EXHIBIT NO. ___(WJE-1T)
DOCKET NO. ____________
2005 POWER COST ONLY RATE CASE
WITNESS: W. JAMES ELSEA

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-_______**

PREFILED DIRECT TESTIMONY OF
W. JAMES ELSEA (NONCONFIDENTIAL)
ON BEHALF OF PUGET SOUND ENERGY, INC.

JUNE 7, 2005

PUGET SOUND ENERGY, INC.

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PUGET SOUND ENERGY, INC.

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I. INTRODUCTION

Q. Please state your name, business address, and position with Puget Sound Energy, Inc.

A. My name is W. James Elsea. My business address is 10885 N.E. Fourth Street Bellevue, WA 98004. I am the Financial Analysis Manager of Energy Resources for Puget Sound Energy, Inc. ("PSE" or "the Company").

Q. Have you prepared an exhibit describing your education, relevant employment experience, and other professional qualifications?

A. Yes, I have. It is Exhibit No. ___(WJE-2).

Q. What are your duties as Financial Analysis Manager of Energy Resources for PSE?

A. As Financial Analysis Manager of Energy Resources, I am responsible for the analysis of individual power resources and portfolios of power resources for the Company's Least Cost Plan and resource acquisition processes.

Q. Please summarize the contents of your testimony?

A. My testimony describes the modeling tools and analyses the Company utilized to evaluate the various resource alternatives that were proposed in response to its Requests for Proposals ("RFPs") to meet its need for additional power resources. I describe the various models and how they were used in the Company's quantitative valuation of the Hopkins Ridge wind generating facility ("Hopkins Ridge Project") compared to other resource options. I also describe how the Company updated its assumptions and inputs to these models during the course of its evaluation so that its ultimate decision to acquire the Hopkins Ridge Project was based on current information.

II. MODELING TOOLS AND ANALYSES UNDERLYING THE COMPANY'S EVALUATION OF POTENTIAL POWER RESOURCE ALTERNATIVES

A. Overview of the Company's Resource Planning and Acquisition Models

Q. What approach did the Company take to modeling the various resource alternatives proposed in response to its RFPs?

A. Consistent with the methods described in both its 2003 and 2005 Least Cost Plans, PSE followed a resource planning approach in evaluating potential alternatives. This approach treats the Company's electric resource portfolio as an integrated whole and captures dynamic interactions between various parts of the portfolio, including but not limited to PSE's retail electric loads, its existing electric resources and potential new resources. It also identifies net effects on cost and risk for the overall portfolio of adding various potential resource alternatives to the portfolio.

Q. What models were used in evaluating potential resource alternatives?

A. PSE used three models in evaluating potential resource alternatives: the AURORA model, the Portfolio Screening Model and the Acquisition Screening Model. Two of these models, the AURORA model and the Portfolio Screening Model, were also used in the 2003 Least Cost Plan and in the analysis of the alternatives to acquisition of the Frederickson I plant that was described in the Company's 2003 power cost only rate case, Docket No. UE-031725.

Q. Please describe these models.

A. The AURORA model is a fundamentals-based production costing model that simulates regional wholesale power market prices using, among other factors, the supply of resources, the demand for power and constraints due to transmission. The Portfolio Screening Model is a Microsoft Excel-based model, specific to PSE, that allows the Company to evaluate alternative portfolios of existing and new resources to serve load. The third model, the Acquisition Screening Model—a scaled-back version of the Portfolio Screening Model—was used to screen initial bids.

Q. Why did the Company use the Acquisition Screening Model to screen initial bids?

A. Due to the large system requirements of the Portfolio Screening Model and the number of proposals expected in response to the Wind and All-Source RFPs, the Company developed a more streamlined Acquisition Screening Model to analyze and rank the cost of resource proposals submitted in response to such RFPs. The Acquisition Screening Model is essentially the Portfolio Screening Model without the existing PSE resources and full PSE load. The Acquisition Screening Model produces a ranking of resource costs similar to the results from the Portfolio Screening Model. The Company used the costs projected by the Acquisition Screening Model, in connection with other evaluation criteria described in the prefiled direct testimony of Mr. Roger Garratt, Exhibit No. ___(RG-1HCT), to select a smaller group of project proposals to be analyzed in more detail with the Portfolio Screening Model.

Q. Were there any differences in modeling used for the RFP process in comparison to the modeling the Company performed for its 2003 Least Cost Plan?

A. Yes. In the evaluation of potential new resources for the 2003 Least Cost Plan, the portfolio approach focused primarily on "generic" electric resource technology alternatives (*e.g.*, conservation programs, wind power, combined-cycle gas turbines, single-cycle gas turbines, conventional coal-fired generation), rather than focusing on specific resource acquisition opportunities. This allowed PSE to develop a comprehensive and integrated view of the effect of adding various resource types to its overall portfolio. In addition to using an updated run of its existing AURORA model in the 2003 LCP, PSE developed and used an Excel-based portfolio simulation model--the Portfolio Screening Model--to evaluate generic alternative resource strategies, with explicit assessment of key uncertainty factors.

For the 2004 RFP process, the Company used the Portfolio Screening Model and an Acquisition Screening Model specifically developed for the RFP process to model the potential impact on its portfolio of adding various specific resource acquisition opportunities rather than the "generic" resource technology alternatives employed in the 2003 LCP. As part of the RFP evaluation process, the Company also updated certain assumptions and inputs to its AURORA and Portfolio Screening Models to evaluate the effect on the Company's analyses of changes in energy markets since the time it conducted its 2003 Least Cost Plan modeling.

B. The AURORA Model

1. Overview

Q. Please describe the AURORA model.

A. The AURORA model is a fundamentals-based hourly production cost model that relies on factors such as supply resources, regional demand for power and transmission to simulate competitive wholesale power markets. Aurora uses hourly demand and individual resource operating characteristics in a transmission constrained, chronological dispatch algorithm for the entire Western Electricity Coordinating Council ("WECC") region.

AURORA simulates, on an hourly basis, economic dispatch of the regional fleet of generating resources to meet regional electric loads, based on fuel prices and other variable operating costs, inter-regional transmission limitations and other factors. A primary result produced by AURORA is a long-term forecast of wholesale market prices for power (the "optimization mode") that simulates the addition of new generating resources, as needed, to maintain long-run market equilibrium. *See generally* Exhibit No. ___(WJE-3).

Q. Can AURORA be used to model operation of a utility's resource portfolio?

A. Yes. In addition to the market-wide analysis described above, AURORA can simulate hourly economic dispatch of a utility's generation resource portfolio. When used in this mode, AURORA produces forecasts of variable operating costs for the utility's generating resources but does not include all fixed costs for existing or new resources. *See generally* Exhibit No. ___(WJE-3). The Company used this mode of AURORA to forecast a portion of the power costs included in this filing, as described in the prefiled direct testimony of Ms. Julia M. Ryan. *See* Exhibit No. ___(JMR-1T).

Q. How does this use of AURORA to forecast power costs for this filing differ from the mode of AURORA used to evaluate various long-term resource alternatives?

A. When forecasting power costs with AURORA for the rate year in a rate case, the Company focuses on the output related to near-term power cost projections (the first two years or less, depending on the date of the rate year and the time the Company prepares its initial case for filing). Input assumptions regarding natural gas prices for the first 24 months are based on the forward market for natural gas prices, as described in Ms. Ryan's testimony.

When used to evaluate long-term resources, the natural gas prices assumed in AURORA are a combination of forward market prices for the first two years followed by a commercial forecast of gas prices based on fundamental supply and demand factors for the following years. Since the resource planning function is concerned with resource costs over a 20-year horizon, it is not particularly critical that the forward market price data regarding the first 24 months of that time period be updated on an ongoing basis.

Other input assumptions, such as hydro availability, also differ because the Commission has approved different inputs for purposes of developing projections of power costs to embed in rates than those the Company has historically used for long-term planning purposes.

Q. Is AURORA a PSE Model?

A. No. AURORA is a computer model developed by EPIS, Inc., that is used by utilities throughout the Northwest and across the country. AURORA is also used by the Northwest Power and Conservation Council.

Q. Does PSE update or re-write AURORA model code?

A. No. EPIS releases new versions of the model, as developed. For the 2003 LCP and the 2004 resource acquisition process, the Company used AURORA version 6.3. For the 2005 LCP, PSE used AURORA XMP (v. 7.3.0.22), which EPIS released in 2004. While PSE does not update the AURORA code, it does maintain and update certain data input assumptions.

