PSE PUGET SOUND ENERGY

DRAFT LEAST COST PLAN
March 31, 2003

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for Gas & Electric

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PUGET SOUND ENERGY

To: Participants in PSE's Least Cost Plan Process

From: Charlie Black

Date: March 31, 2003

Subject: Draft Least Cost Plan

Enclosed is a printed copy of the March 31, 2003 draft of Puget Sound Energy's Least Cost Plan. The draft report is also available in electronic form on PSE's web page, at www.pse.com/account/rates/rates.html.

The enclosed document sets forth PSE's draft long-term electric resource plan, as well as the Company's draft long-term natural gas resource plan. It reflects the results of extensive analysis and valuable input from a wide variety of perspectives. This process has helped PSE make significant advances in its resource planning efforts, including updating our analytical methods and models to explicitly address major sources of uncertainty and risk.

The primary purpose for issuing the draft Least Cost Plan is to gather further public input. We would very much appreciate your comments and suggestions on this document. PSE will accept public comments on the enclosed document throughout April. However, it would be most helpful if you can provide your thoughts by Friday, April 18, 2003 to Veronica Neumann. Veronica's e-mail address is veronica.neumann@pse.com. Comments can also be mailed to:

Veronica Neumann
Puget Sound Energy
411 108th Avenue NE – OBC-11N
Bellevue, WA 98004

In addition, PSE has scheduled a meeting of the Least Cost Plan Advisory Group beginning at **9:30 a.m.** on Tuesday, April 8, 2003. The meeting will be held in the first floor conference room (behind the Briazz cafe) at the One Bellevue Center Building, 411 108th Avenue NE in Bellevue.

To the extent possible, PSE will reflect your comments in the final version of the Company's Least Cost Plan to be issued on April 30, 2003. We will also have the opportunity to further reflect your input in an update of PSE's Least Cost Plan, scheduled for August 31, 2003.

I look forward to receiving your comments on the enclosed draft Least Cost Plan.

Sincerely,

Charlie Black

Charlie Black

Enclosure: March 31, 2003 Draft Least Cost Plan

PREFACE

As part of its long-term resource strategy development, PSE pursues a Least Cost Plan process. This document provides a perspective of the company's Least Cost Plan process. Moreover, this document serves to satisfy state requirements regarding Least Cost Planning as described in WAC 480-100-238 and WAC 480-90-238. The Least Cost Plan was developed in consultation with Commission staff and with public input, and is organized into 16 chapters:

Chapter I – Executive Summary
This chapter provides PSE's electric and gas resource strategy, in addition to highlights of major issues from each chapter of the Least Cost Plan.

Chapter II – Planning Issues
This chapter examines major regional and federal industry issues influencing PSE's long-term resource strategy.

Chapter III – PSE's Current Situation
This chapter provides an overview of PSE, including its current customer base, financial position, major regulatory issues, and its electric and gas optimization and hedging strategy.

Chapter IV – Stakeholder Interaction
This chapter describes the role of public participation in developing the Least Cost Plan, additional regulatory expectations and key stakeholder issues of concern identified through the public input process.

Chapter V – Load Forecasting
This chapter explains PSE's load forecasting methodology, its key forecast assumptions and provides electric and gas billed sales and customer forecasts.

Chapter VI – Distribution System Facilities Planning
This chapter addresses the mechanics of PSE's gas and electric delivery systems, and key considerations and benefits of the distribution planning process.

Chapter VII –Existing Electric Resources
This chapter lists PSE's existing electric resources, including its conservation and efficiency programs, and generation supply resources.

Chapter VIII – Electric Load-Resource Outlook
This chapter provides a recap of PSE's electric load forecast, discusses the loss of resources over the next 10 years, and presents PSE's electric load-resource outlook.

Chapter IX – New Electric Resource Opportunities
This chapter identifies resource opportunities, including conservation, renewable and thermal resources, and other resource opportunities such as demand response programs, fuel conversion, distributed generation and conservation voltage reduction.

Chapter X – Electric Portfolio Analysis
This chapter describes PSE's electric portfolio analysis process, including portfolio planning levels, portfolio construction, the analysis process, probabilistic risk analysis and consideration of other key uncertainties.

Chapter XI – Electric Resource Analysis Results and Judgment
This chapter presents the results of the electric resource analysis, and the application of company judgment in developing its long-term electric resource strategy.

Chapter XII – Electric Resource Strategy
This chapter describes PSE's electric strategy, discussing the role of conservation, renewables, traditional supply-side resources and power purchases in meeting PSE's long-term electric resource needs.

Chapter XIII – Existing Gas Resources
This chapter provides a snapshot of PSE's existing gas resources, including its conservation and efficiency programs, and supply resources.

Chapter XIV – New Gas Resource Opportunities
This chapter identifies new resource opportunities available to PSE, including conservation and efficiency programs, and supply resources.

Chapter XV – Gas Portfolio Analysis and Strategy
This chapter presents the analytical process objectives, an overview of the analytical process, analytical results and outlines PSE's recommended long-term gas resource strategy.

Chapter XVI – Action Plans
This chapter updates PSE's previous action plan and provides a new two-year action plan for implementing its long-term electric and gas resource strategy.

To assist the reader in the review of this Least Cost Plan, Exhibit A references the WAC rules governing requirements for the electric Least Cost Plan to chapters within the document where discussion of the topic can be found. Exhibit B addresses WAC rules regarding the gas portion of the Least Cost Plan.

Exhibit A
Electric Least Cost Plan Regulatory Requirements

STATUTORY/REGULATORY REQUIREMENT	CHAPTER
WAC 480-100-238 (3) (a) –A range of forecasts of future demand using methods that examine the impact of economic forces on the consumption of electricity and that address changes in the number, type and efficiency of electrical end-uses.	• Chapter III, PSE's Current Situation • Chapter V, Load Forecasting
WAC 480-100-238 (3) (b) An assessment of technically feasible improvements in the efficient use of electricity, including load management, as well as currently employed and new policies and programs needed to obtain the efficiency improvements.	• Chapter VII, Existing Electric Resources • Chapter IX, New Electric Resource Opportunities
WAC 480-100-238 (3) (c) An assessment of technically feasible generating technologies including renewable resources, cogeneration, power purchases from other utilities, and thermal resources (including the use of combustion turbines to utilize better the hydroelectric system).	• Chapter X, Electric Resource Analysis • Chapter XI, Electric Resource Analysis Results and Judgment
WAC 480-100-238 (3) (d) A comparative evaluation of generating resources and improvements in the efficient use of electricity based on a consistent method, developed in consultation with commission staff, for calculating cost-effectiveness.	• Chapter X, Electric Resource Analysis • Chapter XI, Electric Resource Analysis Results and Judgment
WAC 480-100-238 (3) (e) The integration of demand-side forecasts and resource evaluations into a long-range (e.g., twenty years) least cost plan describing the mix of resources that will meet current and future needs at the lowest costs to the utility and its ratepayers.	• Chapter XII, Electric Resource Strategy
WAC 480-100-238 (3) (f) A short-term (e.g., two-year) plan outlining the specific actions to be taken by the utility in implementing the long-range least cost plan.	• Chapter XVI, Action Plans
WAC 480-100-238 (4) Progress report that relates the new plan to the previously filed plan.	• Chapter XVI, Action Plans

Exhibit B
Gas Least Cost Plan Regulatory Requirements

STATUTORY/REGULATORY REQUIREMENT	CHAPTER
WAC 480-90-238 (3) (a) –A range of forecasts of future gas demand in firm and interruptible markets for each customer class for one, five, and twenty years using methods that examine the impact of economic forces on the consumption of gas and that address changes in the number, type, and efficiency of gas end-uses	• Chapter V, Load Forecasting
WAC 480-90-238 (3) (b) An assessment for each customer class of the technically feasible improvements in the efficient use of gas, including load management, as well as the policies and programs needed to obtain the efficiency improvements.	• Chapter XIII, Existing Gas Resources • Chapter XIV, New Gas Resource Opportunities
WAC 480-90-238 (3) (c) An analysis for each customer class of gas supply options, including: (i) A projection of spot market versus long-term purchases for both firm and interruptible markets; (ii) An evaluation of the opportunities for using company-owned or contracted storage or production; (iii) An analysis of prospects for company participation in a gas futures market; and (iv) An assessment of opportunities for access to multiple pipeline suppliers or direct purchases from producers.	• Chapter XIV, New Gas Resource Opportunities • Chapter XV, Gas Resource Analysis and Strategy
WAC 480-90-238 (3) (d) A comparative evaluation of gas purchasing options and improvements in the efficient use of gas based on a consistent method, developed in consultation with commission staff, for calculating cost-effectiveness	• Chapter XV, Gas Resource Analysis and Strategy
WAC 480-90-238 (3) (e) The integration of the demand forecasts and resource evaluations into a long-range (e.g., twenty-year) least cost plan describing the strategies designed to meet current and future needs at the lowest cost to the utility and its ratepayers.	• Chapter XV, Gas Resource Analysis and Strategy
WAC 480-90-238 (3) (f) A short-term (e.g., two-year) plan outlining the specific actions to be taken by the utility in implementing the long-range least cost plan	• Chapter XVI, Action Plans
WAC 480-90-238 (4) Progress report that relates the new plan to the previously filed plan.	• Chapter XVI, Action Plans

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I. EXECUTIVE SUMMARY

A. Introduction

As part of its long-term resource strategy development, PSE pursues a Least Cost Plan process. This document provides a current perspective of the Company's Least Cost Plan process. Moreover, this document serves to satisfy state requirements regarding Least Cost Planning as described in WAC 480-100-238 and WAC 480-90-238. The Least Cost Plan examines PSE's electric and gas resource needs over the next 20 years, and through robust analysis and consideration of price, supply and weather risks, reviews the necessary mix of conservation programs and supply resources to meet any electric or gas resource need. This document builds upon the draft Least Cost Plan filed in December 2002, specifically providing the results of the Least Cost Plan analysis process and long-term resource strategy recommendations. PSE believes its LCP meets necessary statutory requirements and seeks a letter from the WUTC accepting this Least Cost Plan filing.

PSE maintains an open commitment to actively encouraging public involvement in this process. As of March 31, 2003, seven formal Least Cost Planning meetings, in addition to dozens of informal meetings and communications have taken place, with meetings scheduled to solicit additional stakeholder feedback. A number of stakeholders including WUTC Staff, consumer advocates; individual customers from industrial, commercial, and residential classes; environmental organizations; the Northwest Power Planning Council; and the Washington State Department of Community, Trade and Economic Development have actively participated in meetings. The stakeholder meetings provide an avenue for constructive feedback and useful information to guide the Least Cost Plan process. PSE wishes to express gratitude to those who have attended the Least Cost Planning meetings for their time and energy devoted to the Least Cost Plan process. PSE encourages the continuation of this active participation as the Company's planning process proceeds.

B. Key Findings

PSE believes it has an opportunity to pursue a balanced electric resource portfolio strategy that meets customer needs, keeps rates low and protects against market risks, such as those recently experienced in the region. Due to both the growing load factor in its service territory, and the loss of existing resources over the next 10 years due to reduced hydro and combustion turbine generation, and the expiration of power purchase and NUG contracts, PSE has a need for new electric resources. The planning standards that PSE believes appropriate call for adequate energy resources to serve each month's electric load under average hydro conditions, and having enough capacity resources to meet customer peak loads of 16 degrees Fahrenheit. Both energy and capacity resources will be shaped to fill winter deficiencies, without creating summer surpluses.

The initial objective of PSE's long-term electric resource strategy is to acquire at least 150 aMW of new conservation resources over the next 10 years. PSE intends to serve at least 5 percent of its load with wind resources, and will strive to meet 10 percent of its load requirements through renewable resources by 2013. A diverse mix of other resources, including combined cycle gas-fired generation in the near-term and possibly coal later in the decade, plus market purchases, provide options for meeting the rest of PSE's resource needs. PSE will shape resources to meet two needs – to balance the portfolio within the year and to avoid the associated risks of being out of balance in certain months of the year. In addition, PSE will continue to monitor the market for opportunities for resource acquisitions and power contracts, but not at the expense of its commitment to conservation.

PSE's gas Least Cost Plan analysis highlights that PSE has a portfolio of gas resources that provide a reliable supply of natural gas to its customers at least cost. PSE does not need to make any gas resource acquisition decisions in the near term, but the Company will continue to refine its analysis of resource requirements to ensure that its customers have a reliable, least-cost supply of gas. The analysis demonstrated a relatively low risk in the near term due to the portfolio structure, but opportunities exist to enhance the value and reduce the effect of price risk on the portfolio. Within the next few years and depending on the growth in firm loads, PSE will face decisions regarding resource acquisitions that change the structure of its portfolio.

PSE's action plan to achieve its long-term energy resource strategy focuses on nine key areas:

- ***August 2003 Update*** – Upon receiving the regional assessment of conservation potential, PSE will analyze the information and update its Least Cost Plan modeling and resource strategy in a WUTC filing in August 2003.
- ***Conservation*** – PSE will achieve an annual target of 15 aMW and 2.1 million therms of conservation savings per year for the next 20 years. In addition, the Company will continue

supporting customer education and awareness of energy efficiency measures, and its participation in regional collaborative efforts.

- ***Renewable Resources*** – PSE will examine wind integration issues for incorporating wind resources into its portfolio, consider releasing an RFP for renewable resources and continue to explore ways to provide 10 percent of PSE's energy needs through renewable resources.
- ***Demand Management*** – PSE will continue to participate in collaborative efforts to advance demand management techniques such as fuel conversion, time-of-use rates, conservation voltage reduction and distributed generation for its customers and for the region.
- ***Supply-Side Acquisition*** – PSE will continue to monitor the market for generation asset and power contract acquisitions that fit within its financial and resource needs.
- ***Energy Supply, Gas*** – PSE will continue to explore detailed analysis of Propane Air options and cost estimates, new pipeline projects, additional storage options, the feasibility of expanding Jackson Prairie's storage capacity and deliverability, and long-term supply basin pricing differentials to assist in the determination of preferred pipeline alternatives.
- ***Energy Demand Forecasting*** – PSE will develop more detailed load shape and duration data and analyze the results of electric to gas conversion pilot program to determine impact on gas load.
- ***Distribution Facilities Planning*** – PSE will continue its participation with other EEI utilities in the FERC NOPR process for distributed generation, while seeking opportunities to deploy distributed generation for least cost capacity deferral, and to improve PSE's distribution gas and electric planning process
- ***Integrated Resource Modeling*** – PSE will continue the on-going process of evaluating new gas and electricity resource options and alternative resource strategies to meet customer needs. In addition, PSE will continue development of model databases to better assess the impacts of alternative gas price scenarios, resource costs, and load forecasts on PSE's resource portfolio.

C. Planning Issues

Events occurring in the energy industry over the past several years have been instructive to PSE in a number of ways. Most importantly, the Western Energy Crisis illustrated the vital importance of sound resource planning and supply decisions, and the critical importance of well-designed and liquid markets. Other key highlights include:

- Supply adequacy and price volatility issues remain a regional concern, and PSE's obligation is to balance price and risk for its ratepayers.

- Resource adequacy in the Pacific Northwest region continues to mean having enough "controlled" resources to meet customer needs.
- Under all planning scenarios, PSE will continue to participate in the wholesale market to buy and sell energy and capacity to balance fluctuations in loads and resources, and it will continue to seek non-energy financial intermediaries for financial derivative products to smooth price fluctuations.
- Regional interdependencies will continue to affect resource availability and price volatility.
- Reliance on hydro resources poses unique challenges for planning supply and will continue to present risks to future merchant power development in the region.
- Merchant power retrenchment creates a potential window of opportunity for PSE to develop assets to meet its resource needs.
- The current financial condition of counterparties in the wholesale energy market and PSE's own creditworthiness, limit PSE's ability to enter into long-term forward power contracts.
- The future of the wholesale market structure remains uncertain in the West even as FERC continues to move forward with its Standard Market Design.
- On the federal level, the U.S. Congress will likely examine three primary issues of interest to PSE during the 108th Congress – a comprehensive, national energy bill; the extension of the energy production tax credit; and proposals to amend the Clean Air Act. All three issues could impact PSE's long-term resource strategy.
- State lawmakers have introduced legislation to stimulate greater investment in renewables, conservation and cleaner technology. Due to state legislative concerns regarding higher energy costs and a focus on allocating limited tax revenues to meet basic government services and the state budget deficit, it is anticipated that through the next biennial period (2003-2005), public policy decisions directly impacting utility costs will be relatively few and of moderate impact.

D. PSE's Current Situation

To gain a full understanding of the context in which the Least Cost Plan process occurs, internal PSE factors such as its financial, regulatory and business strategy must be considered. In all these arenas, PSE pursues strategies limiting overall supply risk, while allowing both stakeholders and customers to benefit from its prudent business strategy. Other key conclusions include:

- PSE's financial policy focuses on one main goal – improving its credit rating.

- PSE's Power Cost Adjustment (PCA) mechanism, which resulted from a 2002 rate settlement agreement, shares the costs or benefits of higher or lower power costs between customers and shareholders. In addition to providing for cost-sharing, the PCA limits PSE's financial exposure to power supply costs over a threshold of $40M over a four-year period, providing prompt rate adjustments in highly volatile power markets.
- On the gas side, PSE has a Purchased Gas Adjustment (PGA), which allows the Company to pass through to its customers, on a dollar-for-dollar basis, the actual increases and decreases of gas supply costs and "upstream-of-the-city gate" gas transmission and storage resource costs.
- PSE's electric portfolio optimization and hedging approach – which reaches one to two years into the future, seeks to ensure physical supplies exist to serve customer need, while optimizing the portfolio's value and limiting price volatility for customers and earnings risk to PSE shareholders.
- PSE operates its core gas portfolio in a conservative manner in order to be certain that at all times it can cover peak day demand. This approach can leave PSE long on supply sources during certain times of the year, thus PSE utilizes a variety of contract and operational techniques to generate revenues and cut down energy costs to its customers.
- PSE must not only manage gas price risks for serving its LDC end-use customers, but also for procuring supply for its gas-fired electric generation portfolio. Although no clear solution for eliminating price risk volatility exists, PSE can use available financial tools to control and hedge these costs to some degree.
- PSE's ability to execute risk management strategies is constrained by the number and creditworthiness of counterparties, and by its own credit rating and limited access to credit.

E. Stakeholder Interaction

PSE maintains an open commitment to actively encouraging public involvement in its Least Cost Plan process. Not only has PSE held stakeholder meetings to discuss its Least Cost Plan process and provide a forum for public guidance, PSE has also reviewed and incorporated written comments from stakeholders into its current Least Cost Plan process. Other key highlights include:

- As of March 31, 2003, PSE has held seven formal Least Cost Plan meetings, in addition to dozens of informal meetings and communications, with key stakeholders including WUTC staff; consumer advocates; individual customers representing industrial, commercial and residential customers; environmental organizations; the Northwest

Power Planning Council; and the Washington State Department of Community, Trade and Economic Development.

- During these meetings, a variety of topics were addressed, including electric sales forecasts and assumptions, PSE resource needs, transmission constraints, renewable resources, gas and electric distribution planning, natural gas supply and hedging risk, and the AURORA modeling process, among others.
- In addition to meeting Least Cost Plan regulatory requirements, PSE also addressed additional regulatory expectations as presented by the WUTC in its August 2001 letter to PSE commenting on PSE's 2000-2001 Least Cost Plan.
- Stakeholder issues of concern have centered on three main issues – whether the Least Cost Plan provides a basis to justify resource acquisition, if sufficient and fair treatment has been given to renewable resources and energy efficiency, and the proper allocation of risk between the Company and its customers.
- PSE has incorporated these stakeholder issues of concern into Least Cost Plan process. The Company has reviewed its assumptions, expanded the depth and robustness of its analysis, examined a wide range of electric resource opportunities, and continued to seek public input.

F. Load Forecasting

Each year, PSE develops a 20-year forecast of customers, energy sales and peak demand for its electric and gas service territories. PSE uses this forecast in short-term planning activities such as the annual revenue forecast, marketing and operation plans, as well as in various long-term planning activities such as the Least Cost Plan, and the transmission and distribution plans. For this Least Cost Plan, PSE updated its forecast methodology for its billed sales forecast in order to more accurately account for large industrial and commercial customers moving to transportation schedules and to correct for modeling issues. Other major chapter highlights include:

- Annual real GDP is anticipated to grow at 3.2 percent in the next 20 years.
- Employment growth in PSE's service territories will likely grow at a slower rate (1.6 percent) than its 30-year historical growth rate, fueled mainly through growth in the service sector.
- Electric nominal rates are anticipated to grow between 2 and 2.6 percent per year over the next twenty years, resulting in declining real electric rates.
- Gas rates are anticipated to increase at less than 2 percent per year, lower than the long-term rate of inflation.

- Electric conservation savings are assumed to be 15 aMW per year for the next 20 years, as compared to the rate case settlement, which required PSE to achieve 15 aMW of savings for 2003 only. Gas conservation savings are assumed to be 2.1 million therms per year.
- PSE's conservation assumptions beyond 2003 will be revisited after further collaborative studies are completed by the third quarter of 2003.
- PSE electric sales are expected to grow at an average annual rate of 1.4 percent per year in the forecast to 2,891 aMW in 2022.
- PSE anticipates a projected growth rate of electric customers at an average annual rate of growth of 1.7 percent per year between 2002-2022, to 1.35 million customers in 2022.
- Electric peak load forecasts are expected to grow by 1.6 percent in the next twenty years.
- PSE's natural gas billed sales are expected to grow at an average, annual rate of growth of 2.1 percent per year in the next 20 years from 1,022,230 Mtherms in 1998 to 1,562,567 Mtherms by 2022.
- PSE anticipates a projected growth rate of natural gas customers at 2.7 percent per year in the next 20 years.
- The gas peak day forecast predicts peak firm gas requirements increasing from 7.8 Mtherms in 2002 to 12.2 Mtherms in 2022, or a growth rate of approximately 2.2 percent in the next 20 years.

G. Distribution System Facilities Planning

Distribution system facilities planning represents a key component of the Least Cost Plan process. Changes or additions to the delivery system may provide a less expensive alternative to building additional facilities. Other key highlights of this chapter include:

- The changing electric demand profile related to the proliferation of computers and other highly sophisticated electronic equipment, coupled with higher performance standards, create an additional distribution planning challenge for both the gas and electric distribution systems.
- Performance standards regarding safety and reliability form a basis for distribution system planning.
- PSE pursues an asset management approach to distribution planning whereby PSE seeks to ensure the full utilization of existing facilities before adding a new facility, unless the cost advantage of early installation offsets the cost of having the facility at a low level of utilization.

- The steps in the distribution planning process include a system review, system base modeling, system alternative modeling, development of project descriptions and the determination of a prioritized list of projects.
- Planning alternatives for distribution facilities planning may take one of two paths – building new facilities or making operational adjustments to existing facilities.
- To improve the overall efficiency of its distribution planning operations, PSE has initiated the use of value-based budgeting.
- PSE has made greater investments in modeling and telemetry systems, as well as automated meter reading (AMR) technology as a means to manage its delivery system on an improved real-time basis.
- Regulatory, business practice and technology barriers challenge the wide-spread application of distributed generation, however, PSE actively pursues targeted applications of distributed generation as a least-cost capacity deferral alternative to traditional distribution system upgrade or expansion.

H. Existing Electric Resources

PSE utilizes a balanced mix of conservation and efficiency, net metering, and generation supply resources, including hydro, coal, NUG contracts, CT's and long-term contracts with Qualifying Facilities and with non-Qualifying Facilities. Other key highlights include:

- PSE currently has approximately 20 conservation programs in place, with nearly 10 more pilot/new programs underway.
- PSE has provided conservation services for its electricity customers since 1979, saving 249 aMW (cumulative load reduction) through 2001. The Company has invested approximately $310 million in electricity conservation since 1989 and has realized energy savings representing over 11% of PSE's average existing annual electric loads.
- From September 2002 – December 2003, PSE's conservation programs and services are expected to achieve 20.2 aMW of energy savings.
- PSE's schedule 150 net metering customers provide a resource of approximately 37 kW.
- PSE's generation portfolio resources consist of 2,287 aMW – 40 percent from hydro, 25 percent from the Colstrip plant, 22 percent from NUG contracts, 7 percent from Encogen and 6 percent from other contracts.
- Most of PSE's NUG contracts, totaling 498 aMW, and long-term contracts, totaling approximately 210 aMW, expire in the 2011-2012 time period, creating a deficiency between PSE's load forecast and existing resources.

I. Electric Load-Resource Balance

For many utilities, load growth represents the primary driver in their load-forecast outlook. In contrast, PSE faces the current loss of existing resources, with further losses anticipated over the next 10 years, in addition to load growth in its service territory. By 2012, PSE loses some of its current hydro and combustion turbine resources, in addition to the expiration of power supply and NUG contracts. Other chapter highlights include:

- PSE anticipates its electric load to grow from 2,377 aMW in 2004 by 238 aMW to 2,660 aMW in 2013. By 2023, PSE has an anticipated electric load of 3,140 aMW.
- PSE anticipates its expected winter peak to grow from 4,819 MW in 2004 by 695 MW to 5,514 MW in 2013. By 2023, PSE has an expected winter peaking need of 6,490 MW.
- By 2010, PSE will lose 314 aMW of energy and 755 MW of capacity through the expiration of power supply contracts.
- PSE's loss of hydro resources by 2012 will decrease its load resources by 102 aMW.
- The loss of PSE's Whitehorn combustion turbine will decrease its load resource by 134 MW.
- The expiration of PSE's NUG contracts in 2011-2012 will deplete PSE's resources by 498 aMW.
- PSE simulated the dispatch of its existing resources to serve the forecast load over the 20-year period to quantify its load resource outlook.
- For planning purposes, PSE is reserving its simple cycle combustion turbines (SCGTs) for several purposes including serving winter peak load requirements, as reserves for unit outages at other facilities, and to back up hydro in low years. In addition, the SCGTs may be a resource to "back up" intermittent wind resources.
- However, for planning purposes, the load-resource outlook reflects the full availability of its higher efficiency combined cycle gas-fired generation resources. PSE's SCGTs have poorer fuel efficiencies than current combined cycle technology and limited run-time due to existing permits.
- For planning purposes, PSE reflects the full baseload capacity of its combined cycle resources.

J. New Electric Resource Opportunities

PSE has a wide variety of available electric resource opportunities to balance its load-resource outlook. Conservation, renewable and thermal resources, and other alternatives such as demand response programs, fuel conversions, distributed generation and conservation voltage reduction offer potential opportunities. Other chapter highlights include:

- As part of the current effort to develop new supply curves, PSE is reviewing new and emerging measures anticipated to become cost-effective over the next 5 to 10 years.
- Resource supply alternatives include renewable resources such as wind, biomass, solar and geothermal energy, while thermal resources options focus on gas-fired and coal sources.
- Fuel conversion, the switching of end-users from electricity to gas, represents a potential cost-effective efficiency resource opportunity.
- Conservation voltage reduction, another potential new resource opportunity, involves reducing local distribution service voltage on certain circuits, with certain end-use loads, to provide energy savings.
- Distributed generation consists of several technologies – fuel cells, micro turbines, mini-turbines and reciprocating engines – that provide near-term opportunities for electric resource needs.
- PSE considers demand response programs such as its recent time-of-use program or critical peak pricing products as another option for meeting electric resource needs. Currently, PSE is participating in a collaborative effort to examine time-of-use scenarios and conduct program analysis.
- Transmission constraints – including thermal limitations in PSE's control area and stability limitations around Colstrip – add to the cost and time frame of building new generation and increase the cost of delivering energy from facilities not directly interconnected with PSE's system.
- Additions in 2003 to gas transmission capacity will increase delivery of 200,000 Dth/day, however, much of this capacity has been contracted by sponsors of pending power plants.

K. Electric Portfolio Analysis

Since PSE filed its last Least Cost Plan, the Company has significantly updated and improved the analytical process for determining its least-cost electric resource strategy. Most significantly, PSE has incorporated probabilistic analysis of key risk factors such as the market prices for gas and power, hydro availability and the correlation between these three factors with its analytical process. Other key highlights of this chapter include:

- In absence of a regional or state regulatory requirement on sufficiency standards for resource planning, PSE examined eight planning levels. These levels ranged from a "do nothing" approach assuming PSE's current energy and capacity deficit grows with demand, to a planning level requiring energy in all months to be at 110 percent of the total monthly load and capacity needs to meet a 13-degree F hour at SEA-TAC.
- At these planning levels, energy needs in 2004 ranged from 10 to 674 aMW, growing to 1,176 to 1,874 aMW by 2013.
- For capacity, the possible capacity needs in 2004 ranged from 307 to 1,558 MW, increasing to 2,156 to 3,562 MW in 2013.
- PSE constructed portfolios consisting of a mix of gas, coal and wind resources. Specific construction rules regarding availability of new resources guided the construction of the portfolios. In addition, three methods of seasonal shaping were utilized in the portfolio construction.
- The first step of PSE's resource analysis process consisted of developing basic inputs and assumptions such as retail customer and electric loads, existing power supply resources, natural gas price forecast and wholesale electricity market prices.
- PSE developed a dispatch model which provides MWh and variable costs for each resource considered by PSE in order to screen the various portfolios.
- PSE used the dispatch model results to derive a "bottom up" revenue requirement for each new resource. The revenue requirement, the variable cost and the cost of market purchased were used to develop a net present value (NPV) of the 20-year strip of incremental costs for each portfolio.
- After regional updated conservation assessments become available in May 2003, PSE will update its analysis with conservation resource estimates for an August 2003 filing to the WUTC.
- In addition to performing probabilistic risk analysis, PSE modeled two alternative scenarios for market power prices. Moreover, PSE examined other uncertainties such as retail load growth scenarios, emission impacts and the impact of the possible expiration of the wind production tax credit in December 2003.

