has contracts for energy generated from landfill gas and waste incineration. These resources have limited availability and site-specific costs making them less useful for generic modeling needs. Although nuclear energy is being considered for some new developments in other parts of the country, PSE has not considered it for the portfolio analysis this year. Some other gas-fueled technologies such as cogeneration plants and combined heat and power (CHP) were not judged as “generic” resources. These technologies capture waste heat and improve overall efficiency; however, the economics are very project specific because they require a steam host and negotiated terms.

PSE considered modeling in its portfolio analysis with two other generic coal technologies: integrated gasification combined cycle (IGCC) and IGCC with carbon sequestration. Currently, the IGCC technology owners can't provide generic cost estimates to PSE because the capital costs are specific to each fuel source, and development of a specific proposal requires significant preliminary engineering. As the industry gains more commercial experience with these plants, generic estimates will be more accurate. Until that time, model inputs and results would have an extreme range of uncertainty and would have only speculative value in choosing future resource portfolios. Similarly, carbon sequestration technology and costs have not been developed and tested on a commercially ready basis. PSE will continue to monitor and seek opportunities for these and other new supply resources as they become mature and cost-effective.

The following table lists the costs and operating characteristics of the generic resources used in the model.

Exhibit X-2
Summary of Generic Resources for PSM

$2006	Gas Turbine Periods 1 & 2	Scrubbed Coal Period 2 Only	Wind Period 1	Wind Period 2	Biomass
Capacity	400 MW	600 MW	150 MW	150 MW	80 MW
Capital Cost	$790/kW in WA	$1,672/kW	$1,438/kW	$1,438/kW	$1911/kW
Heat Rate	6,711 Btu/kWh	9,274 Btu/kWh			n/a
Fuel	CERA RVM	MT/WY $0.91/mmBtu	None	None	$10/MWh for fuel (waste) transportation
FOR	5%	10%	68%	68%	15%
Fixed Gas Transmission	$25/kW-yr				
Fixed O&M	$11.40/kW-yr	$27/kW-yr	$50.00/kW-yr includes transmission	$29.15/kW-yr	$51.30/kW-yr
Fixed Electric Transmission	$21.03 /kW-yr		$0.00 / kW-yr Included in FOM	$0.00 / kW-yr Included in FOM	$15.00 / kW-yr
Transmission Build [FOM]	None	$99.60 / KW-yr[1] (2006 + 2.5% esc.) $31.81/KW-yr[2] (Regional)	None	$58.02 / kW-yr[1.] (2006 + 2.5% esc.) $31.81/kW-yr[2.] (Regional)	None
Variable O&M	$2.39/MWh	$3.42/MWh	$4.00/MWh Update for 400-450 total MW	$4.30/MWh Update for more than 450 total MW	$3.30
Fuel Basis Differential	$0.359/mmBtu = $2.41/MWh				$10/MWh for fuel transportation
Emissions	CO_2: 411 Tons/GWh	CO_2: 953Tons/GWh	None	None	None

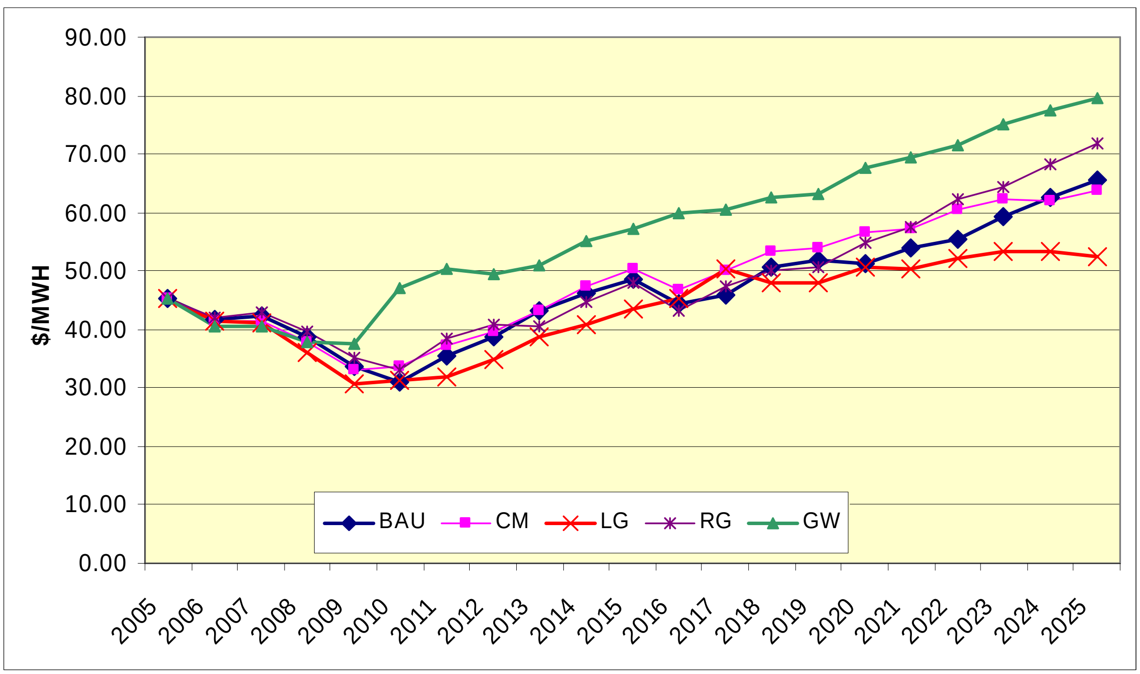
[1] Participant-funded transmission for BAU, CM, GW, LG and RG scenarios.
[2] System-wide rates for Transmission Solution scenario.

C. Energy Price Forecasts

Electricity

Five power price forecasts were created using the AURORA model. One forecast was created for each of the scenarios except the Transmission Solution scenario, which uses the Business as Usual power price forecast. Each scenario is based on a set of assumptions that describe a possible future world (see the following section for more details about the scenarios). The prices represent the cost of dispatching the marginal resource in a Northwest market like the Mid-Columbia. Exhibit X-3 shows a comparison of the five AURORA price forecasts. Appendix C provides tables of monthly prices for all of the forecasts.

Exhibit X-3
Electricity Price Forecasts by Scenario



Demand for power in the Northwest and throughout the western United States is taken into account in the electricity price forecast. The database includes annual average growth rates for each area, which were compared to those used by the Northwest Power and Conservation Council and EIA. All growth rates are linear with no intertemporal changes (i.e. a growth rate could be 1.8 percent per year for 2005-2025 rather than reflecting a long-term pattern of slowing or increasing growth). For the Robust Growth and Low Growth scenarios, base growth rates were adjusted proportionately following PSE's high and low growth rate forecasts.

Demand for power is met with existing resources, planned new resources that are in the database with specific online dates, and future plants selected by the AURORA model using its optimizing algorithm. The AURORA database includes more than 3,000 existing plants in the WECC. Plants that are under construction and scheduled to be online in 2005 for gas plants, and in 2006 for coal and wind plants, are also included in the database.

Over time, energy demand grows beyond the capacity of PSE's existing plants, and the model brings new plants online using its optimizing process (further discussion of the optimizing process can be found in Appendix C). Also driving the development of new plants are renewable portfolio standards (RPS), which are mandated in many western states (Exhibit X-4). In total, these mandates require that thousands of megawatts of renewable energy capacity be added over the study period.

Exhibit X-4
Renewable Portfolio Standards in WECC

State	RPS Standard
California	20% by 2017
Nevada	15% by 2013
Colorado	10% by 2015
New Mexico	10% by 2011
Arizona	1.1% by 2007

An important input to an electric price forecast is a gas price forecast. As discussed in the gas price forecast (Chapter V), PSE relied on three CERA price forecasts created under different scenario assumptions. The CERA Rearview Mirror forecast is based on a scenario in which the future is much like the past. Rearview Mirror, therefore, was the basis for PSE's Business as Usual, Current Momentum and Transmission Solution scenarios. PSE's High Growth scenario also used CERA's Rearview Mirror forecast, while PSE's Low Growth scenario is based on CERA's low growth World in Turmoil forecast. Finally, PSE's Green World scenario used the Shades of Green forecast from CERA. Note that the forecasts are extrapolated beyond 2020.

Transmission between areas is another important factor in determining power prices. Transmission tends to equilibrate prices between areas as power moves from less expensive to more expensive areas. For example, the Northwest is a winter-peaking area. Yet prices are higher in the summer as more expensive resources are brought online to send power south to meet the greater demand in summer-peaking California. While the AURORA model will "build" new power plants to meet increasing demand, it does not have an algorithm for increasing transmission over time. The model includes "physical" transmission between areas, which is often greater than the "available" transmission on a contract basis. AURORA is not a transmission model and does not reflect contractual constraints. Hence, the Transmission scenario uses the Business as Usual AURORA price forecast and transmission builds are considered in the portfolio analysis.

AURORA hourly prices are capped at the $250/MWh level based on the FERC-mandated level from 2001. Since prices fall below $250/MWh for most hours, price caps don't have much impact on average prices. Nevertheless, PSE uses an hourly dispatch model where a few hours of very high prices can make some resource decisions appear overly beneficial. Most of the highest priced hours occur in September, when hydro availability is low and summer demand is still high. Note that the $250 price cap is also used by the Northwest Power and Conservation Council.

D. Uncertainty Analysis

Electric Planning Scenarios

One of the most important improvements for the quantitative analysis, compared to the previous Least Cost Plan, is the inclusion of scenarios. The shift to scenarios reflects current uncertainty about energy policy, environmental issues and the macro economy. In the 2003 Least Cost Plan, PSE analyzed uncertainty using Monte Carlo analyses that covered a range of possible prices, shaped around a mean or expected level. Monte Carlo uncertainty is based on quantifiable variability found in historical statistics for which a distribution can be derived. The 2005 Least Cost Plan continues the Monte Carlo analysis and adds an additional level of analysis with scenarios.

Benefits of scenarios are seen when changing events can drive costs and, therefore, the decision process and when probability distributions cannot be statistically defined and defended. Scenarios represent a fundamental change between the important issues that are observed today. For example, scenario analysis is appropriate for considering a renewable portfolio standard, where the passage of such legislation is possible but uncertain. On the other hand, Monte Carlo is appropriate for power prices where there is an expected level and a historical distribution.

One important aspect to scenario analysis is that it takes a holistic approach to the important variables. For example, rather than looking only at the impact of an exogenous CO_2 charge on portfolio resource selection, the process includes a long-term analysis for power prices based on optimal regional new resource construction which takes the charge into account. An important starting place for the scenarios is the three CERA gas price forecasts.

Exhibit X-5 at the end of this section provides a summary of the six scenarios PSE included in the analysis.

Business as Usual

The Business as Usual (BAU) scenario best represents current reality for gas and power prices, and for policy direction. This scenario is considered the least speculative about the future. It relies on the CERA Rearview Mirror gas price forecast as its foundation. The growth in demand for PSE and the western United States is "normal." The scenario considers only proven technologies for generation.

For renewables, it takes into account various renewable portfolio standards (RPS) that have been implemented in some western states by adding new renewable resources to the database over time. However, it follows the CERA assumption that some of these laws may be too ambitious in the long run, thus they are relaxed after 2011. Nevertheless, the RPS resources total 8,677 megawatts of renewable energy in the WECC. The PSE portfolio sets renewable capacity targets at 10 percent of load by 2013.

There is currently no carbon tax at the federal level to include in this scenario. It does take into account the Washington state carbon charge (P.L. 3141) and assumes this same level for Oregon's public service charge.

Transmission in the region is currently constrained in many places, making increased development of resources far from the load implausible. Hence, if more coal is to be included in the portfolio, this scenario adds the cost for new transmission facilities to the cost of the resource without regard to any benefits to the regional transmission system. The transmission constraint keeps coal out of the portfolio until 2015, at which point new coal is introduced with a transmission cost of over $99/kW/yr. Wind also requires more transmission if the portfolio is to go above the 10 percent renewable target.

Current Momentum

The Current Momentum (CM) scenario takes into account some of the possible or likely changes in policy toward renewable resources and carbon charges. In recent years there has been increased interest and support for a renewable portfolio standard for Washington state and Oregon, although opposition remains. This scenario includes a Washington state renewable portfolio standard of 10 percent of load by 2013. For federal carbon policy, PSE adopted the recommendation from the National Commission on Energy Policy of $5/ton of CO_2 starting in 2010 and increasing by 5 percent per year.[1] The CM scenario keeps the current fuel price forecasts and the current demand forecast unchanged from the BAU scenario. Transmission is funded by participants only, unchanged from the BAU scenario above.

Green World

The Green World (GW) scenario is significantly different from the BAU and CM scenarios. First, it starts with the CERA Green World natural gas price forecast, which assumes that pipelines from Alaska are not built, resulting in a much higher gas price. In this scenario, all WECC states meet their renewable portfolio standards. Washington and Oregon have an RPS of 10 percent by 2013, rising to 15 percent by 2020, for a total of 22,790 MW of renewable energy. Those renewable resource levels are also implemented by PSE.

At the federal level, the CO_2 charge is based on the Pew Center for Climate Change's summary of the MIT analysis of the McCain-Lieberman cap-and-trade bill. The Pew Center focuses on the MIT scenario which allows for the most market-oriented flexibility. This scenario assumes a CO_2 cost of $11/ton starting in 2010 and stepping up to $16/ton in 2015 and to $23/ton in 2020.

Note that the mandated RPS (in all areas) would have a cost that would be passed through to either taxpayers or ratepayers depending on the state's policy. Those costs, however, are not included in the market price, which is based on the marginal cost of the last resource. The RPS costs, along with all other new resource costs, are included in the PSE portfolio.