2. Assumptions Used by the Company in AURORA

Q. What assumptions does the Company use in AURORA?

A. The Company establishes the parameters that define the optimization process by making certain assumptions regarding (i) the geographical market; (ii) load forecasts; (iii) the existing and planned generating resources; (iv) the forecasted price of fuel; (v) hydro availability; and (vi) transmission constraints.

Q. What geographical assumptions does the Company use for AURORA?

A. The Company uses the AURORA databases for the Western Interconnection to forecast power prices used in evaluating potential resources and portfolio costs. The WECC region comprises all of the Western Interconnection, which spans fourteen states in the Western U.S. (including Washington), two Canadian provinces (British Columbia and Alberta) and Baja California del Norte, Mexico. *See* Exhibit No. ___(WJE-4). All of the Company's resources and loads are located within the Western Interconnection and the WECC region.

Q. Does the WECC region represent the geographic region used in AURORA by PSE?

A. Yes. For modeling purposes, however, AURORA subdivides the WECC region into 13 areas. These subdivisions are primarily by state and province, except for California (two areas), Nevada (the southern part of the state combined with Arizona), and Oregon and Washington and Northern Idaho (combined into one area). *See* Exhibit No. ___(WJE-5). These areas approximate the actual economic areas in terms of market activity and transmission.

Q. How are load forecasts determined?

A. Load forecasts are created for each area and include the base year load forecast and an annual average growth rate. Hourly and monthly load shape factors are applied to such forecasts to estimate the daily and annual changes in demand.

Q. Does the Company use the load forecast prepared by the AURORA vendor, EPIS?

A. Yes. For analyzing resource acquisition strategies, PSE used the EPIS long-run load forecast, which provide data for all areas throughout the WECC. The EPIS long-run load forecast relies on data assembled by the U.S. Department of Energy's Energy Information Administration ("EIA") and the North American Electric Reliability Council ("NERC").

Q. What generating resources are included in the AURORA forecasts?

A. All generating resources within the WECC are included in the resource database. Information on each resource includes its area, capacity, fuel type, efficiency, and expected outages (both forced and unforced). PSE updates resource-specific information with its current knowledge of Northwest resources and utilizes EPIS, Henwood, public sources (Cal-ISO, California Energy Commission, etc.) and private contacts to update the over 3,000 electric power resources in the West.

The AURORA model also incorporates resources that are under construction with expected online dates; however, because of numerous factors causing uncertainty, PSE included only new natural gas-fired plants in California, Oregon and Washington that were scheduled to be operational by the end of 2004. *See* Exhibit No. ___(WJE-6).

Q. How does PSE account for fuel costs in AURORA?

A. The costs of natural gas and coal are the two most important fuel costs used by PSE in AURORA. For natural gas, PSE forecasts prices for natural gas received at the Henry Hub (NYMEX), AECO, Rockies, San Juan, Topoc, Malin and Sumas hubs. PSE adopted the October 2003 Cambridge Energy Research

Associates ("CERA") Rearview Mirror forecast as its base forecast for the period beyond the first two-year horizon for evaluation of RFP bids in 2004. In addition to the Rearview Mirror forecast, PSE also uses the CERA World in Turmoil forecast for other scenarios. Coal prices were also reviewed and updated based on information from PIRA Energy Group ("PIRA"), PSE's Colstrip operation, Northwest Power and Conservation Council and three developers of coal-fueled plants.

Q. How does PSE account for water availability in AURORA?

A. Water availability greatly influences the price of electric power in the Northwest. For reqource acquisition planning, PSE assumes that hydropower generation is based on the average stream flows for the 60 historical years of 1928-1987. *See*, *e.g.*, Exhibit No. ___(WJE-7). For sensitivity analysis, PSE can vary the hydropower availability in the Portfolio Screening Model.

Q. How does AURORA account for transmission?

A. Electric power is transported between generation plants and load on high voltage transmission lines. When the price in one AURORA area is higher than it is in another, electricity will flow from the low priced market to the high priced market (up to the maximum capacity of the transmission system), which will move the prices closer together.

Within the AURORA model, transmission ties are only defined between the 13 areas within the WECC. The model takes into account the following factors that contribute to the price: (i) the cost to transport energy from one area to another, which limits how much energy is moved, and (ii) the physical constraints on how much energy can be shipped between areas. The limited availability of high voltage transportation between areas allows prices to differ greatly between adjacent areas.

PSE did not make adjustments to the database of transmission costs and transfer capabilities that were provided by EPIS.

Q. Does AURORA have other characteristics that affect its usefulness to analyze a specific utility's electric resource portfolio?

A. Yes. First, AURORA produces large output data sets that can make it time-consuming to evaluate a large number of cases and alternatives. Second, AURORA does not have sophisticated capabilities to model fixed costs for addition of potential new resources to a utility's portfolio, including reflection of the utility's specific financial and regulatory circumstances. This makes it difficult to compare total (fixed and variable) costs for different resource portfolio strategies.

C. The Portfolio Screening Model

1. Overview

Q. Please describe the Portfolio Screening Model.

A. In its resource planning efforts for the 2003 Least Cost Plan, PSE developed and used a dedicated, PSE-specific model to analyze cost and risk for the various portfolio-planning levels called the Portfolio Screening Model. *See* Exhibit No. ___(EMM-3) at 486-529 (describing the Portfolio Screening Model in detail).

Q. Why did PSE decide to develop and use the Portfolio Screening Model?

A. First, as part of the 2003 LCP development, PSE was seeking a modeling tool that could be used to quickly evaluate and compare results for a wide range and large number of alternative resource strategies. Second, PSE was seeking a model that could be used to calculate variable costs for all resources, including existing and new resources, as well as fixed costs for new resources. As noted above, AURORA does not address fixed costs for new resources added to a utility's portfolio. Third, PSE was seeking a model that could be used to perform probabilistic analysis of several key uncertainty factors, including multiple correlations among the uncertainty factors. Fourth, PSE was seeking a model that could be used to address other topics such as end effects for resource alternatives that have varying lives. Based on these specialized needs, PSE determined that a dedicated computer model would provide the most effective solution.

Q. What was the first use of the Portfolio Screening Model?

A. The Portfolio Screening Model was first used in the 2003 LCP and was used subsequently to evaluate alternative resources in the process that resulted in the acquisition of a 49.85% interest in Frederickson 1.

Q. How was the model developed?

A. The model was developed in late 2002 and during 2003 as various enhancements were added. The model is built in Microsoft Excel and uses an Excel add-in, Crystal Ball, to perform Monte Carlo simulation of key uncertainty factors. The model includes a component that simulates hourly dispatch of PSE's existing resources and potential new resources. The model also includes other components that develop fixed costs.

Q. Is the Portfolio Screening Model a simulation model or an optimization model?

A. It is a simulation model. In other words, the model can be used to evaluate cost and risk for a wide variety of resource alternatives and portfolio strategies, but it does not include logic designed to automatically select the lowest-cost combination. As such, the Portfolio Screening Model can be viewed as an analytical tool that supports and assists the process leading to the utility's resource strategy – including application of judgment to the model results.

Q. What types of resource planning issues did PSE address with the Portfolio Screening Model?

A. PSE used the model to perform a number of analyses during development of the 2003 Least Cost Plan. One major use of the model was for the analysis of portfolio costs and risks at different levels of resource sufficiency. This analysis was used to help select PSE's portfolio planning level for energy and for capacity and to determine its resulting need for new electric resources. A second major use of the model was for the evaluation of various combinations of new electric resources to meet the Company's need for new resources. This analysis was used to develop PSE's long-term strategy for types, amounts and timing of new electric resource additions. The model was also used to perform other analyses of PSE's electric resource portfolio, including sensitivity studies.

Q: Could you provide an example of the conclusions that the Company reached in its 2003 Least Cost Plan based on the Portfolio Screening Model?

A. One of the most important conclusions from this analysis was that a diversified mix of new resources helps to mitigate risks more effectively than relying exclusively on a single resource technology to meet PSE's entire need for new electric resources. Each of the available resource technologies has its own set of advantages and drawbacks, including its costs (e.g., level and structure of costs, availability of tax credits), degree of exposure to fuel price risks and environmental characteristics. PSE addressed these tradeoffs by using the

Portfolio Screening Model to analyze portfolio cost and risk for different combinations of new resources under key uncertainties.

2. <u>Assumptions Used by the Company in the Portfolio Screening Model</u>

Q. What input assumptions are needed for the Portfolio Screening Model?

A. The inputs for the Portfolio Screening Model fell into four categories: (i) plant characteristics; (ii) plant cost data; (iii) PPA cost data; and (iv) other assumptions.