L. Electric Resource Analysis Results and Judgment

The results of PSE's electric load-resource analysis include the following conclusions:

- When portfolio planning levels are considered in pairs with progressive increases in the energy and capacity planning levels together, expected costs to customers are shown to be higher at the higher combined planning levels.
- However, evaluation of increasing energy planning levels (holding the capacity planning level constant) indicates that expected costs to customers are lower at higher energy planning levels. Factoring in the market risks associated with energy planning levels that exceed PSE customer needs, provides supporting for an energy planning level that matches expected customer needs on a month-by-month basis.
- Evaluation of increasing capacity planning levels (holding the energy planning level constant) indicates that expected costs to customers increase when moving to higher capacity planning levels. However, these results are based on analysis that primarily focuses on single cycle gas turbines (SCGTs) as a source of capacity. Other potentially lower-cost sources of capacity should be examined. Further, PSE also needs to consider its obligations to meet reliability requirements and its obligations to serve winter peak needs of its customers.
- Evaluation of tradeoffs between expected costs to customers and risk (represented as variability of costs) results in a conclusion that moving from a lower energy planning level to one that meets each month's expected needs does not increase risk and produces a modest reduction in expected cost.
- Analysis of several approaches for shaping new resource additions to the seasonal profile of the need for resources indicates that Joint Ownership or other approaches to seasonally shape new resources increases expected cost but also significantly reduces risk. Forward sales of new capacity resources during the non-winter period also reduce risk and do not significantly affect expected costs. PSE found seasonal exchanges to increase expected costs and not reduce risks.
- Analysis of resource portfolios that defer new resource additions until 2008 shows that such a strategy, if executable, may reduce expected costs but would create an unacceptable increase in risk. Further, counterparty credit constraints and other factors make it unlikely that such a deferral strategy could be implemented.
- Analysis of several mixes of various resource technologies indicates that a portfolio composed of gas-fired and coal-fired generation could have the lowest expected cost and the lowest risk. However, this result is highly dependent on assumptions about key

uncertainty factors such as future costs for emissions from fossil-fueled resources. Consideration of this and other factors affecting each major resource type leads to a conclusion that a diversified resource strategy can spread risks and reduce the overall level of risk.

In developing its preferred resource strategy, the Company also considered a number of judgmental factors, including the following:

- The Washington State Energy Strategy update, issued in February 2003 includes Guiding Principles that address utility obligations to plan and acquire adequate resources to meet their customers' long-term needs, and to protect customers from supply shortages and market price volatility. These Guiding Principles further support the Company's selection of a balanced resource strategy including energy and capacity planning levels that provide adequate resource to meet expected customer needs.
- PSE also must consider risks associated with relying on the regional power market to make up for imbalances in the Company's electric resource portfolio. These risks increase significantly when the Company's portfolio is out of balance.
- Economic dispatch models used for resource planning studies are typically based on underlying assumptions that energy markets will remain in continuous equilibrium over the long-term. Actual market conditions diverge from this assumption and market prices can in fact be highly volatile. This phenomenon can lead to a 'disconnect' that could entice utilities to plan on meeting their customers' resource needs by relying on a market that turns out to be more volatile and higher-cost than was assumed as an input into the initial analysis. PSE has concluded that it should not pursue a "free-rider" strategy that depends on other entities in the regional market to provide new resources to meet its customers' needs. PSE intends to do its part in contributing to regional load-resource balance.
- Beyond the base case analysis, consideration of other factors support the development of a diversified resource strategy. These include recognition that each major resource type has both appealing features and existing or potential aspects that may make them more costly or risky. Since no available generating resource technology is clearly superior to all other alternatives, the Company's preferred resource strategy identifies a mix of resource alternatives.

M. Electric Resource Strategy

PSE believes it has an opportunity to pursue a balanced resource portfolio strategy that meets customer needs, keeps rates low and protects against market risks, such as those recently experienced in the region. Several key components drive PSE's long-term electric resource strategy:

- Energy resources will be adequate to serve each month's expected customer energy needs under average hydro conditions.
- PSE has a goal of having capacity resources adequate to meet customer peak loads of 16 degrees Fahrenheit.
- Both new energy and new capacity resources will be shaped to fill winter deficiencies, without creating summer surpluses, to the extent feasible.
- PSE will acquire at least 150 aMW of new conservation resources over the next 10 years.
- PSE will serve at least 5 percent of its load with wind resources, and will strive to meet 10 percent of its load requirements through renewable resources by 2013.
- A diverse mix of other resources, including combined cycle gas-fired generation in the near-term and possibly coal in 2006, in addition to market purchases provide options for meeting the rest of PSE's resource needs.
- PSE will continue to monitor the market for acquisition opportunities and power contracts, but not at the expense of its commitment to conservation.

N. Existing Gas Resources

PSE relies upon a variety of resources – including both conservation and efficiency, and supply resources – to serve its gas customers. Currently, PSE does not anticipate requiring additional firm capacity until sometime around 2010. Other key highlights include:

- PSE recently increased its commitment to conservation, agreeing in August 2002 to double its annual conservation target. During the 16-month period from September 2002-December 2003, PSE's portfolio of natural gas conservation programs and services expect to achieve 2.9 million therms of cost-effective energy savings, at a utility cost of $3.9 Million.
- PSE holds a total of 869,938 Dth/day of pipeline capacity to its city-gates – 456,381 Dth/day and 413,557 Dth/day of firm TF-1 and TF-2 transportation capacity of the Northwest Pipeline, and additional upstream capacity on other pipelines.

- PSE has contractual access to two storage projects, providing a total storage capacity of 20,944,021 Dth. PSE utilizes storage capacity to provide an immediate source of firm gas supply, allow for less expensive, off-peak purchases of gas, for load balancing, and to use its transportation and gas supply contracts at a higher load factor.
- PSE's peaking resources include Liquefied Natural Gas (LNG), Peak Gas Supply Service (PGSS) and vaporized propane-air.
- This Least Cost Plan focuses more on the reliability of its pipeline capacity and the outlook for natural gas supplies than it does on supply contracts.

O. New Gas Resource Opportunities

Over the 20-year planning period, PSE has a number of opportunities to explore new conservation and efficiency initiatives, and modify the structure of its resource portfolio. These opportunities arise as capacity contracts expire or additional capacity opportunities become available. Other key highlights include:

- PSE has access to a variety of cost-effective gas conservation and efficiency resource opportunities in each of the customer sectors to help meet gas energy needs.
- PSE expects newer, more efficient technologies will allow increased precision with which users are able to monitor, operate, maintain and manage natural gas energy consumption.
- Several of PSE's pipeline capacity contracts expire between 2004-2016. These pending expirations, coupled with PSE's renewal rights and proposed new pipelines, create opportunities for PSE to make alternative gas resource decisions.
- Along with the expiration of its pipeline capacity contracts, PSE has a number of opportunities to modify its gas storage capacity positions over the next eight years.
- PSE expects to maintain its current approach to making diversified purchases among the Rockies, British Columbia and Alberta supply basins in order to provide reliability and price protection.
- The average of the estimates from industry sources of North American gas reserves is 1,186 Tcf, or almost 60 years of demand at current levels.
- Reserve additions in the basin's tributaries to PSE's firm transportation receipt points indicate growing exploration and production activity.
- Pipeline and producers have demonstrated a willingness to develop the facilities to bring gas into the Northwest region as necessary.

P. Gas Resource Analysis and Strategy

PSE analyzed its resource portfolio in light of expected changes and under a variety of assumptions. This evaluation demonstrated that PSE has developed and maintains a portfolio of gas resources that provides a reliable supply of natural gas to its customers at least cost. Other key highlights include:

- The analysis demonstrated that there is relatively low risk in the near term due to the portfolio structure, but opportunities exist to enhance the value and reduce the effect of price risk on the portfolio.
- Within the next few years and depending on the growth in firm loads, PSE will face decisions regarding resource acquisitions that change the structure of its portfolio.
- In the interim, it is not cost-effective to terminate any of its pipeline capacity contracts since new capacity is 30 percent higher than existing capacity.
- Further, PSE's demonstrated ability to optimize the gas resource portfolio provides additional benefit to its customers by reducing the risk in the average cost of gas, and extracting the maximum benefit for its customers.
- PSE does not need to make any resource acquisition decisions in the near-term. PSE continues to refine its analysis of resource requirements to ensure that its customers have a reliable, least-cost supply of gas.
- The modeling exercise identified an "ideal", least-cost portfolio structure. Because this portfolio structure relied upon assumptions and forecasted data, PSE understands that the selected portfolio serves as a reference point for its gas resource procurement and management strategy.

II. PLANNING ISSUES

This chapter provides insight into major industry and Company issues which may impact PSE's resource choices. As mentioned in the preface, PSE continually pursues a least-cost planning process, with the current Least Cost Plan filing offering a snapshot of this process. To fully understand the factors compelling PSE to consider certain resource alternatives, one must be cognizant of external industry events. This chapter addresses many of these significant planning issues including the recent Western Energy Crisis, the regional supply situation, merchant power retrenchment, the wholesale energy commodity market, uncertainty of regional development, transmission planning uncertainty and potential federal and state legislation. An examination of these issues provides the proper context for understanding PSE's electric and gas needs, and resultant resource strategies.

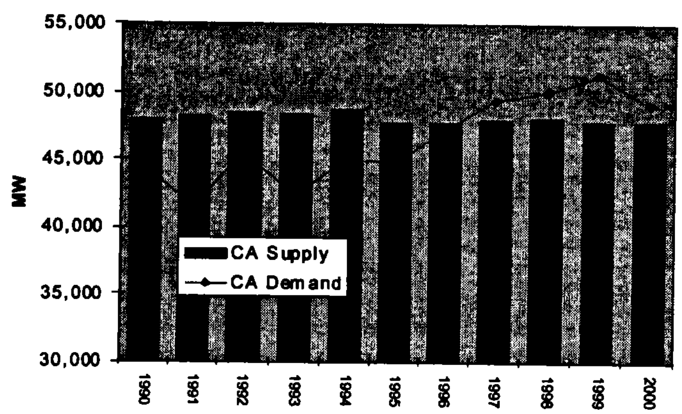
A. Western Energy Crisis

Crisis Overview

Starting in the early 1990s, and continuing through 2000, the California economy created robust load growth. Amid this strong regional economic growth, supply remained fairly stagnant with little additional generation capacity being built for nearly a decade (see Exhibit II-1). In part, environmental restrictions, a heavy reliance on QF capacity, and the state's emphasis on conservation and efficiency initiatives contributed to the lack of capacity additions. In addition, the state policy choice to forego long-term power contracts and instead rely on the apparent surplus power in the spot market undercut of adequate generation resources. After only a few years reliance on the spot market, a regional drought significantly reduced hydro production in 2000 drying up the surplus power in the spot market. With the drop in hydro power availability from the Northwest, California lacked the resources it depended upon during its traditional winter/spring facility maintenance period and its summer peak period. As Exhibits II-2 and II-3 illustrate, market prices for electricity and gas began to

Exhibit II-1

California Supply/Demand



skyrocket in the face of this supply/demand imbalance. The confluence of factors set the stage for the power crisis to emerge in California and spread to other parts of the western region.

Exhibit II-2

CA PX Prices

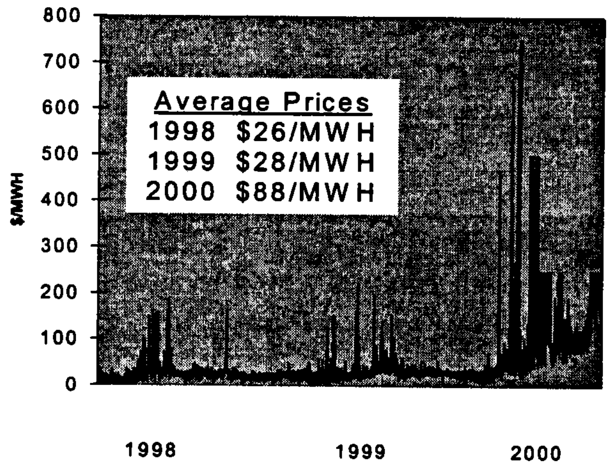
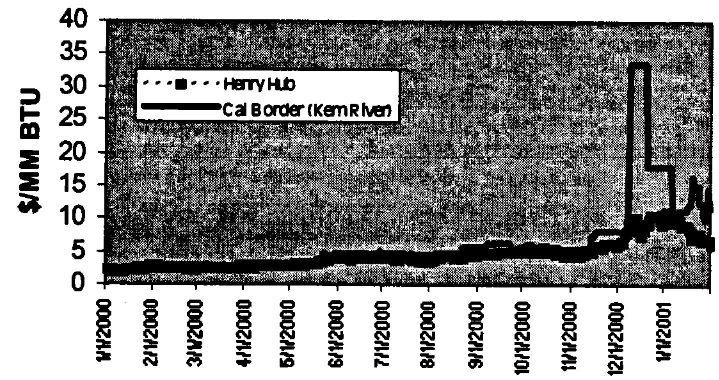


Exhibit II-3

California Gas Prices (2000-2001)

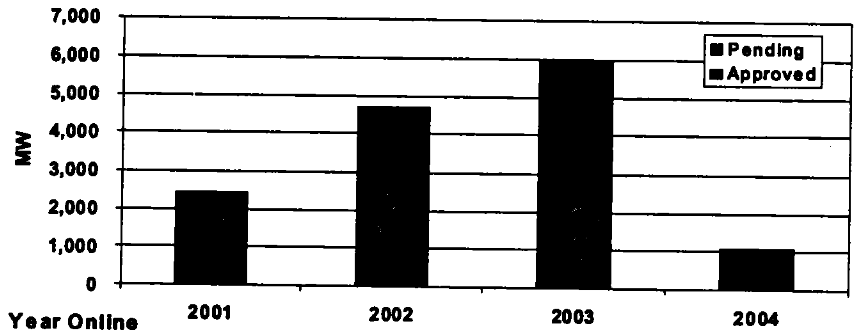


The energy crisis had significant financial impacts on California's largest utilities. The California utilities, unable to pass through to customers skyrocketing costs of spot market purchases, quickly became cash strapped and illiquid in the face of rising prices on the Power Exchange (PX), from which they were required to buy. This in turn led to the rapid downward spiral of the financial health of the two largest utilities in the state – Southern California Edison and Pacific Gas & Electric – due to the heavy cash requirements of the wholesale market purchases, their inability to recover costs in their rates, and their subsequent inability to meet the terms of numerous outstanding commercial paper obligations. Regulations in California prohibited the utilities from entering into forward contracts, effectively preventing them from hedging against the risk of skyrocketing market prices and halting the downward spiral. Likewise, QFs that relied on utility credit and payment streams lost their creditworthiness and some ceased operation, further exacerbating the power shortage.

Current Situation

Over the past 18 months, the California market has returned to a more normal state due to a contracting economy, the rapid addition of new generation in the state (~5,600 MW), a reformed regulatory process and relatively mild summers in 2001 and 2002 (See Exhibit II-4). The State continues to reform the regulatory environment and work toward resolution of disputes over long-term power contracts signed during the height of the power crisis. Moreover, the State has focused on measures to return stability to the power market and revamp the supply procurement process. Beginning in January 2003, the utilities resumed responsibility for procuring resources to meet their native load customer obligations, under a co-signatory arrangement between the utilities and the California Department of Water Resources. Once the utilities return their credit ratings to investment grade, the utilities will take over these agreements and the DWR will exit the power supply procurement business.

Exhibit II-4
CA Generation Development



Lessons Learned

The Western Energy Crisis clearly illustrated the continual need for proactive approaches to resource planning, and the need for sound business and financial analysis to guide supply decisions. The events of 2000-2001 raised important questions on the soundness and durability of the merchant generation developer business model and financial wisdom of relying upon the spot market to serve customers. Further, the Western Energy Crisis highlighted regulators and customers' intolerance for extreme price volatility. As will be further discussed in Chapter III, the Western Energy Crisis has lead PSE to re-examine its fundamental market assumptions and place greater emphasis on optimization and hedging strategies.

B. Regional Supply Situation

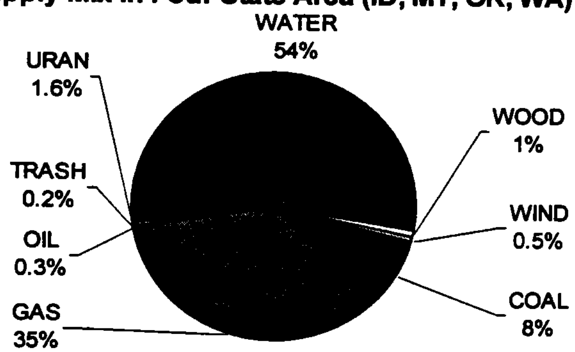
Current Supply Mix

As of 2001, the four-state region of Idaho, Montana, Oregon and Washington had nearly 68,000 MW of installed capacity (See Exhibit II-5), of which 54 percent came from hydro resources. The region's heavy dependence upon hydro provides strong advantages and disadvantages. From one perspective, hydro provides an inexpensive source of power, contributing to low regional energy prices. However, in dry years, with hydro availability below average, the price impacts in the merchant market can be devastating for net purchases of energy such as consumers experienced during the 2000-2001 power crisis. Although hydro represents a large share of regional capacity, this fuel source has energy limitations, with energy potential as little as 50 percent of total installed capacity.

Keeping with the national trend, the fuel of choice for power plant developers over the past five years has been natural gas. While gas prices hovered in the $2 to $3/MMBtu range during the late 1990s, developers viewed gas-fired, combined-cycle capacity as the technology of choice given its quick construction turn around, high level of efficiency, and forecasts suggesting low cost gas supply.

Exhibit II-5

Supply Mix in Four State Area (ID, MT, OR, WA)



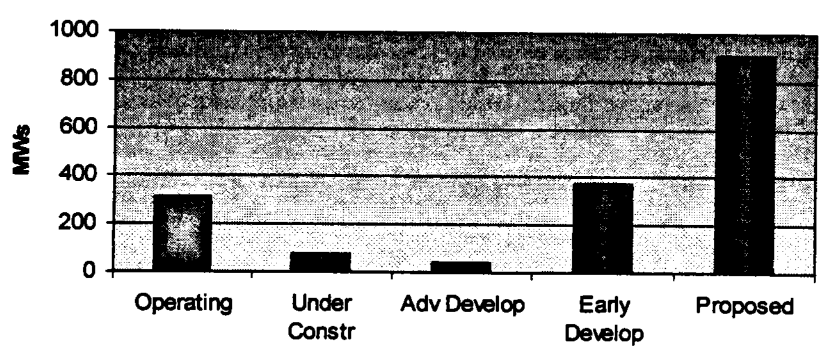
	Installed Capacity (MW)
WATER	36,235
GAS	23,516
COAL	5,772
URAN	1,107
WOOD	650
WIND	324
OIL	182
TRASH	140
Total	67,926

Source: RDI PowerDat, October 2002 release

Coal-fired generation comprises only eight percent of the region's installed capacity mix. Gas price volatility contrasted with the price stability of coal has led to a renewed interest in coal plant development in states such as Wyoming, Illinois and Kentucky. Siting challenges in the Puget Sound basin create challenges to coal facility development in the immediate region. Further, the BPA has failed to timely improve transmission constraints to plants located east of the Cascades, creating additional challenges to further coal development.

Exhibit II-6

Wind Capacity in the Pacific Northwest



Renewable resources only provide approximately two percent of the region's supply mix, however, utilities and independent developers in the Washington area have shown increased interest in certain renewables such as wind energy. As Exhibit II-6 illustrates, more than 1,400 MW of wind capacity, comprising 16 independent wind projects, are at varying stages of development, with over 300 MW currently installed in the Pacific Northwest region.[1] The average available capacity for a wind resource is approximately one-third of its installed capacity, thus it is necessary to divide the total installed wind capacity number by one-third to derive a comparable figure to other installed generation in the region.

Planning Impacts for PSE

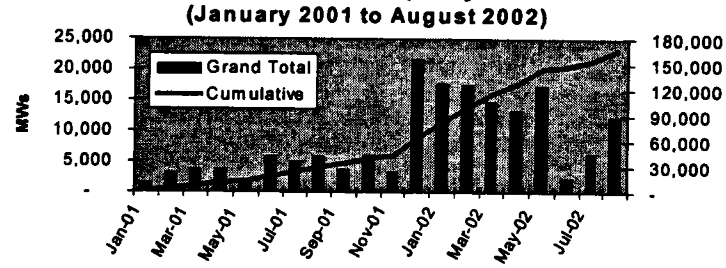
The regional dependence on hydro resources represents an important planning issue for PSE. According to NPPC, the region's hydro resources can vary 4,000 MW above or below the historical average of 16,000 average MW in a given year. At the average level, the hydro resources satisfy over 70 percent of the region's annual average load of 22,000 aMW. With an additional 2,000 MW of hydro availability, that figure jumps to over 80 percent. When conditions emerge that provide for either an average year or an above-average year for hydro, the economics of merchant generation are severely undermined. In light of this uncertainty regarding merchant gross margins, a disincentive has developed for building more regional merchant generation unless tied to a long-term power purchase agreement with a creditworthy utility. With capital markets dominating the merchant sector today, their response to existing market conditions and expectations for the future market will be a powerful determinant of the regional supply situation that develops over the next several years. From a planning perspective, PSE expects that the region's heavy dependence on hydro resources, coupled with the disincentive for new merchant generation based on low regional prices, will not lead to significant new capacity additions in the region.

C. Merchant Generation Retrenchment

National Picture

The declining interest in financing merchant plants, and the ensuing inability of merchant generators to complete planned projects in the Pacific Northwest, represents a national, not

Exhibit II-7
Cancelled or Tabled Capacity in the U.S.
(January 2001 to August 2002)



[1] Exhibit II-6 defines the Pacific Northwest region consists as ID, MT, NV, OR, UT, WA and WY.

regional issue. On a national level, merchant generation retrenchment has become a new industry paradigm. During the time period from January 2001 – August 2002, developers tabled or canceled 160,000 MW of proposed new generation (see Exhibit II-7). Lenders and equity investors have pulled back their support for new development projects as they reconsider the business and financial models guiding merchant power markets.

Several factors have contributed to the merchant generation retrenchment trend. As the U.S. economy slowed and the stock market turned bearish, merchant companies lost an enormous amount of market capitalization – many such as AES, Aquila, Calpine and Dynegy losing over 90 percent of their peak valuations. Once successful merchant developers now find themselves struggling to raise necessary capital to not only meet existing debt obligations, but also to fuel future growth plans. Compounding the need to raise capital, many merchant generators have received multiple credit downgrades over the past year, making it more difficult to refinance existing debt or acquire funding to continue on-going projects. These national trends, coupled with the financial uncertainty produced by variable Northwest hydro supplies, further the merchant retrenchment trend in the Northwest.

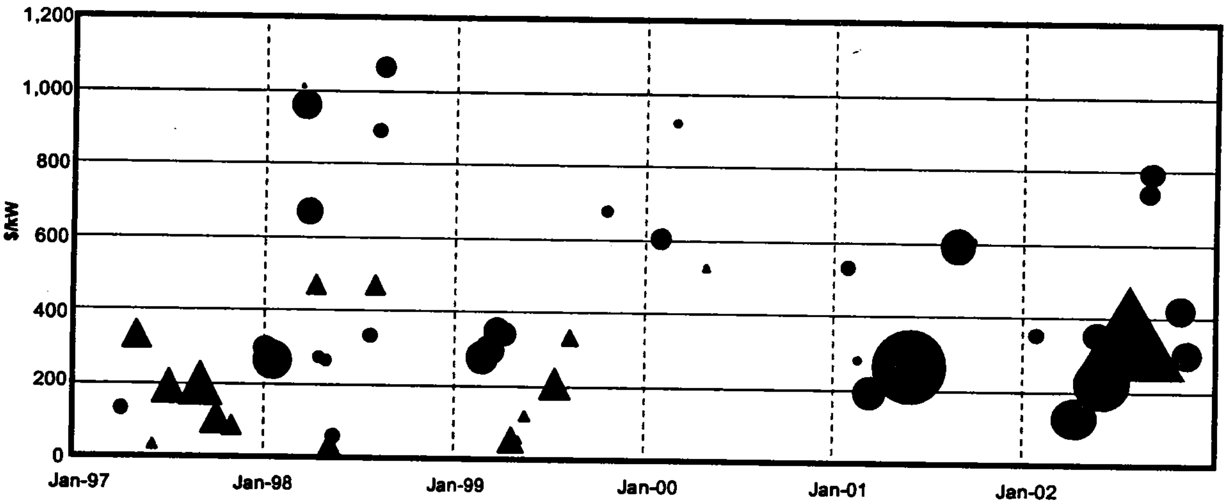
The inability to access capital runs counter to the business model of many merchant generators, who assumed a continued access to capital. Merchant generators have increasingly been forced to retrench from development plans, and instead to focus on strengthening their balance sheets, refinancing outstanding debt positions and persuading both Wall Street and rating agencies of the long-term viability of their business models. At the same time, the merchant generators have taken steps to improve financial disclosure to bolster their credit ratings, and worked to restore confidence in the bank lending and financial market sector.

Impact of Merchant Generation Retrenchment

The financial crisis impacting the merchant generation market has led to a multitude of cancelled or tabled projects in the planning and mid-construction phases. As a means to raise cash and address liquidity concerns, developers have increasingly turned to asset sales, putting many assets on the market for potential buyers. Ready buyers do not always present themselves as few adequately financed buyers exist given the current state of capital markets. A wide discrepancy between bid and ask prices has also developed. Sellers need to realize at least book value in order to avoid selling at a price that may force independent accountants to require management to write down the existing asset portfolio or create a capital loss with no offsetting capital gain. As Exhibit II-8 illustrates, generation assets transaction values have recently begun to trend down toward replacement values. Even given recent lower transaction prices, Sellers still face a quandary – sell an asset to provide capital, but risk selling at a below book price, thus creating a capital loss and possibly a requirement to record an impairment of additional assets.

Exhibit II-8

Generation Asset Transaction History 1997-2002



Reflects all fuel-specific transactions for gas, coal, and gas/oil. Does not reflect nuclear, renewable or bundled (e.g. coal + gas) transaction

Gas Coal Gas/Oil

Implications for PSE – the Buy vs. Build Debate

As discussed earlier in this chapter, the merchant generation retrenchment trend has been a significant factor in the Northwest region. As Exhibit II-9 illustrates, over 40,000 MW of proposed new generation capacity has been tabled or cancelled in the WECC region. As on the national level, the troubles challenging the merchant generators have led to a pressure to sell assets, creating opportunities for a utility such as PSE considering new resource alternatives for its portfolio. The decision whether to build or buy an

Exhibit II-9

Cancelled/Tabled Capacity by NERC Region
(Jan. 2001 to Aug. 2002)

	WECC	SERC	ECAR	MAIN	FRCC	ERCOT	NPCC	SPP	MAAC	MAPP
Total	41,143	31,495	20,558	17,520	15,615	11,874	11,638	8,614	6,760	1,140

existing plant is part of the resource planning process. From a buy perspective, idle or cancelled merchant plants in the region provide an opportunity for PSE to buy an existing merchant plant or partially completed plant. Under this scenario, zoning and permitting issues have been resolved, eliminating construction risk and saving PSE time and money.

The status of the merchant power market also impacts the buy side of the equation. Typically the buy choice consists of either the purchase of a market product or a tolling agreement whereby PSE pays for the right to use an existing resource and provide its own fuel. The long-term purchase power arrangement holds less financial promise as many possible partners for PSE have left the energy marketing business or have unacceptable credit ratings.

For more information on generation project development, please refer to Appendix A.

D. Wholesale Energy Commodity Trading Market

Background

Retrenchment in the merchant power sector closely parallels the diminished activity in the wholesale energy commodity trading market. Commodity trading in the electric and gas markets grew rapidly over the past decade as competition in the gas and electric markets began to take root. Growth in electricity trading moved almost in lockstep with the increase in merchant generation development. Merchant developers, in order to take advantage of emerging market opportunities, used a number of different electric commodity trading approaches. Some traded around the physical assets in their portfolio, while others took more speculative positions betting on forecasted market movement. Still others relied on the commodity market to lock in prices for themselves and their customers, and protect the value of their assets. Regardless of the approach taken, the commodity markets provided a means of hedging commodity and investment risks, and creating liquidity for those in long and short positions in the market. The commodity markets were an integral part of the development of the merchant sector. For fuel, the markets provided a means for the merchants to lock-in their fuel price risk. For electricity output, it provided the means by which the merchants could take advantage of market volatility to capture additional revenue. For some, this also provided a primary source of revenue.