[1] Table 2-1, page 26, "Ending the Energy Stalemate," NCEP, December 2004

Exhibit X-3, “Electricity Price Forecasts by Scenario,” shows the GW scenario to have much higher energy prices than the other scenarios. This is a function of the higher gas prices and the carbon charge. Like the BAU scenario, transmission costs are participant-funded.

Low Growth

The Low Growth (LG) scenario, as the name implies, takes a less bullish view of electricity demand growth for PSE and the WECC. The electric demand growth rate for PSE is the Company’s forecasted low growth rate, which has an annual average growth rate of 1.2 percent compared to the base growth rate of 1.8 percent. In the AURORA model, each area has its own growth rates, which were reduced proportionately with the growth rates of PSE (e.g. a region with 1.5 percent growth rate was reduced to 1 percent.). The CERA forecast used in this scenario was The World in Turmoil. This forecast involves an economy in recession with low demand and therefore low gas prices. As with the BAU scenario, there is no new renewable portfolio standard in the Northwest and only the existing emissions charge is included. The transmission constraint keeps coal out of the portfolio until transmission is completed in 2015, at which point new coal is introduced at a cost of over $99/kW/yr. Exhibit X-3 shows that power prices under this scenario are lowest, reflecting low demand and low gas prices.

Robust Growth

The Robust Growth (RG) scenario was created to provide symmetry with the LG scenario. The annual average growth rate for PSE was increased from 1.8 percent to 2.3 percent and the growth rates for all areas within the WECC were also increased proportionately. As in the BAU and CM scenarios, the gas price forecast used in the RG scenario was the CERA Rearview Mirror. Again, as in the BAU scenario, there is no new renewable portfolio standard in the Northwest and only the existing emissions charge is included. The transmission constraint keeps coal out of the portfolio until transmission is completed in 2015, at which point new coal is introduced at a cost of over $99/kW/yr. Exhibit X-3 shows that the power prices under this scenario are similar to those in BAU and CM for the first 15 years, reflecting the gas price forecast.

Transmission Solution

The Transmission Solution (TS) scenario was created to analyze the limitations placed on development of new resources because of the region’s significant transmission constraints. Given the uncertainty regarding the ultimate form of a regional transmission solution and the cost recovery for transmission investments, PSE created two transmission cost estimates for the analysis. The previous scenarios assume direct participant funding wherein the costs of necessary transmission upgrades are added to the cost of the resource, without regard to the regional benefits to the transmission system. The TS scenario assumes regional pricing where upgrades are recovered through rolled-in-rates charged to all system users in recognition of the regional benefits.

The portfolio results of this scenario can be directly compared to the BAU scenario because the only difference is the cost and availability of transmission and because the TS uses the BAU power price forecast. A regional transmission solution with the cost spread over all electric power entities is much less expensive than the participant (PSE)-funded process in the BAU and CM scenarios. For example, the cost of new transmission facilities to relieve constraints from Montana to Sammamish has been estimated at over $1 billion. If funded by PSE, without credit for any regional transmission benefit, the fixed cost of the transmission would be $99/kW/yr in 2006 dollars. A regional transmission solution where system expansions are funded by system-wide wheeling rates would cost $31.81/kW/yr. In 2006 dollars, transmission for increased wind energy capacity from Columbia County to Sammamish would have fixed costs of $58/kW/yr if participant-funded, whereas a regional transmission solution is assumed to cost $31.81/kW/yr.

Exhibit X-5
PSE 2005 Least Cost Plan
Scenario Input Assumptions

	Business as Usual	Current Momentum	Green World	Transmission Solution[4]	Low Growth	Robust Growth
Scenario Theme: An energy future assuming...	Existing environmental and regulatory environment	Current environmental regulatory and policy momentum is enacted	Strong state and federal policy supporting environmental issues	Regional transmission solution and system-wide rates	Low economic growth	High economic Growth
Electric Demand	Base Region and PSE	Base Region and PSE	Base Region and PSE	Base Region and PSE	Low Growth Region and PSE	High Growth Region and PSE
Gas Prices	CERA Rear view mirror	CERA Rear view mirror	CERA Shades of Green	CERA Rear view mirror	CERA World in Turmoil	CERA Rear view mirror
Coal-Fired Generation	Scrubbed pulverized coal plants available except CA	Scrubbed pulverized coal plants available except CA	Mitigated coal plants become available in 2010.	Scrubbed pulverized coal plants available except CA	Scrubbed pulverized coal plants available except CA	Scrubbed pulverized coal plants available except CA
Renewables[5]	No WA/OR RPS. WECC States meet goal in 2011 then economics decide. PTC decline linearly over planning period.	WA/OR passes RPS at 10% by 2013. WECC States meet goal in 2011 then economics decide. PTC decline linearly over planning period.	WA/OR passes RPS at 10% by 2013 going to 15% by 2020. WECC States meet RPS goals for entire planning horizon. PTC decline linearly over planning period	No WA/OR RPS. WECC States meet goal in 2011 then economics decide. PTC decline linearly over planning period.	No WA/OR RPS. WECC States meet goal in 2011 then economics decide. PTC decline linearly over planning period.	No WA/OR RPS. WECC States meet goal in 2011 then economics decide. PTC decline linearly over planning period.
Environmental / Carbon	$1.60 per ton WA applied to 20% of expected output at 60% cap factor.	National cap and trade system established. Carbon costs start at 5$/ton in 2010 and escalate at 5% thereafter. National Com. on Energy Policy	Carbon costs are 11$/ton in 2010, 16$/ton in 2015, 23$/ton in 2020. Pew Center on Global Climate Change.	$1.60 per ton WA applied to 20% of expected output at 60% cap factor.	$1.60 per ton WA applied to 20% of expected output at 60% cap factor.	$1.60 per ton WA applied to 20% of expected output at 60% cap factor.
Transmission	No regional solutions. Transmission additions are participant funded by 2015	No regional solutions. Transmission additions are participant funded by 2015	No regional solutions. Transmission additions are participant funded by 2015	Regional transmission solution reached to support resource diversity with system-wide rates by 2012	No regional solutions. Transmission additions are participant funded by 2015	No regional solutions. Transmission additions are participant funded by 2015

[4] Analysis done in Portfolio Model only
[5] PSE meets 10 percent renewables target by 2013 in all scenarios

Probabilistic Analysis of Risk Factors

In addition to using scenarios to assess risk, this 2005 Least Cost Plan continues to assess portfolio uncertainty through probabilistic Monte Carlo modeling. As in the 2003 version, the 2005 plan relies on Monte Carlo analysis to consider three uncertainty factors: market prices for natural gas, market prices for power, and hydroelectric generation availability. The annual variability of power and gas prices, as well as the correlation between these variables, was updated. The variability of hydroelectric generation and correlation with power prices was held at the same values used in the 2003 Least Cost Plan. The following table (Exhibit X-6) shows the Monte Carlo input assumptions. Annual variability is calculated as the standard deviation divided by the mean, expressed as percent.

Exhibit X-6
Monte Carlo Input Assumptions

	Variability and Distribution	Correlations		
		Gas Price	Power Price	Hydro
Gas Price	53% Log normal	1.0	.95	
Power Price	36% Log normal	.95	1.0	-.54
Mid-C Hydro	8% Normal		-.54	1.0
West Side Hydro	12% Normal		-.54	1.0

E. Electric Planning Portfolios

The Portfolio Screening Model tests generic resource portfolios against the scenarios described previously in Section D. Modeling generic resource portfolios allows PSE to determine which mix of resources is likely to be competitive for given gas prices, power prices, and other costs. Based upon PSE's recent RFP and acquisition experience, PSE is considering near-term (Period 1) resource mixes and long-term (Period 2) resource mixes. This section describes the portfolio timing considerations, the four portfolios that are tested in this Least Cost Plan, the steps involved in constructing portfolios for the model, and a summary of portfolio and scenario combinations.

Portfolio Time Period Considerations

An important consideration in this Least Cost Plan analysis is the limited resource alternatives available to PSE today because of constraints on the transmission system for firm resources. Until transmission congestion is relieved, energy resource choices may be limited to natural gas plants, power bridging agreements, and biomass and wind plants in western Washington. Increased transmission availability will create opportunities to access other resources, namely, coal and additional wind capacity. To represent the transmission problem in the model, PSE divided the planning horizon into two periods. Period 1 includes the planning years that will occur prior to a transmission solution, while Period 2 includes the planning years that will occur subsequent to a transmission solution.

In the TS scenario, a regional solution is achieved by 2012, and period 2 begins in 2013. In the other scenarios, transmission is delayed and period 2 doesn't become available until 2016.

Exhibit X-7 shows the generic resource considerations for the two time periods. Before transmission solutions (Period 1), the supply-side resource options available to PSE are expected to be gas plants, PBAs, and limited renewables. A transmission solution (Period 2) provides access to additional wind and coal plants in addition to gas plants. In Exhibit X-7, 10 percent renewables refers to meeting 10 percent of PSE's load needs with renewable resources by 2013 and continuing to meet 10 percent of the load with renewables into the future. The 15 percent renewables indicates a requirement to meet load in 2020 with 15 percent renewables and to continue at that level. PSE's two wind plants currently being developed are included as resources to meet these requirements. Exhibit X-8 shows the schedule of renewable generation additions to meet the 10 percent and 15 percent levels under the base electric load forecast.

Exhibit X-7
Future Energy Needs with Two Time Periods

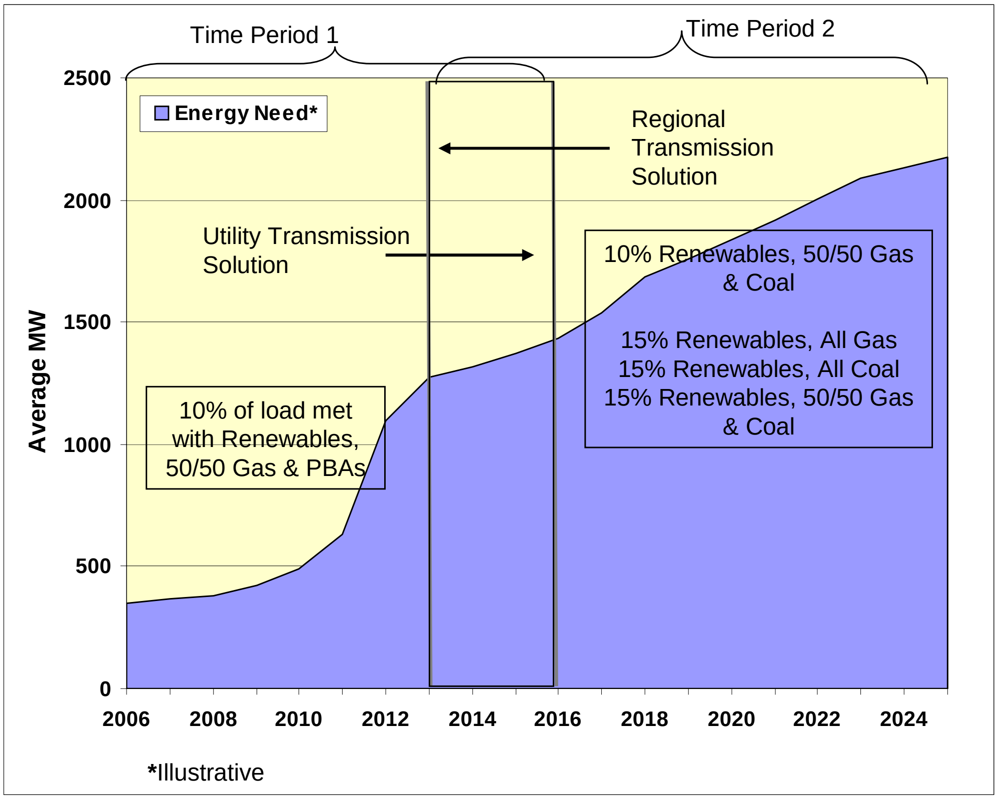


Exhibit X-8
Renewable Generation Necessary to Meet Load Requirements

AMW	2013	2020	2025
10% of Load	279	314	344
15% of Load	279	471	516

Four Supply Portfolios

The four supply portfolios and corresponding descriptors, which are used throughout the document, are summarized in Exhibit X-9. Additionally, when CCCTs are added, additional duct firing capacity is added. Any remaining peak capacity needs are met with winter call options for every portfolio and time period.

Exhibit X-9
Portfolio Descriptions

Portfolio Descriptor	Period 1 Generation Mix	Period 2 Generation Mix
10% Renewable and 50/50 Coal & Gas	10 percent of load is met with renewable generation by 2013 and the balance of the energy need is met with an equal portion of CCCTs and PBAs.	10 percent of load is met with renewable generation and the balance of the energy need is met with an equal portion of scrubbed coal and CCCTs.
15% Renewable and 50/50 Coal & Gas	10 percent of load is met with renewable generation by 2013 and the balance of the energy need is met with an equal portion of CCCTs and PBAs.	By 2020, 15 percent of load is met with renewable generation and the balance of the energy need is met with an equal portion of scrubbed coal and CCCTs.
15% Renewable and Coal	10 percent of load is met with renewable generation by 2013 and the balance of the energy need is met with an equal portion of CCCTs and PBAs.	By 2020, 15 percent of load is met with renewable generation and the balance of the energy need is met scrubbed coal.
15% Renewable and Gas	10 percent of load is met with renewable generation by 2013 and the balance of the energy need is met with an equal portion of CCCTs and PBAs.	By 2020, 15 percent of load is met with renewable generation and the balance of the energy need is met CCCTs.