Plant characteristic data inputs for existing and potential new resources included the following:

- Capacity
- Heat rate
- Maintenance outage schedule
- Forced outage rate
- Sample 8760 hour generation profile for wind projects
- Emission rates for SO_2, NO_X, and CO_2

Plant variable cost data inputs for existing and potential new resources included the following:

- Variable O&M per MWh
- Pipeline commodity charges plus fuel use (losses) and Washington state use tax
- Variable transmission charges

Plant fixed cost data inputs included the following:

- Capital cost including AFUDC and deal transaction costs
- Fixed O&M per kW of capacity
- Fixed A&G costs per kW of capacity (including property taxes and insurance)
- Book and tax depreciation rates
- Fuel transportation costs including fixed pipeline and lateral charges

- Fixed transmission costs including wheeling, ancillary services and imbalance or integration costs
- Other imbalance or integration costs

PPA cost data inputs included the following:

- PPA capacity and energy
- PPA energy shape by season by on-peak and off-peak
- PPA fixed prices and escalation
- PPA variable prices, and or variable adders
- Transmission costs: fixed and variable
- For tolling PPAs: fixed and variable gas transportation, variable O&M heat rate, seasonal and maintenance outage forecast, forced outage rate

Other data inputs included the following:

- PSE retail load and hourly load shape
- PSE hydro generation both owned and contracted
- Costs of borrowing debt and equity capital (weighted average cost of capital for levelizing costs)
- Natural gas price
- Power price (hourly output from AURORA)
- Variability and correlation parameters for sensitivity testing of power prices, gas prices and hydro generation
- Trading values of emissions
- S&P imputed debt risk percentage
- Production tax credits for qualifying renewable projects

Q. Please describe the sources of data used for analysis using the Portfolio Screening Model.

A. The Company relied on information provided in the responses to its RFPs for construction and development capital costs, fixed and variable operating costs, PPA pricing, as well as plant or contract performance characteristics. The Company also provided its own cost estimates for certain line items to achieve consistency among projects in the analysis.

Q. Can you please provide examples where the Company provided its own cost estimates for certain line items to achieve consistency among projects?

A. Yes. The most significant example is the price of natural gas fuel and transportation for proposed gas-fired projects. The price of gas and transportation must be consistent with the forecast of power prices in order to make reasonable comparisons of dispatch for the thermal plant bids.

Another example of data consistency is that each bid was evaluated for power delivery to the PSE system. The Company prepared its own estimate of power transmission and integration for the specific locations using tariffs for transmission and either tariff rates for ancillary services or PSE's estimate of integration costs.

Q. Did PSE use consistent input assumptions for both AURORA and the Portfolio Screening Model?

A. Yes. Although AURORA and the Portfolio Screening Model use slightly different logic, consistent data inputs were used for both models where possible. Because the long-term gas price forecasts changed since the August update of the 2003 LCP, the AURORA model and Portfolio Screening Model were updated consistently. Assumptions about generic generation plant costs are different between AURORA and Portfolio Screening Model. AURORA generic costs represent a regional view of costs, while Portfolio Screening Model has more specific costs for transmission and construction.

Q. What other costs are accounted for in the Portfolio Screening Model?

A. In addition to the initial capital investment and annual operating costs, the debt and equity costs for the Company are input into the model. For these analyses, the Company assumed a weighted-average cost of capital of 8.76%. Using these inputs, the Portfolio Screening Model contains logic for calculation of annual revenue requirements.

Additionally, the Portfolio Screening Model calculates the benefit or cost of the end effects (explained below) beyond the 20-year study horizon. For bids including tolling arrangements with demand charges or power purchase agreements ("PPA"), the Portfolio Screening Model calculates the level of imputed debt that would be assigned by the Standard and Poor's Rating Agency and cost of an equity offset to this imputed debt.

Q. What is imputed debt?

A. Standard & Poor's Ratings Services views electric utility PPAs as debt-like in nature and has historically capitalized these obligations on a sliding scale known as a "risk spectrum." Standard & Poor's applies a 0% to 100% "risk factor" to the net present value ("NPV") of the PPA capacity payments, and designates this amount as the debt equivalent.

Q. Why does Standard & Poor's impute a debt equivalent to PPAs?

A. According to Standard & Poor's, the imputed debt adjustment is designed to

> allow for more meaningful comparisons with utilities that build generation. Utilities that build typically finance construction with a mix of debt and equity. A utility that leases a power plant has entered into a debt transaction for that facility; a capital lease appears on the utility's balance sheet as debt. A PPA is a similar fixed commitment. When a utility enters into a long-term PPA with a fixed-cost component, it takes on financial risk. Furthermore, utilities are typically not financially compensated for the risks they assume in purchasing power, as purchased power is usually recovered dollar-for-dollar as an operating expense.

Exhibit No. ___(WJE-8) at 1.

Q. How does Standard & Poor's calculate the imputed debt cost?

A. Standard & Poor's 1994 update of its 1992 Corporate Finance Criteria generally discusses the imputed debt calculation methodology:

> To analyze the financial impact of purchased power, S&P employs the following financial methodology. The net present value of future annual capacity payments (discounted at 10 percent), multiplied by a "risk factor" represents a potential debt equivalent – the off-balance sheet obligation that a utility incurs when it enters into a long-term purchase power contract.

The calculation begins with the determination of the fixed obligations that are equal to the actual demand payments, if so defined in the contract, or 50 percent of the expected total contract payments. This yearly fixed obligation is then multiplied by a risk factor.

Q. How does this relate to PSE's imputed debt costs?

A. Standard & Poor's has determined that PSE's current contracts have a risk factor of 30 percent. *See* Exhibit No. ___(WJE-9) at 5. Prior to this recent change (approximately May 2004), PSE contracts had risk factors between 15 percent and 40 percent. Imputed debt is the sum of the present value, using a 10 percent discount rate and a mid-year cash flow convention, of this risk adjusted fixed obligation. The cost of imputed debt is the equity return on the amount of equity that would be acquired to offset the level of imputed debt to maintain the Company's capital and interest coverage ratios. For a more detailed example of such calculation, please see Exhibit No. ___(EMM-6) at 81.

3. Output Generated by the Portfolio Screening Model

Q. What kinds of output results does the Portfolio Screening Model produce?

A. One of the key outputs of the Portfolio Screening Model is a 20-year NPV of expected costs for the portfolio, including fixed costs for new resources and variable costs for all new and existing resources included in a particular portfolio being evaluated. Another important type of output is portfolio risk. Risk is measured by standard deviation and by the difference between the 95th percentile cost and the 20-year NPV expected cost for the portfolio.

Additional outputs include (i) dispatch results for each type of generating resource technology, (ii) megawatt-hour quantities and dollar amounts for power purchases and (iii) sales, fuel and O&M costs. Revenue requirements, taking into consideration end effects for resources with different lives, are also produced for each potential new generating resource technology included in a particular portfolio being evaluated.

Q. Please explain what you mean by the term "end effects."

A. For planning purposes we are using a twenty-year time frame; the resources we were evaluating in the portfolio model, however, could have shorter or longer lives than twenty years. To measure the impact a particular resource had on the Company's portfolio, it was necessary to quantify this timing difference. This adjustment represents the end effects, and its purpose is to put all the resources on an equal basis during the planning period.

Q. How does the model address end effects for utility-owned generating resources?

A. Thermal resources, for example, have 30-year book lives that leave a 10 year "overhang" for resources added in year one. This overhang increases for resource additions made in later years of the evaluation period. PSE dealt with this effect by developing a market value of the overhang from each new supply resource in the portfolio and subtracting the year-end book value in the last year of the evaluation period in order to calculate an NPV. The year-one NPV of this net market value, whether positive or negative, was then added to the expected cost of the portfolio to compensate for the overhang issue. (A negative net market value increases expected cost and a positive net market lowers expected cost.)

Q. How does the model address end effects for PPAs shorter than 20 years?

A. Many PPAs have contract terms of less than 20 years. In this case, when the PPA expires, generic supply resources are added to replace the PPA. These supply resources are then treated as described above, where the net market value is developed and added to (or subtracted from) the expected cost as appropriate.

Q. Does the Portfolio Screening Model calculate revenue requirements for PSE's entire electric resource portfolio?

A. No. The Portfolio Screening Model does not include fixed, or economically "sunk" costs, for PSE's existing electric resources. Therefore, the Portfolio Screening Model results are useful for purposes of relative comparisons between alternatives, rather than for the purposes of determining absolute levels of costs or revenue requirements for rate-setting purposes.