One of the theories driving the competitive wholesale markets has been a belief that market forces would lead to timely development of new generation. Over time it was widely believed that market signals in the form of spark spreads and marginal generation additions would determine when and where additional capacity would be added to the system. The vehicle for providing these market signals has been the commodity trading markets. While by no means perfect, without these markets, it is unlikely that the level of growth witnessed over the past three years across the country with nearly 150,000 MW of new capacity added to the grid would have occurred.

Current Status

For the merchants, the current economic stagnation and the surplus of generating capacity in the market have been sending bearish signals to the sector. At some point, most observers believe this trend will reverse itself, but the question of timing remains. In anticipation of this eventual reversal, some companies with load obligations have moved away from the short-term commodity markets, relying more on bilateral contract arrangements for their supply. Companies on the opposite side – those with capacity and energy for sale – have largely pulled back from the commodity trading markets as a means for clearing their resources in the market. Many national energy trading and marketing entities have reduced trading activity in various regions in which they have an existing market presence since they no longer have strong credit ratings to support this activity and merchant trading is not in favor with investors. In some cases, companies have announced plans to retreat to trading around just their core assets, while others have announced that they will exit trading entirely. Electric and gas commodity trading markets have seen reduced volumes of trading activity, in turn reducing liquidity and price transparency in the market. Several entities such as Aquila, Allegheny Energy, El Paso, Reliant Energy and Dynegy recently announced a complete exit from the wholesale non-regulated trading business. Morgan Stanley, one of the few highly rated trading houses, recently announced plans to close its Portland trading office.

The decline in forward commodity markets has also affected the willingness of producers to continue adding new gas production. Despite record gas prices, the number of active gas rigs is recovering slowly due to uncertainty about future gas prices, federal tax policy, and capital availability. The war in the Middle East exacerbates this uncertainty. When coupled with the very cold 2002 – 2003 winter in the eastern part of North America, industry observers expect gas prices to remain high over the next 12 – 24 months before declining.

Merchant generators were the anchor loads on most of the new pipeline expansions proposed for western pipelines. With these plant cancellations came a corresponding cancellation in pipeline capacity additions. While these pipeline cancellations will not affect the reliability of the resources used by PSE to supply its firm gas customers, they will contribute to volatility in gas prices and hence, market-based electric prices. When combined with the need to refill depleted storage field and potential for a lower than normal hydro year in the Northwest and Sierra snow pack, the potential for price spikes in natural gas and power in the western markets significantly increases.

The troubles plaguing the merchant sector have led to a sharp decline in the number of creditworthy counterparties that PSE can transact with in commodity markets. The decline in the sector has made transacting more difficult by not only reducing the number of counter-parties, but also eliminating commodity products that PSE has relied on to manage its supply risks. Compared to one year ago, many of PSE's counterparties no longer hold investment grade credit ratings. At the same time as the number of creditworthy counterparties have declined, few firms have newly entered the marketplace. The scope and scale of trading activity is hard to predict at this time, particularly with respect to their trading in the Pacific Northwest – a relatively small and illiquid region.

Implications for PSE

The decline in wholesale energy commodity trading market activity impacts PSE's resource planning options. The decline in counterparty credit has decreased the number of entities PSE can transact with, and in combination with constraints imposed by PSE's own weak credit standing, significantly limited PSE's access to the commodity products it has relied upon to manage its owns supply risks. Approximately one-third of PSE's current counterparties no longer hold an investment grade credit rating. And PSE's current credit rating limits the extent and types of transactions that it can enter. As PSE considers its resource options, the state of the wholesale energy commodity trading market makes it more difficult for PSE to contract for supply or supply risk mitigation products in the near future. As a result, PSE expects that it will incur a higher level of volatility in gas and energy prices than it believes appropriate.

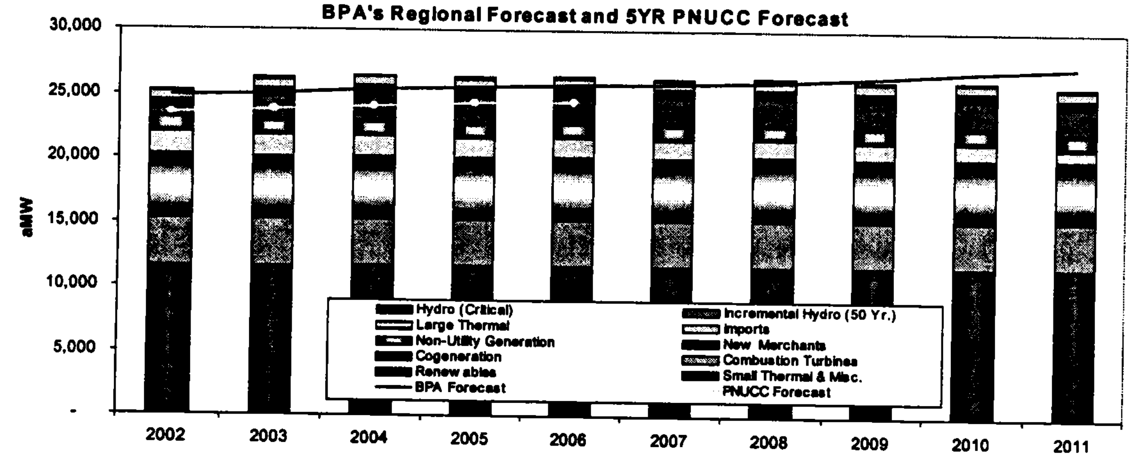
E. Uncertainty of Regional Resource Development

Overview

Currently, the Western region has adequate supply to its needs. However, as Exhibit II-10 illustrates, the majority of investor-owned utilities will be deficit firm resources past 2004 without new regional resource development. The Pacific Northwest Utility Conference Committee

(PNUCC) projects that the regional firm resource deficit will grow to over 4,700 MW at peak load (3,800 MW on an annual energy basis) by 2006. The path for new resource development in the region remains uncertain due to the current environment which does not create incentives for merchant generators to develop new resources. Without new resource development, the West may find itself confronting a supply crisis similar to that of 2000-2001.

Exhibit II-10



Current Situation

Several factors contribute to the uncertainty of future resource development, including the state of the merchant market, lack of utility incentives and the regulatory environment in many Western states.

As detailed earlier in this chapter, the market turmoil in the Western markets has created uncertainty regarding the financial survivability of many of the top merchant developers in North America. For at least the next 12-24 months, industry observers expect the merchants will remain in a mode of credit quality restoration, pursuing only limited growth opportunities. Largely, merchants will be taking steps to strengthen their balance sheets and improve basic cash flow from existing operations. With utilities preferring shorter duration power contracts, and tight capacity markets for merchants, developers have little motivation to assume undue risks and place themselves in a similar situation as they find themselves today.

Without a robust merchant market to rely upon, it would follow that investor-owned utilities would pursue resource development to meet their needs. However, incentives to develop resources largely do not exist, and regulatory situations in many states create a disincentive for such steps. Not unlike the merchants, investor-owned utilities have concerns over their credit quality and liquidity, and have suffered the impacts of the Western Energy Crisis. Investor-owned utilities also have the issue of regulatory risk. Many companies such as PG&E and Southern California Edison continue to work through regulatory and legislative issues. As Exhibit II-11 illustrates, many states in the region have pending issues, creating an uncertain regulatory environment. Although these issues differ by state, the same basic principle holds – without confidence regarding cost recovery for facility development, utilities do not have an incentive to build generation to meet their resource needs. Indeed, regulatory and development risks, and the uncertainty surrounding approval and rate treatment makes the prospect of new utility-owned generation a high-risk proposition.

Exhibit II-11
Western State Regulatory Uncertainty

STATE	ISSUES/CONDITIONS
California	• Regulatory evolution • Pending merchant litigation • Restriction on duration of new PPAs to one year • Credit crisis overhanging IOUs • Retirement of older gas plants in urban areas • Long-term procurement plans to be issued by IOUs in April
Idaho	• Lack of rain & snow in the northwest has dried up hydro sources • Idaho Power projected that existing resources would be insufficient to meet loads as early as 2003 • Transmission constraints in the Pacific Northwest continue to hamper import capabilities
Montana	• Northwestern Energy saddled with high debt (85 percent debt load); possibility of bankruptcy higher than average • Transmission constraints remain on imports and exports
Nevada	• Nevada Power concerned that California will be short 5,000 MW in Summer 2003 • Approval of Nevada Power's Energy Supply Plan for 2003-05 remains uncertain pending further review by the PUC • Sierra Pacific still facing financial hardship from power purchase disallowances and its high debt load (73 percent)
Oregon	• Largest utility has bankrupt parent • Threat of PGE municipalization slowing decision making • Open PSC investigation regarding IOU resource policies – includes issues such as competitive bidding, new resource rate treatment • Cumbersome & long siting and development process • LCP policies & procedures remain on hold until results of investigative docket are finalized (UM-1056)

Impacts for PSE

In light of the continuing financial fall-out from the Western Energy Crisis and the still uncertain regulatory and market environment, PSE remains concerned about the overall supply situation in the region and whether market participants have the incentives to build needed new generation in the next three to five years. Under the current conditions, it appears unlikely that merchants and utilities are receiving the necessary price signals and risk recovery support to pursue new capacity investment. As discussed in further detail in Chapter XI, the regional supply situation factors into PSE's long-term strategic resource planning.

F. Transmission Planning Uncertainty

Overview

On the regulatory front, a great deal of uncertainty remains surrounding regional transmission planning initiatives. PSE's transmission system, along with the regional high voltage transmission system, is undergoing fundamental restructuring mandated in large part by three different Federal Energy Regulatory Commission (FERC) initiatives – Order 888 and 889, Order 2000, and the Standard Market Design Notice of Proposed Rulemaking.

Released in May 1996, FERC's first initiative, Orders 888 and 889, required all public utilities, including PSE, to file open access transmission tariffs that would make utilities' electric transmission systems available to wholesale sellers and buyers on a nondiscriminatory basis. PSE complied with Order No. 888 and 889, and gained FERC approval of its open access transmission tariff.

On December 20, 1999, FERC issued Order 2000 to encourage transmission-owning utilities, such as PSE, to turn operational control of their high voltage power lines over to independent entities called Regional Transmission Organizations (RTOs), while still maintaining ownership of their power-grid assets and receiving revenues from their use. FERC intends RTOs to provide centralized, unbiased operation of the power grid to promote economic and engineering efficiencies. This regulation required each FERC jurisdictional public utility that owns, operates or controls facilities for the transmission of electric energy in interstate commerce to file plans for forming and participating in an RTO to FERC by October 15, 2000. In November 2000, PSE and nine other utilities filed the Stage 1 document for the formation of RTO West and received conditional approval to proceed with the development of an RTO. Since the initial filing, a Stage

II filing has been made with discussions underway on a Stage III filing. The filing utilities anticipate several more months of discussion before a more fully developed proposal for RTO West will be filed for FERC approval. Thereafter, the respective Company boards would have to decide to proceed and seek state regulatory approvals. Depending on regional support, RTO West could be operational as early as the beginning of 2006.

On July 31, 2002, the FERC issued a Notice of Proposed Rulemaking (NOPR) proposing a Standard Market Design (SMD) that would significantly alter the markets for wholesale electricity and transmission and ancillary services in the United States. The new SMD would establish a generation adequacy requirement for "load-serving entities" and a standard platform for the sale of electricity and transmission services. Under the new SMD, Independent Transmission Providers would administer spot markets for wholesale power, ancillary services and transmission congestion rights. Electric utilities, including PSE, would be required to transfer control of transmission facilities over to the applicable Independent Transmission Provider. Public meetings were held during the fourth quarter of 2002, with the comment period for certain issues extended to February 28, 2003 with the final SMD expected to be issued July 31, 2003. Once FERC issues the final SMD, a phased compliance schedule will begin with final implementation expected to take effect by the end of 2005.

Implications for PSE

Currently, PSE is assessing the impact of the proposed SMD on its operations, as well as how the SMD would impact the RTO West proposal. The uncertainty over transmission markets, rates and operations, in addition to the recent volatility in wholesale power markets in the West, has severely limited investment in the region's transmission system. Limited regional transmission system investment has exacerbated congestion problems that affect how PSE satisfies its electric power requirements. As a consequence of this fluid regulatory environment, a great deal of uncertainty exists over the availability, terms, costs, and rates of PSE's continued use of its own transmission system, as well as those of BPA and other regional utilities. This makes some aspects of planning for obtaining and transmitting power for PSE's load obligations more difficult than in the past. For purposes of this Least Cost Plan, however, PSE has assumed that it will be entitled to maintain its use of its transmission system (and that of other utilities) consistent with FERC open access regulations in about the same manner as it currently does, recognizing that at some point the actual entity operating its transmission system may be an independent transmission operator. PSE bases this assumption on a current understanding of the pricing, planning, and operational structure currently set forth in the RTO West proposal, although the Company recognizes the question of how transmission service will be regulated, how much it will cost, and how it will be operated still remain uncertain.

G. Pending Federal Initiatives

Overview

Issues currently before the United States Congress and various federal agencies may affect PSE's available choices for adding new resources to its portfolio. In the current 108th Congress, three primary issues stand out. First, Congress intends to pass a comprehensive, national energy bill. Second, the energy production tax credit is set to expire at the end of 2003 year, which could affect PSE's decisions regarding the economics of purchasing qualified renewable resources. Third, Congress may begin work on various proposals to amend the Clean Air Act, affecting the allowable level of air emissions from power production facilities.

For the energy bill, many familiar issues remain undecided especially in regards to the sections affecting the electricity and natural gas industries. An energy bill in the 108th Congress will likely address several key matters affecting the electricity and natural gas industry as well as aspects of FERC's authority. Much of the debate will begin in the House with the Senate engaging in the debate later in the session. Specifically for FERC, the House energy committee leadership would like to provide FERC with partial jurisdiction over the interstate transmission of non-jurisdictional entities including the Bonneville Power Administration. They would also like to clearly authorize Bonneville and other federal power marketing agencies to participate in a regional transmission organization and enhance FERC's authority for siting critical interstate electric transmission lines. House committee leadership would also like to amend the hydroelectric relicensing process for fishway alternatives. Beyond FERC, House committee leadership seek repeal of the Public Utility Holding Company Act of 1935 (PUHCA) and to amend the Public Utility Regulatory Policies Act of 1978 (PURPA). They also hope to enhance consumer protection, increase the criminal penalties for those who violate the Federal Power Act and authorize the construction of the "southern route" of a natural gas pipeline from Alaska's North Slope. The role of the federal government in implementing a renewable portfolio standard (RPS) will continue to be a source of debate. Senate Democrats strongly supported RPS during the last Congress, however, House Republican opposition left this as one of the major unresolved issues in the energy bill conference committee last year.

As in the last session of Congress, the Ways and Means Committee will write one of the most important aspects of the energy bill - the tax package. Those in the Northwest will be closely watching the issue of extending the renewable energy production incentive. This incentive which expires at the end of 2003 provides approximately a 1.8-cent per kilowatt-hour tax credit (in 2002 dollars) for the owners of wind farms and other renewable resources. Issues critical to the development of new renewable resources in the Northwest and around the nation, include the manner of extending the credit and whether Congress extends the "placed in service date" for new qualifying facilities.

Congress also intends to address the issue of air quality. The Bush Administration and other interests in Congress have again put forward several proposals to modify Clean Air Act requirements for power plants including the Bush Administration's *Clear Skies* proposal. All of these bills seek to reduce the emission of three primary air pollutants – sulfur dioxide, nitrogen oxides, and mercury. Three proposals also require reductions in a fourth pollutant – carbon dioxide. In rough terms, the proposals seek to reduce nitrogen oxides by approximately 80 percent from 1998 levels; sulfur dioxide by 65 and 85 percent from 1998 levels and mercury by 90 percent of current levels or an amount set by the EPA. In the bills that include carbon dioxide reductions, the cap would be set at 1990 emissions levels. The *Clear Skies* proposal does not include a carbon dioxide program. Most of the bills include a system that would implement national or regional caps through a tradable allowance program. If Congress does not pass a comprehensive set of amendments to the Clean Air Act, the Environmental Protection Agency will likely use its existing authority to proceed with its own proposals to tighten power plant air emissions.

Implications for PSE

Any national energy bill passing Congress will likely be comprehensive, addressing many aspects of the utility industry. Many in Congress believe that last year's work on the energy bill has made it easier for Congress to pass a comprehensive bill in 2003. However, as seen in the last Congress this debate could go on until the end of the 108th Congress with the possibility that again no action would occur.

Several likely provisions of such an energy bill would impact PSE. Changes to FERC's authority and the requirement that the Bonneville Power Administration participate in an RTO would significantly impact PSE. Possible amendments to the Public Utility Regulatory Policies Act

(PURPA) also have the potential to affect decisions PSE makes about renewal of current PURPA contracts as well as any new requirements. As PSE evaluates wind resource proposals from Northwest wind farm developers, the extension of the energy production incentive will be a key issue of interest. Proposed amendments to FERC's mandatory conditioning regulations for hydroelectric licenses would yield a small improvement to the relicensing process.

In regard to a comprehensive multi-pollutant bill, the operation of existing and possible new PSE thermal facilities could be affected by the passage of any of the proposals under consideration. While PSE currently complies with state and local air emissions caps on existing facilities, Washington State does not have a carbon-dioxide program. The implementation of a federal carbon dioxide program would create a new set of regulations that PSE would have to address. Some believe that not creating a carbon dioxide program preserves more of a market for coal resources and reduces the need for utilities to switch to natural gas or renewable generation resources as a method for compliance. Tradeoffs like these will be weighed by PSE as it evaluates the role of coal and natural gas resources in its portfolio. Should Congress not pass a comprehensive bill, the EPA approach will be done much more incrementally through existing authority, a situation which would likely create regulatory uncertainty and make for a more difficult utility planning process.

H. State Policy Developments

In the wake of the 2000-2001 energy crisis the Washington State Legislature initiated a review of the State Energy Strategy, which was last published in 1993. The Community, Trade and Economic Division completed an "interim update" of this report and published it in February 2003. The update focuses primarily on electricity and features "13 Guiding Principles" that provide useful insights into the direction of state energy policy over the near-term. These themes of energy system enhancements/reliability and environmental protection were embodied in these principles:

1. Encourage all load-serving entities to adopt and implement integrated resource plans to ensure they have adequate resources to meet their obligation to serve their customers' projected long term energy and capacity needs.
2. Encourage the development of a balanced, cost-effective and environmentally-sound resource portfolio that includes conservation, renewables, and least-cost conventional resources.

3. Protect the benefits to Washington consumers from the Federal Columbia River Power and Transmission System.
4. Preserve and promote Washington's cost-based energy system to benefit the end use consumer by providing reliable power and reduce consumers' vulnerability to supply shortage and price volatility. At the same time, the state should promote policies that harness market forces in the wholesale energy market to reduce customer costs and increase reliability while protecting the environment.
5. Encourage utilities, BPA and others as they work to reduce congestion and improve the reliability of the transmission system, to assess all potentially practicable and cost-effective alternatives, including but not limited to targeted demand reductions, generation additions, system upgrades, and new line construction.
6. Foster a predictable and stable investment climate to facilitate adequate and efficient access to capital markets for independent power producers, federal agencies and Washington's public and private energy industry.
7. Promote Washington State as a leader in clean energy technologies by supporting and attracting companies that are active in developing, manufacturing and selling them. In addition, lead by example with clean energy, energy efficiency, and sustainable practices in state and local government operations.
8. Use data and analysis based on sound scientific and economic principles to inform energy policy.
9. Evaluate energy policies by how well they improve the safety, security, and reliability of the system.
10. Educate the public on energy issues.
11. Actively engage with nearby states, provinces, tribes, and the federal government to help accomplish common energy goals.
12. Promote policies and programs that provide access to basic energy services to those on limited incomes.
13. Promote energy policies that maintain and or improve environmental quality.

Energy legislation in recent years has reflected many of the themes represented above. Perhaps most persistent has been efforts to require utilities to increase that proportion of their energy resource portfolios dedicated to renewables and conservation. Closely related to this effort has been legislation to require developers/operators of thermal generation facilities to reduce greenhouse gas emissions. While there is some agreement among energy stakeholders that these objectives may be beneficial over time, there remains considerable disagreement over how, when and at what cost these objectives should be achieved.

Attempts by lawmakers to stimulate greater investment in renewables, conservation and cleaner technology generally falls into one of two categories: 1) mandates that set specific standards to be met over time, or 2) economic incentives that attempt to lessen investment risk. The former elicits concerns about ever higher energy costs, and the latter competes for limited tax revenues needed to meet basic government services and eliminate the state's record budget deficit. Because of these and related concerns, it is anticipated that through the next biennial period (i.e., 2003-2005) public policy decisions directly impacting utility costs will be relatively few and of moderate impact.

Legislative proposals introduced in 2003 that could impact PSE resource choices include:

- *Portfolio Standard – HB 1544*: This legislation directs electric utilities to purchase conservation and "green energy" resources according to a prescribed schedule. Existing voluntary "green energy" programs (e.g., PSE's Green Tags) would not be credited against the mandated standards. This legislation applies to utilities, industrial customers buying energy from the market and direct service industries.

- *Taxes – HB 1316/HB1703*: HB 1316 changes the basic tax structure for utilities from a tax on gross utility revenues to a volumetric tax. Depending on the rates applied, tax shifting would likely occur between customer classes and could influence customer/utility choices between gas and electricity. This legislation also increases taxation on Public Utility Districts, which translates into higher prices for energy sales to PSE. Due to state budget shortfalls, utility tax revenues will continue to be a topic of legislative interest. HB 1703 offers tax incentives to promote production of electricity from alternative sources of energy.

- *HB 2119*: This legislation establishes a center for the establishment of a voluntary registry to document reductions in greenhouse gas emissions that are reported and achieved by sources within the state prior to enactment of federal greenhouse gas standards. Establishes the framework for emissions inventories and verification of amounts and reductions of emissions. Should the program become mandatory in conjunction with adoption of federal standards costs to utility, operations could be substantial.

- *HB 1005*: This legislation establishes a Joint Task Force on Long-Term Energy Supply. It declares that the state energy strategy be revised to consider implications of wholesale market volatility upon the electric industry. The task force is composed of 13 members including members of both houses of the Legislature and the Executive Branch. The task force is directed to review and recommend revisions to the state energy strategy and to report to the Governor and the Legislature by December 31, 2003 on revisions and specific actions that could can be undertaken to implement the State's energy strategy. Allows for the periodic formation of the task force to review the state energy strategy. This intent of this legislation is to directly influence future state energy policy.

I. Summary

Events occurring in the energy industry over the past several years have been instructive to PSE in a number of ways. Most importantly, the Western Energy Crisis illustrated the vital importance of sound resource planning and supply decisions, and the critical importance of well-designed and liquid markets. Other key highlights include:

Supply adequacy and price volatility issues remain a regional concern, and PSE's obligation is to balance price and risk for its ratepayers.

Resource adequacy in the Pacific Northwest region continues to mean having enough "controlled" resources to meet customer needs.

Under all planning scenarios, PSE will continue to participate in the wholesale market to buy and sell energy and capacity to balance fluctuations in loads and resources, and it will continue to seek non-energy financial intermediaries for financial derivative products to smooth price fluctuations.

Regional interdependencies will continue to affect resource availability and price volatility.

Reliance on hydro resources poses unique challenges for planning supply and will continue to present risks to future merchant power development in the region.

Merchant power retrenchment creates a potential window of opportunity for PSE to develop assets to meet its resource needs.

The current financial condition of counterparties in the wholesale energy market and PSE's own creditworthiness, limit PSE's ability to enter into long-term forward power contracts.

The future of the wholesale market structure remains uncertain in the West even as FERC continues to move forward with its Standard Market Design.

On the federal level, the U.S. Congress will likely examine three primary issues of interest to PSE during the 108th Congress – a comprehensive, national energy bill; the extension of the energy production tax credit; and proposals to amend the Clean Air Act. All three issues could impact PSE's long-term resource strategy.

- State lawmakers have introduced legislation to stimulate greater investment in renewables, conservation and cleaner technology. Due to state legislative concerns regarding higher energy costs and a focus on allocating limited tax revenues to meet basic government services and the state budget deficit, it is anticipated that through the next biennial period (2003-2005), public policy decisions directly impacting utility costs will be relatively few and of moderate impact.

III. PSE'S CURRENT SITUATION

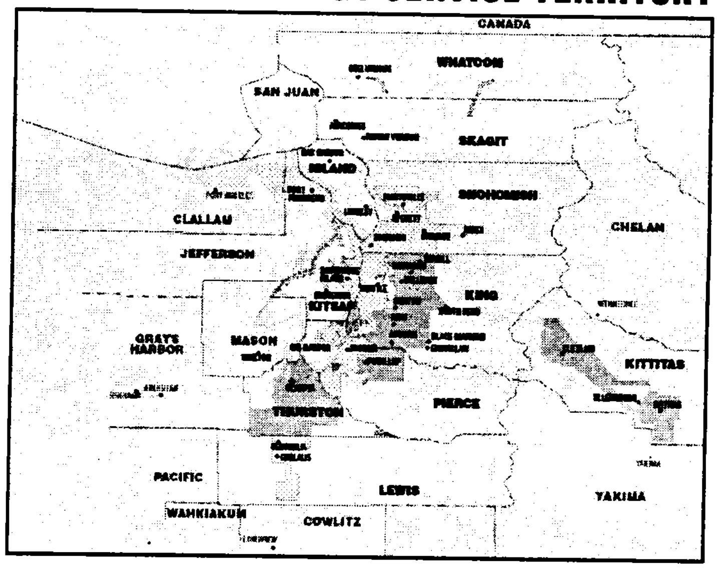
This chapter focuses on PSE's internal issues which must be taken into account in order to fully understand the context in which PSE's Least Cost Plan process occurs. This chapter begins with an overview of PSE's service territory, including its location as well as a description of its customer base. Section B describes PSE's financial position, its latest financial results and policy. The next part of this chapter addresses electric specific issues including the Power Cost Adjustment (PCA) mechanism and PSE's electric optimization and hedging approach. Next, this chapter addressed natural gas issues, including gas cost synergies between PSE's gas and electric functions, the Purchased Gas Adjustment (PGA) mechanism, PSE's gas optimization and hedging approach, and gas supply issues.

A. Overview

PSE is the largest integrated utility based in the state of Washington serving over 958,000 electric and 622,000 gas customers. As Exhibit III-1 illustrates, its gas and electric service territory covers over 6,000 square miles and serves more than half of the population in the state. Areas served include the Seattle, Tacoma, Bellevue metro areas in addition to the fast growing suburbs surrounding the metro area. While most of the nation experiences average customer growth of 1.5 percent, PSE has experienced annual growth rates of 1.8 percent and 2.6 percent in its electric and gas customer bases, respectively.

Exhibit III-1

PUGET SOUND ENERGY SERVICE TERRITORY



Combined electric and natural gas service
Electric service
Natural gas service

Puget Sound Energy's service territories:
Electric Service: Island, Jefferson, parts of King (not Seattle), Kitsap, Kittitas, Pierce (not Tacoma), Thurston, Skagit and Whatcom counties. (Public utility districts also serve parts of some counties.)
Natural Gas Service: King, Lewis, Pierce, Snohomish, Thurston and parts of Kittitas counties.

Puget Sound Energy is Washington state's largest energy utility, providing electric and natural gas service to more than 1.2 million customers, primarily in Washington state's Puget Sound region.

PSE has two market areas – the electricity and natural gas service areas. Geographically, the two areas overlap each other to a considerable degree. As a result, they share similar economic and industrial structures. The electric service area contains Kitsap County, home of the Puget Sound Naval Shipyard, but not

Snohomish County, the site of the large aerospace assembly plant. Thus the electric service area has more government employees, but less aerospace employment than the natural gas service area.

Largely, PSE services separate electric and gas customers, providing service to 305,300 customers that take both gas and electric service from PSE. Exhibits III-2 and III-3 provide a breakdown of numbers of customers receiving electric or gas service from PSE, and Exhibits III-4 and III-5 detail PSE's retail revenue attributed to different customer groups.