General Portfolio Construction Rules

PSE employed several “rules” to guide the construction of meaningful theoretical portfolios. The portfolios are generic in nature to provide a guide for the resource selection process. This process entails three primary steps, each with a number of special considerations.

1) *Add renewables*—The portfolio construction process begins by adding renewable resources to meet the requirements of the renewable portfolio standard (10 percent, 15 percent of load) or PSE’s target from the 2003 Least Cost Plan for a given scenario. It is likely that highest capacity factor wind sites will be developed in the near term. Therefore, it is assumed that PSE would add Wind first to secure as many of these desirable sites as possible relatively early. Next, Biomass is added as needed in order to meet renewable targets. If the transmission solution occurs in 2013, 300 aMW of wind and 50 aMW of biomass are added in Period 1. If the transmission solution is 2016, 300 aMW of wind and 75 aMW of biomass are added in Period 1.

2) *Add other resources in 25 MW increments*—In Period 1, new combined cycle gas plants and PBAs are added in equal proportion (subject to the 25 MW increment constraint) to meet the remaining energy need. In Period 2, resources are added to all portfolios discussed above in 25 MW increments, until the minimum monthly aMW deficit is 13 aMW or less in each year. In some portfolio/scenario combinations, small temporary surpluses exist in certain years. This is a mathematical consequence of the 13 aMW or less deficit requirement combined with the 25 MW increment rule. Generally, in the 50/50 Gas & Coal and the 50/50 Gas & PBA portfolios, resources are added in as close to a 50/50 proportion as possible.

3) *Add Capacity to meet peak demand*—Duct firing is always added to CCCTs. Whenever PSE adds a CCCT resource, duct firing is added at a rate of 13.5 percent of the capacity of the CCCT. PSE bases its 13.5 percent assumption on the average of the projects Tenaska reviewed in its study supporting the 2003 Least Cost Plan. Additional peak demand needs are met with winter (November-December) call options. In most years, winter call options are purchased in order to meet monthly on-peak capacity demands so that PSE is never in a capacity deficit situation.

Exhibits X-10.1 through X-10.4 illustrate total incremental energy resource additions by 2025 for the four portfolio alternatives evaluated in the scenarios in which increased transmission capacity is available in 2016 and load growth is normal (BAU, CM, GW). These charts do not include the existing portfolio resources. In Exhibit X-10.1 and X-10.2, the figures do not show an equal portion of gas and coal because of the addition of gas plants in Period 1. Therefore, this portfolio actually has a higher proportion of gas plants since the equal mix only refers to Period 2 additions. In all portfolios, PBAs are replaced in Period 2 with gas and/or coal plants.

Additionally, the new biomass and wind additions shown plus the two wind projects currently being developed equal the renewable requirements by 2025. Please note that the renewable targets established are based upon meeting a percentage of load, and not upon meeting a percent of resource additions.

Exhibit X-10.1

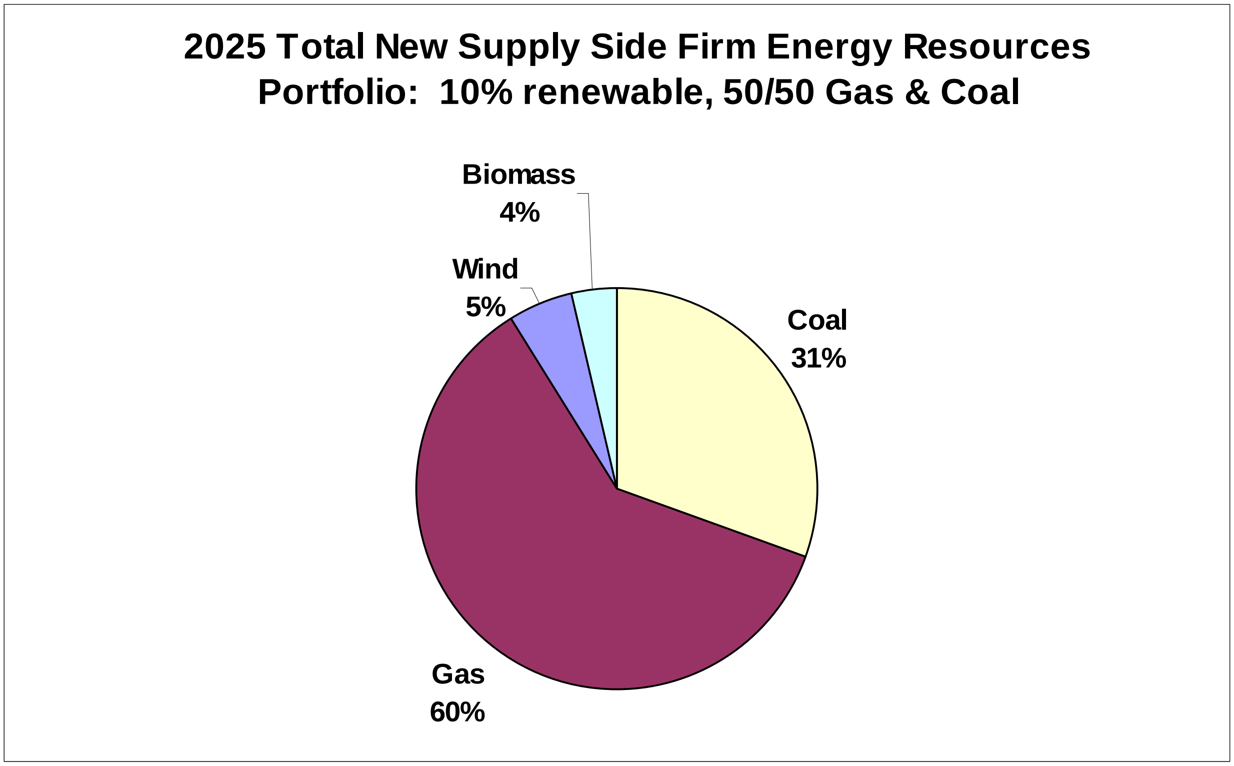


Exhibit X-10.2

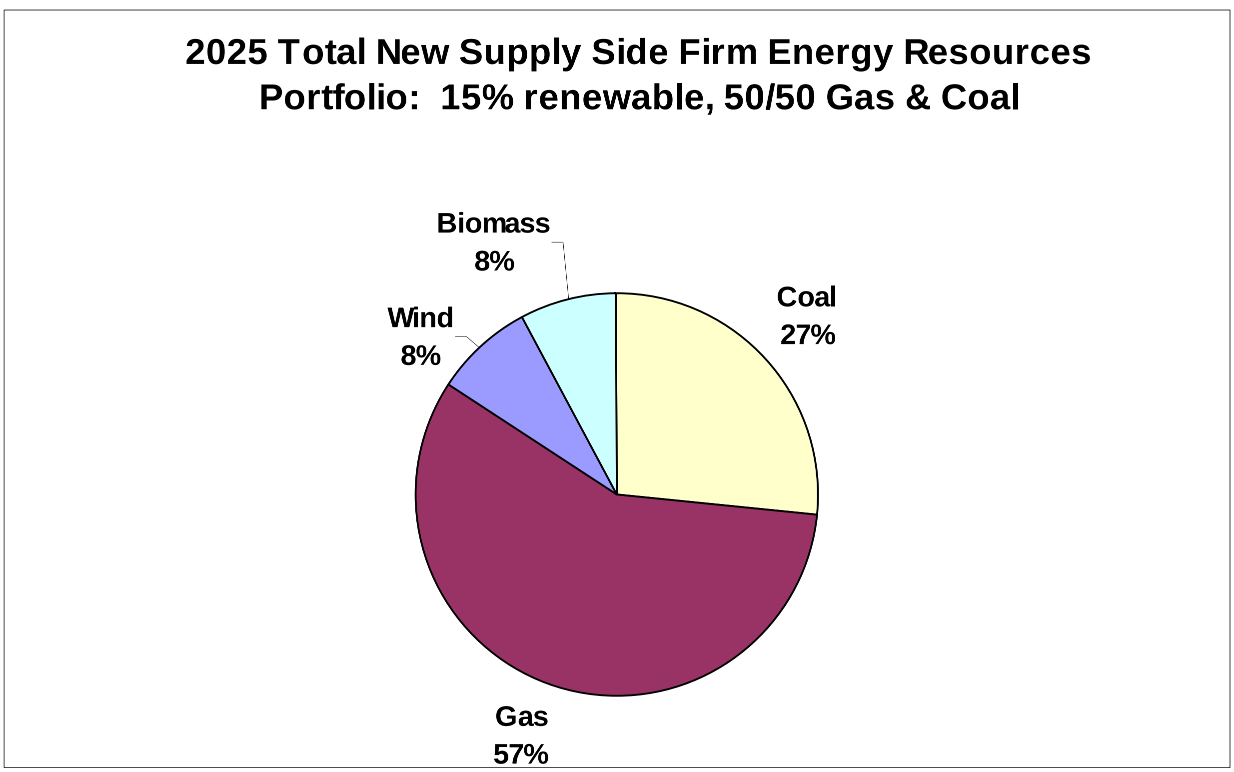


Exhibit X-10.3

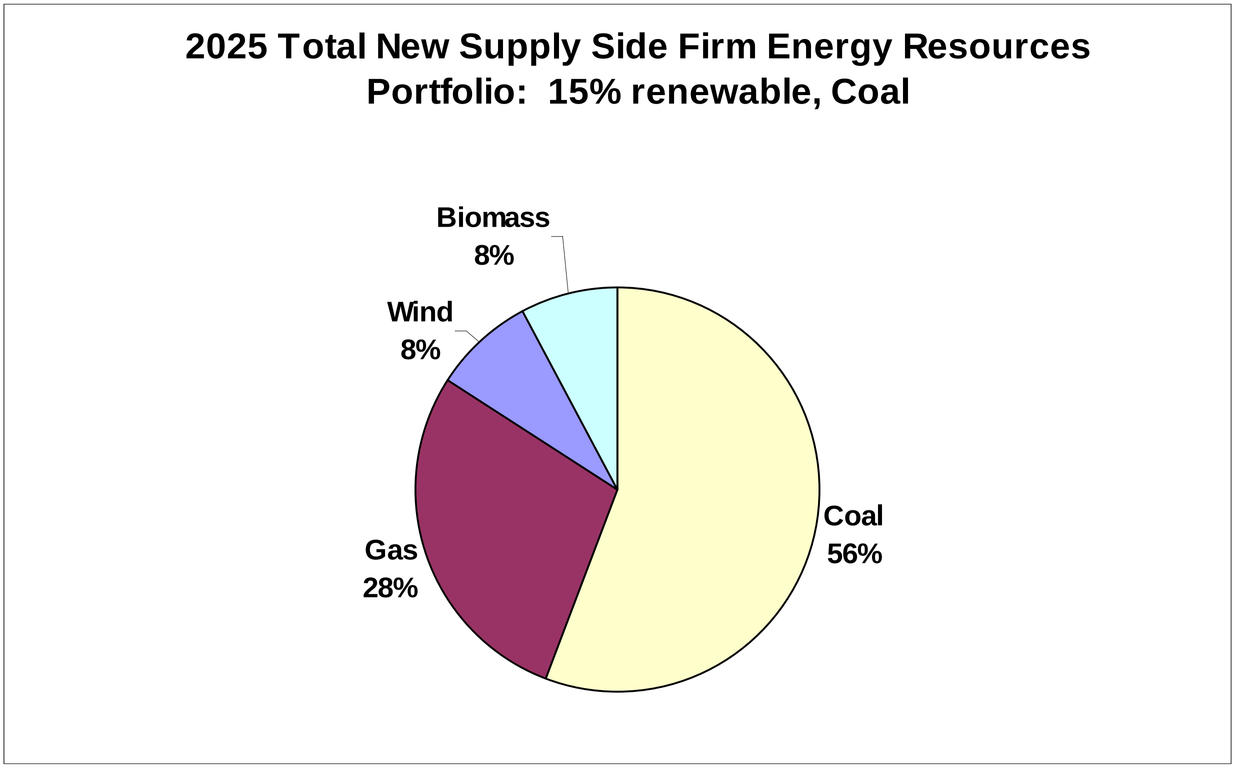
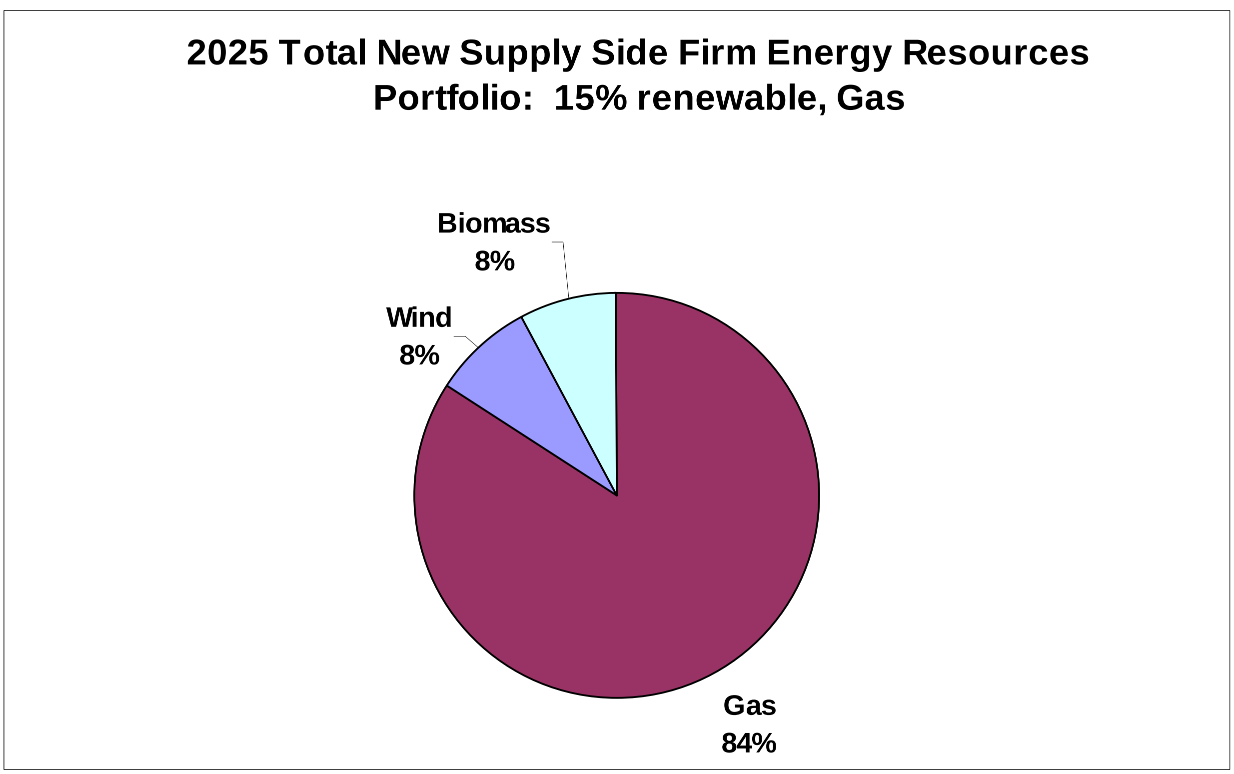