4. Strengths and Weaknesses of the Portfolio Screening Model

Q. Please describe some of the strengths of the Portfolio Screening Model.

A. The strengths of the Portfolio Screening Model include the following:

(1) the model provides the capability to perform portfolio risk analyses of power prices, gas prices, hydro generation and wind generation, including correlations among these uncertainty factors;

(2) the model includes both fixed costs for potential new resources and variable costs for existing resources and potential new resources;

(3) reasonably quick run-time allows the model to be used to evaluate a wide range of portfolio strategies;

(4) the model is customized to reflect PSE's electric resource portfolio;

(5) the model has been well-described to Commission Staff and members of the Least Cost Plan Advisory Group; and

(6) the model is flexible and can be updated as improvements are identified.

Q. Please describe some of the limitations of the Portfolio Screening Model.

A. The limitations of the Portfolio Screening Model include the following:

(1) the model does not represent certain operational constraints for electric generating facilities, including ramp rates, start-up costs, and minimum unit run time requirements;

(2) the model assumes that addition of new resources to PSE's electric resource portfolio has no effect on power prices in the regional market;

(3) the model stretches the limits of Excel (thus, it will be hard to expand it further unless Microsoft increases the underlying capabilities of Excel); and

(4) care must be taken to test and document changes to model logic and data structures, to avoid risks that such changes could have unintended and unnoticed effects.

D. The Acquisition Screening Model

Q. Please describe the Acquisition Screening Model.

A. As mentioned previously, the Acquisition Screening Model is essentially the Portfolio Screening Model without the existing PSE resources and full PSE load. The model calculates fixed and variable costs for individual new resources, the impact of end effects, and the benefits or costs of hourly generation that is aligned or not aligned with PSE's load shape. The model is used to screen resource bids and save run time compared with the Portfolio Screening Model.

Q. Why did PSE decide to develop and use the Acquisition Screening Model?

A. The electronic file size of the Portfolio Screening Model pushes the limits of Microsoft Excel application. The electronic file size of the Acquisition Screening Model is less than half the Portfolio Screening Model, which makes the Acquisition Screening Model more suitable to multiple copies and multiple evaluations of resource opportunities. Although the Acquisition Screening Model did not contain the remainder of PSE's portfolio, the Acquisition Screening Model resource cost (along with the comparison of generation relative to load shape) provides a reasonable indication of how well a proposal would benefit the portfolio.

Q. How did PSE utilize the Acquisition Screening Model in its evaluation of potential new resource alternatives?

A. The Acquisition Screening Model was used to calculate 20-year levelized costs to be used in conjunction with quantitative screening criteria in Stage 1 of both the Wind RFP and All Source RFP.

Q. Did PSE use consistent input assumptions for the Acquisition Screening Model as well as the AURORA and the Portfolio Screening Model?

A. Yes, the Acquisition Screening Model and Portfolio Screening Model use the same input assumptions: (i) hourly power prices from AURORA, (ii) monthly gas prices, (iii) capital costs, and (iv) PSE load shape.

Q. Please describe some of the strengths and limitations of the Acquisition Screening Model.

A. As discussed above, the Acquisition Screening Model is a scaled-back version of the Portfolio Screening Model. Therefore, the relative strengths and weaknesses of the Acquisition Screening Model and Portfolio Screening Model are the same.

III. APPLICATION OF AURORA, THE PORTFOLIO SCREENING MODEL AND THE ACQUISITION SCREENING MODEL IN THE RFP EVALUATION PROCESS

A. Overview

Q. Please describe how the Company applied the modeling tools described above in its evaluation of the potential resource alternatives submitted in response to its RFPs?

A. As further described in the direct testimony of Mr. Roger Garratt, PSE evaluated the proposals in a two-stage process. The Company's quantitative modeling in Stage 1 was used to help screen the proposals on a stand-alone basis against certain criteria for selection to a short list. Stage 2 further evaluated the short-listed and other proposals selected for continuing investigation in a more detailed level. A primary focus in Stage 2 examined the interaction of the most promising resources and combinations of resources within PSE's existing portfolio.

High-level documentation of the Company's quantitative evaluation and modeling are located at Exhibit No. ___(WJE-12), Exhibit No. ___(WJE-13HC) and Exhibit No. ___(WJE-14HC).

B. Stage 1. Acquisition Screening Model

Q. How did the Company utilize the Acquisition Screening Model in the Stage 1 Analysis?

A. PSE used the Acquisition Screening Model in the Stage 1 analysis to summarize and compare quantitative factors (i.e., the relative costs of individual resource proposals) on an equivalent basis. The quantitative factors analyzed by the Acquisition Screening Model include the following: (i) pro forma energy generation with economic dispatch; (ii) revenue requirement; and (iii) 20-year levelized cost including fixed and variable resource costs as well as imputed debt for PPAs, transmission costs (including ancillary services and integration costs), and end effects.

Q. Please summarize the results produced by the Acquisition Screening Model.

A. The results of the Acquisition Screening Model in the Stage 1 analysis varied depending on the type of technology. The projected levelized-costs (by fuel type) were as follows:

Technology Type	Number of Bids	Projected Levelized-Costs
Natural Gas Ownership	10	$60 - $85 per MWh
Natural Gas Ownership and PPA	6	$63 - $79 per MWh
Wind	23	$44 - $96 per MWh
Wood Waste	4	$46 - $65 per MWh
Geothermal	2	$67 - $78 per MWh
PPA Gas	13	$52 - $99 per MWh
PPA existing Coal	4	$42 - $70 per MWh
PPA new Hydro	1	$64 per MWh
Heat Recovery	2	$47 - $66 per MWh
Coal Ownership	1	$53 per MWh

The Company's report of the Stage 1 quantitative analysis from May 2004, which contains the above information, is found at exhibit No. ___(WJE-10).

Q. What did the Company do with this cost ranking information?

A. By using the levelized-cost generated by the Acquisition Screening Model, in addition to the qualitative factors described in Mr. Garratt's testimony, Exhibit No. ___(RG-1HCT), PSE identified thirteen proposals that warranted lesser priority due to high costs, unacceptable risks, and/or feasibility constraints and placed these lower priority proposals on the "constrained" list for limited consideration.

Q. What did the Company do next?

A. Through weekly evaluation meetings, the evaluation teams worked toward a consensus regarding the proposals that were most favorable. Proposals were reviewed by resource type and by combining the evaluation criteria ratings and sorting on the Acquisition Screening Model levelized-cost rankings. Ultimately, eighteen proposals were selected to a "most favorable" list by eliminating proposals that had high costs, unacceptably high risks or feasibility constraints. As Mr. Garratt describes, further evaluation led to development of a "continuing investigation" list. Ultimately, the seven projects with the most favorable costs and feasibility were placed on the Stage 1 "short" list.

Q. What did the Acquisition Screening Model show with respect to projects that made the Stage 1 "short" list?

A. All but one of the Acquisition Screening Model 20-year levelized costs of the proposals selected for the "short" list ranged from $42/MWh to $48/MWh, which is at the low end of the range of levelized costs for all of the proposals submitted in response to the Company's RFPs. The one exception was a 22-year Seasonal On-Peak PPA for winter energy at $63.80 per MWh. *See* Exhibit No. ___(WJE-11HC).

Q. Why did the 22-year Seasonal On-Peak PPA for winter energy nevertheless make the "short" list?

A. The Acquisition Screening Model's levelized costs of the proposals did not fully address the value of the 22-year Seasonal On-Peak PPA offer. That offer was for on-peak power during September through March. On-Peak AURORA prices during September through March were compared to the 22-year Seasonal On-Peak PPA proposed contract prices in the Stage 1 screening. On a present value basis, the 22-year Seasonal On-Peak PPA contract was lower than forecast market prices; therefore, the 22-year Seasonal On-Peak PPA merited further consideration in the Stage 2 evaluation and was selected for the "short" list for evaluation in the Portfolio Screening Model.

Q. What projects did PSE place on the "short list"?

A. PSE placed the following seven project proposals on the "short list":

Code	Project Name Owner/Developer
A02b	Wild Horse Wind Project Zilkha Renewable Energy
A03	Hopkins Ridge Wind Project RES North America, LLC
A06	150 MW Wind Project
A19	2-yr PPA (Centralia Coal Plant) Arizona Public Service (APS)
A24b	10-yr PPA (Coal Plant)
A30	22-yr Seasonal On-Peak PPA
A39	NWPL Sumas Recovered Heat Project ORMAT Nevada, Inc.