Exhibit III-2
PSE Electric Customers by Customer Type

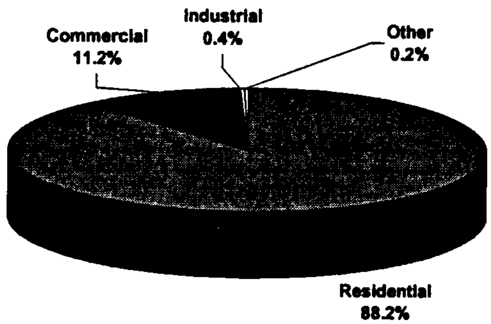


Exhibit III-3
PSE's Gas Customers by Customer Type

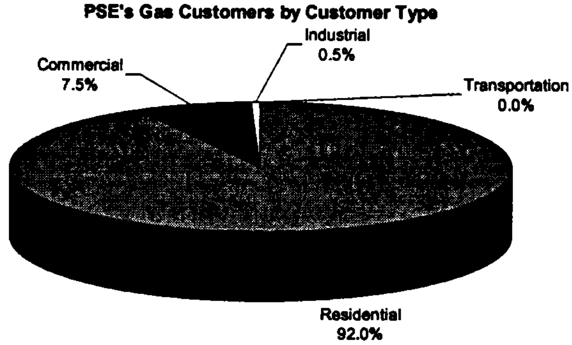


Exhibit III-4
PSE Electric Retail Revenue by Customer Type

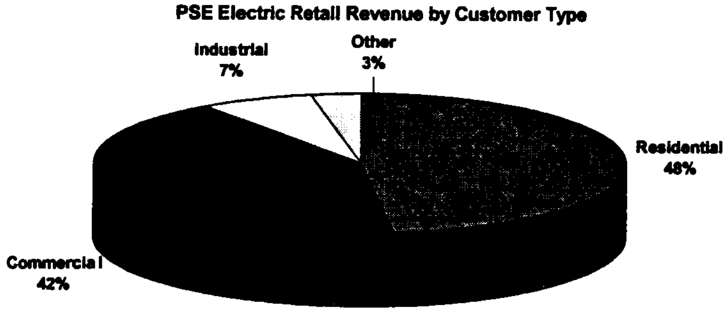
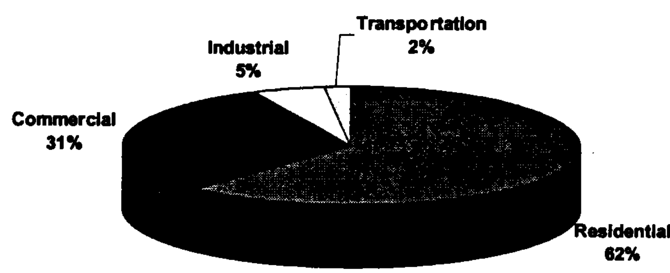


Exhibit III-5
PSE Gas Retail Revenue by Customer Type



B. PSE's Financial Condition And Policy

PSE Financial Condition

Puget Sound Energy, an integrated natural gas and electric utility, has total revenues of $2.4 billion. As of the end of 2002, PSE held over $6 billion in total assets, which consists primarily of electric and gas operations. From 2001 to 2002, PSE achieved a nine percent improvement in total earnings from its operations, realizing an increase from $98.4 million to $110.1 million.

Over 90 percent of the Company's earnings come from its regulated operations, which affords the Company a much greater level of stability than other companies that had expanded broadly into unregulated ventures. PSE's corporate credit rating is at the lowest investment grade rating of BBB-/Baa3 by the ratings agencies Standard & Poors (S&P)and Moody's, respectively. Moody's has PSE on negative outlook. As of the close of 2002, the Company maintained a debt-to-equity ratio of 63.9 percent – a marked improvement from the debt-to-equity ratio of 69.7 percent at the end of 2001.

When breaking down the components of PSE's earnings picture on a per share basis, the regulated operations contributed $1.14 per share in 2002 compared with $1.11 in 2001. PSE's construction services subsidiary, InfrastruX Group, also provided positive earnings to the Company in 2002 with $0.10 per share, compared with just $0.03 per share in 2001.

PSE Financial Policy

PSE's financial policy focuses one primary goal – improving its credit rating. For most of the last decade, the Company has not generated sufficient cash flow from operations to cover both its capital expenditure requirements and its cash dividends. PSE obtained funds for those purposes by selling more debt and increasing the financial leverage on the Company. Debt as a percent of total capitalization increased from approximately 50 percent at the end of 1992 to nearly 60 percent at the end of 2001. In February 2002, the Company reduced its annual cash dividend to $1.00 per share from $1.84 per share thus reducing the net cash outflow from the business and retaining more primary capital to rebuild the balance sheet. In November 2002, the Company issued 5.75 million shares of common stock and raised net cash proceeds of $115 million. The proceeds of such sale were used to pay down debt and provide working capital and further improve the Company's common equity ratio.

Also during 2002, PSE applied for and received modest increases in its base electric and gas rates in mid-2002 that will improve the generation of cash from operations. Together the rate increases provide PSE nearly $95 million of additional annual revenue. The associated rate settlement created a power cost adjustment formula that will help rebuild common equity by effectively limiting shareholder exposure to $40 million plus one percent of costs in excess of that amount through June 30, 2005.

Initiatives to enhance PSE's common equity ratio are designed to enables the Company to pursue its major financial major goal – restoring solid credit ratings. A Company's common equity ratio serves as an indirect indicator of its ability to generate cash flow from operations to cover the interest due on its debt. Both debt investors and rating agencies look to the times interest coverage as a key indicator of creditworthiness. Standard & Poors (S&P), a prominent credit rating agency publishes financial benchmarks used to rate creditworthiness. S&P looks at a company's earning base, rate of return, and its capital structure as a key determinant of its ability to generate cash coverage of its regular interest payments and other fixed charges.

Credit rating agencies also factor in a company's purchased power agreements (PPAs) into the ratings assigned to a company. Typically, credit rating agencies treat a portion of the costs associated with PPAs as an additional form of debt. Agencies include this alternative or "imputed" debt when assessing capital ratios, and interest on the imputed debt when assessing coverage ratios. Thus, PPAs create the need for additional equity in the capital structure to offset this imputed debt and the cost of a PPA must include the cost of this additional equity. As PSE examines its preferred resource options, the treatment of the PPAs and the impact on common equity ratio and creditworthiness must be considered.

C. Power Cost Adjustment Mechanism

In PSE's most recent general rate case, the parties to the proceeding agreed to, and the Commission approved, a Power Cost Adjustment ("PCA") effective beginning in July of 2002. The PCA was designed to improve the Company's financial stability after the five-year rate stability period in effect after the merger of Puget Power and Washington Natural Gas. This mechanism addresses certain financial impacts associated with potentially volatile wholesale power markets and fluctuations in hydropower availability due to uncertain weather conditions. The PCA accomplishes this goal by tracking the difference between PSE's modified actual power costs relative to a power cost baseline.

Under the PCA, customers share in deviations from the modified actual power cost baseline through a graduated series of annualized "sharing bands." The first plus or minus $20 million deviation of modified actual cost from the benchmark is considered a "dead band" in which shareholders borne all cost deviations. Customers and shareholders evenly share deviations in the range of $20 to $40 million (plus or minus). A third sharing band includes deviations between $40 to $120 million, of which customers cover 90 percent of the deviation and shareholders cover the other 10 percent. Finally, a fourth sharing band, for all deviations in excess of $120 million, is shared by assigning 99 percent to customers, 1 percent to shareholders.

Actual power costs may be modified for two factors, prior to comparison with the baseline. The first adjustment allows for the removal of a portion of the Company's fixed cost of its Colstrip generation facility if equivalent availability of the unit drops below 70 percent. The second adjustment focuses on new resources and allows short-term new resources (i.e., less than two years) to be included in actual costs, with prudence considered in the WUTC's annual review of PSE's PCA. New long-term resources will be included at the lower of actual cost or average embedded cost, as a bridge, until prudence can be reviewed in a Power Cost Only Rate Case or General Rate Case.

In addition to the sharing bands, PSE's PCA includes an overall cap. Through June 30, 2006, the PCA caps the Company's share of cost deviations from the baseline at plus or minus $40 million. The overall cap provides the Company with additional protection from potential power cost volatility during a time when the Company agreed with regulators and other parties to rebuild the equity component of its capital structure.

D. PSE Electric Optimization and Hedging Approach

Once PSE has selected and implemented a least-cost resource portfolio, the structure of the portfolio remains essentially fixed until the next opportunity to modify one or more resources. The structure of the selected portfolio also defines the fixed costs that PSE will incur until the next portfolio modification. The focus then shifts to managing the variable costs of the portfolio components to minimize average costs and cost volatility. The continuous process of selecting the least cost portfolio and managing it to minimize costs and cost volatility is known as "portfolio optimization". Management of PSE's energy resource portfolio focuses on the management, at any given point in time, of an existing mix and level of long-term and short-term resource commitments – along with the resulting short-term risk exposures. Portfolio management activities include hedging the portfolio against many of the risks that are addressed in long-term resource planning and acquisition. However, portfolio management is a comparatively more dynamic process, involving anticipating and protecting against shorter-term risks and taking actions based on actual circumstances such as observed hydro reservoir levels or shifts in forward market prices for electricity and natural gas. Currently, PSE's weak credit and constrained ability to post cash or Letters of Credit as collateral limit the Company's ability to pursue certain strategies.

PSE adheres to a near-term portfolio risk management philosophy of protecting its energy portfolio from commodity price risk exposure and counterparty risk exposure. The following principles guide PSE's risk management practices: 1) identify risk exposure in the energy portfolio, 2) measure the degree of the risk exposure, 3) develop and test risk management strategies designed to reduce risk exposure, 4) implement risk management strategies that minimize energy cost volatility, and 5) implement the risk management strategies approved by the Risk Management Committee. The energy risk management function focuses on risk mitigation and value protection of the portfolio.

PSE manages its energy supply portfolio to achieve three primary objectives:

- ensure that physical energy supplies are available to serve retail customer requirements;
- manage portfolio risks to serve retail load at overall least cost while limiting undesired volatility on customer bills and PSE financial results; and
- optimize the value of PSE energy supply assets.

PSE manages the physical and financial positions and exposures through real-time trading, daily pre-scheduling, hedging, supply portfolio management, and optimization. Specifically PSE may purchase and sell energy in the spot and forward markets, and dispatch or displace generation units and nominate storage injection or withdrawal, both to balance the supply portfolio and to achieve net cost reductions.

PSE manages financial exposures associated with price and volumetric risks consistent through the following processes:

1. PSE manages the price and volumetric risks associated with its retail and wholesale energy sales with a diverse supply portfolio of resources that includes hydro, coal-based generation, combustion turbines, non-utility generation contracts, long-term purchase and exchange contracts, gas supply contracts, gas transportation and electric transmission, storage and peaking options and physical and financial wholesale energy and options on energy purchases and sales.
2. At times when PSE's energy supply resources may exceed its sales customer obligations, PSE manages the price risk associated with the excess resources by

entering into forward energy sales transactions or options on energy sales transactions. For example, PSE may forward sell energy at fixed prices or purchase put options at fixed strike prices.

3. At times when PSE's sales obligations exceed available resources, PSE manages the price risk associated with deficit resources by entering into forward energy purchase transactions or options on energy purchase transactions. For example, PSE may enter into energy purchases at fixed prices or purchase call options at fixed strike prices.
4. PSE manages the location risk associated with the anticipated energy resource sales by entering into purchase and sales transactions that have the same delivery point, term, and volume as the anticipated transaction. At times PSE may tie purchases and sales together by acquiring firm transmission rights to deliver energy associated with purchase or sale transactions to the point of receipt/delivery for the anticipated transactions.
5. PSE enters into other derivative products such as weather, hydro, and plant outage derivatives for purposes of managing exposure in the energy portfolio. These instruments and their strategic application to the portfolio shall be approved by the Risk Management Committee.

Management of PSE's wholesale energy portfolio proves to be a highly dynamic process driven by a number of factors, including:

- Relatively predictable diurnal and seasonal fluctuations in PSE's retail customer requirements;
- Less predictable fluctuations in PSE's energy supply requirements due to temperature swings, economic conditions, system outages and customer growth;
- Year-to-year, seasonal, and short-term variability in stream flows and hydroelectric generation and short term supply demand imbalance in gas supply markets;
- Forced outages of generation;
- Volatility in market prices for energy; and
- Constraints in electric transmission, gas transportation capacity and storage injection/withdrawal capability.

PSE manages a complex energy portfolio that requires careful measurement of volumetric and financial exposures. Specifically, PSE monitors financial positions on a daily basis, analyzes physical and financial variability, conducts portfolio and scenario analysis, develops risk management strategies and executes risk management strategies while giving consideration to financial reporting requirements and accounting treatment under FASB Statement No.133.

PSE strives to find a healthy tension between removing price exposure, but doing it so as to not assume large hedging costs. In addition, the Company seeks to optimize idle capacity and maximize the operational flexibility of its assets and contracts. The optimization is a cost-mitigation function, as it helps defray some of the fixed costs associated with transmission and inventory costs.

For more detailed information on PSE's risk management practices, see Appendix B, Portfolio Management Perspectives.

E. Gas Cost Synergies Between PSE-Gas and PSE Electric

A key regulatory issue of consideration for PSE focuses on the issue of whether establishing a gas cost floor for electric generation at the higher of cost or market is still appropriate, given the expected future gas transmission and supply resource requirements of both the electric and gas sectors. This section provide regulatory history on this issue and provides insight into how challenges of today's resource environment impact this issue.

Regulatory History

During the Puget Power/Washington Energy merger proceeding, Docket UE-951270, WUTC staff expressed concern over whether lower gas costs achieved for the electric system would come at the expense of gas customers, and whether merger savings would actually flow to electric customers. While electric rates would not be reduced automatically through an adjustment mechanism similar to the gas PGA/deferral process, electric customers would enjoy the benefit of gas cost efficiencies achieved through the impact of lower costs on future rates. As a result of the settlement stipulation in PSE's recent general rate case, Docket UE-011570, these cost benefits would be realized either via a power cost only rate proceeding or through the operation of the power cost adjustment mechanism (see Section C for more detail on the Power Cost Adjustment mechanism).

During the course of the merger proceeding, two alternative methods for transfer pricing of gas supplies procured by PSE for electric generation were considered. The first alternative would require PSE to procure gas supplies for electric generation on a completely stand-alone basis –

maintaining separate gas supply commodity and transportation portfolios for electric generation and retail gas service. This transfer pricing treatment would benefit PSE by reducing the probability of cross-subsidization and providing ease of monitoring, however, the economies from purchasing gas supplies for a combined portfolio would be eliminated. Not only would electric and gas customers lose the cost-reducing benefits of combined gas purchasing, but gas customers would lose the benefit provided by the contribution from electric generation to fixed gas supply and capacity cost recovery.

The second transfer pricing alternative addressed in the merger case sought to combine the gas supply procurement process, while imposing certain price controls. These price controls consisted of two cost floors, the higher of which would be used to price gas supplies for electric generation. The first cost floor equaled the Company's short-run incremental cost of gas, defined as the highest cost of incremental commodity gas supply available for dispatch plus transportation cost. The second cost floor equaled the market price of delivered gas. Defining the first cost floor as the highest cost commodity gas available for dispatch could mean electric generation would always receive the highest cost supply. Application of this principle would result in distinct disadvantage to electric generation and, ultimately, to ratepayers.

Various contractual obligations (annual, monthly or daily take-requirements, exchange agreements, and storage injection timetables) and physical pipeline limitations (actual location of various supplies or resulting from Operational Flow Orders issued by the pipeline), limit the Company's ability to turn on the least expensive gas first. Therefore, it should be expected that the optimized portfolio for any given day would utilize both high and low cost gas supplies which reflect those obligations and limitations. This results in incremental gas supplies (above core market requirements) frequently being nominated at costs less than the average cost of the optimized portfolio.

Under the second pricing alternative, lower cost supplies would be added to the core market portfolio, reducing the average cost, however, the highest cost supply in the portfolio would be transferred to electric generation, further reducing the average cost of the core market portfolio. While the gas customers would receive all the benefits of this treatment, it would have the effect of forcing electric generation purchases into the market for its gas purchases.

In the merger proceeding, PSE asserted that "available for dispatch" should be defined as gas supply which the Company may, at its discretion, turn on or off on a daily or monthly basis, as the situation demands. Further, PSE asserted it should be supplies available only after the core market requirements have been met through optimization of the portfolio. This broader definition of "available for dispatch" proved problematic as the frequent presence of firm supplies in the portfolio which, due to contractual or physical limits, would be dispatched regardless of the electric generation sale. These firm supplies may have a higher unit cost than other supplies available for dispatch and, if used as the transfer price floor, could create the pricing dilemma described above.

The lack of available data on prices of delivered or bundled spot market supplies made it difficult to apply the second floor, market price of delivered gas. Published spot prices reference various supply basins or pipeline hubs, not city-gate delivery points. Likewise, on any given gas trading day there may be no capacity release transactions on the applicable pipeline bulletin boards for similar transportation capacity segments. In instances such as this, the Company may need to use the average of other off-system sales during the same time period for similarly situated customers as the indicator of market price. In other instances, it may be necessary to capture the "quotes" of offered prices from other suppliers as evidence of the current market price.

The Stipulation approved by the WUTC in Docket UE-951270 resolved the transfer pricing issue by pricing intra-company transfers of natural gas "at the higher of market or the cost of incremental supplies with flexible take provisions.

Exhibit III-6
PSE Level of Gas Sales for Electric Generation

	Dth	Amount	Ave. $/Dth
Total 2000	45,419,986	$190,234,346	$4.188
Total 2001	52,794,466	$237,327,479	$4.495
Total 2002	25,683,130	$64,470,233	$2.510

F. Purchased Gas Adjustment Mechanism

PSE's gas tariff includes a WUTC-authorized Purchased Gas Adjustment (PGA) mechanism. This PGA mechanism allows the Company to pass through to its customers, on a dollar-for-dollar basis, the actual costs of gas supply and "upstream-of-the-city-gate" gas transmission and storage resource costs. The transmission and storage costs represent resources that PSE does not own but rather contracts for leased capacity on behalf of its gas sales customers. Periodically, (at least once every 15 months) PSE estimates the costs of gas supply and related pipeline/storage capacity costs to serve the Company's projected sales volumes over the ensuing 12 months and, with WUTC approval, establishes PGA unit rates designed to recover those projected costs from customers. Subsequently, each month the Company compares the actual costs of gas supply and capacity expenditures to the amounts recovered from customers under the PGA rates. Any difference is deferred to the regulatory asset or liability account for future recovery or refund to customers.

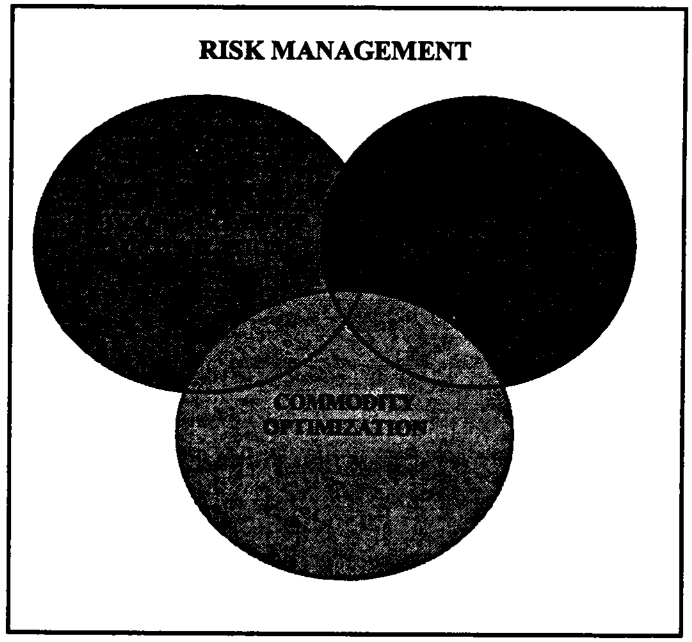
Periodically, usually every 6-12 months, PSE requests authorization from the WUTC to begin refunding over-collected gas costs or recovery of under-collected gas costs through a separate PGA Tracker unit rate. After audit of the deferred gas cost amounts by the WUTC, the PGA Tracker unit rates are approved to allow "amortization" of the over or under-recovered amounts, generally over a period of less than a 24 months. Through the operation of this mechanism, customers receive periodic "price signals" related to the current trend in the cost of gas. However, customers are not exposed to the day-to-day fluctuations in market prices for gas supply. PSE is permitted to recover 100 percent of any over or under recovery of its actual gas costs.

G. PSE's Gas Portfolio Optimization and Hedging Approach

Once PSE has selected and implemented a least-cost resource portfolio, the structure of the portfolio remains essentially fixed until the next opportunity to modify one or more resources. The structure of the selected portfolio also defines the fixed costs that PSE will incur until the next portfolio modification. The focus then shifts to managing the variable costs of the portfolio components to minimize average costs and cost volatility. The continuous process of selecting the least cost portfolio and managing it to minimize costs and cost volatility is known as "portfolio optimization", and applies to PSE's transmission, capacity, and commodity contracts within the context of a risk management framework. This section discusses the application of the portfolio optimization to each type of contract. And while handled separately in the text, in practice, this optimization affects more than one resource and is closely integrated with risk management.

Exhibit III-7

Gas Portfolio Optimization



Transportation Optimization

PSE maintains sufficient capacity to meet the needs of its firm customers on a design day. When not using firm transportation capacity to serve the needs of its firm customers, PSE manages the unused capacity to generate additional revenues through off-system sales, releases of capacity, and exchanges of gas. PSE credits the revenues from these activities to the cost of gas, minimizing the cost of the portfolio, and the average cost of gas to firm customers. Each of these activities is covered in turn.

Off-System Sales. Capacity optimization opportunities arise because PSE has unused, firm transportation during the off-peak periods to move gas from one region to another region. The largest opportunity for PSE currently exists in buying low cost gas in the Rocky Mountain supply basin and re-selling it in the Pacific Northwest Market Area, which includes liquid market points such as Stanfield and Sumas, as well as other less liquid points along the I-5 Corridor. PSE buys gas from other marketers, traders, aggregators, and LDCs, and resells it at a profit to other parties along the pipeline and developers in different market areas.

PSE Gas Supply Operations personnel constantly monitor the markets for opportunities to monetize idle transportation capacity. These opportunities are viewed on a daily, monthly, and seasonally spot basis. With these deals, PSE enters into "bundled" transactions that incorporate a commodity and transportation component, and generates additional revenue used to reduce the cost of gas to its firm customers.

Capacity Release. PSE also captures the value of geographic price differences by releasing temporarily unused transportation capacity to other pipeline shippers. PSE estimates its available capacity for release on a daily, monthly, and annual basis, with the open market determining the value of the capacity. The quantity available for release is not constant, and fluctuates with the seasons and expected weather. Before releasing the capacity, PSE considers numerous factors, including the number of consecutive days that such capacity would be required by PSE, the recall provisions by PSE, the projected gross margin, and whether a gas sale provides higher margin opportunity.

When PSE releases capacity, it posts the amount of capacity and terms of the release on the pipeline's electronic bulletin board (EBB). In order to bid on the capacity and become a replacement shipper on the pipeline, the replacement shipper must satisfy the pipeline's creditworthiness standards. Capacity releases shorter than 31 days can be made on a pre-arranged basis, and are posted on the EBB to notify the market. Otherwise, the capacity is posted, and released to the highest bidder. The winning replacement shipper pays PSE a price (fixed or variable) to use the capacity for the term of the release, and has the freedom to use the capacity as it sees fit pursuant to the terms of the pipeline's tariff and PSE's release. Capacity released with recall provisions typically has a lower value in the market.

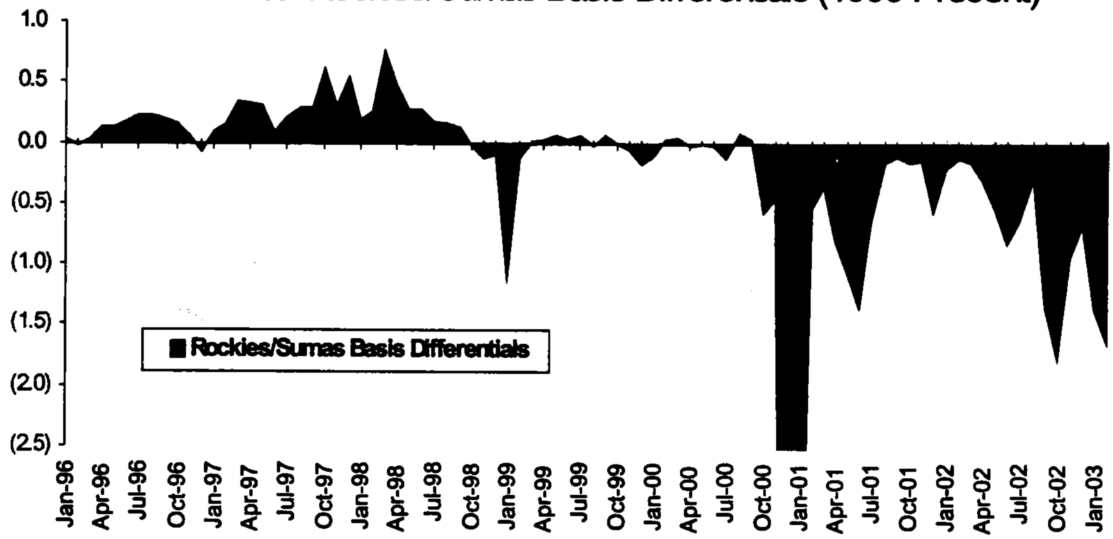
PSE has found the capacity release market to be subject to seasonal variations. As might be expected, winter capacity typically receives a higher value as most of the capacity will likely be used. The lower capacity factors in the summer allow for a larger available amount of capacity for release, at a relatively low value. PSE targets its capacity release efforts to the following broad market segments – PSE's industrial and commercial customers or the marketers serving them; merchant and regulated gas-fired electric generation owners and operators; gas producers; and marketers and aggregators.

In the last two to three years, the chief regional pricing differential has been comparing lower priced U.S. Rockies prices with other basin and city-gate prices. Exhibit III-8 illustrates the historical value of the price differential between U.S. Rockies supply basin and the Pacific

Northwest Market Area. Price differences between regions create the opportunity for transportation optimization.

Exhibit III-8

Historical Rockies/Sumas Basis Differentials (1996-Present)



Source: Inside FERC.

Storage Optimization

The PSE core gas portfolio includes approximately 21 Bcf of annual storage capacity, both in its market area and in the U.S. Rockies supply basin, as described above. PSE manages the storage capacity used to meet core customer needs by injecting gas when it is less expensive, and withdrawing it when it is more expensive. Unless needed by its firm customers, PSE releases storage capacity and sells storage services to offset gas costs to its firm customers. Due to its credit constraints and aggressive third-party bidding from companies holding no storage, PSE has found it advantageous to release storage capacity and sell services, rather than manage the storage for others.

Storage Capacity Release – PSE has actively released storage capacity in the U.S. Rockies (Clay Basin) during the last few years. Since large quantities of Clay Basin capacity are not crucial to the requirements of daily operations, PSE has conducted RFP processes for the release of excess capacity. If storing gas does not appear attractive because the price spread between summer injections and winter withdrawals does not appear economical, then storage capacity could be released and the winter gas hedged.

PSE does not consider releasing storage capacity at Jackson Prairie, since this storage plays an essential role in covering peak day demand (unlike Clay Basin) and has too much value as a daily operational load-balancing tool. However, PSE extracts additional value from Jackson Prairie through the sale of storage services.

Storage Service Sales – PSE does sell a limited volume peaking service at its Jackson Prairie storage facility, essentially serving the same function as selling a call option in the Seattle market area. PSE expects to continue selling these calls provided that it does not compromise service to firm customers. PSE offers these transactions for a limited volume and number of days during the year to ensure that PSE maintains adequate resources to meet core customer requirements if load requirements increase unexpectedly.

Gas Portfolio Management Summary

PSE operates its core gas portfolio in a conservative manner, in order to be certain that at all times it can cover peak day demand. However, because this approach leaves PSE long on supply resources throughout the remainder of the year, PSE trading and operations staff uses a variety of techniques to recover costs and generate additional revenues, including available risk management tools. PSE does not speculate on the commodity price for its core gas portfolio, but chooses instead to manage assets in a less risky manner. Cost mitigation is sensitive to regional price differentials, seasonal price variability, credit issues, and market liquidity.

H. Gas Supply Issues

PSE procures gas supply not only for its gas customers, but also for the Company's gas-fired electric generation resources. A host of factors including the price volatility seen in the West, the surge in new gas-fired generation in the U.S., demise of market players who provided greater liquidity to energy commodity markets, and mixed forecasts of average gas prices, have heightened the importance of the issue of gas price risk for PSE. This sections highlights the differences between purchasing gas for LDC end-use customers, the challenges in this process and options for managing risk.

Differences Between LDC End-Use and Electric Generation Purchases

A single organization within PSE manages gas procurement for the LDC and use by gas-fired electric generation resources. The same principle for both types of purchases hold – to assure supply reliability at a low cost. Fundamentally different risks impact LDC end-use gas procurement and power production gas procurement. For the LDC, PSE procures gas at prevailing market prices, and purchases most of its gas at index. As described in Section G, the Company engaged in some fixed-price hedges for the period of November 2002-October 30, 2003. The LDC cannot substitute another product for gas, and purchases all of its gas at market locations corresponding to its firm transportation receipt points and its storage locations, it functions mostly as a price taker in the market. Under its PGA described earlier, PSE can recover in full the costs of its gas procurement for LDC customers.