Exhibit X-10.4



Summary of Portfolio and Scenario Combinations

The four portfolios are analyzed across five of the scenarios: BAU, CM, TS, RG, and LG. Two of the portfolios are not applicable for the GW scenario. An inherent assumption in the GW is that significant amounts of renewable generation are built. For that reason, the 10 percent Renewable and 50/50 Coal & Gas portfolio is not applicable. Additionally, the GW scenario assumes less reliance on conventional coal technology. Therefore, the 15 percent Renewable and Coal portfolio was also not analyzed in the GW scenario. Ultimately, the testing of portfolios and scenarios resulted in 22 PSM runs with Monte Carlo analysis.

F. Supply-side Analytical Results and Conclusions

The analysis of the 2003 Least Cost Plan focused on defining a planning standard for determining new supply needs and finding the theoretical best mix of resources to meet the growing need. The 2005 analysis is meant to go a step beyond and identify areas of risk, then recommend actions for acquiring appropriate resources given the key uncertainties.

The main emphasis of this analysis is to explore the key uncertainties described throughout this Least Cost Plan. As an enhancement to the 2003 Least Cost Plan, PSE has incorporated scenarios into this Least Cost Plan analysis. While there is a great deal of uncertainty around future gas prices, power prices, transmission costs, and environmental regulation, the scenarios allow analysis of portfolios under varying assumptions.

Reference Case Findings (Business as Usual Scenario)

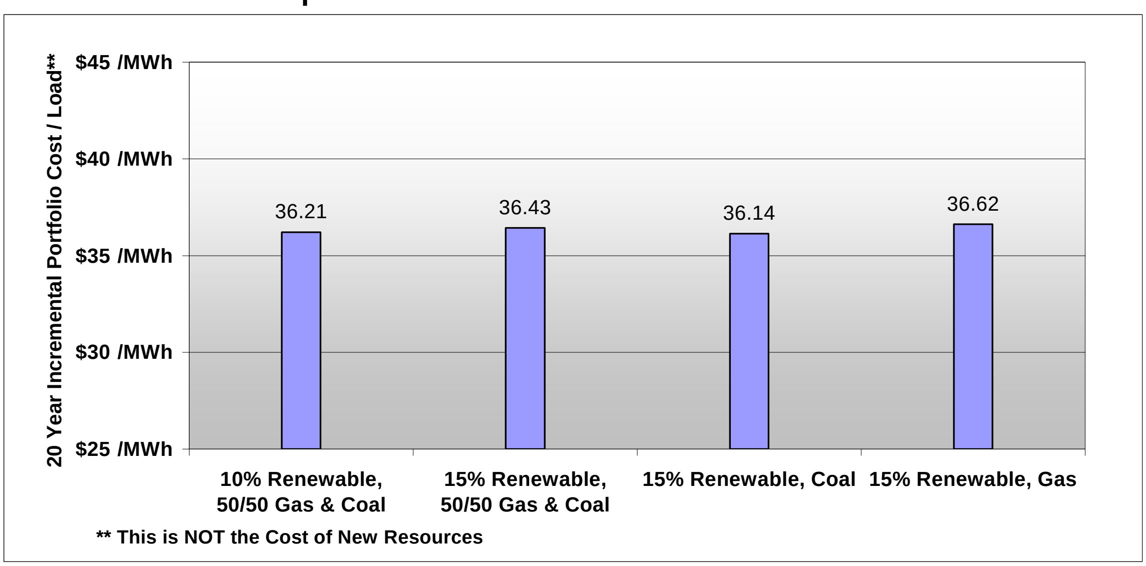
For analytical comparisons, it is useful to establish a reference case. The BAU scenario serves as the reference case. Compared with other scenarios, the BAU scenario makes fewer changes in assumptions from the current regulatory and market environment. Each subsequent scenario starts with the assumptions of the BAU scenario to build potential futures. To better understand the results presented below, the primary scenario differences from BAU are summarized as follows:

- Current Momentum Scenario (CM) includes incremental assumptions about possible or likely changes in policy favoring renewable resources, and implements carbon emission charges.
- Green World Scenario (GW) contains significant assumption changes about higher gas prices, renewable portfolio standards, as well as carbon emission charges.

- Transmission Solution Scenario (TS) includes assumptions about regional transmission improvements completed by the end of 2012 with costs recovered through system rolled-in rates.
- Low Growth Scenario (LG) assumes a smaller rate of load growth as compared with BAU, and LG also assumes lower prices for natural gas.
- Robust Growth Scenario (RG) assumes a rate of load growth higher than BAU.

Exhibit X-11 shows the expected 20-year incremental portfolio cost in dollars per MWh for the BAU scenario. There is little difference in the expected incremental portfolio cost across the four portfolios. The 15 percent Renewable and Coal portfolio is slightly lower cost than the other three portfolios. The range of costs is less than $0.50 per MWh or within 1.5 percent. Appendix G includes the detailed results of the portfolio analysis. Each $1 per MWh is equivalent to about $225 million of present value revenue requirements for all except the LG and RG scenarios. It is important to remember that the portfolio cost does not equal total power costs because it does not include the capital or fixed operating costs for PSE's existing resources.

Exhibit X-11
Expected Cost Result for Business as Usual

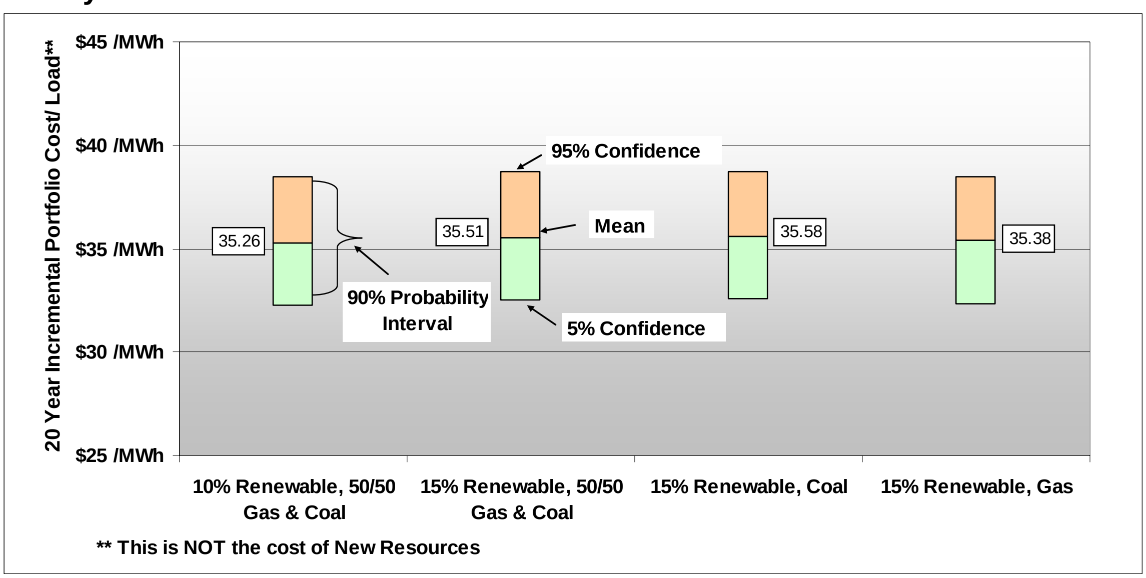


The Portfolio Screening Model (described in Appendix C) uses hourly power prices from AURORA, monthly gas prices from CERA and hourly average hydro generation as forecast by

AURORA. Using these inputs and running the PSM model in static mode produces the results shown in Exhibit X-11.

When PSM runs with Monte Carlo variability, the model produces a range of portfolio costs based upon the historical variability of power prices, gas prices and hydro generation. The stochastic results from this Monte Carlo analysis indicate that the portfolio with 10 percent renewable generation and 50/50 Coal & Gas is the lowest cost portfolio. Once again, the difference between the portfolio mean values is relatively small, less than 1 percent. The stochastic results also show little difference in risk among portfolios. Exhibit X-12 provides the range of results within a 90 percent probability interval as well as the mean of the 100 iterations. In general, when historical volatility of gas prices, power prices, and hydro generation is considered, portfolios become less costly than the static case outcomes. This reduction in portfolio cost is due to the potential option value of both existing and new natural gas generation plants. Option value is created by the flexibility of gas plants to respond to favorable market conditions that occur when the power price is higher than the variable cost of operations including fuel. In the PSM, option value occurs when the Monte Carlo simulated power prices are much higher, in relative terms, than simulated gas prices.

Exhibit X-12
Dynamic 20-Year Incremental Unit Costs for Business as Usual Portfolios



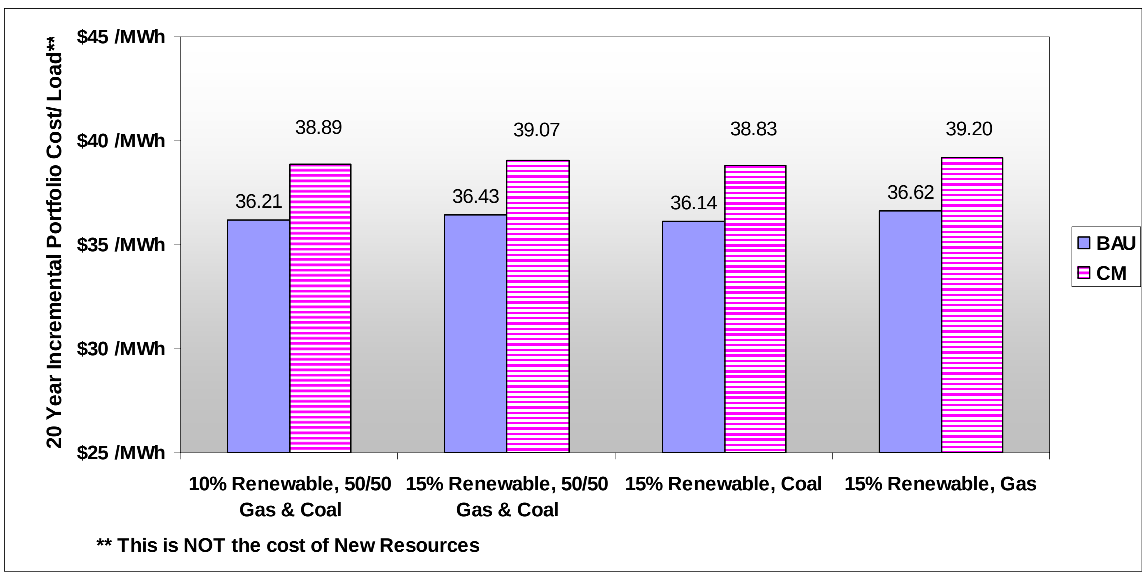
Scenario Approach to Evaluating Risk

As discussed earlier in this chapter, several scenarios were developed to help evaluate the effect of risk on the resource portfolios. The scenarios CM and GW address environmental risk associated with carbon costs and the addition of Renewable Portfolio Standards (RPS) in the WECC. The TS scenario primarily addresses the impact to portfolio costs of a regional transmission solution that shares the cost of transmission expansion through system-wide rates. Scenarios LG and RG show the impact of lower demand and higher demand for electricity. The LG case also incorporates a lower gas price forecast to reflect overall lower demand for natural gas.

Current Momentum

A comparison of the expected incremental portfolio costs for the BAU and CM scenarios is displayed in Exhibit X-13.