C. Stage 2. Portfolio Screening Model

1. Evaluation Criteria

Q. Did the Company apply the same evaluation criteria in Stage 2 that it did in Stage 1?

A. Yes, PSE continued to apply the following Stage 1 primary criteria in Stage 2: (i) compatibility with PSE resource need; (ii) cost minimization; (iii) risk management; (iv) public benefits; and (v) strategic and financial. For a more detailed description of the criteria, please see the prefiled direct testimony of Roger Garratt, Exhibit No. ___(RG-1HCT).

Q. What additional quantitative measures were added in the Stage 2 analysis?

A. For the Stage 2 analysis, the Company added the following quantitative criteria to the Stage 1 criteria: (i) portfolio cost, (ii) portfolio unit cost, and (iii) risk (or uncertainty) of portfolio cost.

Q. How did the Company utilize the Portfolio Screening Model in the Stage 2 Analysis?

A. The quantitative team first revisited the 2003 LCP resource strategy to update and reaffirm the current resource assumptions and strategy. After affirming the strategy, the quantitative team selected over 35 portfolio combinations from (i) the "short" and (ii) the "continuing investigation" list to analyze portfolio costs.

The Portfolio Screening Model provided for a portfolio cost ranking of each proposal and a framework to evaluate the long-term costs of each option and how it would be expected to perform in the PSE portfolio.

<u>2. Revisiting 2003 LCP Generic Resource Strategy</u>

Q. Why did the Company revisit the 2003 LCP Generic Resource Strategy in the Stage 2 Analysis?

A. As discussed above, the Least Cost Plan modeling and analysis determines a generic 20-year resource strategy based on forecasted market conditions. By contrast, the acquisition process is the process through which PSE considers specific potential resource options and costs in the context of PSE's portfolio.

The 2003 LCP strategy included the following: (i) an enlarged conservation program; (ii) a renewable energy goal of 10% of load by 2013; (iii) shared gas resources while PSE is long during the summer (through 2011); and (iv) a 50/50 split between gas and coal for additional resources in 2012 and beyond. *See* Exhibit No. ___(EMM-4) at 95.

Through the RFP process, the Company discovered additional information regarding potential resource options and costs that the Company wanted to consider in the context of a more generic review of resource acquisition issues. In addition, by Stage 2 of the Company's RFP evaluation process, the data that informed the 2003 LCP was over a year old, and the Company wanted to check whether its 2003 LCP strategy was still sound prior to making any long-term resource acquisition commitments.

Q. What did the Company do to revisit the 2003 LCP Generic Resource Strategy in the Stage 2 Analysis?

A. The Company reconsidered a number of strategies and conclusions from the 2003 LCP in light of information provided in response to its RFPs and in light of current information about long-term wholesale market forecasts and other factors, as described below. *See generally* Exhibit No. ___(WJE-12).

a. Utilizing Shared Resources To Avoid Further Long Positions During The Summer

Q. How did the Company revisit the portion of the 2003 LCP with respect to utilizing shared resources to avoid further long positions during the summer?

A. The Company assumed in the 2003 LCP that PSE could realize lower costs by sharing ownership of a combined cycle combustion turbine ("CCCT") project if PSE was surplus power in the summer months. The results of the bids from the All-Source RFP process, however, did not confirm the practicality of this assumption. Therefore, PSE removed the strategy involving utilization of shared resources to avoid further long positions during the summer.

b. Split Of Coal And Gas Thermal Resources

Q. How did the Company revisit the portion of the 2003 LCP with respect to 50/50 split of coal and gas thermal resources?

A. For the 2003 LCP, the Company assumed that it would begin meeting resource needs for 2012-2023 with a portfolio comprised of 50% coal and 50% gas. During the Stage 2 analysis, the Company changed such dates to 2009-2024.

Additionally, the strategy involving a 50/50 split of coal and gas thermal resources required PSE to further update its power price forecast. At the summary level, revisiting the strategy means rerunning Aurora with new assumptions, updating

Portfolio Screening Model with new prices and assumptions, and rerunning Portfolio Screening Model to test resource portfolios run in the 2003 LCP.

c. Update to Power Price Forecasts

Q. How did the Company revisit the portion of the 2003 LCP with respect to power price forecasts?

A. The updated power price forecast considered in the Stage 2 analysis addressed two primary issues: (i) consideration of the power price forecast issues resulting from the internal AURORA logic and (ii) "reoptimizing" (i.e., repeating the analysis) with both the new gas prices and generic resource costs. I discuss these elements in greater detail below.

d. Other Updates to the 2003 LCP

Q. Were there other significant assumption changes compared with the 2003 LCP?

A. Yes, the information gathered by the Company during the RFP process changed the 2003 LCP assumptions regarding (i) market purchases, (ii) wind capacity credits, (iii) wind capital costs, and (iv) the cost of meeting peak supply with call options instead of single cycle turbines.

(i) Updates Regarding Market Purchases

Q. How did the 2003 LCP's assumption regarding market purchases change during the acquisition process?

A. For the 2003 LCP, the Company assumed that it would rely on market purchases only to balance hourly loads and resources. The Stage 2 acquisition analysis, however, assumed that the Company would use market purchases to meet any resource need not otherwise met through specific resource additions.

(ii) Updates Regarding Wind Capacity Credits

Q. How did the 2003 LCP's assumption regarding wind capacity credits change during the acquisition process?

A. The Company determined in the Stage 2 analysis that wind capacity credits could reach approximately 20% of nameplate capacity; whereas the 2003 LCP assumed no wind capacity credits. The 2003 LCP assumption is based on the fact that no-one can turn the wind on when power demand is peaking. It is probable there will be times when the wind is not blowing, and the load is peaking. But on the other hand, it is also probable that the wind plant will be generating when the hourly peak occurs. Given this latter probability, the acquisition analysts felt that the capacity credit should not be zero. The approach was to look to how others were treating capacity credit and make a reasonable assumption for PSM valuation.

(iii) Updates Regarding Wind Capital Costs

Q. How did the 2003 LCP's assumption regarding wind capital costs change during the acquisition process?

A. The Company determined in the Stage 2 analysis, based upon bids received in response to the Wind RFP, that it underestimated wind capital costs in the 2003 LCP by nearly $200/KW. The 2003 LCP assumed a wind capital cost of $1,003/KW, whereas the wind capital cost averages from the RFP bid process was approximately $1,200/KW.

(iv) Updates Regarding Peak Supply Cost

Q. How did the 2003 LCP's assumption regarding peak supply cost change during the acquisition process?

A. For the 2003 LCP, the Company assumed peak supply costs were represented by single-cycle gas turbines at $4/kw-month (all year), with an example dispatch price of $58 per MWh assuming gas at $5 per MMBtu. For the Stage 2 analysis, the Company assumed peak supply costs were represented by call options at $2.50/kw-month (for the four winter months November through February), with an example dispatch price of $60 per MWh assuming gas at $5 per MMBtu. A similar process was used in the 2005 LCP. *See* Exhibit No. ___(EMM-6) at 239.

<u>3. Updating the Power Cost Forecasts in the 2003 LCP</u>

Q. Above, you deferred your discussion of the updated power forecasts used in the Stage 2 analysis. Could you please address such revised forecasts?

A. Yes. As part of its evaluation, the Company wanted to consider new gas price forecasts, generic plant costs and types, and strategy and cost for meeting peak demand. The RFP process informed the Company that the capital cost of new wind plants is higher than had been modeled generically in the 2003 LCP. Additionally, the initial incoming proposals did not include any seasonal joint ownership options for new gas plants.