Different practices and risks impacts PSE's gas procurement activities on behalf of its gas-fired generation portfolio. Not only does the Company monitor its forward fixed-price risk (which can be managed through physical and financial products), it also carefully watches the implied market heat rates when deciding whether to dispatch a unit. Therefore, the Company must be sensitive to both the absolute price levels, but also the price relationships between gas and power. Having a diverse portfolio of owned generation of hydro, gas and coal, and power purchase contracts, provides PSE some flexibility in how it handles individual assets and contracts within the integrated portfolio. Gas supply issues are a relatively modest portion of the entire portfolio management scope.

For both of PSE's gas procurement obligations, the Company has in place adjustment clauses, which allow it to recover its costs for gas used for each function. The two clauses – the purchase gas adjustment clause, or PGA, and the power cost adjustment clause, or PCA were both described earlier in this chapter. The PGA is a pass-through mechanism, whereas the PCA is a mechanism with a deadband around a forecasted amount with the graduated sharing of costs between customers and shareholders. The further from the deadband, the lower the burden (or the lower the benefit, in the case of profits exceeding the deadband) for shareholders, since the purpose of the clauses is to encourage PSE to achieve its goals for managing gas and power costs. Through the PCA, PSE is encouraged to manage gas price risks on behalf of its customers to hedge against the possibility of rising prices or temporary price spikes. Outside of the PGA mechanism, the WUTC and interested parties have been supportive of PSE incorporating some hedging in the core gas portfolio. To manage gas price exposure, PSE can leverage a variety of physical and financial tools that are available in the market for purchasing gas and managing the cost implications of on-going gas procurement needs.

Options for Managing Gas Price Risk

As an LDC, PSE has used a variety of long and short-term tools to mitigate its gas price risks in meeting the needs of its end-use customers. These tools seek to mitigate gas price risks through the use of fixed-price, forward gas contracts, and leased or owned gas storage capacity. A variety of financial tools also allow PSE to manage its gas supply portfolio on a short and long-term basis dynamically over time.

With respect to gas in its power portfolio, some industry observers have expressed a concern that a reliance on gas-fired generation carries significant market risk. A host of risk mitigation products offered through the market can help mitigate these potential risks. PSE pays a price for these tools, for example, the further out in the future that PSE attempts to lock in gas prices, the greater the premium the Company must pay. Financially it would be imprudent for PSE to eliminate all volatility as the price would far outweigh the benefits to be gained. Furthermore, the Company would be straddled with significant exposure to above-market contracts in the future, which would also risk placing the Company's generating units in an unattractive position in the regional supply stack. Gas procurement strategies for power production must balance the pursuit of stable costs with the cost for that stability. While the costs for end use gas must be deemed prudent, the costs for gas used in power production, although bearing the same burden of prudence, must also not compromise the unit's competitiveness.

Risks to Gas Procurement for Electric Generation Portfolio Use

PSE faces challenges multifaceted and ever-changing challenges to securing gas supply for its electric portfolio. In addition to the constant effort of balancing shareholder and customer interests, PSE must also manage the dynamic effects of the market on the Company's existing and future gas supply position. Specific challenges that PSE will confront in managing gas supply for the Company's gas-fired units include:

- Minimizing counterparty risk by limiting transactions to those possessing investment grade credit or with sufficient collateral to support a transaction,
- Diversifying supply sources to mitigate the impact of physical supply interruptions due to force majeure events, and
- Continually updating the Company's supply portfolio to reflect its forward view of the market by either increasing or decreasing its positions, depending upon the expected plant requirements for fuel, given price relationships between gas and power.

These issues are not much different than those faced in building the supply positions for serving end-use customers. The only difference rests in the regulatory determined recovery of expenses related to gas procurement for end-use consumption and power generation. However, the same tools enable PSE to meet the challenges of electric portfolio generation portfolio gas supply procurement and end-use customer supply procurement.

Gas Price Risk Summary

Gas procurement remains a complex, dynamic, and fluid process for PSE. Price volatility will continue to be a part of the market mix that PSE evaluates as it makes decisions affecting the Company's short and long-term supply positions. Over the past several years it has become evident that gas prices in the Pacific Northwest will continue to be influenced by a wide range of variables including actual/forecasted weather patterns, gas storage trends, gas fired generation demand, and pipeline capacity availability. Throughout the procurement decision process, PSE takes into account fundamental supply and demand information, including these factors, to guide it in making supply acquisition and risk management decisions in pursuit of supply stability at reasonable prices.

I. Summary

To gain a full understanding of the context in which the Least Cost Plan process occurs, internal PSE factors such as its financial, regulatory and business strategy must be considered. In all these arenas, PSE pursues strategies limiting overall supply risk, while allowing both stakeholders and customers to benefit from its prudent business strategy. Other key conclusions include:

- PSE's financial policy focuses on one main goal – improving its credit rating.
- PSE's Power Cost Adjustment (PCA) mechanism, which resulted from a 2002 rate settlement agreement, shares the costs or benefits of higher or lower power costs between customers and shareholders. In addition to providing for cost-sharing, the PCA limits PSE's financial exposure to power supply costs over a threshold of $40M over a four-year period, providing prompt rate adjustments in highly volatile power markets.
- On the gas side, PSE has a Purchased Gas Adjustment (PGA), which allows the Company to pass through to its customers, on a dollar-for-dollar basis, the actual increases and decreases of gas supply costs and "upstream-of-the-city gate" gas transmission and storage resource costs.

- PSE's electric portfolio optimization and hedging approach – which reaches one to two years into the future, seeks to ensure physical supplies exist to serve customer need, while optimizing the portfolio's value and limiting price volatility for customers and earnings risk to PSE shareholders.
- PSE operates its core gas portfolio in a conservative manner in order to be certain that at all times it can cover peak day demand. This approach can leave PSE long on supply sources during certain times of the year, thus PSE utilizes a variety of contract and operational techniques to generate revenues and cut down energy costs to its customers.
- PSE must not only manage gas price risks for serving its LDC end-use customers, but also for procuring supply for its gas-fired electric generation portfolio. Although no clear solution for eliminating price risk volatility exists, PSE can use available financial tools to control and hedge these costs to some degree.
- PSE's ability to execute risk management strategies is constrained by the number and creditworthiness of counterparties, and by its own credit rating and limited access to credit.

IV

IV. Stakeholder Interaction

Chapter IV addresses stakeholder issues, including public input into the Least Cost Plan process and specific stakeholder issues of concern. This chapter begins with an overview of PSE's commitment to public involvement in the planning process, and describes its public input process. Section A also provides a synopsis of formal meetings held to date. Next, in response to the Washington Utilities and Transportation Commission ("WUTC") August 2001 comment letter in response to PSE's 2000-2001 Least Cost Plan, PSE provides a list of additional regulatory expectations and points the reader to the Least Cost Plan section that addresses each expectation. The end of this chapter summarizes the major stakeholder issues identified during the Least Cost Plan process to date, organized around major themes. Again, in describing these issues of concern, PSE provides references to relevant portions of the Least Cost Plan addressing these specific issues.

A. Public Participation

PSE maintains an open commitment to actively encouraging public involvement in its Least Cost Plan process. As of March 31, 2003, seven formal Least Cost Planning meetings, in addition to dozens of informal meetings and communications have taken place, with additional meetings scheduled during April to solicit additional stakeholder feedback. A number of stakeholders including WUTC Staff, consumer advocates; individual customers from industrial, commercial, and residential classes; environmental organizations; the Northwest Power Planning Council; and the Washington State Department of Community, Trade and Economic Development have actively participated in meetings. The stakeholder meetings provide an avenue for constructive feedback and useful information to guide the Least Cost Plan process. PSE wishes to express gratitude to those who have attended the Least Cost Planning meetings for their time and energy devoted to the Least Cost Plan process. PSE encourages the continuation of this active participation as the Company's planning process proceeds.

The following section provides an overview of the Least Cost Planning meetings convened as of March 31, 2003.

Kick-off Meeting: August 26, 2002

During this meeting, participants addressed four primary topics. First, PSE and stakeholders discussed initial approaches to PSE's Least Cost Plan process. Second, PSE presented its draft electric sales forecast, including forecast assumptions and new forecasting methods. Third, PSE compared its sales forecast against future resources, illustrating a growing need for resources. Fourth, PSE reviewed current transmission constraints and how these constraints impact resource planning. During this meeting, the issue of planning criteria – specifically, the cost of meeting peak demands under normal versus dry hydro conditions was also addressed.

Renewable Resource Meeting: October 10, 2002

At this meeting, PSE enlisted several outside experts to present information regarding renewable resource opportunities and development issues. Specific presentations and discussions focused on wind, geothermal, and renewable resource projects on Vashon Island. Following the presentations, meeting participants engaged in an informative round-table discussion.

Distribution Planning Meeting: October 16, 2002

The Company explained its process for conducting gas and electric distribution system planning. Participants discussed the topics of planning criteria and distributed generation.

Energy Risk Management and Natural Gas Supply Meeting: October 22, 2002

This meeting focused on two distinct topics – natural gas supply and hedging risk. First, PSE provided a presentation on natural gas supply for gas sales customers. Next, the company explained how PSE models risk, including an overview of hedging for the Company's electric and gas portfolios. During this meeting, customers' sensitivity and interest in energy risk management issues became apparent, as well as the critical need by PSE to keep customer and interested parties informed of the Company's actions in this area.

Updated Demand Forecast, Resource Need, Next Steps Meeting: December 11, 2002

During this meeting, three key topics were addressed. First, PSE provided a presentation of its updated electric sales forecast, including updated forecasting methods and results. The Company also explained how it adapts its billed sales forecast to hourly loads. Next, PSE presented its need for resources based on robust Aurora modeling. Finally, the Company discussed with participants the screening analysis – including numerous probabilistic variables – it is performing on various resource portfolios, and its analysis decision-making process. The Company stated a willingness during this meeting to analyze additional scenarios offered by participants, including some portfolios on generic demand side management programs.

Least Cost Plan Advisory Meeting – Electric: March 14, 2003

This meeting focused solely on PSE's electric Least Cost Plan, providing stakeholders with a progress report on the Company's actions. PSE began the meeting by presenting its draft electric resource strategy. Other topics covered were an update on PSE's load-resource outlook, a review of planning assumptions, an overview of the analytical approach and draft results so far, a discussion of the Company's judgmental considerations, and a list of next steps for completing the electric portion of the Least Cost Plan.

Least Cost Plan Advisory Meeting – Electric and Gas: March 25, 2003

This meeting focused primarily on PSE's gas Least Cost Plan. PSE began the meeting with a review of its gas demand forecast, including a description of its methodology and major assumptions. Next, PSE presented the overview of its gas load-resource balance. As a follow-up to the March 14, 2003 meeting on the electric Least Cost Plan, PSE provided a brief analysis update on its AURORA power price forecast, and expected costs to customers under the various combined energy and capacity planning levels. The meeting ended with a review of next steps and the Least Cost Plan schedule.

B. Additional Regulatory Expectations

Following PSE's previous Least Cost Plan, the Washington Utilities and Transportation Commission (WUTC) issued a comment letter dated August 21, 2001, providing a list of issues for PSE to address in the next Least Cost Plan. Exhibit IV-1 references the WUTC expectations to chapters within the Least Cost Plan where a discussion of the topic can be found.

Exhibit IV-1
Additional Regulatory Expectations for PSE's Least Cost Plan

AUGUST 28, 2001, LETTER	CHAPTER
p. 3: A detailed description of risk-management strategies and how those strategies advance the twin goals of low and stable retail rates should be a critical component of PSE's next plan. Moreover, the plan should empirically support the chosen strategies with a short-term evaluation of their economic effects.	• Chapter III, ,PSE's Current Situation • Appendix B, Portfolio Management Perspectives
p. 3: Supply Resource Planning – The next plan should assess the volatility and cost trade-offs (core customer benefits and risks) of acquiring power by building new generation facilities, by securing bi-lateral contracts, or through market products. The plan should describe how participating in the market furthers Puget Sound Energy's portfolio management responsibilities.	• Chapter II, Planning Issues • Appendix B, Portfolio Management Perspectives
p. 3: PSE should integrate DSM into the planning for other types of supply.	• Chapter IX, New Electric Resource Opportunities • Chapter XVI, Action Plan
p. 3: DSM – In addition, Puget Sound Energy should: • Update its list of cost-effective and technically available DSM options (the Regional Technical Forum could aid this effort); • Determine whereby DSM becomes a practical and cost effective tool to address short-term and volatile situations or introduce new technologies; • Balance load management opportunities with energy efficiency programs within the DSM portfolio; and, • Reconsider fuel conversion opportunities in appropriate parts of the service territory.	• Chapter IX, New Electric Resource Opportunities • Chapter XVI, Action Plan
p. 3: Electric Portfolio Analysis – Puget Sound Energy should re-run the model using various scenarios of market volatility to see if the low-cost outcome changes.	• Chapter X, Electric Portfolio Analysis • Chapter XVI, Action Plan
p. 4: Distributed Generation and Conservation – The plan should establish criteria for assessing when distributed generation and conservation will improve PSE's localized distribution system or system wide operation, cost, and reliability. With those criteria, PSE should identify opportunities for deploying distributed generation and conservation.	• Chapter X, Electric Portfolio Analysis • Chapter XVI, Action Plan
p. 4: Demand Forecasting – • PSE should consider using or at least discuss more robust analytical techniques such as Monte Carlo simulation, quadratic or constrained optimization procedures, and combinations of econometric and operations research. • The next plan should pay special attention to forecasting industrial loads. PSE should consider whether potential changes in industrial load affects its preferred resource strategy. • PSE should reevaluate the current plan's approach of using a	• Chapter V, Load Forecasting • Chapter X, Electric Portfolio Analysis

AUGUST 28, 2001, LETTER	CHAPTER
relatively small sample of weather observations.	
p. 5: Integrated Resource Planning – PSE should consider using more flexible and robust modeling techniques that emulate real word conditions in its next plan.	• Chapter X, Electric Portfolio Analysis • Chapter XI, Electric Analytical Results & Application of Judgment Chapter XV, Gas Resource Analysis and Strategy
p. 5: Short-Term Component – The LCP also needs a short-term component –a plan to cope with real world prices, supply and/or demand contingencies that are substantially outside of the expectations contained in the Integrated Resource Plan.	• Chapter X, Electric Portfolio Analysis
p. 5: Pricing Mechanisms – • The plan should describe, perhaps as part of the DSM analysis, the expected consequences of alternative pricing mechanisms • The plan should also discuss whether alternative pricing mechanisms alter the balance of risk and opportunities between retail customers and PSE. • Finally, the plan should consider the pricing mechanism's effect on the capacity and energy demand forecast.	• Chapter IX, New Electric Resource Opportunities • Chapter XVI, Action Plan

C. Key Stakeholder Issues of Concern

PSE has actively solicited stakeholder comments throughout its Least Cost Plan process. As detailed above, meetings have been held regularly since the end of summer 2002, and stakeholders were encouraged to provide written comments on PSE's December 2002 Least Cost Plan progress update. From reviewing these written comments and noting stakeholder opinions expressed during the stakeholder meetings, PSE has identified three main areas of stakeholder concern:

- A concern that the Least Cost Plan does not provide a sufficient basis to justify resource acquisitions.
- Concerns that not all resource acquisition alternatives, including renewable resources, conservation and efficiency, and fuel conversion, have been fully explored.
- The allocation of risk between the Company's shareholders and ratepayers.

The remainder of this section provides more detail in each of these areas, and directs the reader to sections within the Least Cost Plan document which directly address these concerns.

Least Cost Plan as Basis for Resource Acquisition

Some stakeholders have raised questions over the amount and timing of PSE resource needs, and whether the Least Cost Plan serves as a justification for an already-determined resource acquisition strategy. Some stakeholders question whether PSE's resource needs consist of a capacity, not an energy, deficit that could be met by PSE pursuing more conservation and demand side management, utilizing its CT's and Encogen purchase more, or making more market purchases. As an extension of this issue, some stakeholder have raised concerns over some of PSE's assumptions, most specifically, whether PSE's demand forecast takes into account the Puget Sound region's perceived weak economy. Issues raised by stakeholders question if the current buyer's market may compel PSE to pursue a resource acquisition process and use its Least Cost Plan filing as a tool to justify this strategy.

Since its previous Least Cost Plan, PSE has performed an extensive review of its assumptions and portfolios, and enhanced its analysis process. Chapter X details PSE's analytical process, while Appendix J details PSE's updated assumptions driving its analysis. Chapter XI provides the results of PSE's analysis and a discussion of the subjective factors guiding PSE's recommended long-term electric resource strategy. Finally, Appendix H provides insight into operational considerations for PSE's existing simple cycle combustion turbines.

Resource Acquisition Alternatives

Several stakeholders questioned how comprehensively PSE looked at alternatives to resource acquisition, including energy efficiency, seasonal exchanges, fuel conversion, conservation, load management techniques and increased demand side management measures. Some stakeholders expressed concern over PSE's use of a 15 aMW conservation target over the 20-year planning period, instead of growing the conservation target each year.

As Chapter IX and its accompanying Appendices D and G illustrate, PSE began its analysis process by surveying a wide range of possible electric resource alternatives, including demand response alternatives, Conservation Voltage Reduction (CVR), fuel conversion and distributed generation resources; renewable resources such as wind, biomass, solar and geothermal energy; as well as thermal resource alternatives such as gas and coal. Also, as part of its electric resources strategy and as detailed in PSE's two-year action plan in Chapter XVI, PSE has made commitments to further evaluate electric resource alternatives in the short-term and to re-assess the 15 aMW target agreed to in PSE's latest rate case.

Allocation of Risk

Stakeholders expressed concern over how PSE will allocate risks between the Company's shareholders and its customers. PSE addresses this issue both through its analysis process and its application of judgment to the analysis results. As Chapter X describes, in lieu of the existence of a prescribed regulatory standard, PSE evaluated eight different planning levels and the trade-off between costs and risks to customers. As detailed in Chapter XI, PSE assessed the cost and risk trade-off for each of the different planning portfolios.

D. Summary

PSE maintains an open commitment to actively encouraging public involvement in its Least Cost Plan process. In addition to holding formal stakeholder meetings to discuss its Least Cost Plan process and informally seeking stakeholder input, PSE has also reviewed and incorporated written comments from stakeholders into its current Least Cost Plan process. Other key highlights include:

- As of March 31, 2003, PSE has held seven formal Least Cost Plan meetings, in addition to dozens of informal meetings and communications, with key stakeholders including WUTC staff; consumer advocates; individual customers representing industrial, commercial and residential customers; environmental organizations; the Northwest Power Planning Council; and the Washington State Department of Community, Trade and Economic Development.
- During these meetings, a variety of topics were addressed, including electric sales forecasts and assumptions, PSE resource needs, transmission constraints, renewable resources, gas and electric distribution planning, natural gas supply and hedging risk, and the AURORA modeling process, among others.
- In addition to meeting Least Cost Plan regulatory requirements, PSE also addressed additional regulatory expectations as presented by the WUTC in its August 2001 letter to PSE commenting on PSE's 2000-2001 Least Cost Plan and recommending future issues for consideration.
- Stakeholder issues of concern have centered on three main issues – whether the Least Cost Plan provides a basis to justify resource acquisition, if sufficient and fair treatment has been given to renewable resources and energy efficiency, and the proper allocation of risk between the Company and its customers.

- PSE has incorporated stakeholder issues of concern into the Least Cost Plan process. The Company has reviewed its assumptions, expanded the depth and robustness of its analysis, examined a wide range of electric resource opportunities, and continued to seek public input.

V. LOAD FORECASTING

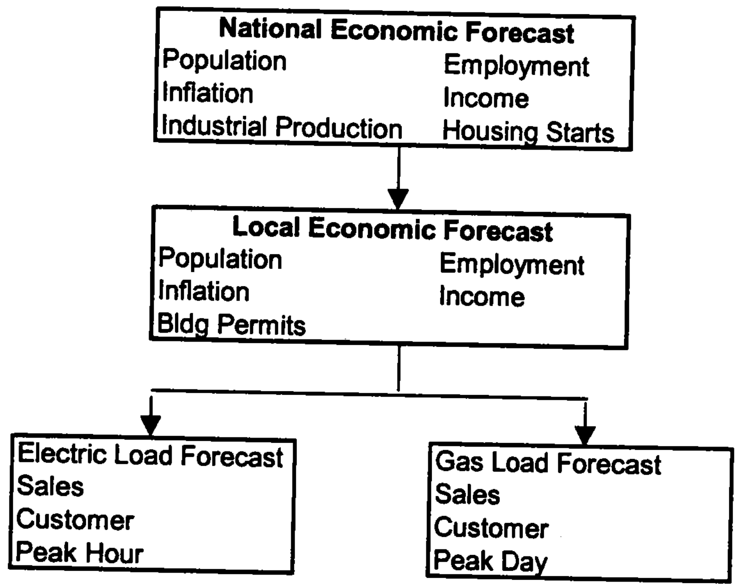
Each year, PSE develops a 20-year forecast of customers, energy sales and peak demand for its electric and gas service territories. PSE utilizes the forecast for short-term planning activities such as the annual revenue forecast, marketing and operations plans, as well as in various long-term planning activities such as the Least Cost Plan, and the transmission and distribution plans. This chapter provides a description of the forecasting methodology employed for billed sales and customer count forecasts, and peak hour or peak day forecasts; the development and sources of forecast inputs and assumptions; and a summary of customer, sales and peak demand forecasts. For purposes of supply planning and portfolio management, PSE prepares a load forecast, as opposed to solely relying upon a billed sales forecast. This chapter ends with an overview of the load forecast, while Appendix C provides the methodology used to convert a monthly billed sales forecast to a load forecast

A. Forecast Methodology

Billed Sales and Customer Counts Forecasts

PSE designed its forecasting process to provide monthly forecasts of customers and billed sales at the customer class and service territory levels. The five customer classes for electric include residential, commercial, industrial, streetlights and resale. The eleven gas customer classes (class identifier in parenthesis), by type of customers, include firm – residential (2), commercial (5), industrial (4), commercial large volume (27), industrial large volume (67); interruptible - commercial interruptible (26), industrial interruptible (66); and transportation - commercial firm transportation (32), commercial interruptible transportation (30), industrial firm transportation (72) and industrial interruptible transportation (70). PSE's electric service territory covers the nine counties in the state (Whatcom, Skagit, Island, King, Kittitas, Pierce, Thurston, Kitsap and Jefferson), while the gas service territory covers six counties (King, Snohomish, Pierce, Thurston, a small portion of Kittitas, and Lewis). The people in these counties account for about two-thirds of the state's population. The forecasting models are premised upon electricity or gas as an input into the production of various outputs. In the case of the residential sector, the output is "home comfort", which includes the different end uses such as space and water heating, lighting, cooking, refrigeration, dish washing, laundry washing and various other plug loads. In the case of the non-residential sector, these outputs include HVAC, lighting, computers, and other production processes. Thus, economic and demographic conditions, both locally and at the national level, drive the demand for energy. Exhibit V-1 provides an illustration of the forecasting model.

Exhibit V-1
PSE Forecasting Model Overview

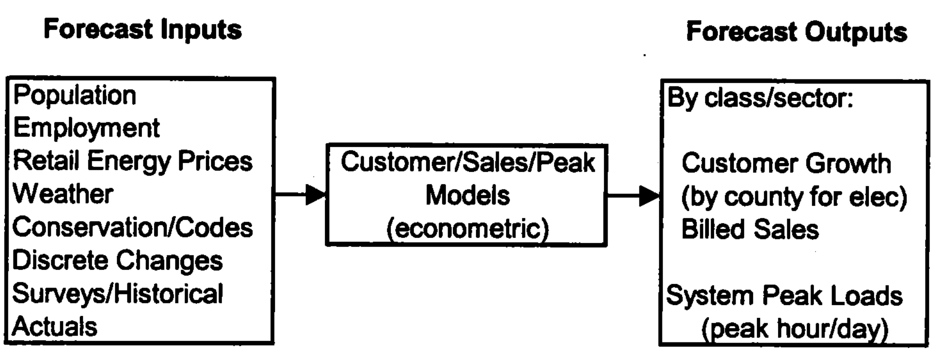


PSE used a mixed end-use and econometric model to develop its long-term billed sales forecasts in its previous Least Cost Plan. Specifically, electric sales forecasts from the residential and commercial sectors were developed by using end-use models (RHEDMS and CEDMS, respectively), while those in the industrial sector were developed by an econometric model at the two-digit SIC level. Gas sales forecasts for residential customers were also developed using an end-use model, while the non-residential sectors utilized econometric approaches. PSE implemented a new approach in developing this year's billed sales forecasts for the Least Cost Plan.

PSE relied upon a new approach that utilized an econometric approach to develop the relationship between electricity or gas demand, and the economic and demographic factors at the customer class level. PSE chose this method for several reasons. First, the end-use models required data from end-use surveys, which have not been done in several years. Second, the reliance upon SIC codes did not provide reliable data as many SIC codes were either outdated or missing when the billing system was replaced. This made distinguishing between single-family vs. multi-family customers or by standard industrial classification codes an inaccurate measure. In addition, the new North American Industrial Classification System (NAICS) is currently being implemented, which will result in the reclassification of some industrial classes and require a recasting of historical data. Further, large industrial and commercial electric customers have moved to transportation or "retail wheeling" schedules, leaving only a small amount of the industrial sector still receiving firm service. This would have been difficult to model at the two-digit SIC level. Accordingly, PSE developed an alternative method of capturing the effect of economic conditions on billed sales, and will re-classify the commercial and industrial customers using the NAICS categories.

Other factors affect the use of energy as well. Exhibit V-2 provides a more detailed diagram of the econometric forecasting model. For a more detailed discussion of PSE's billed sales and customer forecast methodology, please refer to Appendix C, Load Forecasting Methodology.

Exhibit V-2
PSE Econometric Forecasting Model



Billed sales in the month are defined as the sum of the billed sales across all customer classes, where billed sales for each class are estimated from the product of sales per customer equations and the customer count equations.

Peak Load Forecasts

PSE also projects peak load forecasts in the next 20 years to support planning for peak capacity requirements, and long-term distribution and transmission planning activities. For electric, the peak hour for the normal and extreme design temperatures represent the relevant peak loads. For PSE, these design temperatures both occur in January, with a 23-degree normal peak and 13-degree extreme peak. For gas, PSE uses peak day for the design day temperature to represent its relevant peak for gas. The Company bases its design peak day requirements for this forecast on the Company's historically coldest day in the last 20 years as measured at SeaTac Airport, containing 51-degree days (14°F average temperature, 24-hour, which occurred on February 2-3, 1989), versus the 55-degree day used in the 2000 Least Cost Plan (based on the coldest day in the last 50 years). PSE also uses the minimum hourly temperature in this peak day for gas distribution planning. Consistent with this 51-degree day, PSE uses 10 degrees, which is based on the historical data in the last 20 years. PSE recognizes the possibility of similar weather conditions likely occurring in the future and has planned to meet these customer requirements on a least cost basis.

The "coldest day in the last 20 years" standard for the gas peak day and peak hour planning criteria is consistent with the criteria used by several other major gas utilities in the region. The gas planning criteria is more conservative than the "normal peak hour" and "extreme peak hour" criteria used for electric due to the differences in the nature of the two services. Restoration of service to gas customers after a shortage of supply or insufficiency of capacity is significantly more costly and time consuming than the restoration of electric service. Gas service restoration requires the manual relighting of most appliances within the customers' premises, whereas electric restoration does not usually require any such labor intensive efforts. In addition, the performance capability of the gas delivery system is degraded each successive day of a cold weather period (due to the inability to refresh line-pack) thus requiring a more conservative planning criteria to provide a comparable reliability of service for the two fuels.

A more detailed discussion of the forecasting model is presented in the Appendix C.

B. Key Forecast Assumptions

Energy use forecasts depend upon major inputs into the model such as economic activity and fuel prices. Regional economic growth increases employment and the demand for electricity. Economic growth also increases the number of customers by attracting more customer migration. Retail energy prices affect the type of fuel used in appliances, and the appliance efficiency and utilization levels. Conservation and other programs instituted by PSE also affect energy consumption. The following section presents the assumptions and forecast of economic and demographic variables and retail prices, conservation savings, and other key assumptions used for this forecast.

Economic and Demographic Assumptions

The Puget Sound area is a major commercial and manufacturing center in the Pacific Northwest with strong links to the national and state economies. These links create jobs not only for directly-affected industries, but also indirectly for supporting industries through multiplier effects. Thus, the performance of the national and regional economies impacts the service territory economy.