Exhibit X-13
Expected Portfolio Costs - Current Momentum vs. Business as Usual

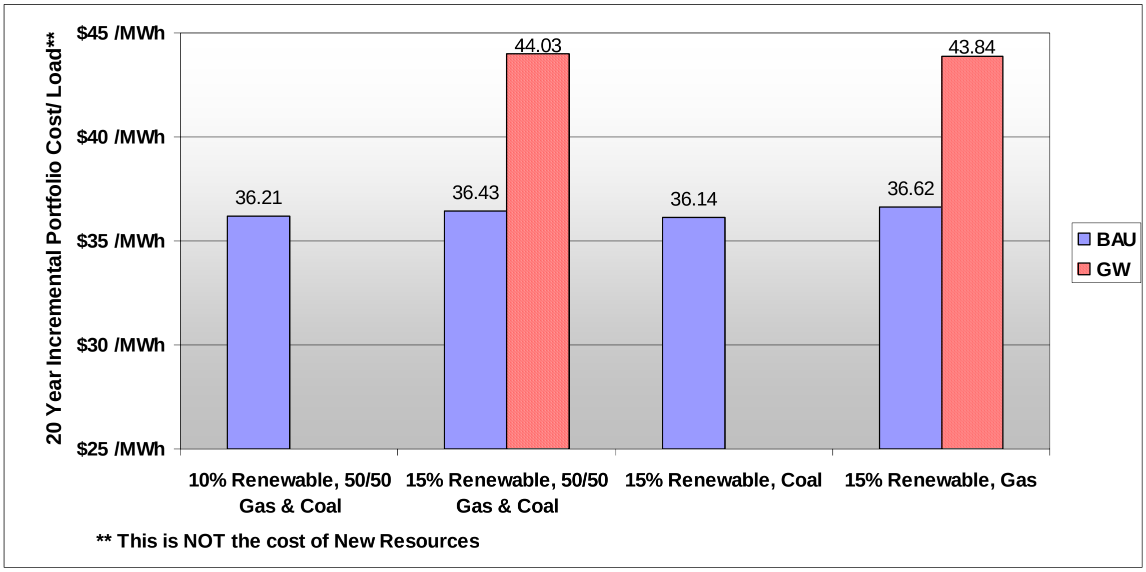


Increases in carbon costs and power prices in the CM scenario indicate an overall increase in portfolio costs from $2.58 to $2.70 per MWh. This equates to a cost increase of approximately $600 million in PV of expected portfolio costs. The lowest cost portfolio is still the 15 percent Renewable and 100 Coal. However, the 10 percent Renewable with 50/50 Coal/Gas portfolio is only $12.5 million more costly over the 20 years.

Green World

A comparison of the expected incremental portfolio costs for BAU and GW scenarios is displayed in Exhibit X-14.

Exhibit X-14
Expected Portfolio Costs – Green World vs. Business as Usual

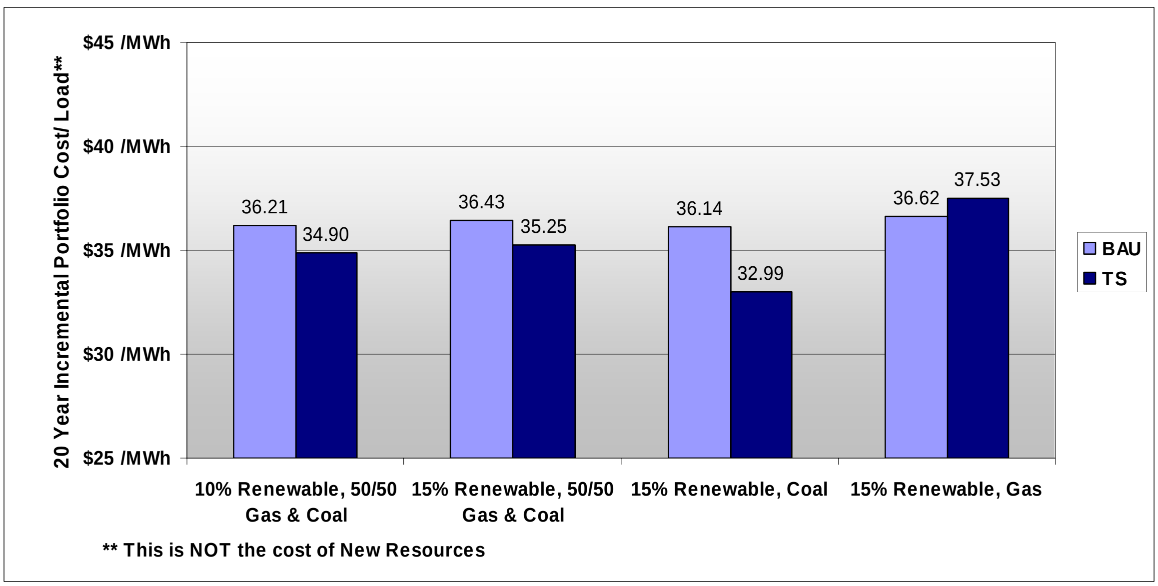


This analysis included only two portfolios in the GW scenario. The portfolio with only 10 percent renewable resources and the portfolio with 100 percent coal were deemed not feasible in a GW. Portfolio costs in the GW increased by a total of $7.23 to $7.60 per MWh compared with BAU. This significant increase in costs results from a combination of higher fuel costs (see Chapter V), higher power prices (see Chapter X, section C), and greater costs associated with CO_2 production. The majority of the cost increase of the GW scenario is due to emissions costs.

Transmission Solution

A comparison of the expected incremental portfolio costs for the BAU and TS scenarios is displayed in Exhibit X-15. In general, a regional transmission solution leads to lower portfolio costs when coal plants are part of the mix. The only portfolio to increase in cost with the transmission solution is the portfolio with 100 percent gas. In the 100 percent gas portfolio, PSE's existing wheeling costs increase with the regional sharing of incremental transmission costs, but the portfolio does not benefit from the lower cost wind or coal that would be made available from the increased transmission to those resources located in eastern Washington, Idaho, or Montana. Conversely, the coal and wind plants located in those areas, which are currently transmission-constrained, see the largest benefit of a regional transmission solution. Transmission availability and cost is a significant driver of PSE's overall portfolio cost.

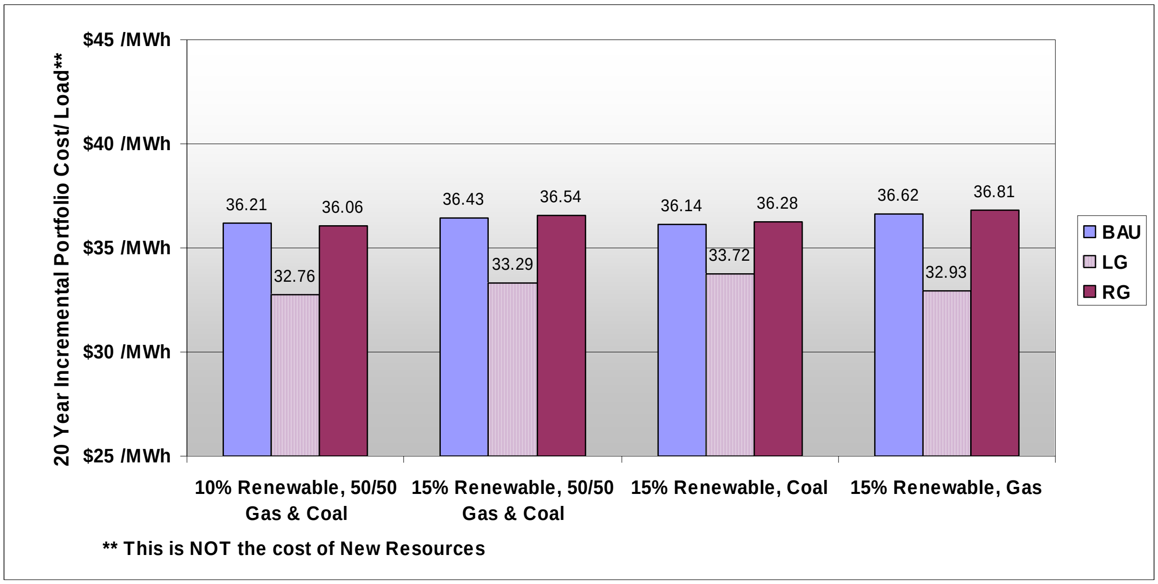
Exhibit X-15
Expected Portfolio Costs – Transmission Solution vs. Business as Usual



Low Growth and Robust Growth

A comparison of the expected incremental portfolio costs for BAU and the LG and RG scenarios is displayed in Exhibit X-16

Exhibit X-16
Expected Portfolio Costs – Growth Scenarios vs. Business as Usual

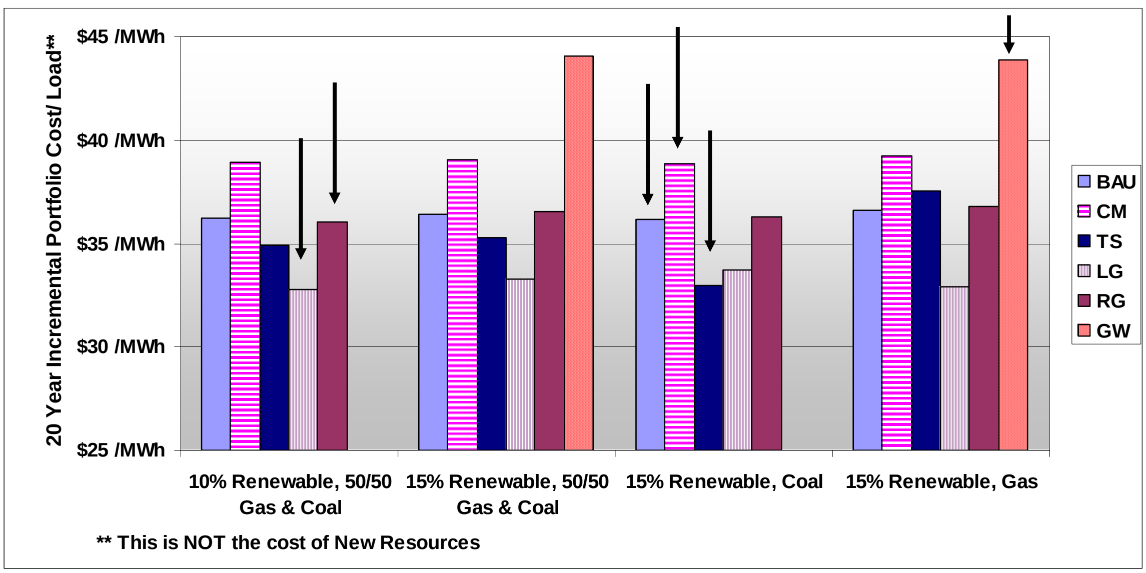


Decreases in regional demand and PSE demand, along with the lower gas prices assumed in the LG scenario, significantly reduce the expected portfolio costs. Some of the decrease, about 1$/MWh, is attributable to lower gas prices. The balance of the decrease, about 2$/MWh, is driven by lower PSE demand. Lower PSE demand reduces the need for new supply by 400 aMW. In the RG scenario, increases in regional and PSE demand cause slight increases in expected portfolio costs because incremental plants cost more than embedded average cost. With a significant proportion of generation expiring in the 2011 time period, any change in demand is directly offset by new resources. The RG scenario requires the addition of another 460 aMW of new supply.

Static Results - All Scenarios

A comparison of the expected incremental portfolio costs for all scenarios and portfolios is displayed in Exhibit X-17. The arrows point to the low cost portfolio for each scenario. Most arrows point to the 15 percent Renewable and Coal portfolio. However, when looking across portfolios for a single scenario, it is observed that the differences between portfolio costs are very slight under most scenarios except the TS scenario. It appears that a transmission solution with system-wide rates would have the biggest impact when choosing between portfolios. Additionally, the LG scenario shows that strategies to reduce electric demand could have a significant impact on portfolio cost. Based upon the static results alone, PSE should work toward finding a transmission solution and continue to pursue a diversified portfolio of natural gas plants, coal plants, and renewable plants. It appears that going to a 15 percent renewable target is slightly more costly, but PSE should continue to evaluate renewable costs on a case-by-case basis. These conclusions do not yet consider risk.

Exhibit X-17
Static Portfolio Costs – All Scenarios



Dynamic Results – All Scenarios

The next figure (Exhibit X-18) superimposes the static results of all scenarios on the BAU dynamic result. The BAU expected cost is greater than the BAU dynamic mean. This is a result of the option value of gas plants. Exhibit X-18 also shows that the dynamic result of the BAU scenario does not bound the outcomes of the scenarios. Looking at the expected results from the dynamic analysis in Exhibit X-19, the 10 percent Renewable and 50/50 Gas and Coal portfolio is lowest cost for most scenarios. Comparing Exhibits 17 and 19, it is apparent that the dynamic results shift the selection of portfolios toward those with a higher proportion of natural gas plants.