Q. What were the changes in the underlying current and forecasted markets?

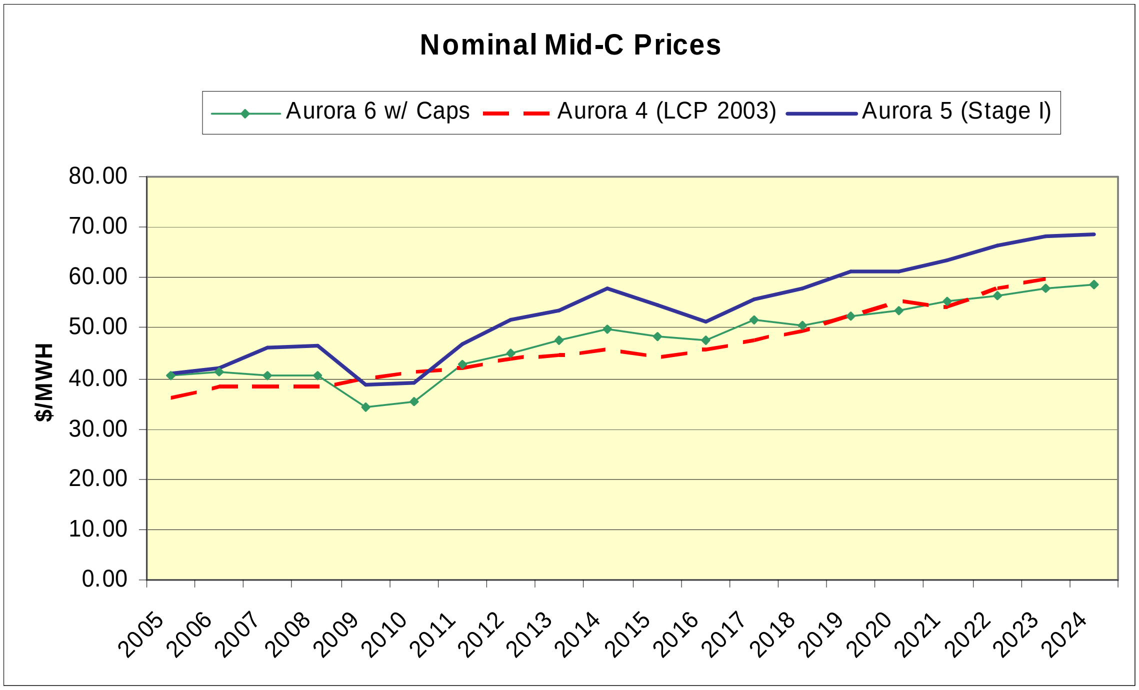
A. The key assumptions updated during the resource acquisition process to derive the AURORA electricity price forecast are the natural gas price forecast, and the generic plant costs and characteristics. The gas price forecast used in the Stage 2 analysis was the 4th quarter 2003 update to the CERA Rear View Mirror scenario, which was significantly higher than the forecast used in the 2003 LCP. *See* Exhibit No. ___(WJE-13HC) at 12. With the higher gas prices, the optimization routine in AURORA selected coal as a substitute for gas-fired plants, and the lower variable cost of coal held the power prices to a lower increase percentage than the gas price increase percentage. In the long term, this updated AURORA model adds a mix of wind, gas, and coal in WECC that is roughly 25 percent wind and the remainder being a 50/50 mix of coal and gas resources.

Q. What AURORA assumptions did the Company change to update its power price forecast?

A. AURORA has the capability to simulate the addition of new generation resources and the economic retirement of existing units through its long-term optimization run mode. For Stage 1, AURORA had been updated with CERA 2003 Gas prices, but had not been "reoptimized." Another change was that PSE adjusted the developer mix by dropping the unique shared resource joint ownership model. The result was a slightly lower cost of capital for development of resources. These assumption changes resulted in Stage 2 forecast power prices that are higher than the 2003 LCP prices, and lower than the Stage 1 prices. *See* Exhibit No. ___(WJE-13HC) at 12.

Q, How did the power price forecast change from Stage 1 to Stage 2?

A. As shown in the following graph, the Stage 1 prices showed an increase from the August 2003 LCP, as might be expected from the increase in natural gas prices. With the "reoptimization" of AURORA and associated assumptions, however, prices are only slightly higher than the 2003 LCP:



Q. What do you mean by "re-optimization of AURORA"?

A. Re-optimizing means allowing the AURORA logic to develop the optimal set of future resources in the WECC over a 20 year period. AURORA "retires" uneconomic plants and brings online new resources to meet each area's growing load. The resulting AURORA optimized price forecast is available for input into the Portfolio Screening Model.

Q. Did the Company have concerns with the re-optimized power price forecast?

A. Yes. The AURORA model produced some untenable long-term price spreads between peak and off-peak prices during August and September. The hourly prices output showed that average peak prices were driven upward by a number of extreme hours where the price was in the $200 to $500 per MWh range. Exhibit

No. ___(WJE-12) at 8-10. For example, the August on-peak to off-peak price difference was $50 to $90 per MWh every year starting in 2013.

Q. Why does PSE consider such August and September long-term price spreads as "untenable"?

A. PSE believes that such price spreads can occur in a cyclic pattern but will not continue year after year. Non-market and market forces would create new supplies or change existing hydropower operations to reduce these spreads. PSE investigated several approaches to model a more reasonable price spread.

Q. What did PSE do to address this issue?

A. The alternative chosen was to apply a price cap of $250 per MWh, such as the Federal Energy Regulatory Commission ("FERC") instituted on October 1, 2002. The choice does not imply that PSE believes that price caps will be implemented at this time. However, for modeling purposes, the $250 per MWh price cap is reasonable, useful and used by Northwest Power and Conservation Council as well.

Q. Does this affect the August and September time periods for all years considered in the Stage 2 analysis?

A. No. The number of hours per year affected by the price cap increases with time. For example, AURORA predicted that the $250 per MWh price cap would not affect any hours for calendar year 2008. By calendar year 2014, however, AURORA was predicting 46 hours over the $250 per MWh price cap, and AURORA was predicting 71 hours over the $250 per MWh price cap for calendar year 2020. Exhibit No. ___(WJE-12) at 8.

4. Scenarios Considered

Q. Did the Company use analytic methods other than Monte Carlo analysis to analyze uncertainty?

A. Yes. In addition to using Monte Carlo analysis, the Company used scenario analysis. Whereas Monte Carlo analysis analyzes the impact of uncertainty within a trend, scenario analysis analyzes the impact of major shifts in long-term trends of certain variables. In other words, Monte Carlo analysis examines variability around a *single* long-term trend, and scenario analysis examines the impact of *multiple* long-term trends.

Additionally, the Company performed Monte Carlo analysis on each of the scenarios analyzed. Coupling Monte Carlo analysis with scenario analysis provides a reasonable analysis of potential variability and its implications for decision making.

Q. Did the Company's natural gas price forecasting assumptions change?

A. Yes, as mentioned previously, PSE used the CERA Rearview Mirror forecast—updated in the fourth quarter of 2003—which was significantly higher than the gas price forecast that PSE used in the 2003 LCP. *See* Exhibit No. ___(WJE-13HC) at 12.

Q. Did the Company rely exclusively on the CERA Rearview Mirror natural gas price forecast and capping the summer electricity prices at $250 MWh in conducting the Stage 2 analysis?

A. No. Due to increases in natural gas prices, PSE determined that the Monte Carlo approach might not provide sufficient energy price variability to adequately test the various acquisition alternatives. Stated another way, the Company was interested in how the resource evaluations might change under significantly different power and gas price assumptions.

Q. What did the Company do to test this?

A. PSE developed the following four price scenarios to provide a more robust test of portfolio cost and risk:

1) the Base Price Scenario, which relies on the CERA Rearview Mirror natural gas price forecast with summer electricity price caps of $250 per MWh, as discussed above;

2) a No Price Cap Scenario, which also relies on the CERA Rearview Mirror natural gas price forecast but removes the summer electricity price caps of $250 per MWh;

3) a Low Gas Price Scenario, which relies on the CERA World In Turmoil natural gas price forecast; and

4) a Reserve Margin Scenario, which relies on a planning reserve proposed by FERC in its Notice of Proposed Rulemaking regarding Standard Market Design. *See Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design,* Notice of Proposed Rulemaking at ¶489, FERC Docket No. RM01-12-000 (July 31, 2002).

Q. Please describe the first and second scenarios.

A. As discussed above, the first scenario (the Base Scenario) relies on the CERA Rearview Mirror natural gas price forecast with summer electricity price caps of $250 per MWh.

The second scenario (the No Cap Scenario) is the same as the Base Scenario but with the $250 per MWh price caps removed.