National Economic Outlook. The DRI-WEFA Spring 2002 Long-term Trend Projections (25-year focus) provides the long-term national economic outlook. As the name suggests, the forecast exhibits only mild variations in growth over the next 25 years. After recording its first recession in about 10 years, DRI predicted the national economy would grow at about 2.3 percent in 2002, after which it would follow its underlying historical growth rate of approximately 3.2 percent in the next 20 years. Annual real GDP growth occurred at about 3.1 percent between 1970 and 2000. The major factor contributing to this result despite declining labor force participation as the percent of population of working age declines is the assumption of higher productivity growth due to efficiencies induced by technology. Exhibit V-3 summarizes the national economic forecasts used an inputs to the model.

Exhibit V-3
National U.S. Economic Outlook

	2002	2003	2005	2010	2015	2020	aarg
GDP (96$B)	$9,548.2	$9,909.3	$10,569.3	$12,300.0	$144,450.8	$16,895.1	3.2%
Employment (mill)	131.7	133.8	138.4	146.4	154.8	161.9	1.2%
Population (mill)	279.1	281.3	285.9	297.7	310.1	322.7	0.8%

aarg: average annual rate of growth

A national economic recovery is expected in the near term, albeit at a slow pace. While consumer spending has bolstered the economy, an expectation for flat or negative business and state/local government spending remains. Although federal spending will likely grow, the growth will not be enough to offset declines in other sectors. The Federal Reserve Board recently reduced the federal funds rate by another 50 basis points in an effort to jump-start the economy. However, near-term uncertainties over a potential war with Iraq, consumer confidence levels, companies' abilities to overcome accounting issues and retain profit levels, and a stock market recovery still plague the national economy.

Regional Economic Outlook. During the next two decades, PSE expects employment in its service territory to grow at a slower rate (1.6 percent) compared to it 30-year historical growth rate of 3.3 percent per year. Even at this rate, local employers will likely create approximately 580,000 jobs between 2002 and 2020 – more than one-third of the jobs in the area today. During this period, 730,000 new residents are expected in the area, raising the population to nearly 4.1 million. Currently, the regional economy faces one of its worst recessions in the last 20 years, with employment declining in 2002 by about two percent. Nearly 30,000 company-wide layoffs at Boeing, and additional layoffs in the high technology and telecom sectors, have contributed to this recession. In the near-term, employment is expected to grow only modestly by about one percent in 2003 before jumping by about four percent in 2004. The 2002 decline in employment impacted the region in that it will not likely reach the peak employment levels reached in 2000 until mid- to late-2004. Factors contributing to the long-term slower growth in employment include not only the current recession, but also an expectation that Boeing's more efficient production processes will not provide the historical employment highs of 2000. Exhibit V-4 summarizes the employment and population data used as inputs.

Exhibit V-4
Electric Service Area Economic Growth Assumptions

	2002	2003	2005	2010	2015	2020	aarg
Electric Service Area							
Employment (thousands)	1,695.5	1,718.6	1,795.6	1,972.9	2,124.2	2,277.2	1.6%
Population (thousands)	3,351.2	3,373.5	3,438.7	3,659.1	3,859.5	4,078.9	1.1%
Gas Service Area							
Employment (thousands)	1,686.0	1,707.9	1,788.9	1,969.9	2,120.5	2,276.1	1.7%
Population (thousands)	3,333.8	3,354.0	3,420.7	3,645.3	3,850.5	4,075.3	1.1%

Most of the long-term growth in employment is expected to come from the service sectors, including business services and computer industries. Not all counties will grow at the same pace, with smaller counties such as Island and Jefferson experiencing a higher growth rate compared to the growth in King county. However, the absolute amount of jobs created will still be higher in King County than the smaller counties.

Retail Energy Price Assumptions. PSE's electric demand models require predictions of various retail energy prices. Energy prices affect the choice of fuel for the new appliances, the efficiency levels and the utilization rates of existing and new appliances. Exhibit V-5 provides forecasts of retail rates for electric and gas for the three major customer classes.

Exhibit V-5
Retail Rate Forecasts

(nominal)	2003	2005	2010	2015	2020	aarg
Residential						
Electric, cents/kwh	6.18	6.18	7.36	8.36	9.72	2.6%
Natural gas, cents/therm	67	71	74	83	93	1.9%
Commercial						
Electric, cents/kwh	6.66	6.65	7.38	8.38	9.75	2.1%
Natural gas, cents/therm	60	65	65	73	82	1.8%
Industrial						
Electric, cents/kwh	6.13	6.14	6.82	7.74	9.01	2.2%
Natural gas, cents/therm	55	61	63	70	79	1.2%

The forecast of electric rates includes the 6.5 percent rate case settlement increase effective July 2002. The forecast also assumes a deferral of the BPA residential exchange credit, implying slightly higher rates near-term but lower rates long-term. To determine long-term retail rates, PSE utilized DRI-WEFA's forecast of electric rates for the state and adjusted DRI-WEFA's rates to provide starting points similar to PSE's retail rates. PSE assumes real electricity prices will decrease over time, driven by a variety of changes – competitive pressures bringing costs down, additional capacity in supply-short regions, declining coal prices, and efficiency improvements for new generation technologies. Based on DRI-WEFA's model, the Northwest is expected to add more generation – mostly expected to be gas-fired facilities with a small amount of coal, and a small amount of wind due to government mandates. As most of the region continues to rely on gas for new generation, the prices are likely to become more similar to the average for the region. Exhibit V-5 illustrated that electric rates growing between 2 percent and 2.6 percent in the next twenty years, meaning that real electric rates will decline given an inflation rate of about 3 percent.

Gas retail rates forecast include the 5.8 percent rate case settlement increase effective September 2002. The forecast also includes an increase in the gas conservation rider in March 2002. Finally, adjustments were made due to lower projections of gas costs and the refund of deferred gas cost in 2003 and 2004. As a result, PSE's model projects gas retail rates to decline in 2003 from 2002 levels.[1] From 2003 to 2020, gas rates are expected to increase at less than two percent per year, again lower than the long-term rate of inflation. PSE bases long-term growth rates in gas on DRI-WEFA's forecast, which assumes that the marginal cost of gas will be increasing with the depletion of lower cost reserves, and the transportation cost becomes higher due to the movement into new areas of gas further away from the market. However, the impact of increasing supply cost on long-term gas prices will be limited by the potential for higher LNG and Alaskan gas imports and the demand response to higher prices. Demand response would include use of alternate fuel, lower thermostat settings, plant shutdowns, or moving gas intensive industries to countries with lower cost fuels. Therefore, PSE expects gas retail rates to decline or not change much in real terms.

Conservation Savings. For base planning purposes, the new forecast assumes 15 aMW of new savings per year for the next 20 years as compared to the rate case settlement which required PSE to achieve 15 aMW of savings for 2003 only. The conservation assumption beyond 2003 will be revisited after further collaborative studies are completed by the third quarter of 2003. This 15 aMW amount equals approximately 0.6 percent of total billed sales, with nearly 82 percent of the savings expected from the commercial and industrial sectors. In contrast, previous forecasts only assumed about 5.5 aMW of savings. For this LCP, savings were adjusted to account for measure life and price overlap factors.

PSE assumes approximately 2.1 million therms in new conservation savings (or 0.3 percent of total billed sales) will occur every year. The Company expects the residential sector to account for 20 percent of the total savings, with the commercial and industrial sectors likely accounting for 60 percent and 20 percent, respectively. For this Least Cost Plan, PSE adjusted savings for measure life.

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[1] PSE filed for an increase in its PGA in March 2003, reflecting the recent increase in national gas prices. Since the LCP is a long-term planning analysis, the retail price forecast has not been adjusted.

Table V-6 illustrates the relative cost of a MW of savings from each of the customer classes by month. If the savings come from the residential class, as compared to the commercial or industrial class, the savings are higher.

Exhibit V-6
Relative Class Contribution to Peaks

CLASS	JAN	FEB	MAR	APR	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC
Residential	1.45	1.32	1.09	0.96	0.83	0.75	0.69	0.7	0.73	0.86	1.23	1.39
Commercial	1.16	1.12	0.97	0.92	0.9	0.9	0.89	0.92	0.91	0.92	1.18	1.21
Industrial	1.05	0.91	0.96	0.98	1.05	1.01	1	1.05	1	0.99	0.92	1.08

Other Key Assumptions

- ***Data Center Loads*** – Given the current economic background for high tech industries, PSE expects loads from data centers to be flat in the future.
- ***Lake Youngs Water Treatment Plant*** – PSE anticipates the Seattle Water Department's water treatment plant will be completed in 2003, adding 2.3 aMW by the middle of the year.
- ***King County Sewage Treatment Plant*** – Due to the development of fuel cells as their alternative power source, PSE expects electric consumption to decline by about 8 aMW by 2005, but gas consumption is expected to increase to 2 million therms a year by 2005.
- ***Immunex*** – Based on discussions with owners, PSE expects the building to consume about one million therms per year by 2004.
- ***Mt. Star Development*** – PSE expects this residential development in Kittitas county to add approximately 150-250 residential customers per year in the next few years.
- ***Real time pricing*** – The effects of either real-time pricing or time of use pricing were not included in this forecast.
- ***Weather*** – PSE based its billed sales forecast on normal weather defined as the average weather using the most recent 30 years ending the first quarter of 2002.

C. Electric Sales and Customer Forecasts

Base Case Electric Billed Sales Forecasts

PSE's electric sales are expected to grow at an average annual rate of 1.4 percent per year in this forecast, from 2,181 aMW in 2002 to 2,891 aMW in 2022 with conservation savings. Without conservation savings, PSE expects billed sales to grow approximately 1.7 percent per year in the next 20 years. Compared to the historical growth rate of 2.1 percent per year, this new forecast anticipates lower sales growth as a result of the ramp up in savings from conservation programs, slower near-term growth in population and employment, and increasing share of multifamily units under new construction in the service territory, with lower use per customer.

Exhibit V-7
Electric Sales Forecasts by Class in aMW

	2002	2005	2010	2015	2020	2022	aarg
Base with Conservation							
Total	2,181	2,243	2,390	2,574	2,798	2,891	1.4%
Residential	1,102	1,135	1,230	1,334	1,445	1,493	1.5%
Commercial	903	930	988	1,070	1,177	1,221	1.5%
Industrial	165	166	156	152	154	155	-0.3%
Others	11	13	15	18	21	23	3.9%
Base without Conservation							
Total	2,182	2,291	2,508	2,713	2,936	3,030	1.7%
Residential	1,102	1,144	1,251	1,354	1,466	1,514	1.6%
Commercial	904	959	1,061	1,158	1,265	1,309	1.9%
Industrial	166	176	181	182	184	184	0.5%
Others	11	13	15	18	21	23	3.9%

The growth pattern until 2010 occurs more slowly, at approximately 1.1 percent per year, compared to the 1.6 percent annual growth beyond 2010. This result largely occurs due to the assumption that most of the conservation measures implemented have an average life of 8 to 10 years.

With more than 80 percent of new conservation savings coming from the non-residential sector, PSE forecasts commercial sales at 1.5 percent per year, with industrial sales anticipated to decline slightly at about 0.3 percent per year. Without conservation, commercial and industrial sales will grow by about 1.9 percent and 0.5 percent per year, respectively. Historically, commercial sales have grown at slightly more than 2 percent per year in the last 10 years. Growth in manufacturing employment drives growth in industrial sales, however, manufacturing employment growth is not expected to grow significantly in the next 20 years. As a result, the share of commercial and industrial sales to total sales declines from 49 percent in 2002 to 47.5 percent in 2022. Residential billed sales grow by about 1.5 percent per year with conservation. Given the declining amount of available land for single family housing development, single family home sale growth will slow down, with an increase in multifamily housing unit sales growth expected. However, average residential use per customer is expected to decline due to construction of multifamily units and additional conservation programs. Consequently, the share of residential sector in total sales is expected to increase modestly by 1 percent from about 50.5 percent in 2002 to 51.5 percent in 2022.

Base Case Electric Customer Forecasts

PSE expects electric customer numbers to grow at an average annual rate of growth of 1.7 percent per year between 2002 and 2022 to 1,354,784 customers in 2022. This projection is slightly lower than the average growth rate of about 1.9 percent per year in the last five years. Customer growth increases less than the historical average in the next five years, then rises slightly to 1.8 percent per year thereafter, consistent with the pattern of growth in population and employment. The long-term projected growth rate of 1.7 percent is lower compared to the historical growth rate of 2 percent per year reflecting the slowdown in population growth and decreasing amount of affordable land to develop.

Exhibit V-8
Electric Customer Count Forecasts by Class (Year End)

	2005	2010	2015	2020	2022	aarg
Total	1,006,365	1,100,176	1,199,495	1,308,581	1,354,784	1.7%
Residential	890,981	972,659	1,060,085	1,155,907	1,196,599	1.7%
Commercial	109,049	120,475	131,602	143,872	148,920	1.8%
Industrial	3,946	4,069	4,083	4,129	4,146	0.3%
Others	2,389	2,973	3,725	4,673	5,119	4.8%

Currently, the residential sector accounts for 88.5 percent of the total number of customers in the service area. Although growing at a slower rate than commercial and industrial sectors, the residential sector will account for most of the growth in the number of customers, in terms of absolute numbers, due to having the largest share of the total customer base. The residential growth also reflects a gradually increasing share of multifamily units in the next 20 years. Thus, its share in the total customer base is not expected to change in the next 20 years.

Electric Peak Hour Forecast (Normal or Expected)

PSE also bases the peak load forecast on the system sales forecast. The annual normal peak load is assumed to occur at 23 degrees, in January.

Exhibit V-9
Electric Peak Forecast in MWs

	2002	2005	2010	2015	2020	2022	aarg
Normal Peak Load w/Conservation	4,670	4,862	5,251	5,702	6,182	6,384	1.6%
Normal Peak Load wo /Conservation	4,660	4,942	5,409	5,853	6,333	6,535	1.7%

PSE expects peak loads to grow by 1.6 percent per year in the next 20 years, with peak load growing slightly faster than total sales. The peak forecasting model utilizes an econometric equation that allows for different effects of residential versus non-residential energy loads, in addition to the temperature observed at peak. These loads are adjusted also for the effects of conservation, which has a monthly shaping that varies by sector. Since the residential energy load is growing slightly faster than the non-residential energy loads (commercial and industrial) after adjusting for conservation, and residential energy contributes more to peak than non-residential energy, the system peak load grows slightly faster than the system energy loads and more similar to the growth rate in residential sales.

Electric Sales Forecast Scenarios

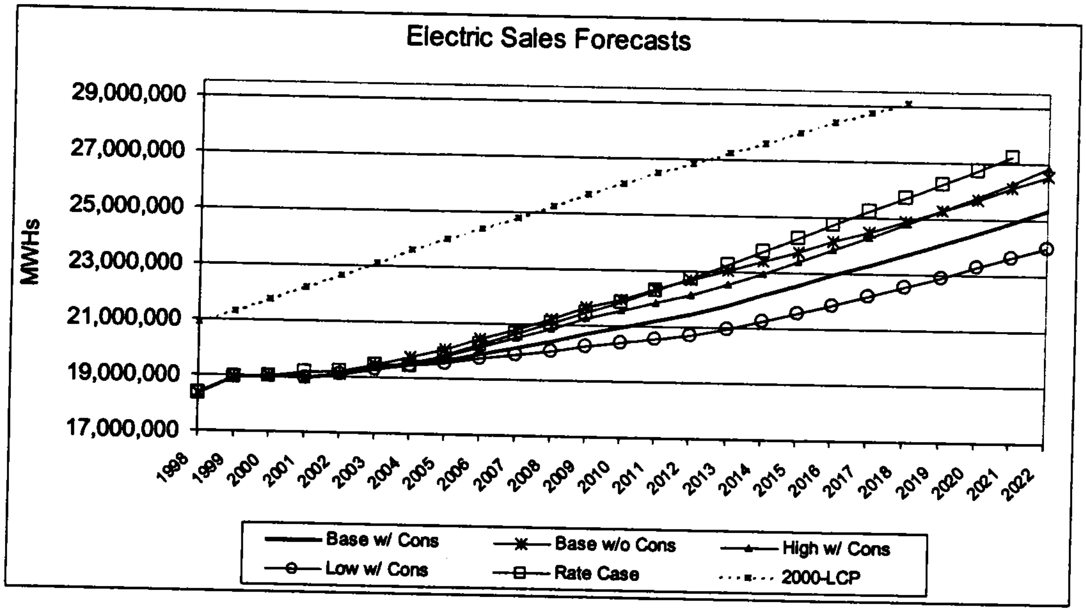
Any forecast carries a degree of risk. The base case long-term sales forecast assumes that the economy grows smoothly over time, with no major shocks or disruptions to the economy. In order to capture the range of economic possibilities in the forecast of billed sales, high and low sales forecast scenarios were developed in order to capture the upper and lower bandwidths where the forecast of sales is likely to fall with 50 percent probability. As an example, the high case forecast assumes a GDP growth rate of 3.6 percent, while the low case assumes a 2.6 percent average growth rate compared to 3.1 percent in the base case scenario. The high case also assumes a low inflation rate, and vice versa for the low case scenario. The other key assumption holds that growth in productivity will be higher in the high case compared to the base case scenario.

In actual implementation, the high and low case sales forecasts were developed using 1999 forecasts of base, high and low population and employment variables – the key drivers in the forecast. High to base and low to base ratios were developed and applied to the current base case forecasts of population and employment. PSE ran the forecasting model with the new set of population and employment forecast scenarios, making no changes to other inputs. Exhibits V-10 and V-11 provide a comparison to the base case forecast with conservation against the high and low case forecasts. The exhibits also illustrate the base case forecast without conservation, the rate case forecast, and the last Least Cost Plan produced in 2000, for comparison purposes.

Exhibit V-10
Electric Sales Forecast Scenarios in aMW

	2002	2005	2010	2015	2020	2022	aarg
Scenarios							
Base case with conservation	2,181	2,243	2,390	2,574	2,798	2,891	1.4%
High case with conservation	2,182	2,260	2,459	2,672	2,945	3,063	1.7%
Low case with conservation	2,181	2,233	2,329	2,458	2,659	2,737	1.1%
Base Case - no conservation	2,182	2,291	2,508	2,713	2,936	3,030	1.7%
F2001 - rate case	2,189	2,268	2,497	2,766	3,054		1.9%
2000 LCP	2,586	2,739	2,981	3,198			1.6%

Exhibit V-11



The 2000 Least Cost Plan case provided the highest forecast because it includes the large industrial and commercial customers, which have since migrated to the transportation or "retail wheeling" schedules. Also, this forecast assumed no near-term slowdown in the growth of population and employment. Note that among the forecasts that excluded the retail wheeling customers, the rate case sales forecast showed the highest forecast because the growth in employment assumed in that forecast was more optimistic in the long-run, even while assuming a decline in employment growth in 2002. The rate case forecast predicts slightly lower sales for the next 10 years than the base case forecast without conservation as the rate case forecast still contains the conservation savings from PEM/TOD and existing programs. The high case forecast predicts lower sales than even the rate case forecast over the 20-year period. The high case forecast is about 3 percent higher while the low case forecast is about 2.6 percent lower than the base case forecast by 2010.

D. Gas Sales and Customer Forecasts

Base Case Gas Billed Sales Forecasts

PSE's natural gas billed sales for PSE are expected to grow at an average, annual rate of growth of 2.1 percent per year in the next twenty years, growing from 1,022,230 Mtherms in 1998 to 1,562,567 Mtherms by 2022. Compared to the historical growth rate of about 2.9 percent per year, this new forecast anticipates a slower growth rate in the future resulting from slower customer growth in the residential sector as well as a slight decline in residential use per customer due to increasing share of conversions and multifamily units with lower use per unit, and appliance efficiencies.

Exhibit V-12
Gas Sales Forecast in Therms (000s)

	2002	2005	2010	2015	2020	2022	aarg
Total - Base with Conservation	1,022,230	1,120,050	1,266,701	1,384,504	1,511,788	1,562,567	2.1%
Residential	499,712	538,819	620,839	697,900	779,054	813,192	2.5%
Commercial	206,039	216,043	240,917	264,362	286,922	295,623	1.8%
Industrial	37,724	39,626	43,539	44,173	45,455	45,967	1.0%
Interruptibles	92,315	95,864	115,999	132,717	146,974	152,276	2.5%
Transportation	186,441	229,698	245,407	245,362	253,383	255,509	1.6%

PSE expects slightly faster growth in gas billed sales over the next eight years compared to the following 12 years because gas rates remain flat nominal in the next eight years, whereas the nominal rate grows at approximately the rate of inflation in the long-term. PSE expects most of the growth to come from the residential sector, mainly from customer growth. As a result, its share to total sales increases from 49 percent in 2003 to 52 percent in 2022. Growth in the non-residential sector will likely result from increasing penetration of gas in commercial and industrial applications or processes and as the price of gas relative to other fuels continue to be economic. Thus, use per customer in each sector is expected to increase, although the number of customers might decrease.

Base Case Gas Customer Forecasts

PSE anticipates a projected growth rate of gas customers at 2.7 percent per year in the next 20 years. In comparison with the historical growth rate of about 4 percent per year, the new forecast reflects slower population growth, hence slower demand for housing, and a declining pool of potential conversion customers.

Exhibit V-13
Gas Customer Count Forecasts by Class (Year End)

	2005	2010	2015	2020	2022	aarg
Total - Base with Conservation	669,443	772,626	881,470	1,003,158	1,056,030	2.7%
Residential	617,591	717,141	822,613	941,176	992,864	2.8%
Commercial	48,304	51,947	55,331	58,465	59,653	1.3%
Industrial	2,806	2,840	2,861	2,882	2,889	0.4%
Interruptibles	632	586	552	521	511	-1.3%
Transportation	111	112	112	113	113	0.2%

Currently, the residential sector accounts for about 92 percent of total customer base. With a growth rate of 2.8 percent per year in the next 20 years, PSE expects the residential share to increase from 92 percent to 94 percent by 2022. The decline in the total pool of conversion customers will be limited by the increasing penetration of gas into multifamily buildings (townhomes and condominiums). While accounting for only about 6 percent of total customer base, PSE also expects the commercial sector to grow slightly, at approximately 1.3 percent per year, in the next 20 years consistent with expected increase in penetration of gas in new buildings. Increasing restrictions on the use of alternative fuels (especially oil and its associated liabilities) contribute to a gradual decline of interruptible customer growth over the planning horizon. Many current interruptible customers, especially the smaller-sized customers, will choose to "firm-up" their demand by seeking solutions ranging from becoming all-firm customers to various combinations of firm, interruptible and transportation services.

Gas Peak Day Forecasts

The gas peak day forecast predicts peak firm gas requirements increasing from 7.8 million therms in 2002 to 12.2 million therms in 2022, or a growth rate of about 2.2 percent per year in the next 20 years. This rate basically equals the same growth rate in total gas billed sales. The forecasted peak days are estimated to be 90 percent accurate within plus or minus 5.5 percent.[2] PSE expects the residential sector to account for about 70 percent of the peak daily requirement compared to 21 percent and 3 percent for the commercial and industrial sectors, respectively. The peak forecasts include the contribution of large volume commercial and industrial customers to peak requirements. PSE computes losses using 1.0 percent of the peak day requirements from the three sectors. The expansion in customer base primarily drives

[2] As discussed earlier, the standard error for the peak day estimate is about 3.2 percent.

growth in peak across all sectors. However, rising base loads also contribute moderate amounts due to increasing saturation of gas in other end uses. This is offset slightly by reductions in heating loads due to increasing efficiencies in appliances and the increasing penetration of gas into the multifamily sector, which has a smaller use per customer.

Exhibit V-14
Gas Peak Day Forecast in Therms (000s)

	2002	2005	2010	2015	2020	2022	aarg
Peak Day Load Total	7,822,784	8,350,742	9,372,901	10,500,329	11,674,861	12,184,509	2.2%
Residential	5,691,421	6,110,857	6,963,176	7,922,978	8,939,900	9,387,111	2.5%
Commercial	1,785,240	1,866,821	2,011,599	2,150,361	2,279,200	2,329,364	1.3%
Industrial	268,669	290,384	305,324	323,026	340,167	347,396	1.3%
Losses	77,453	82,681	92,801	103,964	115,593	120,639	2.2%

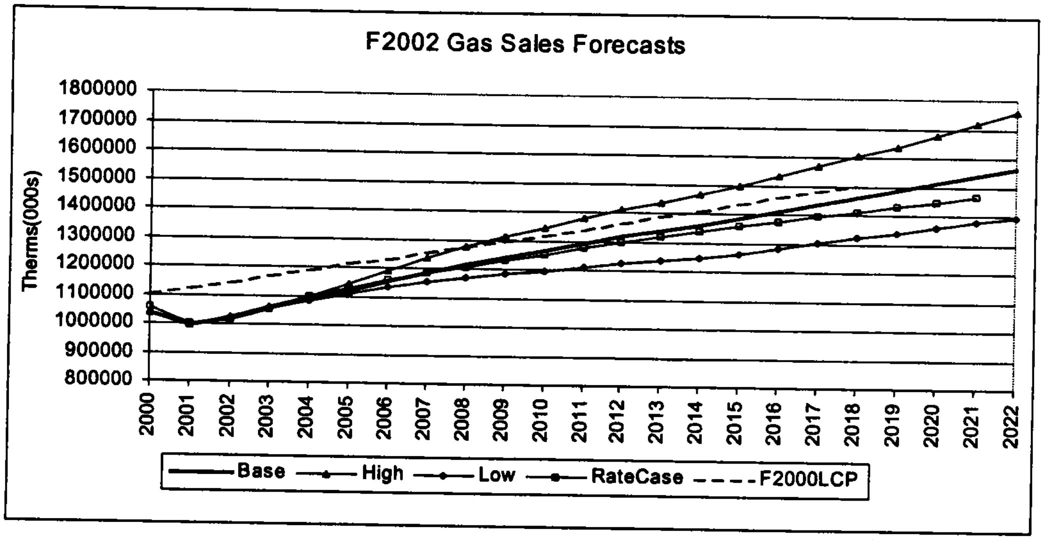
Gas Sales Forecast Scenarios

The high and low case economic scenarios were developed using the same methodology used in electric demand forecast to derive the high and low case scenarios for population and employment for the gas service territory. Exhibits V-14 and V-15 provide a comparison between the current forecasts and the forecasts generated for the rate case and the 2000 Least Cost Plan.

Exhibit V-15
Gas Sales Forecast in Therms (000s)

	2002	2005	2010	2015	2020	2022	aarg
Scenarios							
Base case	1,022,230	1,120,050	1,266,701	1,384,504	1,511,788	1,562,567	2.1%
High case	1,023,176	1,142,161	1,344,884	1,498,239	1,677,649	1,757,849	2.7%
Low case	1,022,126	1,106,939	1,197,388	1,262,506	1,359,810	1,394,458	1.6%
F2001 - rate case	1,012,869	1,129,211	1,253,504	1,356,868	1,448,403		2.0%
2000 LCP	1,144,610	1,213,489	1,318,724	1,435,792			1.8%

Exhibit V-16



The 2000 Least Cost Plan forecast starts higher initially but grows at a slower rate than the current base case forecast. The assumption of a higher growth rate in gas rates in that forecast primarily drive this outcome. The base case forecast predicts about the same growth as the rate case forecast initially, but the rate case forecast predicts slightly lower growth than the base case forecast in the long-run due to the higher growth in gas rates also assumed in the rate case forecast. Use per customer has increased in 2002 as compared to 2001, thus the base case forecast predicts a higher forecast of sales than the base case. However, the base case shows slower near-term growth as compared to the rate case due to slower economic growth, as shown by comparing the projected gas sales for 2005. By 2010, the high case forecast predicts growth about 6.2 percent higher than the base case forecast, while the low case forecast anticipates about 5.5 percent lower growth than the base case forecast.

E. Summary

Each year, PSE develops a 20-year forecast of customers, energy sales and peak demand for its electric and gas service territories. PSE uses this forecast in short-term planning activities such as the annual revenue forecast, marketing and operation plans, as well as in various long-term planning activities such as the Least Cost Plan, and the transmission and distribution plans. For this Least Cost Plan, PSE updated its forecast methodology for its billed sales forecast in order to more accurately account for large industrial and commercial customers moving to transportation schedules and to correct for modeling issues. Other major chapter highlights include:

- Annual real GDP is anticipated to grow at 3.2 percent in the next 20 years.
- Employment growth in PSE's service territories will likely grow at a slower rate (1.6 percent) than its 30-year historical growth rate, fueled mainly through growth in the service sector.
- Electric nominal rates are anticipated to grow between 2 and 2.6 percent per year over the next twenty years, resulting in declining real electric rates.
- Gas rates are anticipated to increase at less than 2 percent per year, lower than the long-term rate of inflation.
- Electric conservation savings are assumed to be 15 aMW per year for the next 20 years, as compared to the rate case settlement, which required PSE to achieve 15 aMW of savings for 2003 only. Gas conservation savings are assumed to be 2.1 million therms per year.
- PSE's conservation assumptions beyond 2003 will be revisited after further collaborative studies are completed by the third quarter of 2003.
- PSE electric sales are expected to grow at an average annual rate of 1.4 percent per year in the forecast to 2,891 aMW in 2022.
- PSE anticipates a projected growth rate of electric customers at an average annual rate of growth of 1.7 percent per year between 2002-2022, to 1.35 million customers in 2022.
- Electric peak load forecasts are expected to grow by 1.6 percent in the next twenty years.
- PSE's natural gas billed sales are expected to grow at an average, annual rate of growth of 2.1 percent per year in the next 20 years from 1,022,230 Mtherms in 1998 to 1,562,567 Mtherms by 2022.
- PSE anticipates a projected growth rate of natural gas customers at 2.7 percent per year in the next 20 years.
- The gas peak day forecast predicts peak firm gas requirements increasing from 7.8 Mtherms in 2002 to 12.2 Mtherms in 2022, or a growth rate of approximately 2.2 percent in the next 20 years.