Exhibit X-18
Dynamic BAU Result and Static Scenario Results

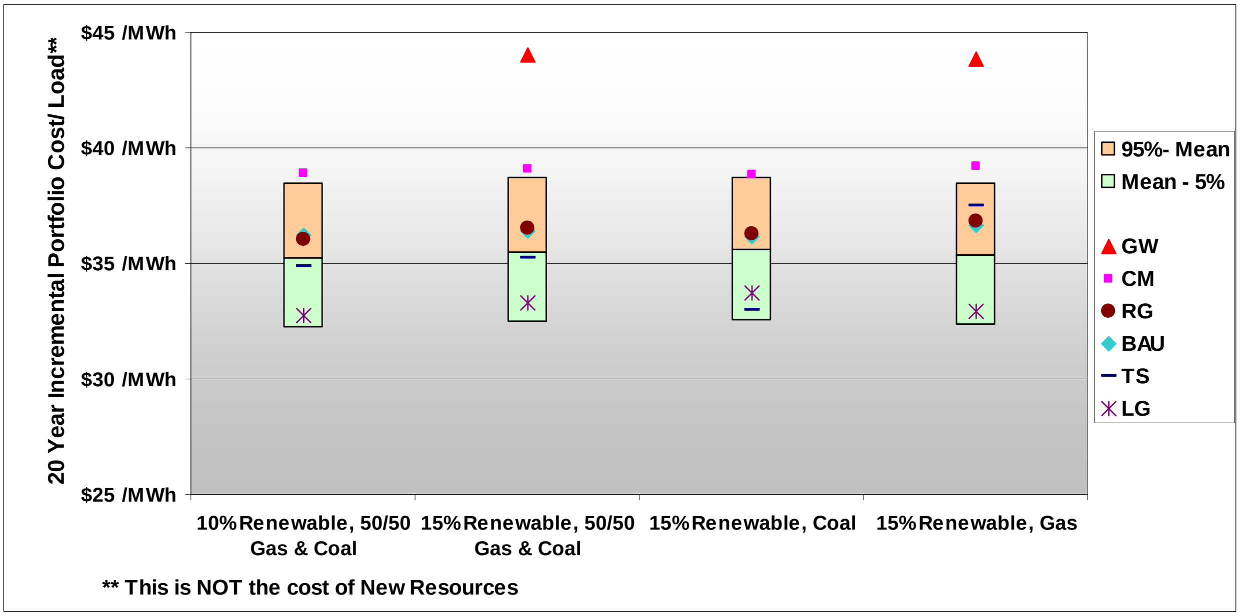
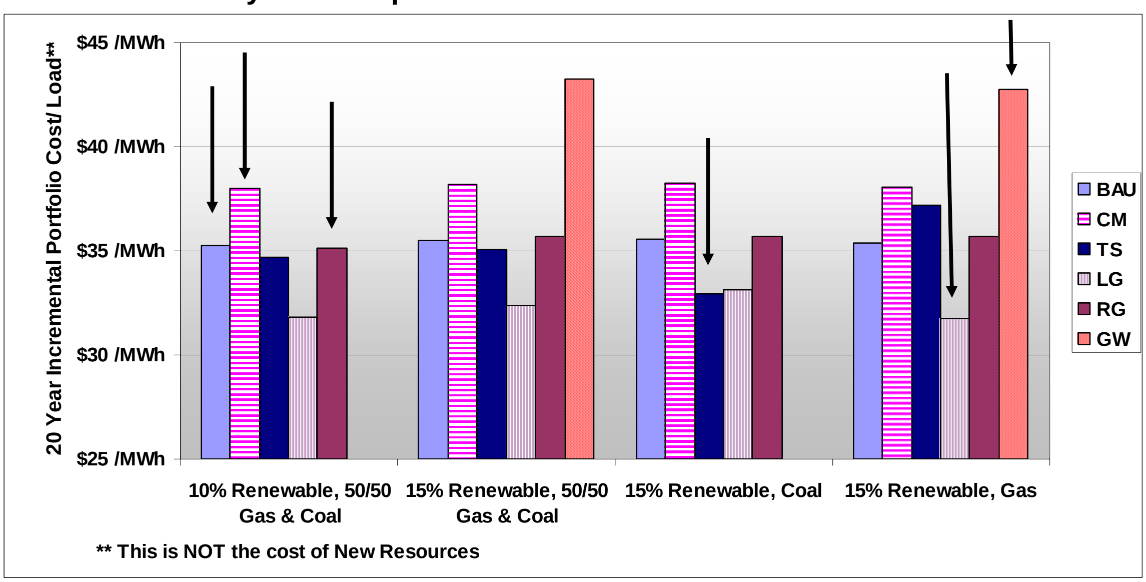


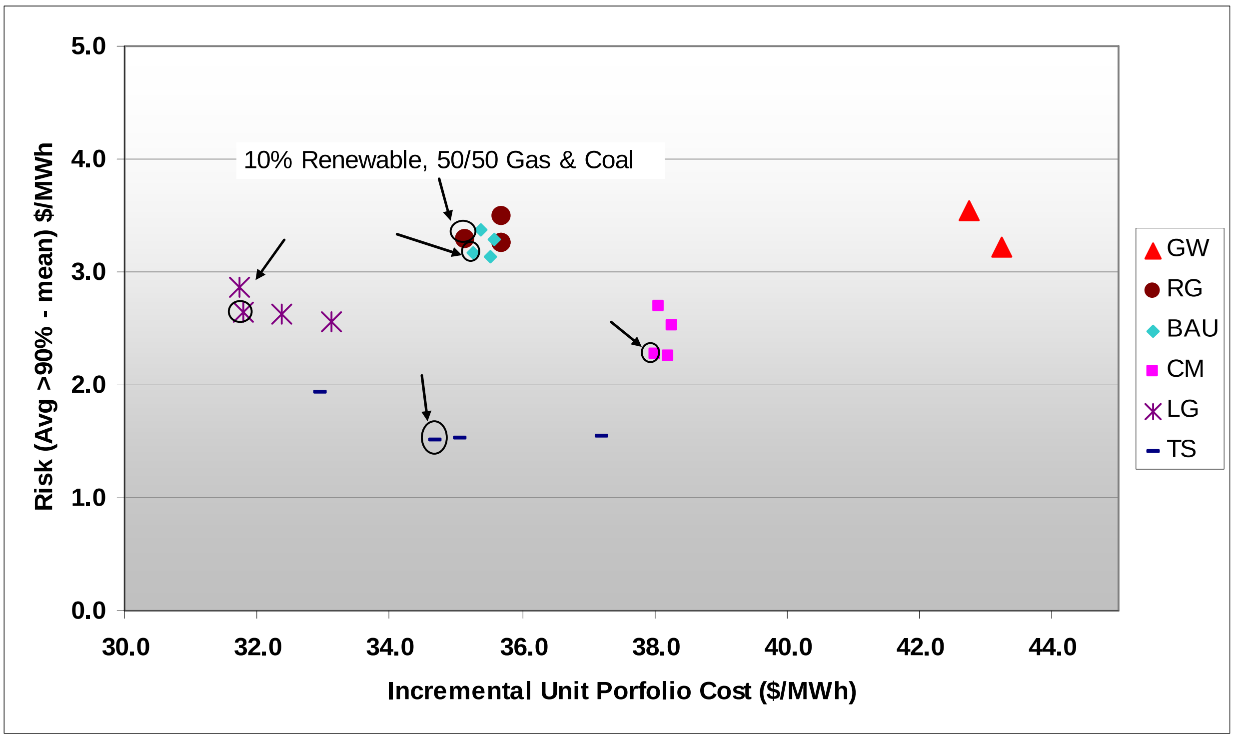
Exhibit X-19
Dynamic Expected Value Results for all Scenarios



Risk for all Scenarios

Similar to the Northwest Power and Conservation Council in their 5th Power Plan, PSE measures risk by examining the bad outcomes, the average value for the 10 percent worst outcomes (Avg > 90 percent). The risk measure used is the difference between the Avg > 90 percent and the mean result. Exhibit X-20 plots this risk vs. incremental unit portfolio cost. The chart shows that the portfolios are clustered together for each scenario. The best portfolio for any scenario cluster is located toward the bottom left corner reflecting lower costs and lower risk.

Exhibit X-20
Dynamic Cost and Risk Tradeoff Results for all Scenarios



As shown, the portfolio with 10 percent renewables and 50/50 gas and coal (circled points in Exhibit X-20) performs best across most scenarios. For three of these scenarios (BAU, CM, and RG), the 10 percent renewables and 50/50 gas and coal portfolio is lowest cost. In the TS case, the 15 percent renewables and all coal portfolio is lower cost but higher risk. Similarly, in the LG case, the 15 percent renewables and all gas portfolio has a slight cost advantage but is higher risk than the 10 percent renewables and 50/50 gas and coal portfolio. For the GW scenario, the 10 percent renewables and 50/50 gas and coal did not meet the scenario parameters and was not modeled. However, of the two portfolios modeled in GW, the diversified portfolio (15 percent Renewable and 50/50 Coal & Gas) was higher cost but lower risk than the all gas portfolio (15 percent Renewable and Gas).

Portfolio Conclusion

Overall, considering both cost and risk together, this analysis supports the selection of the 10 percent Renewables and 50/50 Coal and Gas portfolio since it does well across many different scenarios. (Appendix G shows the detailed results for each symbol in the Exhibit X-20). This analysis also helps determine which uncertainties have the greatest cost impact. It appears that the biggest cost drivers for the PSE portfolio are possible carbon costs based on GW and CM. The LG scenario shows that a reduction in demand can lower costs. Transmission cost and availability is also an important driver of cost and risk. Although the dynamic results show a wide range of cost differences associated with volatility in gas prices, power prices, and hydro generation, the impact across portfolios doesn't favor one portfolio over another.

Summary of Supply-side Key Quantitative Findings

- A regional transmission solution generally reduces portfolio cost when coal resources are in the mix.
- The 15 percent Renewable and Coal portfolio with a transmission solution is the lowest cost portfolio compared to all other portfolios and scenarios with normal growth.
- For many scenarios, portfolios with coal resources lower portfolio costs; however, there is uncertainty regarding environmental costs.
- Scenarios with increasing environmental constraints, that are quantified in the scenario, have 20-year portfolio costs that are about 8 percent higher (CM) and 20 percent higher (GW) than the BAU scenario.
- Volatility in hydro generation, gas prices and power prices generate a 20-year downside risk in portfolio cost that is about 5 percent of the mean in the TS scenario and about 9 percent of the mean in the BAU scenario.
- Over all scenarios, the lowest risk portfolio is the 15 percent Renewable and 50/50 Coal & Gas.
- Slower growth in demand reduces 20-year portfolio cost by reducing additions of newer, incrementally more expensive resources.
- The theoretical least cost portfolio across all scenarios evaluated is diversified with coal, gas, and renewable resources.

Additional Analysis and Conclusions

Aside from the main analysis, a few additional model sensitivity analyses were performed. These analyses were conducted to examine the value of summer sales revenue, the imputed debt costs of PBAs and the benefits of PBAs as a deferral mechanism, and the impact of potential emissions costs on resource selection.

Summer Sales Revenue – PSE is a winter peaking utility and average load is greater in the winter than in the summer. The 2003 Least Cost Plan demonstrated that, to the extent possible, PSE should seek shaped resources to meet its growing winter need. PSE will continue to seek resources shaped to the seasonal load profile. However, because shaped resources are specific proposals, they were not tested in the generic portfolios. Since the coal and gas resources examined in the portfolio analysis are available year round and may increase with summer energy surpluses, PSE decided to analyze the impact of summer sales revenues on the portfolio.

To evaluate whether high-priced summer surplus sales were a significant driver of outcomes from portfolio analysis, PSE developed an alternate BAU scenario, “BAU $125”. In BAU $125, power prices were capped at $125/MWh from April through October and had no cap in the winter months. The original BAU scenario assumes that $250 price caps apply all year. The following table (Exhibit X-21) compares the results of the portfolios in the BAU scenario with the same portfolios in the BAU $125 scenario.

Exhibit X-21
Impact of Seasonal Price Cap on BAU Scenario

	10% Renewable, 50/50 Gas & Coal	15% Renewable, 50/50 Gas & Coal	15% Renewable, Coal	15% Renewable, Gas
Expected (Static) Results				
BAU (assumes $250 cap)	$36.21	$36.43	$36.14	$36.62
BAU w/ $125/MWh Price Cap	$36.63	$36.84	$36.53	$37.05
April-October; No Winter Cap				
Impact of Seasonal Price Cap	$0.42	$0.41	$0.39	$0.43
Dynamic Results				
BAU (assumes $250 cap)	$35.26	$35.51	$35.58	$35.38
BAU w/ $125/MWh Price Cap	$35.70	$35.94	$35.95	$35.86
April-October; No Winter Cap				
Impact of Seasonal Price Cap	$0.44	$0.43	$0.37	$0.49

Several conclusions can be drawn. First, lowering the price cap to $125/MWh and applying the cap only in April through October increases portfolio costs in all scenarios by $0.37 to $0.49/MWh that is equivalent to a PV cost increase of $83 to $109 million over 20 years. Second, there is no change in portfolio ranking. The portfolio with 15 percent renewable with the balance of coal is the least cost portfolio regardless of whether the price cap is $250 for all months or $125 for April through October. And third, as expected, the 15 percent renewable with balance of gas portfolio shows more impact than the other portfolios. In general, the impact of summer surplus sales is not significantly influencing the portfolio outcomes.