Q. Please describe the third scenario.

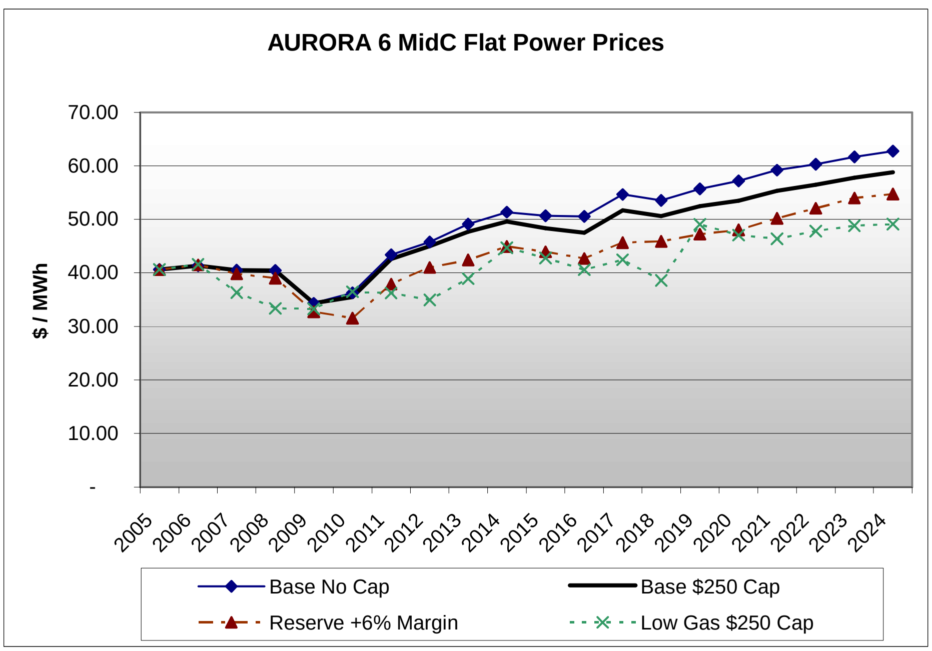
A. The third scenario (the Low Gas Scenario) relies on the natural gas prices from the CERA 2003 forecast titled "World in Turmoil." The World in Turmoil prices were slightly lower than gas prices assumed in the 2003 Least Cost Plan and significantly lower than those in the base CERA "Rear View Mirror" forecast.

Q. Please describe the fourth scenario.

A. The fourth scenario (the Reserve Margin Scenario) included a planning reserve proposed by the FERC in its Notice of Proposed Rulemaking regarding Standard Market Design in FERC Docket No. RM01-12-000. PSE tested a 6% planning reserve by using a load increased by 6% for the "optimization" process, then reverting back to the base load to determine prices. The resulting prices did not have the August spreads as there were adequate resources to meet the peaking demand. Another outcome of this scenario was to lower overall marginal prices because of the increased available capacity through all years.

Q. Please summarize the different results among the four scenarios.

A. The following chart shows the projected power prices using each of the four price scenarios:



In general, the No Price Cap scenario had the highest power prices while the Low Gas Scenario had the lowest power prices. The combination of gas and power price forecasts resulted in four market heat rate scenarios. The market heat rate is the market price of power divided by the market price of gas and is a variable that significantly impacts the economic dispatch of natural gas fired plants. The Low Gas scenario has relatively high market heat rates that would likely favor portfolios with natural gas generation. The Reserve Margin scenario has relatively low market heat rates that would least favor portfolios with natural gas generation. By testing portfolios under these diverse scenario conditions, PSE believes that it has a reasonable and robust measure of portfolio performance.

5. Portfolio Analysis

Q. How did the Company select bids for further evaluation using Portfolio Screening Model in the Stage 2 Analysis?

A. As discussed in the testimony of Mr. Garratt, Exhibit No. ___(RG-1HCT), PSE placed selected project proposals in a "most favorable proposals" list that contained proposals that were either on the "under continual investigation" list or on the "short list."

Together, the "under continual investigation" list and the "short list" comprised the 18 projects with the potential to be evaluated in the Stage 2 analysis using the Portfolio Screening Model. Exhibit No. ___(WJE-15HC).

Q. How did the Company further consider these 18 project proposals with respect to quantitative factors in the context of PSE's portfolio?

A. The Company combined proposals into portfolios by considering the following: (i) cost of the stand-alone resource, (ii) seasonal supply shapes, (iii) resource diversity, and (iv) how well the combinations of resources satisfied the resource need.

Q. Did the Company quantitatively evaluate a self-build proposal?

A. Yes. The company analyzed two options for gas self build using the Acquisition Screening Model and, in addition, evaluated each self build option in the Portfolio Screening Model, as described in Mr. Garratt's direct testimony. The first self-build option, assuming the proposal submitted the RFP to supply equipment for a combined cycle combustion turbine (CCCT), had a levelized cost of $64.65 per MWh. The second self-build option, the installation of two GE LMS100 single cycle combustion turbines (SCCT), had a levelized cost of over $107 per MWh. For comparison, the lowest cost CCCT proposal produced a levelized cost of $61.97 per MWh. When run through the Portfolio Screening Model, these two self-build options produced 20-year portfolio costs typical of the other portfolios that contained natural gas plant proposals.

Q. How many portfolios did the Company develop from these 18 project proposals for evaluation in Stage 2?

A. Initially, PSE developed 37 portfolios for testing by the Portfolio Screening Model in the Stage 2 analysis. Exhibit No. ___(WJE-16HC).

Q. What portfolios were tested and what were the Portfolio Screening Model results?

A. From the original 37 portfolios, PSE selected the following 12 representative portfolios under four price scenarios for further evaluation:

A. Portfolio #1: Market Through Calendar Year 2008
   1. Generic Gas
   2. Natural Gas beginning in calendar year 2009

B. Portfolio #2: Three PPAs
   1. 22-yr Seasonal On-Peak PPA
   2. APS 2-yr PPA
   3. 10-yr Coal PPA

C. Portfolio #5: Three PPAs and One Wind Project
   1. 22-yr Seasonal On-Peak PPA
   2. APS 2-yr PPA
   3. 10-yr Coal PPA
   4. Wild Horse Wind Project

D. Portfolio #7: Entire Short List
   1. 22-yr Seasonal On-Peak PPA
   2. APS 2-yr PPA
   3. 10-yr Coal PPA
   4. Wild Horse Wind Project
   5. Hopkins Ridge Wind Project

6. 150 MW Wind Project
7. ORMAT Recovered Heat Project

E. Portfolio #11: Three PPAs and Two Wind Projects
1. 22-yr Seasonal On-Peak PPA
2. APS 2-yr PPA
3. 10-yr Coal PPA
4. Wild Horse Wind Project
5. 150 MW Wind Project

F. Portfolio #14: Two PPAs and One Natural Gas-Fired Project
1. APS 2-yr PPA
2. 10-yr Coal PPA
3. Project A24 Gas-Fired CCCT

G. Portfolio #17: One PPA and One Natural Gas-Fired Project
1. APS 2-yr PPA
2. Project A32 Gas-Fired CCCT

H. Portfolio #23: Two PPAs, Two Wind Projects, One Coal Project and ORMAT
1. APS 2-yr PPA
2. 10-yr Coal PPA
3. Wild Horse Wind Project - COD Y2007
4. Hopkins Ridge Wind Project - COD Y2007
5. Coal Project A20 - COD Y2010
6. ORMAT Recovered Heat Project

I. Portfolio #25: Two PPAs and One Wind Project
1. APS 2-yr PPA
2. 10-yr Coal PPA
3. Wild Horse Wind Project

J. Portfolio #29: Two PPAs and One Natural Gas-Fired Project
1. APS 2-yr PPA
2. 10-yr Coal PPA
3. Project A29 Gas-Fired CCCT

K. Portfolio #30: Two PPAs and One Wind Project

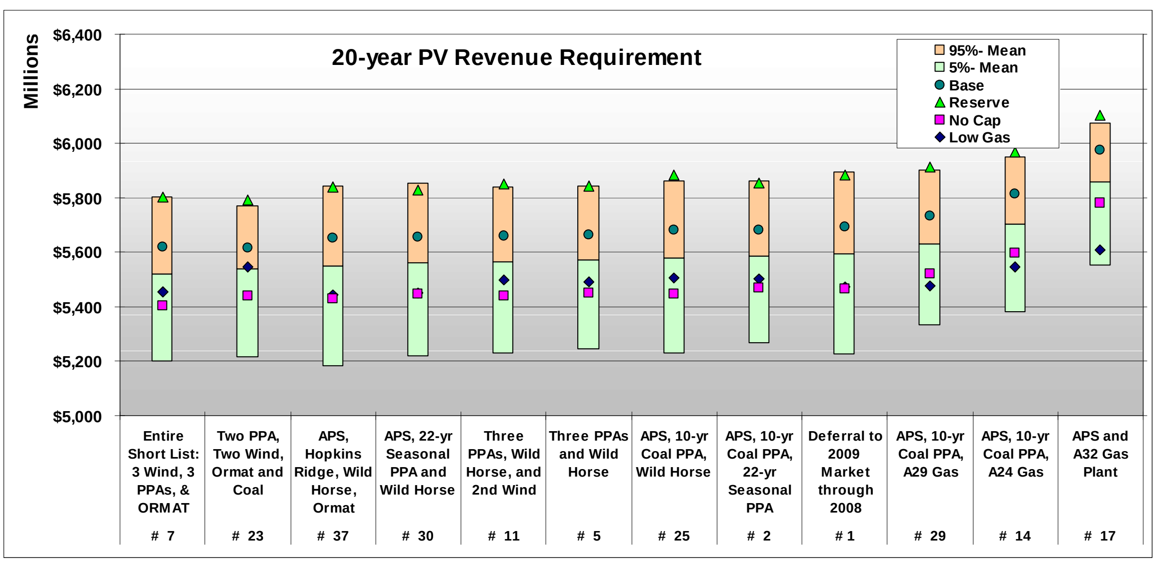
1. 22-yr Seasonal On-Peak PPA
2. APS 2-yr PPA
3. Wild Horse Wind Project