IV

VI. DISTRIBUTION SYSTEM FACILITIES PLANNING

This chapter addresses another key component of the Least Cost Plan process – distribution system facilities planning. This step in the process ensures that all elements of both the gas and electric energy delivery system are tailored to provide safe and reliable service at the lowest cost. Within this integrated view, facilities planning establishes the guidelines for installation, maintenance and operation of the local distribution company's physical plant, balancing the economics, safety and operational requirements of the distribution system. The facilities planning process must also consider environmental conditions, regulatory requirements and changing customer demands, as it reviews cost-effective alternatives and develops contingency plans. As economics, regulations and customer needs change, so does the design of the distribution system facilities. Distribution system facilities planning that responds to infrastructure changes, regional land-use changes and other utility construction proves to be critical in providing least cost facilities.

Specifically, this chapter addresses how the gas and electric energy delivery systems work, listing specific facilities included within the delivery system. Challenges to the planning process, and system performance criteria, for both the customer and the Company, are provided, along with the methods for evaluating alterations to the system, planning tools and modeling techniques. This chapter also describes the types of adjustments that can be made within the distribution system to lessen the need for additional facilities, and details the trade-off process for funding prioritization. This chapter concludes with an overview of distributed generation technologies which could impact the landscape of the electric delivery system.

A. Delivery System Mechanics

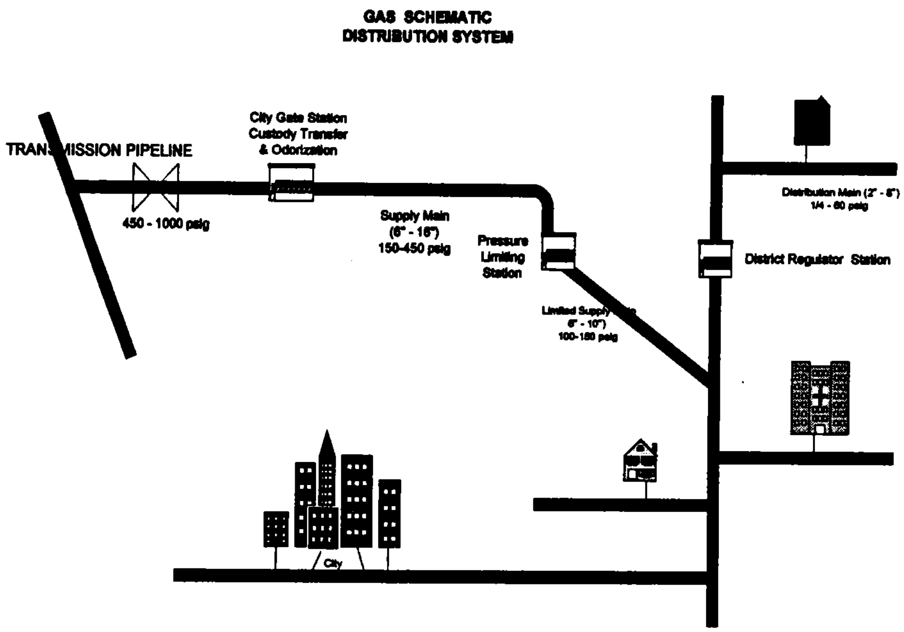
Gas Delivery System

Differential pressure causes the flow of gas through the delivery system, with particular emphasis on two chief factors – the volume of gas being moved and the pressure as it moves. The velocity of the gas as it moves will determine the use of energy during that movement. Gas can move either in a laminar or turbulent manner. This movement behavior serves as a predictor of pressure variations within a delivery system. In addition, the pipe's diameter, material type and roughness, efficiency, length and the fittings used influence the system's pressure.

The delivery system is composed primarily of pipes, valves, regulation equipment (pressure reduction), and measurement equipment (meters). Transmission pipelines typically experience pressure of 450-1,000 pounds per square inch gauge (psig); whereas for a distribution main in a residential neighborhood, the pressure will range between ¼ and 60 psig. Inside a house, the pressure for a stove or space heater will be ¼ psig. Exhibit VI-1 provides a schematic view of the gas local distribution system.

PSE operates approximately 45 city gate stations, 10,798 miles of high, intermediate and low pressure gas distribution lines, and numerous district regulator stations to serve approximately 622,000 natural gas customers. Approximately 305,300 customers receive both gas and electric service from PSE. In areas where PSE provides both electric and gas service, additional efficiencies and lower costs have been realized.

Exhibit VI-1
Gas Schematic Distribution System



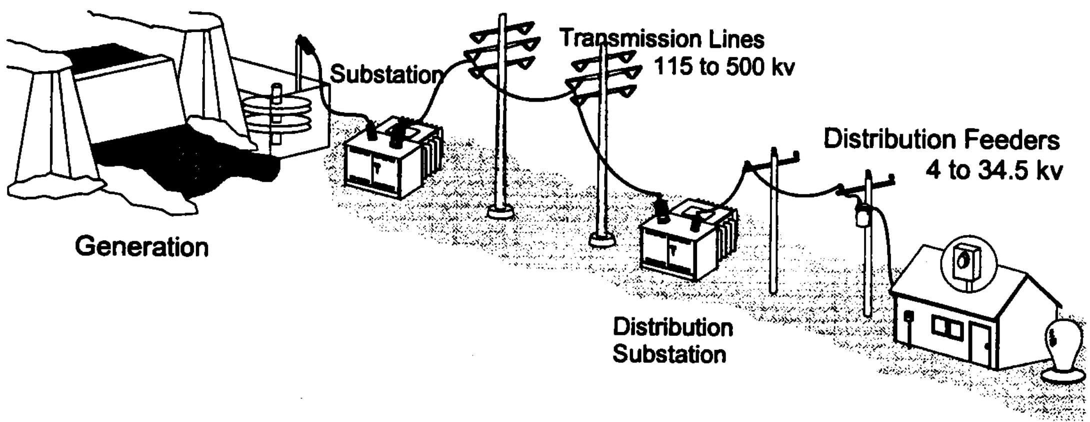
Electric Energy Delivery System

Electric energy is a unique product, moved from electric generators to the consumers over wires and cables, using a wide range of voltages and capacities. Unlike other forms of energy, electrical energy cannot be stored. It must be continuously generated using other forms of energy, such as falling water and steam. The electrical generators and electrical network are designed to automatically regulate the flow of electricity through the system to quickly accommodate the instantaneous changes in consumer demand.

The delivery system is composed primarily of wires, circuit breakers, transformers, regulators and measurement equipment (meters). The voltage of the electricity at the generation site must be stepped up to a high voltage for efficient transmission over long distances. Generally, transmission voltages range from 115 to 500 kV. The substation reduces the voltage for local distribution, generally between 4 and 34.5 kV, and transformers reduce the voltage further for household use. Exhibit VI-2 provides a schematic view of the electric distribution system.

Exhibit VI-2

Electric Distribution System



PSE operates and maintains an extensive electric system consisting of generating plants, transmission lines, substations, and distribution equipment. PSE operates approximately 303 substations, 2,901 miles of transmission, 10,523 miles of overhead distribution, and 8,224 miles of underground distribution lines to serve 958,000 electric customers within a nine-county, 4,500 square mile service territory.

PSE's complex networks of both electric and gas delivery facilities must be flexible enough to meet changing weather and other operating conditions as well as meeting long-run service needs. Due to the significant investment in these facilities, and the important role that energy plays in an advanced society, it is important that PSE make additions and improvements as cost-effectively as possible.

B. Distribution System Planning Challenges

The move toward restructuring, and the recent reconsideration of industry restructuring initiatives, impact how PSE plans for and provides distribution services. Within the gas industry, market dynamics have created a marketplace in which the use of natural gas for electric generation holds substantial rewards. This has precipitated the addition of many natural gas-fueled generation plants, which clearly impact facilities planning as both the gas distribution system to support such plants and the electric system to move the power generated must be available. The proliferation of computers and other highly sophisticated equipment create various needs for diverse power quality needs than had previously been designed for and routinely delivered. These higher performance standards pose additional challenges and costs which need to be reflected in an evolving facilities plan.

Distribution systems generally reflect the history of the area they serve. Many of PSE's long-standing service areas have seen significant growth. Growth management plans, transportation infrastructure and consumer's locational preference make some of these areas preferential, which has an effect on the infrastructure requirements (as more people are drawn to an area, more services are required). Existing distribution systems must be enhanced as growth occurs. Facility planners confront the primary challenge of developing least cost distribution solutions that reliably serve the changing loads of existing customers as well as those of new customers. As mature communities expand, local infrastructure becomes burdened, affecting the amount of rehabilitation possible. Thus, new utility and transportation projects influence the timing and availability of access to the rights-of-way. The distribution system in newer areas could be characterized as a "fresh start," not burdened with a complex grid of existing utilities. These communities are often developed in large projects, with a clearly defined end product. However, due to the size of the projects, the timing of facilities installation may often be complex. Also, the surrounding regulatory, political and economic environments often change, requiring plan modifications in response to these changes.

The economic and operational viability of distributed generation (DG) also presents an additional challenge for both gas and electric systems (see Section G). DG technology, primarily using natural gas as its fuel source, may soon become affordable to the average consumer. As distributed resources become more prevalent, the impacts on gas usage will vary greatly from historical levels. Electric usage will also change based on the type of generation customers' sites (i.e., fuel cell, microturbine, etc. as discussed in Chapter IX). Each of these has a variety of operating characteristics, which pose complexity when integrating into the delivery system. As PSE moves forward, an understanding of the sophistication of customer uses, as well as the expected overall increase in firm load will need to be dealt with effectively. Moreover, PSE believes many customers will begin to rely more heavily on the gas distribution system to supply some of their electricity needs.

C. Performance Standards And Operating Conditions

Performance standards concerning safety and reliability form the basis for system planning. For PSE's gas distribution system, these criteria include:

- The temperature at which the system is expected to perform,
- The level of reliability each type of customer is contracting for,
- The minimum pressure the system must maintain,
- The maximum pressure the system can accept, and
- The system cost customers are willing to pay for target levels of performance.

For PSE's electric system, these criteria include:

- The temperature at which the system is expected to perform,
- The level of reliability each type of customer is contracting for,
- The minimum voltage the system must maintain,
- The maximum voltage the system must maintain, and
- The system cost customers are willing to pay for target levels of performance.

These criteria, in addition to those elements proscribed in state and federal regulations, provide the foundation for the Company's system engineering standards and operational practices.

D. Asset Management Approach

"Asset management" comprises an important part of the distribution planning process. Asset management seeks to assure the full utilization of existing facilities before adding new facilities, unless the cost advantage of early installation offsets the cost of having the new facility at a low level of utilization. To accomplish this effectively, data are required that profile existing usage as well as the system capacities under the variety of test conditions. More sophisticated modeling systems and better real-time information ensures optimal system planning.

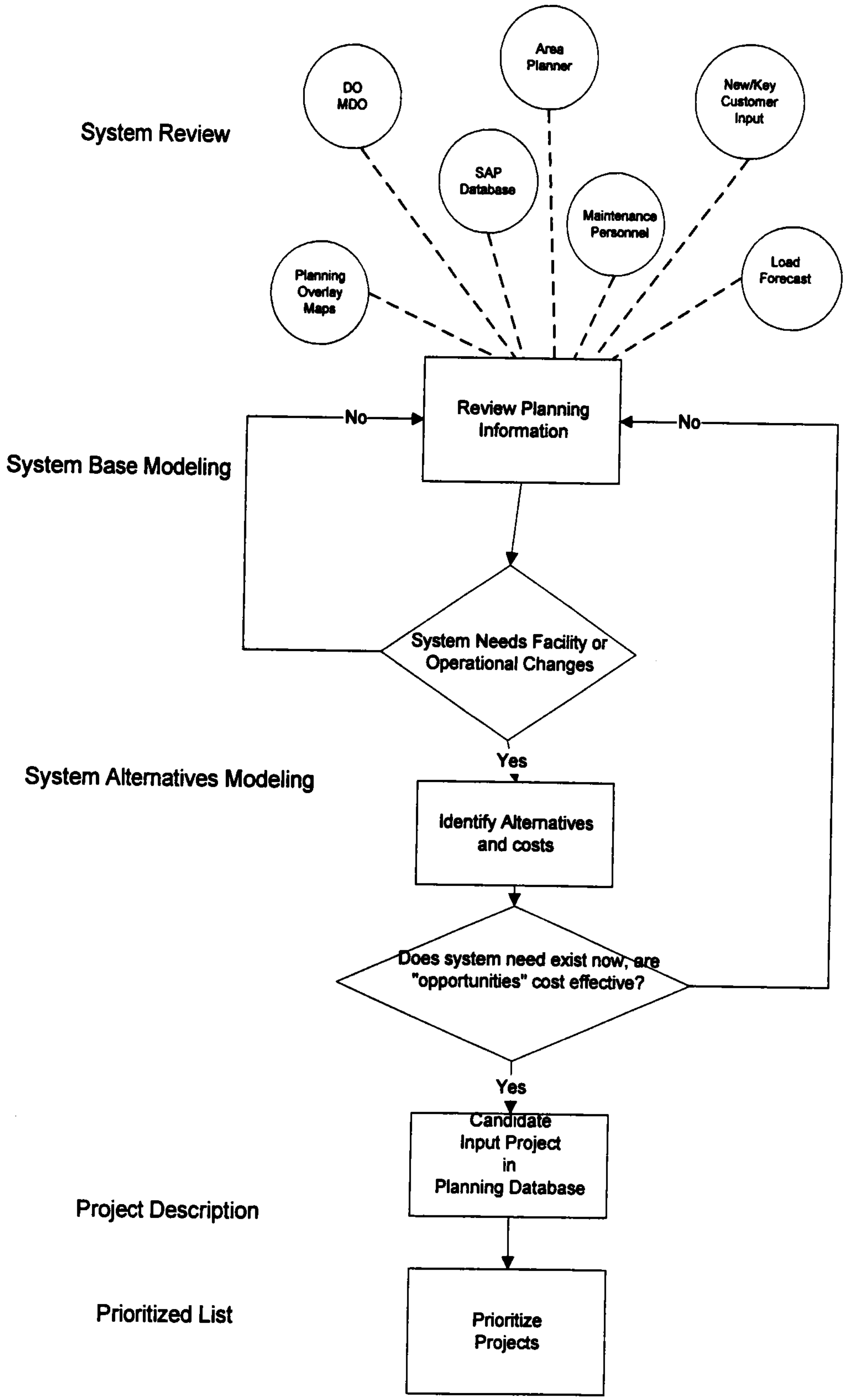
Traditionally, utility planning has been conservative. Within the gas industry, deregulation has influenced many of the conservative precepts originally viewed as fundamental to system design, construction and operation. In the electric industry, the conservative approach resulted over many years of stable rates, surplus generation, and favorable public opinion related to construction of electrical supply facilities. As the electric utility industry evolves, the distribution planning process must become more aggressive. The utility must maximize the efficiency of its facility investments. However, this can not be accomplished by forsaking system performance, as valued by both the customer and the company. Successful asset management assures achievement of maximum efficiency while providing acceptable reliability and safety. Planning for both gas and electric systems simultaneously can bring efficiencies and superior asset management results.

E. The Facilities Planning Process

The facilities planning process begins with an analysis of the current situation, and an understanding of the existing operational and reliability challenges. PSE first evaluates two types of load forecasts – a specific area forecast assessing historical local area customer growth and known developer and customers plans; and the corporate long-term forecast which examines population and employment growth projections in the area (see Chapter V, Load Forecasting). The planner must also evaluate such key parameters as local comprehensive plans, public improvement plans (such as road relocations), and opportunities to upgrade older systems to add capacity and resolve maintenance issues. One must account for the impact of one energy type on the other, and the optimization of the whole energy delivery system. Coordination with other utility services, including water, sewer and telephone, must be explored. Planners use these factors to develop feasible alternative methods to implement facility improvements. Each of these alternatives must be evaluated for its adherence to company and customer performance criteria. Cost estimates must be prepared for each alternative that meets the performance criteria. Lastly, planners select and implement the alternative that best balances customer needs, company economic parameters, and local and regional plan integration. Exhibit VI-3 provides a view of this process.

Exhibit VI-3

Facilities Planning
Planning Process



Planning Alternatives

PSE has two alternative approaches to solving system challenges – facility additions and replacements, or operational adjustments. Both approaches allow for optimal energy delivery. PSE utilizes both approaches to ensure least cost solutions.

Under the facility addition/replacement approach, the distribution system has a variety of facilities that can be used to deliver an optimal energy solution. PSE continually tracks the cost and viability of new technologies which will influence efficient construction of new facilities and management of existing facilities. Gas and electric facility alternatives include:

<u>Gas</u>

- City gate station
- High pressure main
- District regulator
- Intermediate & low pressure main
- Capacity upgrade
- Regulation equipment modification
- Replacement facilities
- Load control equipment

<u>Electric</u>

- Transmission substation
- Transmission conductor
- Distribution substation
- Distribution conductor
- Conductor upgrade
- Substation modification
- Replacement facilities
- Expanded right-of-way (i.e, Tree Watch)
- Load control equipment

PSE uses a combination of methods to produce a load forecast for a particular area of study of the distribution system. From a historical perspective, PSE uses a trend of actual system peak load readings reflecting the loading levels of the system components within the study area. The future near-term forecast tracks permitted construction activity that will result in new loads added to the system within the next two years. Longer-term forecasting comes from PSE's corporate econometric forecasting method which includes growth due to population and employment data by county (see Chapter V, Load Forecasting). Together, these resources provide a 5-year history and 10-year forecast which acts as one of the inputs to the planning process.

Operational management addresses operational and administrative actions the Company may take to ensure reliable service to customers. These actions include ongoing and/or bridging strategies that can be used to optimize the timing of facility improvements. Management of system performance is accomplished through controlling loads, flows, and facilities. For example, load can be managed through curtailment during peak conditions of customers who have selected interruptible tariff services. This load management may also include structuring rates that make it beneficial for customers to shift consumption to non-peak periods, or the application of energy efficiency measures.

Energy flow can be managed by adjusting equipment settings to preserve system throughput, while maintaining system flows and equipment integrity. Examples of this approach include:

- Temporary adjustment of district regulator stations (as executed through PSE's Cold Weather Action Plan) and the adjustment at substations of transformer "turns ratios" (typically done using load-tap changers) which alters the output voltage under a loaded situation.
- Temporarily siting equipment on a distribution system at a lower cost than a permanent upgrade. Examples of this approach include PSE's use of mobile compressed natural gas facilities (CNG) and its evaluation of LNG trailers, as well as its use of the mobile substation and its evaluation of local mobile generation.
- Permanent adjustment of district regulator stations to ensure that stronger systems serve more load, thus delaying the need for upgrades on weaker systems.

Value Trade-Offs

PSE has initiated the use of value-based budgeting to improve the overall efficiency of its distribution planning operations. Value-based budgeting uses a technique known as analytical hierarchy process (AHP) for the allocation of scarce resources. In order to allocate resources wisely, planners must know both the cost and benefits associated with each project. The measurable costs of a project generally follow a straightforward algorithm. PSE uses a software program called Project Analyzer to calculate a wide range of financial performance indicators for each project.

A more difficult task has been to quantify the benefits of a particular project. A single project may have a wide range of benefits for many different stakeholders. AHP enhances the decision-making process in situations where trade-offs among different factors exist. For example, when purchasing an automobile, trade-offs among price, durability, energy consumption, comfort, usability and reliability must be made. The AHP tool allows one to determine the relative importance of the factors in making the decision.

Based on the information received for a variety of areas pertinent to the evaluation, PSE computes a weight for each factor reflecting the relative importance the decision-maker puts on the relevant factors. After developing weights, PSE computes a score for each alternative and ranks a project list. The application of AHP for resource allocation decisions proves to be straightforward, with growing use by other organizations such as Xerox, IBM and Lucent.

Planning Tools And Modeling Techniques

PSE utilizes distribution system models for both its gas and electric delivery system. On the gas side, PSE has a mature system model that undergoes continual updates to reflect new customer loads and system changes including new and replaced facilities as well as operational adjustments. PSE validates the accuracy of the model by comparing its results against actual system performance data. PSE then utilizes the model to evaluate multiple solutions to determine the least cost solution to serve both current and future loads. PSE's model represents the largest integrated system model in the United States.

For the electric system, PSE is creating a system model using Stoner software in companion with its Energy Management System (EMS). As the modeling techniques and PSE's system modeling tools become more integrated, PSE expects that it will be able to further enhance its ability to meet customers energy needs at the lowest possible cost.

For both PSE's gas and electric systems modeling, the process begins with the digital creation of its system, identifying the facilities and their operational characteristics. For pipes, planners focus on the diameter, roughness, length and interconnections. For conductors, key focus areas include the cross-sectional area, resistance, length, construction type and interconnections. PSE then identifies customer loads in the model, either specifically (for large customers) or as block loads. Next, PSE models varying temperature conditions, types of customers served (interruptible versus firm), time of day (at peak daily usage) or with various components out of service (valves closed or switches open). Thereafter, various facility or operational adjustments can also be modeled. Additionally, PSE compares the output studies against actual data in the EMS system to check the accuracy of the base model.

F. Distribution System Automation

PSE recognizes the benefits of managing its delivery systems on an improved real-time basis. This recognition has led to greater investment in sophisticated modeling and telemetry systems, as well as its decision to implement automated meter reading (AMR) technologies. AMR relies heavily upon on communication technologies. Telecommunications technology has long played a key role in supporting the day-to-day operations of the electric and gas utility systems, linking substations, generation plants, gate stations, and other key points along the delivery system including large customer loads and dispatch centers.

Telecommunications media include wire, coaxial cable, telephone, microwave, fiber, power line carrier, packet radio, radio, satellite and optical light-beam technologies. Important factors must be considered in selecting a telecommunications system, including cost, distance between points of communications, location, reliability and type of information to be transported. It will be important to consider the advantages and disadvantages of various communication technologies before making long-term decisions on which communication system to use.

G. Distributed Generation Opportunities

Overview

The term "distributed generation" (DG) does not have an industry standard definition, but generally refers to smaller-scale generation facilities located near the source of the load it serves. DG is not a new concept, but dates back to the earliest days of the electric industry. For much of the twentieth century small-scale customer based generation could not compete economically with utility-owned centralized plants. These economics began to change in the mid-1980's, when centralized fossil plant technology reached maturity, and research and development then focused on microturbines and fuel cell technologies.

In addition, customers' electricity and energy requirements are changing. Some industrial customers now focus on meeting combined electric and thermal needs through one system. Customers such as hospitals and computer-based internet service firms require higher levels of power quality and reliability. Other customers want renewable or environmentally-benign power. In response to these factors and to changing federal laws, relatively small-scale generation has become more common among PSE's large industrial customers. The DG industry is at a junction – it can move from serving niche markets for remote, emergency or other special power needs to becoming a major contributor to the electric system.

Barriers to Distributed Generation Implementation

Although DG offers some potential benefits as part of PSE's distribution system facilities planning process, a host of regulatory, institutional and technical barriers challenge the full-scale implementation of DG technology. In May 2000, the National Renewables Energy Laboratories (NREL) issued a report identifying these challenges. Key findings included:

- *Regulatory Barriers* – New regulatory principles compatible with the distributed power choices in competitive markets need to be developed. Regulatory tariffs and utility incentives to fit the new distributed power models still must be adopted. Other regulatory barriers include establishing an expedited dispute resolution process for distributed generation project proposals and defining the necessary conditions for a right to interconnect.
- *Business Practice Barriers* – Standard commercial practices for any required utility review of interconnection need to be adopted and standard business terms for interconnection agreements must be established. In addition, the industry needs to develop tools for utilities to assess the value and impacts of distributed power at any point on the system.
- *Technical Barriers* – The industry needs to adopt uniform technical standards for interconnecting distributed power to the grid, and adopt testing and certification procedures for interconnection equipment. In addition, development of distributed power control technology and systems needs to be accelerated.

Federal and state agencies have taken some steps to address the barriers identified by NREL. The United States Department of Energy's Distributed Energy Resource (DER) program implements a Distributed Energy Resource Strategic Plan, a national effort promoting the "next generation" of clean, efficient, reliable and affordable distributed energy technologies. FERC has also become involved, initiating an Advance Notice of Proposed Rulemaking (ANOPR) on October 25, 2001 aimed at standardizing Generation Interconnection Agreements and Procedures. Through this process, FERC and a variety of stakeholders have sought to develop standard processes, agreements and applications for interconnecting small resources to the grid in order to:

- Expedite review of interconnection proposals,
- Reduce the major barriers to interconnection (cost, risk, etc), and

- Assure that quick approval of proposed interconnection were minimal or had not grid impact and no safety problems.

In June 2002, the National Association of Regulatory Utility Commission (NARUC) released both the draft Interconnection Agreement and draft Interconnection Procedures with the hope of prompting state DG Interconnection proceedings.

Industry groups have also taken steps to address technology barriers to DG implementation. The Institute of Electric and Electronic Engineers (IEEE) develops specific and voluntary DG standards. An IEEE working group recently developed a Draft Standard for Distributed Resources Interconnected with the Electric Power System, and received approval by the IEEE Board. The IEEE working group is currently seeking to establish main technology criteria and requirements for interconnection of distributed resources with the electric delivery grid.

PSE's Use of Distributed Generation in Facilities Planning

Despite remaining barriers to full-scale DG implementation, PSE strives to incorporate DG elements into its distribution system facilities planning process. Within the distribution planning process, PSE has developed DG screening tools that identify those projects with the highest probability of serving the least cost capacity deferral alternative. Three DG projects have been identified with the screening tool:

1. Peak Shaving strategy at Crystal Mountain
2. Installation of 1.2 MW generator on Lummi Island
3. Selection of Dierenger substation as a DG site

- ***Crystal Mountain*** – PSE identified Crystal Mountain as an area that could reach peak load capacity capabilities within a few years. The load was projected to climb from 5.9 MVA to 11.2 MVA by 2006-2007. The estimated capital cost for a traditional wires solution was about $2.5 million. PSE decided to refurbish and test a 2.4 MVA diesel standby generator located near the load pocket. PSE ran a test to prove the concept and its feasibility, which provided sufficient justification to defer the $2.5 million traditional system upgrade for three to seven years.

- ***Lummi Island*** – PSE installed the Lummi Island 1.2 MVA diesel generator as part of a planned emergency strategy. Lummi Island's existing delivery system consisted of a 12.5

kV cable that was approaching loading limits and had been installed over 45 year ago. As part of the facilities planning process PSE had developed a plan to serve Lummi Island with DG in the event of a cable failure. One of the cables failed in 2002, requiring its replacement. The 1.2 MW diesel generator served as standby while PSE made the necessary arrangements to install the one mile of submarine cable.

- ***Dieringer substation*** – As a combined gas and electric utility, PSE explored the possibility of installing gas generation to offset expected T&D expansion costs. The screening process identified several possible DG sites. The Dieringer substation provided the best site to test the gas and electric delivery systems. PSE developed an environmental check list, analyzed the feasibility of gas and electric interconnections to this site, and solicited DG vendors bids for the generator. With this information, PSE modeled total ownership cost and the sensitivity of cost to changes in key parameters such as spark spread, fuel cost, market prices, and heat rate. The model examined generator efficiency, O&M and the offset of capital deferral of T&D facilities. The analysis showed that generator efficiency and power market conditions significantly drive cost. This result led PSE to defer the implementation of DG at the Dierienger site.

PSE's views the DG technology as one of the alternatives to deliver reliable energy at low cost. Currently, PSE monitors and evaluates DG developments at the federal, state and utility levels. PSE has been contracted to perform the DOE/NREL/GE/PSE project, Universal Interconnect Detail Design. PSE is one of three companies developing the functional requirements for this project. DOE/NREL/GE/PSE project backers hope to develop an advanced universal modular interconnection technology that can provide cross DG platform capability and increased functionality for load management and grid support. This project provides PSE with market intelligence, technical requirements and future technology that will further enhance the distribution planning process at PSE. PSE continues to identify DG issues and stakeholders that will shape the future role of DG and how it could impact the Least Cost Plan process. For information on the topic of DG as an electric resource alternative, please refer to Chapter IX, New Electric Resource Opportunities. For more insight into PSE's long-term view of DG, please refer to PSE's two-year action plan in Chapter XVI.