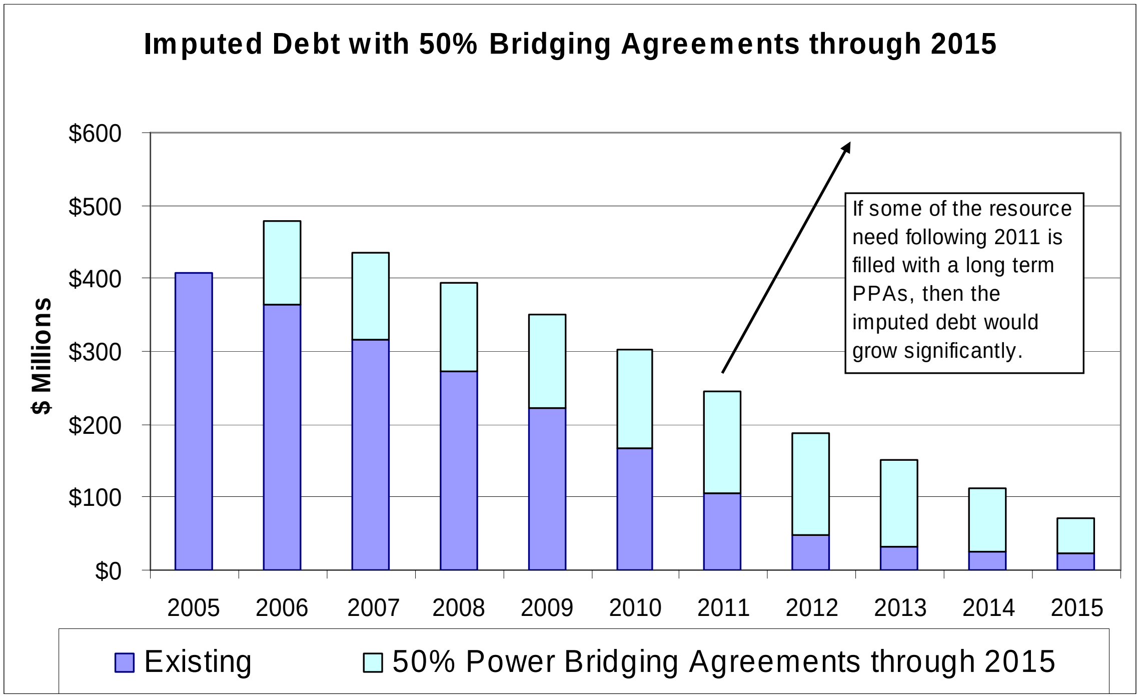
Power Bridging Agreements (PBAs) and Imputed Debt – All portfolios, except TS, in the near term through 2015 contain an equal mix of PBAs and gas generation to meet the resource need that remains after 10 percent renewable supply. Without some mechanism to offset imputed debt costs, the modeled PBAs would increase the imputed debt for PSE and thus put downward pressure on its credit rating (see Chapter IV for a more complete discussion of imputed debt). Using the BAU scenario for illustrative purposes, Exhibit X-22 shows that the accumulated volume of PBA purchases is 750 MW by 2015. Exhibit X-23 shows an annual forecast of imputed debt for the 750 MW of PBAs.

Exhibit X-22
Volume of PBA Purchases

	PBA MW	Accumulated PBA MW
2006	125	125
2007		125
2008		125
2009		125
2010	25	150
2011	175	325
2012	275	600
2013	100	700
2014	25	725
2015	25	750

As described in Chapter X, Section B, "New Generation Alternatives," the PBA is priced using the average of the AURORA market forecast plus a 5 percent premium used to estimate a combination of credit and liquidity risk. The fixed price of the PBA helps to reduce the variability of portfolio costs, but also increases the imputed debt. The imputed debt shown in Exhibit X-23 is based upon the Standard & Poor's calculation, assuming that PSE makes the commitment in 2006 for all of the purchases through 2015. In the actual acquisition process, PSE would weigh the pros and cons of shorter-term vs. longer-term PBAs, and may elect not to enter into a contract years before necessary.

Exhibit X-23



<u>Cost Impacts of No PBAs</u> – A sensitivity study was run to evaluate the portfolio cost impact of PBAs. For this analysis, PBAs were replaced with an equal volume of new gas generation plants in the near term through 2015. The study results can be used to quantify the cost reduction and variability benefits provided by the PBAs priced at AURORA forecast plus 5 percent. The impact of the additional gas generation supply to replace PBAs could have the result of increasing costs by $1.70/MWh, which is equivalent to a present value of $380 million in additional portfolio costs over 20 years.

If PBAs are not available from system purchases at market prices, then the likely source for PBAs will be from tolling arrangements with gas plants. A tolling agreement commits PSE to pay a fixed monthly amount to purchase power from a specific power plant. Typically, under such an agreement, PSE would also be responsible to supply the gas to the plant. Under tolling agreements, the PBA pricing would be more similar to gas plant pricing than to system purchases at market prices. In this case, replacing market priced PBAs with tolling PBAs could be expected to have the same cost impact, $1.70/MWh, as replacing the market priced PBAs with new gas generation. Additionally, tolling PBAs would create imputed debt impacts. Exhibit X-24 compares the No PBA portfolio with the Generic Portfolio. Removing PBAs would increase cost and portfolio variability (Exhibit X-25). While these results indicate PBAs provide value, the terms studied are not standard products and their price and availability will need to be confirmed in the market.

Exhibit X-24

	2006 – 2015	**2016 - 2025**
Generic Portfolio	10% Renewables, 50/50 PBA & Gas	10% Renewables, 50/50 Gas & Coal
No PBA Portfolio	10% Renewables, Balance Gas	10% Renewables, 50/50 Gas & Coal

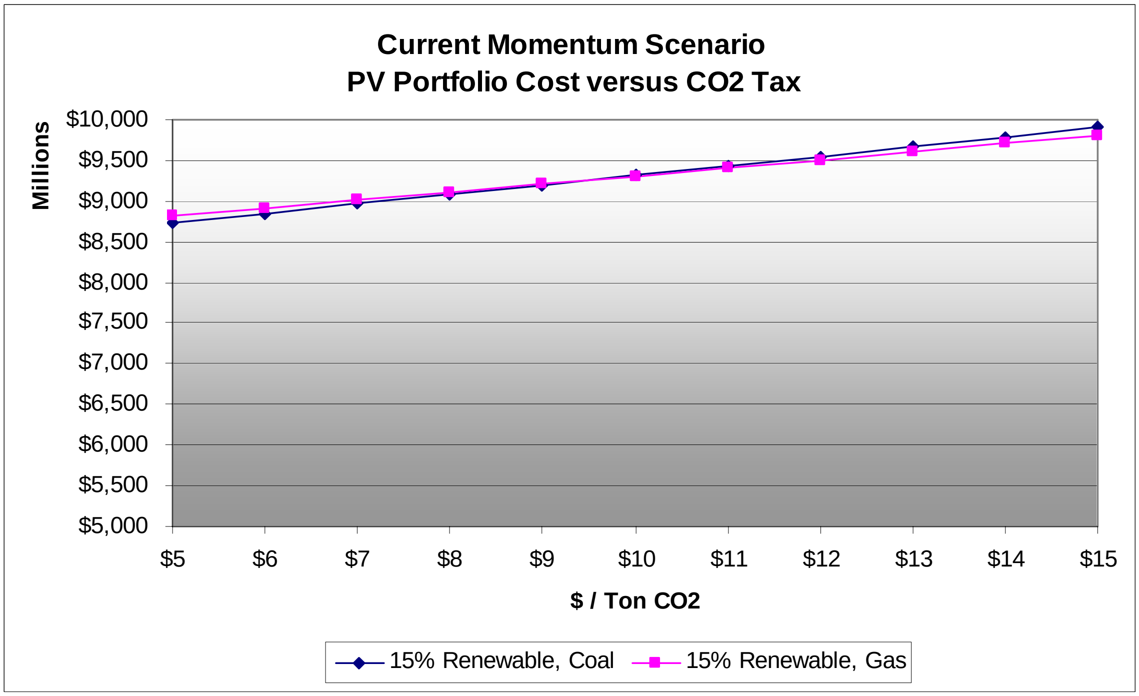
Exhibit X-25

	No PBA Portfolio	**Generic Portfolio**	**Change**
Expected Cost $/MWh	$37.91	$36.21	$1.70
Dynamic Mean $/MWh	$36.68	$35.26	$1.42
Risk = 95% less Mean	$3.98	$3.20	$0.78

Carbon Dioxide Cost Sensitivity Analysis – Two scenarios were developed to integrate the impacts of CO_2 costs into the analysis of portfolios. These scenarios were the CM and GW cases. Although these scenarios provide an indication of whether CO_2 costs impact PSE's decision to build coal in the future, they don't establish the costs that might lead to the decision not to build coal. Therefore, sensitivity analyses were performed to help provide some guidance on this issue.

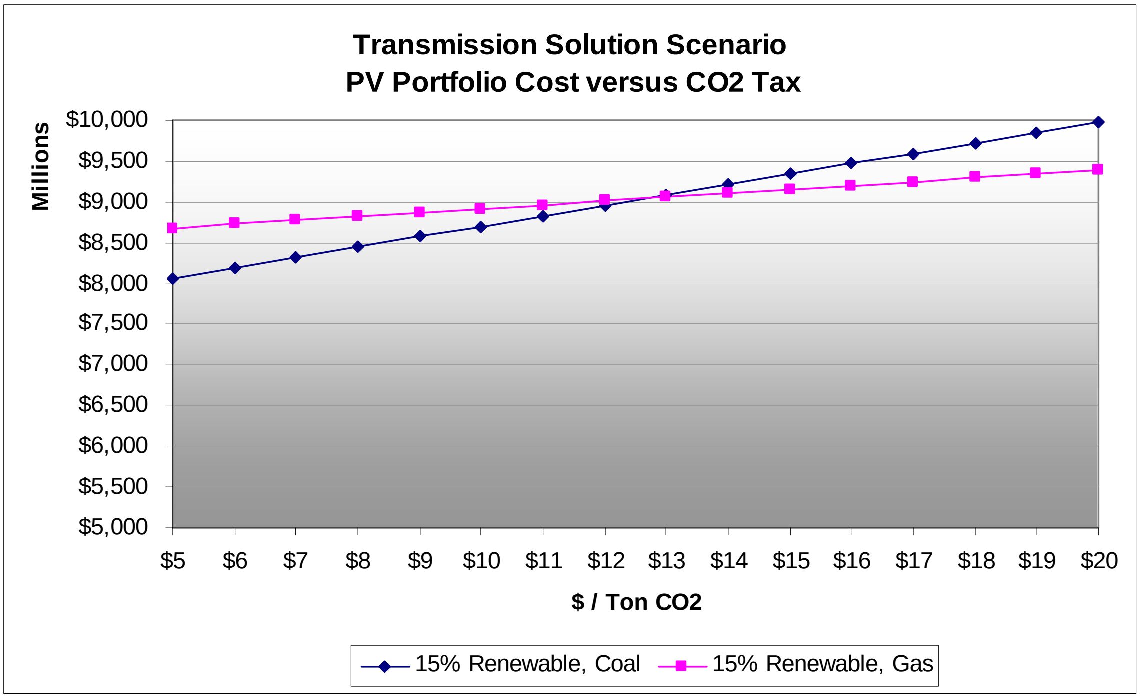
For the analysis, PSE examined what level of CO_2 would lead to the selection of the 15 percent Renewable and All Gas portfolio over the 15 percent Renewable and All Coal portfolio in the CM and TS scenarios. These model runs assumed a CO_2 cost starting in 2010 with a 2.5 percent escalation per year. The value of looking at the CM scenario is that it was a scenario designed to examine CO_2 costs, but did not lead to the selection of an all gas scenario. For CM, the portfolio selection changes to gas from coal between $9 and $10, as shown in Exhibit X-26. The figure also shows that the differences in portfolio costs and CO_2 costs between $5 and $15 per ton are very close.

Exhibit X-26



The other scenario examined was the TS scenario (Exhibit X-27), which includes a regional transmission solution. In this scenario, the cost of coal plants including transmission costs are less than natural gas plants. The analysis shows that the tipping point occurs between \$12 and \$13 per ton.

Exhibit X-27



The analysis and conclusions regarding potential carbon regulation are problematic, as there is so much uncertainty about future policies on CO_2 taxes or "cap and trade" regimes. There are numerous policy assumptions that impact the analysis of carbon charges. These include the size of a carbon charge and its escalation rate, the online date and level of grandfathering for existing resources or distribution of credits, the future fuel prices associated with coal and gas in the future, and the development cost of different control or sequestration technologies in the future.

Summary of Additional Quantitative Findings

- Summer surplus sales do not significantly influence portfolio outcomes.
- Power bridging agreements reduce portfolio cost variability, but increase imputed debt.
- Under current market price assumptions, near-term power bridging agreements are less expensive than gas resources.
- The tipping point analysis indicates that a CO_2 charge, which equates the cost of coal and gas portfolios, would be $9 to $10 in the CM scenario and $12 to $13 in the TS scenario.

G. Demand-side Analytical Results and Conclusions

Demand-Side Analytic Approach

PSE uses the Conservation Screening Model (CSM) (described in Appendix C) for analyzing energy efficiency and fuel conversion programs. CSM integrates demand-side resource potential estimates, which are based upon the achievable cost categories for each end-use, and hourly load shapes for program bundles to reduce PSE customer electricity demand. This reduction in demand offsets the addition of the generation supply resources to meet the energy need. The CSM analyzes thousands of energy efficiency and fuel conversion (demand-side) cases to find the most cost effective combination of supply resource, and energy efficiency and fuel conversion programs. Similar to the electric planning analysis, the primary metric is the 20-year NPV of the incremental portfolio cost in millions of dollars. The goal is to minimize the incremental portfolio cost.

Analysis of demand-side portfolios was a multi-step process because of CSM model limitations. A demand-side portfolio is defined as any combination of the bundle/price points (As described in Chapter VII, there are 17 electric end-use bundles: eight residential bundles, eight commercial bundles, and one industrial bundle. There are up to eight cost categories for the residential and commercial end-uses, and a single cost category for the industrial bundle). Because not every end-use has eight cost categories, there are 95 unique bundle/price points to be considered. Input data to CSM is limited to 65 combinations of bundle/price points for any single model run.

To address the model constraint of 65 bundle/price points, the cost categories were aggregated at the low ends, with most granularities retained in the middle and upper cost categories. The cost aggregations were made initially by reviewing results from the energy efficiency and fuel conversion portfolio analysis of cost levels A to D and combining the cost categories where all bundles at a particular cost level were either accepted or rejected. For reference, cost categories are lettered A to H from lowest to highest cost. The four price points (levelized cost per MWh saved) ultimately utilized in this analysis are:

- Less than $75 per MWh (cost categories A-D)
- $75 - $85 per MWh (cost category E)
- $85 - $95 per MWh (cost category F)
- $95 - $105 per MWh (cost category G)

Cost category G bundles were never selected by CSM; therefore, there was no need to test category H.