L. Portfolio #37: Proposed Portfolio -- Two PPAs and Two Wind Projects

1. APS 2-yr PPA
2. Wild Horse Wind Project
3. Hopkins Ridge Wind Project
4. ORMAT Recovered Heat Project

Q. How did the Company analyze these twelve portfolios?

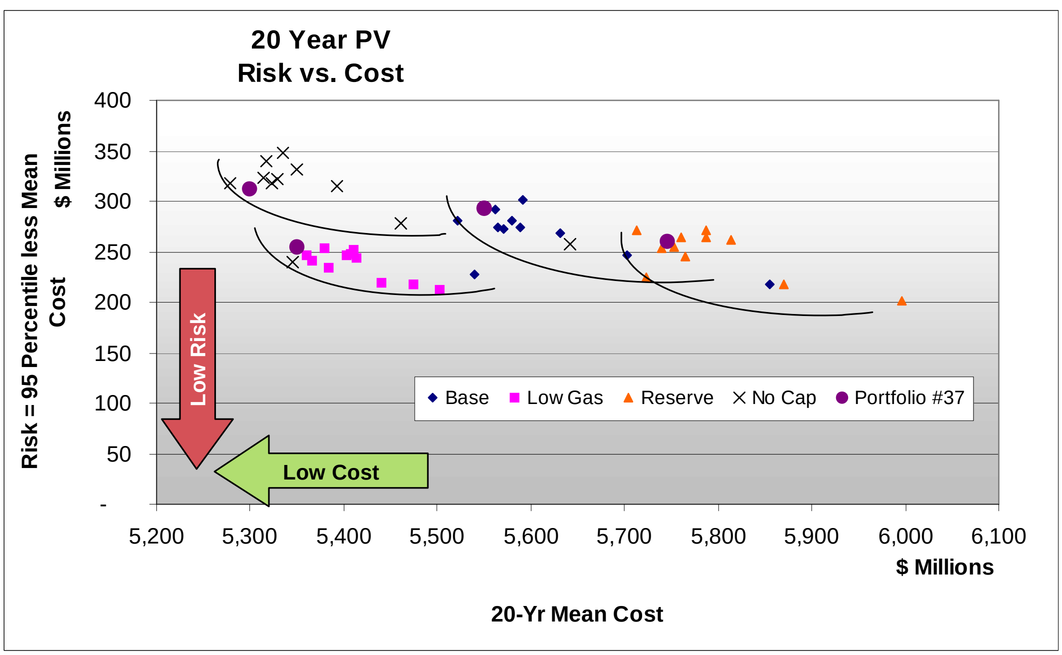
A. The Company calculated the present values of portfolio costs for each of the 12 portfolios. The following graph shows the present value of portfolio cost ranked from lowest cost on the left to highest cost on the right.



The rectangular columns in the above graph represent the range of portfolio costs resulting from 100 Monte Carlo iterations of the Base Price Scenario. The circle is the portfolio cost of the Base Price Scenario before running Monte Carlo. The circle is higher than the mean of the 100 iterations because the iterations capture secondary sales margins when power prices spike relatively higher than gas prices. The triangle, diamond and square represent the portfolio costs in the other scenarios before running Monte Carlo simulation.

Q. How else did the Company analyze these portfolios?

A. The Company prepared a scatter plot of portfolio cost and risk for the twelve portfolios in each of the four scenarios. The following scatter plot shows the portfolio cost on the horizontal axis and risk on the vertical axis.



See also Exhibit No. ___(EMM-17HC) at 27. Risk in the above graph is measured as the difference between the 95th percentile cost and the mean cost. The graph shows that the No Price Cap scenario generally has lower portfolio costs but higher risk than the other scenarios.

The above graph is useful to compare how well portfolios perform in each of the price scenarios. Portfolio #37 (made up of the resources the Company has ultimately pursued as a result of the RFP process) is shown by the large circles on the graph. In each scenario it is one of the lowest cost portfolios with medium level of risk.

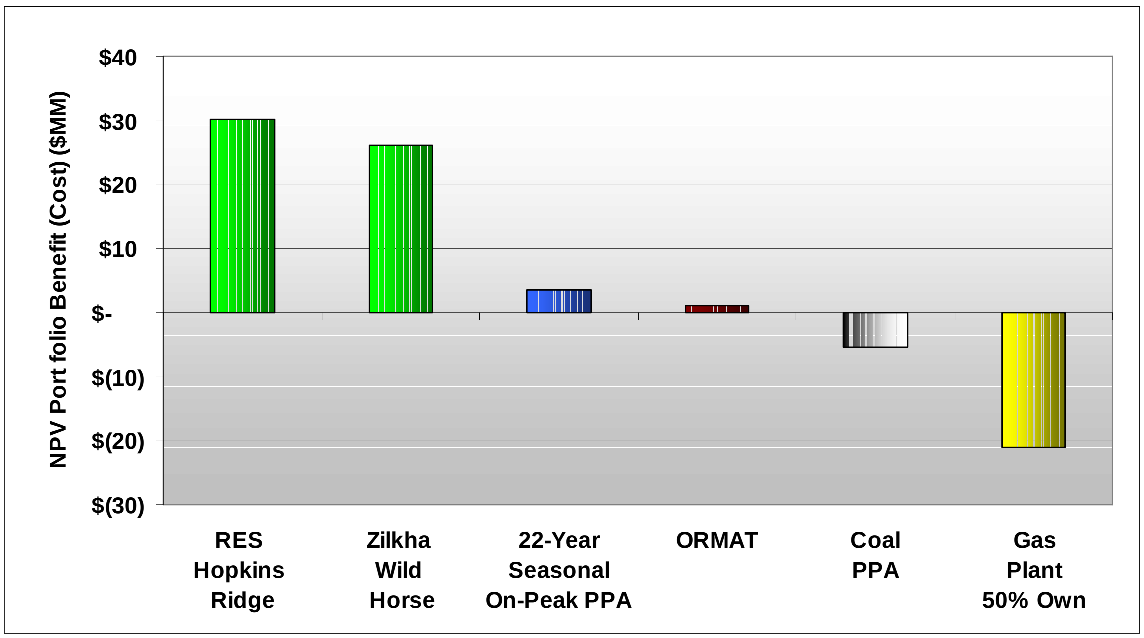
Q. What did the Company conclude from this portfolio analysis?

A. The conclusion of the quantitative analysis in Stage 2 showed that acquisition of the entire Stage 1 "short" list, and most combinations thereof, would present a low cost portfolio. Given this quantitative analysis, the Company was in the position to focus additional efforts on qualitative factors, due diligence, and negotiations regarding final commercial terms in pursuing final contracts to acquire the resources that made the short list, as described in Mr. Garratt's testimony.

Q. Did the Company separately examine the resources that made up the portfolios?

A. Yes, the Company used the Portfolio Screening Model to model the existing PSE portfolio and separately added individual proposals in a separate Portfolio

Screening Model run. The chart below presents the results of such modeling as to including or not including each proposal in the portfolio. The benefit or cost to the portfolio is measured by the change in 20-year NPV total portfolio cost. In each case, the base portfolio assumed energy deficits would be purchased from the market through 2008, and beginning in 2009 a mix of additional wind resources along with an equal mix of gas and coal generation resources would be added to meet the Company's load need.



Q. How did the Hopkins Ridge Project compare to other project proposals submitted in the Wind and All-Source RFPs with respect to quantitative analyses?

A. Very favorably. As discussed above, the wind project proposals had one of the lowest ranges of projected levelized costs ($44 - $63 per MWh) of any fuel type submitted in response to PSE's RFPs. The portfolios with wind had the lowest costs when measured in the Base Price Scenario and generally lower costs when measured in the other three price scenarios. Among the six wind projects on the "most favorable" list, the Hopkins Ridge Wind Project had the lowest projected levelized-cost. *See* Exhibit No. ___(WJE-15HC).

IV. CONCLUSION

Q. Does that conclude your testimony?

A. Yes, it does.

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