Demand-Side scenarios were designed to test the timing of acquiring demand-side resources. Two timing scenarios are represented for both energy efficiency and fuel conversion—a constant rate of acquisition over the entire 20-year planning horizon (normal) and an accelerated rate of acquisition to achieve as much savings as possible over the first 10 years (accelerated). The following are scenario descriptions and show the maximum achievable potential energy savings inputs before testing for cost-effectiveness.

- *Constant energy efficiency acquisition (Normal EE)* – 14.8 aMW/year for 2006 – 2025 from energy efficiency resources only, no fuel conversion.
- *Accelerated energy efficiency acquisition (Accelerated EE)* – 24.3 aMW/year for 2006 – 2015 and 5.4 aMW/year for 2016 – 2025 from energy efficiency resources only, no fuel conversion.
- *Normal replacement fuel conversion plus accelerated energy efficiency* (Accel EE std eff Normal FC) – 26.9 aMW/year for 2006 – 2015 and 8.1 aMW/year for 2016 – 2025 from a combination of accelerated energy efficiency and fuel conversion acquired as equipment is normally replaced at the end of its useful life.
- *Early replacement fuel conversion plus accelerated energy efficiency* (Accel EE std eff Early FC) –34.3 aMW/year for 2006 – 2015 and 4.5 aMW/year for 2016 – 2025 from a combination of accelerated energy efficiency and fuel conversion at an accelerated pace of equipment replacement.

Fuel conversion was analyzed in combination with energy efficiency in order to address interactions between the two. The impacts of fuel conversion can be derived as the difference between a portfolio that includes both energy efficiency and fuel conversion and a portfolio that consists of energy efficiency only. The portfolio screening analysis only examined fuel conversion in combination with accelerated energy efficiency because accelerated energy efficiency was found to be preferable to a constant rate of acquisition at the first stage in the analysis.

Modeling Approach for Simultaneous Assessment of Demand and Supply Resources Steps

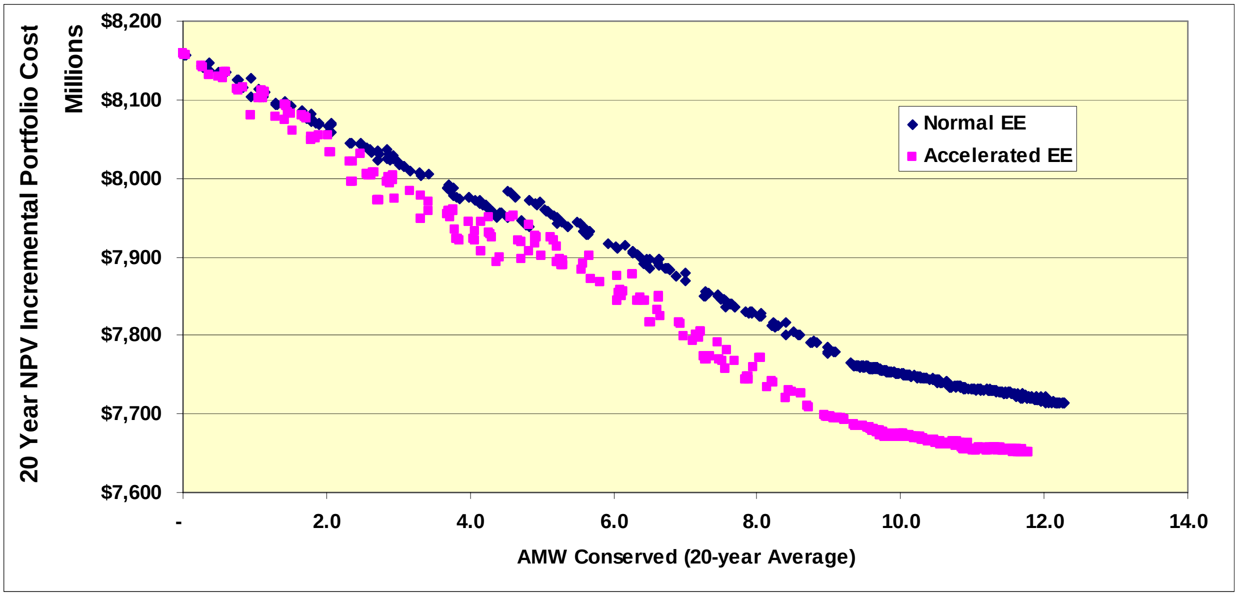
1. Selection of Energy Supply Portfolio
2. Analysis of Energy Efficiency supply curves under normal implementation schedule
3. Analysis of Energy Efficiency supply curves under accelerated schedule
4. Selection of normal vs. accelerated schedule for energy efficiency
5. Analysis of normal level of fuel conversion (normal) with selection from step 4
6. Analysis of accelerated level of fuel conversion (early) with selection from step 4
7. Selection of demand-side case with lowest incremental portfolio cost

Analytic Results

The ultimate goal of running CSM is to determine the level of energy efficiency and fuel conversion that is cost effective in combination with the least cost energy supply portfolio. As determined from the PSM analysis, the supply portfolio used for the demand-side analysis is 10 percent Renewable and 50/50 Coal and Gas resources.

Exhibit X-28 shows demand-side cases (unique combinations of 65 bundles/price points) tested in CSM for the constant rate of acquisition energy efficiency scenario and the accelerated energy efficiency scenario. Over 1,000 cases were tested. The lowest incremental portfolio cost achieved in this sample of cases included all end-use bundles up to the cost category D. Therefore, it can be concluded that all programs up to this cost level are cost effective compared to the selected supply resource portfolio. Additionally, the exhibit shows that accelerated energy efficiency reduces portfolio cost more than a constant rate of acceleration.

Exhibit X-28
Constant Rate vs. Accelerated Rate of Energy Efficiency testing cases up to Cost Point D



Since accelerated EE is more cost effective, the analysis focused on fuel conversion programs combined with accelerated energy efficiency. Again, Exhibit X-29 confirms the acceptance of all demand-side bundles/price points through cost category D because portfolio costs continue to decline as energy efficiency and fuel conversion cost levels increase.

Exhibit X-29
Scenario Results- Cost Points testing cases up to Cost Point D

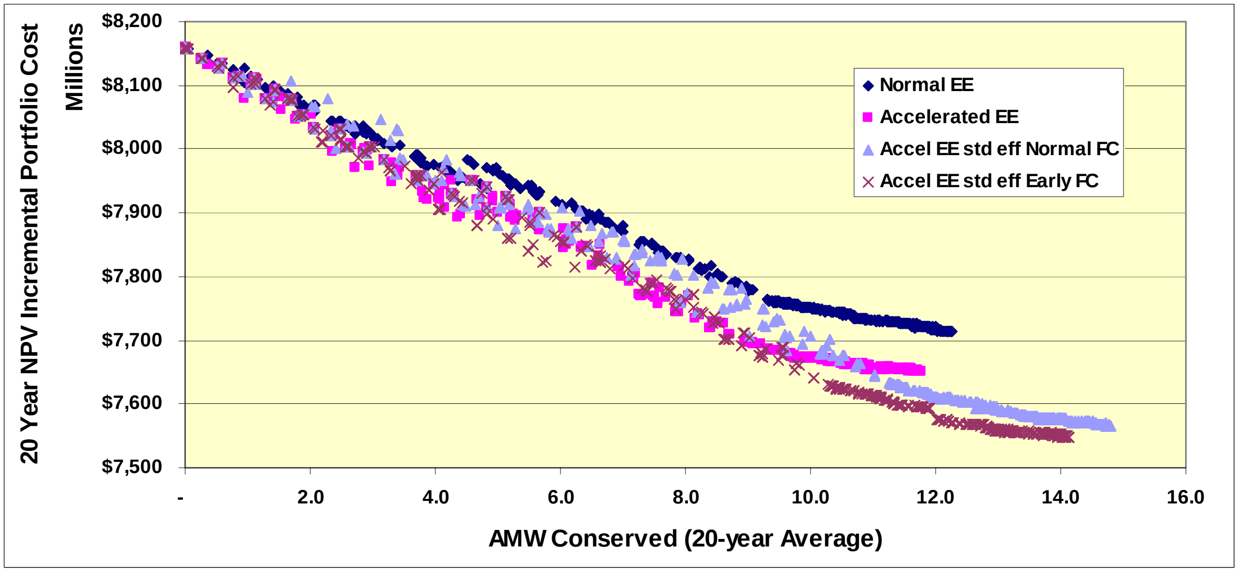


Exhibit X -30 tests energy efficiency and fuel conversion cases through cost level G. The result shows that accelerated energy efficiency plus early fuel conversion is lowest cost. Identifying the minimum point on these curves indicates the optimal level of savings that can be achieved through demand-side programs. The result shows that average energy per year saved through energy efficiency and demand response is approximately 15.5 aMW over the 20-year planning period.

Exhibit X-30
Scenario Results- Cost Points A to G with A to D Combined

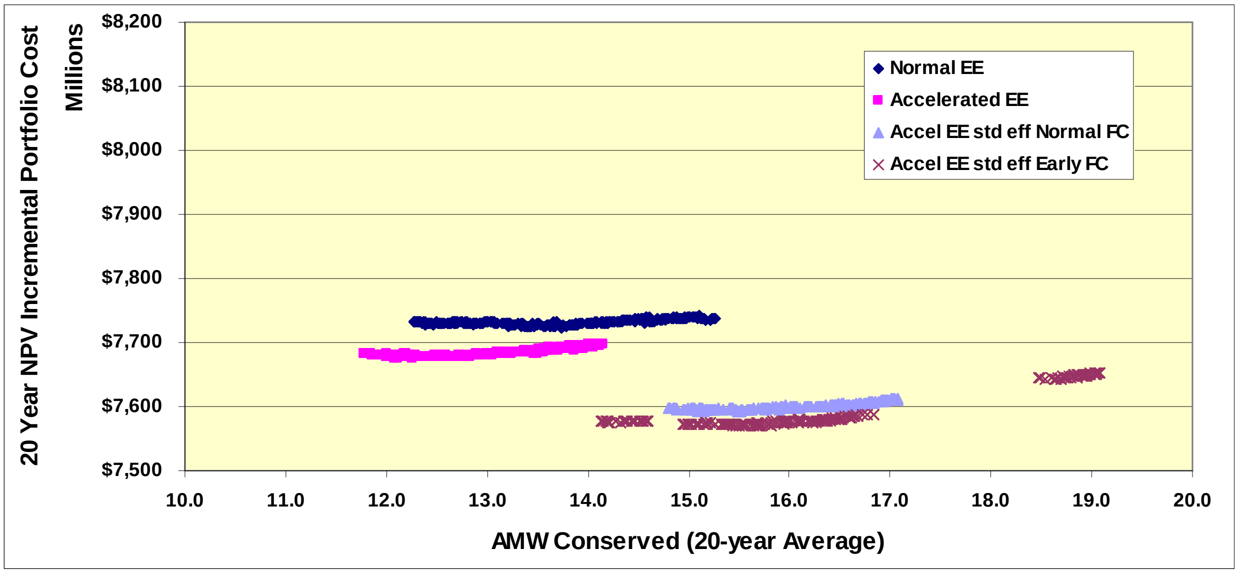


Exhibit X-31 compares the annual energy savings for the accelerated energy efficiency scenario, and the early replacement fuel conversion plus accelerated energy efficiency scenario. Overall, the results show that early replacement fuel conversion plus accelerated energy efficiency will save the PSE portfolio over 300 aMW. Early replacement fuel conversion contributes nearly 90 aMW of energy savings. Exhibit X-32 shows that the addition of demand-side resources not only lowers cost, but also lowers risk. The risk measure is cut by more than half with demand-side programs. This analysis demonstrates that a balanced portfolio with coal, gas, renewable, and demand-side resources is least cost.

Exhibit X-31
Incremental and Cumulative Conservation

	Accelerated Energy Efficiency No Fuel Conversion	
Years	Average (AMW)	Cumulative (AMW)
2006-2015	20	199
2016-2025	5	47
20-Year	12	245

	Accelerated Energy Efficiency Standard Efficiency Early Fuel Conversion	
Years	Average (AMW)	Cumulative (AMW)
2006-2015	28	279
2016-2025	3	34
20-Year	16	313

Exhibit X-32
Comparison of Dynamic Results for 10% Renewable and 50/50 Gas & Coal with and without Demand-Side Programs

Dynamic Results- 100 Trials $ Millions	With Demand-Side Programs	Without Demand-Side Programs
Mean	7,497	7,929
Avg. > 90%	7,804	8,642
Risk (Avg. > 90% - Mean)	307	713

Summary of Demand-side Key Quantitative Findings

- Accelerated energy efficiency provides more benefit to the portfolio than a constant rate of energy efficiency.
- Early fuel conversion benefits the portfolio more the normal fuel conversion.
- After 20 years, the implementation of demand-side resources will result in over 300 aMW of energy savings.
- The least cost portfolio evaluated is diversified with coal, gas, renewable, and demand-side resources.

H. Final Resource Portfolio

Exhibit X-33 shows how the long-term need for resources (2006-2025) could be filled under the constraints and assumptions described throughout this Least Cost Plan. The chart shows the least cost mix of additional resources to fill the planning standard need. The portfolio includes additional renewables such that 10 percent of load is met with renewables by 2013.

Accelerated energy efficiency can provide about 20 average megawatts for each of the first 10 years, then slows down to five average megawatts for the next 10 years. The chart shows the level with both accelerated energy efficiency and early fuel conversion, which increases the potential savings to 28 average megawatts for each of the first 10 years. During Period 1, before more transmission is built, PSE will depend on a mix of power PBAs and gas-fueled turbines. Only after transmission is built can coal be added.

Exhibit X-33