H. Summary

Distribution system facilities planning represents a key component of the Least Cost Plan process. Changes or additions to the delivery system may provide a less expensive alternative to building additional facilities. Other key highlights of this chapter include:

- The changing electric demand profile related to the proliferation of computers and other highly sophisticated electronic equipment, coupled with higher performance standards, create an additional distribution planning challenge for both the gas and electric distribution systems.
- Performance standards regarding safety and reliability form a basis for distribution system planning.
- PSE pursues an asset management approach to distribution planning whereby PSE seeks to ensure the full utilization of existing facilities before adding a new facility, unless the cost advantage of early installation offsets the cost of having the facility at a low level of utilization.
- The steps in the distribution planning process include a system review, system base modeling, system alternative modeling, development of project descriptions and the determination of a prioritized list of projects.
- Planning alternatives for distribution facilities planning may take one of two paths – building new facilities or making operational adjustments to existing facilities.
- To improve the overall efficiency of its distribution planning operations, PSE has initiated the use of value-based budgeting.
- PSE has made greater investments in modeling and telemetry systems, as well as automated meter reading (AMR) technology as a means to manage its delivery system on an improved real-time basis.
- Regulatory, business practice and technology barriers challenge the wide-spread application of distributed generation, however, PSE actively pursues targeted applications of distributed generation as a least-cost capacity deferral alternative to traditional distribution system upgrade or expansion.

VII

VII. EXISTING ELECTRIC RESOURCES

Chapter VII examines PSE's existing resources for meeting customer demand. From a conservation perspective, this chapter first details PSE's conservation and efficiency strategy, providing specific information on existing programs. Next, this chapter describes PSE's existing generation supply resources including generation facilities, and NUG and other contracts.

A. Conservation and Efficiency

Background

PSE has provided conservation services for its electricity customers since 1979, saving approximately 2,183,490 MWh (cumulative, annual) or 241 aMW (cumulative load reduction) through 2002. These energy savings, representing over 11 percent of PSE's average existing annual electric loads, have been captured through energy efficiency programs designed to serve all customers – including residential, low-income, commercial and industrial. In terms of investments in energy efficiency, the Company has invested approximately $310 million in electricity conservation since 1989. All savings have been cost-effective relative to the company's avoided cost in place at the time the measures were implemented. Annual energy savings recur for 10 to 20 years for most measures, while certain lighting and water heating measures may have shorter measure lives.

PSE recently increased its commitment to conservation by doubling its annual conservation targets. In August 2002, PSE filed new conservation tariffs with WUTC. Approximately 20 programs were expanded, and another 10 new programs and pilot projects were initiated. The scope and size of programs resulted from a collaborative effort through the Company's Conservation Resource Advisory Committee ("CRAG"), a committee created in the settlement of the Company's recent general rate case in Docket UE-011570. Under the settlement agreement, during the 16-month period from September 2002 through December 2003, PSE's portfolio of conservation programs and services expect to achieve 20.2 aMW cost-effective energy savings. At the same time, PSE targeted an additional annual 2.5 aMW electrical savings, using C&RD Program Funding available through BPA agreements.

This same plan establishes a framework for future conservation programs beyond 2003. PSE has market research underway to better understand customer preferences, motivations and barriers to conservation. New technologies are under review in cooperation with NEAA and

NPPC. By May 2003, revised conservation supply curves, outlining the amount of cost-effective energy savings achievable in PSE customers' facilities, will be developed. An evaluation plan has been prepared. New measures and program proposals will be evaluated using the avoided cost forecast developed through the Least Cost Planning process. The effectiveness of PSE's latest conservation initiatives, market research findings and conservation potential will be tools for developing new program offerings and targets, and the best strategies for achieving energy efficiencies going forward.

Current PSE Conservation Programs

PSE currently offers conservation programs under tariffs, effective from September 1, 2000 through December 31, 2003. Programs provide for efficiency savings from all customer sectors, including both electricity and natural gas. PSE funds the majority of the programs using electric "rider" funds, collected from all customers. A small portion receive funding through arrangements with the Bonneville Power Administration to provide Conservation and Renewable Discount (C&RD) Credits. Based on best current estimates of costs and savings projections, these conservation programs provide a cost-effective resource.

Exhibit VII-1 provides an overview of current PSE conservation programs. For a more detailed description of these programs, please refer to Appendix D.

Exhibit VII-1

PSE Existing Electric Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
Energy Efficiency Information Services – Personal / Business Energy Profile	• Energy audit surveys, analysis, and report providing customers with customized energy efficiency recommendations.	• No energy savings are currently credited to information programs.
Energy Efficiency Information Services – Personal Energy Advisors	• Phone representatives provide customers direct access to PSE's array of energy-efficiency services and programs.	• No energy savings are currently credited to information programs.
Energy Efficiency Information Services – Energy Efficiency Brochures	• Brochures on program participation guidelines and how-to guides on energy efficiency opportunities.	• No energy savings are currently credited to information programs.
Energy Efficiency Information Services – On Line Services	• Section of PSE's web site dedicated to energy efficiency and energy management information.	• No energy savings are currently credited to information programs.
Residential Energy Efficient Lighting Program (C&RD funding)	• Includes a retail incentive program, new construction & remodelers' incentives, & cross promotional/internet incentives.	• 36,901 MWh (4.2 aMW) • 7-year resource
LED Traffic Signals	• Rebates to traffic jurisdictions installing energy efficient red, green and walk/crossing LED traffic signals.	• 2,027 MWh (0.2 aMW) • 6-year resource
Small Business Energy Efficiency Programs	• Rebates for energy-efficient fluorescent lighting upgrades & conversions, lighting controls, programmable thermostats, & vending machine controllers.	• 3,333 MWh (0.4 aMW) • 10-year resource
Commercial & Industrial Retrofit Program	• Incentives in the form of grants to commercial and industrial customers for cost-effective energy-efficient upgrades.	• 73,063 MWh (8.3 aMW) • 12-year resource
Commercial & Industrial New Construction Efficiency	• Grants to commercial and industrial customers for cost-effective energy-efficient building components or systems.	• 1,333 MWh (0.2 aMW) • 20-year resource
Large Power User Self-Directed Program	• Incentives for eligible C/I customers receiving high-voltage electrical service.	• 20,000 MWh (2.3 aMW) • 12-year resource
Resource Conservation Manager (RCM) Program	• Assists in the implementation of low-cost/no cost energy saving activities with building occupants and facility maintenance staff.	• 26,667 MWh (3 aMW) • 3-year resource

Exhibit VII-1
PSE Existing Electric Conservation Programs

PROGRAM NAME	DESCRIPTION Sept. 2002 – Dec. 2003 Conservation Programs	EXPECTED ANNUAL ENERGY SAVINGS
PILOT Programs – Fuel Switching Pilot	• Incentives toward the cost of converting electric space and/or water heating equipment to equipment fueled by natural gas.	• 4,600 MWh (.5 aMW) • 20-year resource
PILOT Programs – Residential Duct Systems Pilot	• Participating customers receive duct diagnostic measurement services & sealing services from certified contractors at no cost.	• 353 MWh (<0.1aMW) • 10-year resource
Market Transformation Programs – NW Energy Efficiency Alliance	• NWEEA's primary function is market transformation for the benefit of energy efficiency at the manufacturing and retail level.	• 20,000 MWh (2.3 aMW) • 10-year resource life
Market Transformation Programs – Local Infrastructure & Market Transformation & Research	• Funds specific energy efficiency initiatives and/or organizations committed to energy efficiency in the marketplace.	• No savings are credited for these efforts
Public Purpose Programs – Energy Education 6-9th Grade Environmental Education, "Powerful Choices"	• Conservation school-age education program funded by PSE, along with 26 other utilities, cities, and agencies.	• 1,773 MWh • 0.2 aMW
Public Purpose Programs – Residential Low-Income Retrofit	• Funding for installation of home weatherization measures for low-income gas and electric heat customers.	• 2,608 MWh • 0.3 aMW
C&RD Programs – Green Power	• Customers can purchase green power directly on their monthly energy bill at $2 per 100 kWh block.	• 34,585 "Green Tags" through Dec. 2003, to fund 0.4 aMW renewable resources sited in the Pacific Northwest
C&RD Programs – Residential New Construction Lighting Fixtures	• Rebates will be available for both retrofit and new construction electric customers through participating retailers.	• 2,832 MWh (0.3 aMW) • 15-year resource
C&RD Programs – Residential Energy Star Appliance	• Rebates for Energy Star clothes washers) & Energy Star dishwashers for customers who purchase electricity from PSE.	• 2,092 MWh (.2 aMW) • 12-year resource
Energy Efficient Manufactured Housing	• $300 rebate to buyers of qualifying Super Good Cents/Energy Star labeled manufactured homes with electric heat.	• 1,456 MWH (0.2 aMW) • 30-year resource

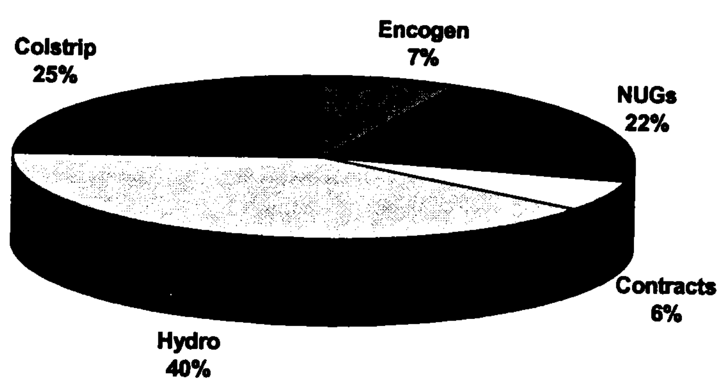
B. Schedule 150 Net Metering Customers

PSE's Schedule 150 net metering customers provide another existing resource source. These customers operate fuel cells or hydro, solar or wind power generators with a total capacity of no more than 25 kW on their own premises. Such generators must operate in parallel with PSE's transmission and distribution facilities. In total, these customers represent approximately 37 kW of supply from 18 photovoltaic sources, four micro-hydro and one wind project.

C. Generation Supply

PSE's generation portfolio currently consists of 2,287 aMW, comprised of a balanced portfolio of assets.[1] Hydro, PSE's largest energy source, fuels 40 percent of PSE's generation portfolio. PSE's share of the Colstrip plant makes up the next largest portion of energy, representing 25 percent of the energy supply. The NUG contracts, which include Tenaska, Sumas and March Point, provide 22 percent of the energy supply. Encogen, a former NUG operation now owned by PSE, provides 7 percent. Various contracts provide the remaining 6 percent. Exhibit VII-2 illustrates PSE's expected energy resource supply under average hydro conditions (40-year) Specific descriptions of PSE's supply portfolio resources are provided below.

Exhibit VII-2
2003 Energy Sources



Hydro

Hydroelectric plants provide approximately 40 percent of PSE's energy needs. Hydro resources include both smaller PSE-owned dams and long-term contracts with larger dams on the

[1] Specific generating plans and contract capacity, and energy estimates may differ slightly from information included in PSE's March 2003 SEC Form 10-K filing and other Company documents. Values included in the Least Cost Plan reflect current pricing estimates which may differ from nameplate or historical values.

Columbia River. Other PSE hydro resources include small dams included in the Contracts section as Qualifying Facilities, and "Net Market Purchases" which are contracted for at the Mid-C and will include significant levels of hydro produced energy. PSE views the primary benefits of hydro as their low cost and use as a load-following resource during the day. During most of the last decade, high average precipitation levels provided utilities in the Northwest with most of their power. However, during years of drought, utilities must go the market to replace the expected hydro energy needs with more expensive sources produced from natural gas or fuel oil. Exhibit VII-3 lists the PSE hydro resources.

Exhibit VII-3
PSE Existing Hydro Resources

PLANT	OWNER	PSE SHARE %	ENERGY (AMW)
Upper Baker River	PSE	100	39
Lower Baker River	PSE	100	45
White River	PSE	100	30
Snoqualmie Falls*	PSE	100	48
Total PSE-Owned			**162**
Wells	Douglas Co. PUD	31.3	146
Rocky Reach	Chelan Co. PUD	38.9	285
Rock Island I & II	Chelan Co. PUD	65.0	204
Wanapum	Grant Co. PUD	10.8	48
Priest Rapids	Grant Co. PUD	8.0	34
Mid-Columbia Total			**717**
Total Hydro			**879**

** Includes "Electron"*

Colstrip and Encogen

PSE owns a 50 percent share in Colstrip 1&2, and a 25 percent share in Colstrip 3&4, a coal plant located in Colstrip, Montana. Two years ago, PSE sold its interest in the Centralia, WA coal plant. Colstrip provides important baseload energy and about 25 percent of overall needs. Pennsylvania Power and Light-Montana (PPL-M) operates the units, with ownership split between PPL-M, PSE, and other northwest utilities. Encogen, a former NUG which PSE purchased in 1999, is a natural gas-fired cogeneration facility located at the Georgia Pacific Mill at Bellingham, Washington. Exhibit VII-4 lists the capacity and planned energy output from Colstrip and Encogen..

Exhibit VII-4
Colstrip and Encogen Expected Energy

UNITS	PSE OWNERSHIP	NAMEPLATE CAPACITY (MW)	ENERGY (AMW)[2]
Colstrip 1 & 2	50%	614	257
Colstrip 3 & 4	25%	1,480	316
Total Colstrip			**573**
Encogen	100%	170	162
Total			**735**

Combustion Turbines

PSE operates four simple-cycle gas turbine facilities. These plants provide important capacity although they typically operate only a few months each year. The lease for the Whitehorn units originally expired in 2004; however, it has been extended to 2009. Fredonia 3 & 4 were purchased in 2000 but the financing was arranged as a long-term lease which expires in 2011. Exhibit VII-5 provides additional detail on PSE's CTs.

Exhibit VII-5
PSE's Combustion Turbines

NAME	PLANT CAPACITY (MW)
Fredonia 1 & 2	202
Fredonia 3 & 4	108
Whitehorn 2 & 3	134
Frederickson	141
Total	**575**

Non-Utility Generators – NUG's

The NUG supply consists of cogeneration plants that PSE contracted with under the PURPA regulations. The plants use natural gas and have "hosts" that use the steam energy in their production processes. All three of the plants are located in Skagit and Whatcom counties, in the northern part of PSE's service territory. The high expense of the NUG contracts are their primary disadvantage. Exhibit VII-6 lists PSE's NUG contracts.

[2] The energy shown for the thermal plants in this section is calculated based on the plant capacities, the forced outage rates and annual maintenance periods assumed in the 2001 General Rate Case filing.

Exhibit VII-6
PSE NUG Contracts

NAME	CONTRACT EXPIRATION	ENERGY (AMW)
March Point I	12/31/2011	82
March Point II	12/31/2011	64
Tenaska	12/31/2011	224
Sumas	12/31/2012	128
Total		**498**

- ***March Point Phase I & II (Gas-fired Cogeneration)*** – On June 29, 1989, PSE executed a 20-year contract (through December 31, 2001) to purchase the full output of March Point Phase I, beginning October 11, 1991, from the March Point Cogeneration Company ("March Point"). March Point owns and operates the facility. On December 27, 1996, PSE executed a second contract (having a term co-extensive with the first contract) to purchase output of a second facility known as March Point Phase II. Both plants are located at the Texaco refinery in Anacortes, Washington. PSE pays the developer according to a predetermined escalating energy rate schedule for energy actually delivered to PSE's system. PSE may displace generation from the project and save the difference between the cost of replacement power and the project's variable operating costs, sharing savings with the project owner.

- ***Sumas Energy Cogeneration (Gas-fired Cogeneration)*** – On February 24, 1989, PSE executed a 20-year contract to purchase from Sumas Cogeneration Company, L.P., which owns and operates the project located in Sumas, Washington. PSE may displace generation from the project and save the difference between the cost of replacement power and the project's variable operating costs, sharing these savings with the project owner.

- ***Tenaska Cogeneration (Gas-fired Co-generation)*** – On March 20, 1991, PSE executed a 20-year contract to purchase the output, beginning in April 1994, from Tenaska Washington Partners, L.P., which owns and operates the project near Ferndale, Washington. In December 1997 and January 1998, PSE and Tenaska Washington Partners entered into revised agreements which will lower purchased power costs from the Tenaska project by restructuring its natural gas supply. PSE bought out the project's existing long-term gas supply contracts, which contained fixed and escalating gas prices that were well above current and projected future market prices for natural gas. PSE became the principal natural gas supplier to the project, and power purchase prices under the Tenaska contract were revised to reflect market-based prices for the natural gas supply.

Other Long-Term Contracts

The next portion of PSE's portfolio consists of 19 long-term contracts that range in capacity from a few megawatts to three hundred megawatts. The group consists of a mix of QF's and contracts with other utilities, and the fuel sources include hydro, gas, waste products, and unidentified sources from outside the area. Most of the contracts will expire by 2011. Long-term contracts with Qualifying Facilities (QFs) provide approximately 38 aMW and long-term non-QF contracts contribute approximately 277 aMW. The risk management group procures short-term contracts (less than one year) and are discussed elsewhere. Exhibit V-7 lists PSE's long-term contracts with QF's and Exhibit VII-8 lists PSE's non-QF long-term contracts.

Exhibit VII-7
Other PSE Long-Term QF Contracts

CONTRACT	TYPE	EXPIRATION	CAPACITY (MW)	ENERGY (AMW)
Port Townsend Paper	Hydro-QF	12/31/2003	0.4	< 1
Hutchison Creek	Hydro-QF	9/30/2004	0.9	< 1
Puyallup Energy Recovery Co.(PERC)	Biomass-QF	4/15/2009	2	2
Spokane Municipal Solid Waste	Biomass-QF	11/15/2012	22.9	16
North Wasco	Hydro-QF	12/31/2012	5	4
Kingdom Energy-Sygitowicz	Hydro-QF	2/2/2014	0.4	< 1
Weeks Falls	Hydro	12/1/2022	4.6	1
Koma Kulshan	Hydro	3/1/2037	14	4
Twin Falls	Hydro	3/8/2025	20	8
Total				**38**

Exhibit VII-8
PSE Non-QF Long-Term Contracts

CONTRACT	TYPE	EXPIRATION	CAPACITY (MW)	ENERGY (AMW)
CSPE	Hydro	3/31/2003	20	4
Supplemental & Entitlement Capacity	Hydro	3/31/2003	10	0
PacifiCorp	Thermal	10/31/2003	200	97
Powerex/Pt.Roberts	Hydro	9/30/2004	8	2
Baker Replacement	Hydro	10/1/2003	7	0
PG&E Seasonal Exchange-PSE	Thermal	12/31/2006	300	0
Conservation Credit - SnoPUD	Hydro	2/28/2010	10	10
Montana Power	Colstrip	12/29/2010	97	82
BPA- WNP-3 Exchange	Various	6/30/2017	50	45
Canadian EA	Hydro	12/31/2025	--	37
Total				**277**

- ***BPA Baker Replacement*** (Term from October 10, 1980 to October 1, 2003). This agreement calls for PSE to provide flood control for the Skagit River Valley by reducing the level of the reservoir behind the Upper Baker hydro project during the months of November through February. During periods of high precipitation and run-off during these months, the water can be stored in the Upper Baker reservoir and released in a controlled manner to reduce downstream flooding. In return for providing flood control, PSE receives power from BPA during the months of November through February to compensate for the reduced generating capability caused by the reduced head at the plant. Three parties are signatories to this agreement: PSE which provides the flood control service and receives power; BPA which provides the power; and the Army Corps of Engineers which pays BPA for the power. PSE is presently negotiating the renewal of this agreement.

- ***BPA Snohomish Conservation Contract*** (Term from March 1, 1990, to February 28, 2010). This agreement, the Conservation Transfer Agreement, is a system-delivery, not a unit-specific, purchased power contract. Snohomish County Public Utility District (PUD), together with Mason and Lewis County PUDs, install conservation measures in their service areas. PSE receives an equivalent amount of power saved over the expected 20-year life of the measures. The Bonneville Power Administration delivers the power to Puget Sound

Energy through the year 2001. PSE will then continue to receive the power from Snohomish County PUD for the remaining life of the conservation measures. The agreement provides for only an energy payment, not a capacity payment, as specified in the agreement.

- ***BPA Columbia Storage Power Exchange – Supplemental Entitlement and Capacity Purchase Agreements*** (Term from August 13, 1964, to March 31, 2003.) These are system-delivery, not unit-specific, power contracts between Puget Sound Energy, BPA, and various other parties. Certain utilities in the northwest United States and Canada have obtained the benefits of additional firm power as a result of the ratification of a 1961 treaty between the United States and Canada under which Canada provides approximately 15,500,000 acre-feet of reservoir storage on the upper Columbia River. As a result of this storage, stream-flow that would otherwise not be usable to serve firm regional load is stored and later released during periods when it is usable. Pursuant to the treaty, one-half of the firm power benefits produced by the additional storage accrue to Canada. PSE benefits from this storage based upon its percentage participation in the Columbia River projects, with one-half of those benefits returned to Canada. Also in 1961, PSE contracted to purchase 17.5 percent of Canada's share of the power to be returned from such storage until a phased expiration of the contract from 1998 through 2003.

- ***BPA Supplemental Entitlement and Capacity Purchase Agreements.*** PSE also has contracted to purchase from BPA Supplemental and Entitlement Capacity in order to maximize the use of PSE's share of the benefits of the additional upstream storage. PSE pays fixed payments over the life of the agreement. The amount of Supplemental and Entitlement capacity purchased from BPA decreases gradually until contract expiration in the year 2003. In 1997, PSE entered into agreements with the Mid Columbia PUDs which specify the amount of PSE's share of the obligation to return one-half of the firm power benefits to Canada beginning in 1998 and continuing until the earlier of the expiration of the PUD contracts or 2024.

- ***BPA – WNP-3 Bonneville Exchange Power (BEP)*** (Term from January 1, 1987, to June 30, 2017). This is a system-delivery, not a unit-specific, purchased power contract. Puget Sound Energy and the Bonneville Power Administration entered into an agreement settling PSE's claims resulting from BPA's action in halting construction on nuclear project WNP-3, in which PSE had a 5 percent interest. Under the settlement agreement, PSE receives from

BPA, for a period of 30.5 years beginning January 1, 1987, a certain amount of power determined by a formula and depending on the equivalent annual availability factors of several surrogate nuclear plants similar in design to WNP-3. PSE is guaranteed to receive not less than 191,667 MWh in each contract year, until receiving total deliveries of 5,833,333 MWh (expected by April, 2004)

- ***Canadian Entitlement Return.*** Pursuant to the treaty between the United States and Canada, one-half of the firm power benefits produced by the additional storage accrue to Canada. PSE's benefits and obligations from this storage are based upon its percentage participation in the Columbia River projects. In 1997, PSE entered into agreements with the Mid Columbia PUDs which specify the amount of PSE's share of the obligation to return one-half of the firm power benefits to Canada beginning in 1998 and continuing until the earlier of the expiration of the PUD contracts or 2024.

- ***Montana Power Company 20-Year Contract*** (Term from October 1, 1989, to December 29, 2010.) This is a unit-specific purchased power contract. The contract specifies capacity payments for each year, subject to reductions if specific performance is not achieved. Energy payments are computed each month and set equal to the actual cost of coal burned at PPL-M's Colstrip Unit Four.

- ***Pacific Gas & Electric Company Seasonal Exchange.*** This is a system-delivery, not a unit-specific, purchased power contract. Under this agreement, 300 MW of capacity, together with 413,000 MWh of energy, is exchanged every calendar year on a one-for-one basis. PSE provides power to Pacific Gas & Electric (PG&E) during the months of June through September, and PG&E provides power to PSE during the months of November through February. (PSE is a winter-peaking utility, while PG&E is a summer-peaking utility.) Neither party makes payments to the other party under the agreement. This contract allows for reciprocal use of each utility's idle generation capacity, with either party able to terminate the contract five years after issuing notice. PG&E defaulted on the contract in 2000. Subsequently, PSE provided PG&E with a termination notice. Currently, PG&E is under Chapter 11 protection, so the outcome of the termination procedure remains uncertain.

- ***Pacific Power & Light Company 15-Year Purchase*** (Term from November 1, 1988 to October 31, 2003.) This is a system-delivery, not a unit-specific, purchased power contract.

The contract specifies fixed yearly capacity payments. PP&L's generation system backs the contractual amount of power. The energy rate is revised annually through the application of a formula that escalates the energy rate at the same rate as the DRI coal price index escalation. However, this escalation is capped at 105 percent of the actual change in coal fuel costs experienced at the Jim Bridger and Centralia coal plants.

- ***Powerex 5-Year Purchase for Point Roberts*** (Term from October 1, 1996, to September 30, 2001.) Powerex delivers electric power to serve the retail customers of Puget within the boundaries of Point Roberts, Washington. The Point Roberts load, which is physically isolated from PSE's transmission system, connects to British Columbia Hydro's electric facilities. Puget pays a fixed price for the energy during the term of the contract, with no capacity charge.

D. Summary

PSE utilizes a balanced mix of conservation and efficiency, net metering, and generation supply resources, including hydro, coal, NUG contracts, CT's and long-term contracts with Qualifying Facilities and with non-Qualifying Facilities. Other key highlights include:

- PSE currently has approximately 20 conservation programs in place, with nearly 10 more pilot/new programs underway.
- PSE has provided conservation services for its electricity customers since 1979, saving 249 aMW (cumulative load reduction) through 2001. The Company has invested approximately $310 million in electricity conservation since 1989 and has realized energy savings representing over 11% of PSE's average existing annual electric loads.
- From September 2002 – December 2003, PSE's conservation programs and services are expected to achieve 20.2 aMW of energy savings.
- PSE's schedule 150 net metering customers provide a resource of approximately 37 kW.
- PSE's generation portfolio resources consist of 2,287 aMW – 40 percent from hydro, 25 percent from the Colstrip plant, 22 percent from NUG contracts, 7 percent from Encogen and 6 percent from other contracts.
- Most of PSE's NUG contracts, totaling 498 aMW, and long-term contracts, totaling approximately 210 aMW, expire in the 2011-2012 time period, creating a deficiency between PSE's load forecast and existing resources.

VIII

VIII. ELECTRIC LOAD-RESOURCE OUTLOOK

Chapter VIII details the outlook for PSE's electric loads and existing resources over the 20-year planning period. The chapter begins with a recap of PSE's load forecast needs, as described in detail in Chapter V. Section B examines the main driver of PSE's load-resource outlook – the loss of existing resources by 2012. Next, this chapter addresses the resource planning assumptions made regarding PSE's existing single cycle combustion turbines and the dispatch modeling process of its existing resources to serve forecasted needs. Finally, the chapter ends with an overview of PSE's electric load-resource outlook for both energy and capacity.

A. PSE Electric Load Forecast Recap

PSE anticipates its electric load to grow at a rate of 1.2 to 1.4 percent over the 20-year planning period. As illustrated in Exhibit VIII-1, PSE has annual energy loads of 2,377 aMW in 2004. The load requirements grow at a rate of 1.2 percent per year through 2013, increasing PSE's load requirement by 283 aMW to 2,660 aMW in 2013. PSE anticipates it load requirement growing at a rate of 1.4 percent per year through 2023, adding an additional 763 aMW to the load for a total annual energy need of 3,140 aMW by 2023.

Exhibit VIII-1
PSE's Annual Energy Needs

	2004	2005	2010	2015	2020	2023
Annual Energy Needs (aMW)	2,377	2,397	2,553	2,750	2,989	3,140

For peak load forecasting, PSE uses an expected winter peak of 23 degrees Fahrenheit, occurring in January. Over the 20-year planning period, PSE anticipates an average annual growth rate of 1.6 percent in peak load. As illustrated in Exhibit VIII-2, PSE has an expected winter peak of 4,819 MW in 2004. The peak load requirements grow at a rate of 1.35 percent per year through 2013, increasing PSE's peak load by 695 MW to 5,514 MW in 2013. PSE anticipates peak load growth at a rate of 1.5 percent per year through 2023, adding an additional 1,671 MW to the peak load for an expected winter peak need of 6,490 MW by 2023.

Exhibit VIII-2
PSE's Expected Winter Peak

	2004	2005	2010	2015	2020	2023
Expected Winter Peak (MW)	4,819	4,862	5,251	5,702	6,182	6,490

B. Loss of Existing Resources

The loss of existing resources, including the expiration of power supply and NUG contracts, and the loss of hydro and combustion turbines through 2012, significantly impacts PSE's electric load-resource outlook. As Exhibit VIII-3 details, PSE will lose 341 aMW of energy and 755 MW of capacity by 2010 due to the expiration of current power supply contracts.

Exhibit VIII-3
Power Supply Contract Expirations Through 2010

COUNTERPARTY	ENERGY (aMW)	CAPACITY (MW)	EXPIRATION DATE
Avista	75	100	12/31/02
Pacificorp	120	200	10/31/03
PG&E Seasonal Exchange	0	300	12/31/06
Montana Power (Colstrip)	84	97	12/29/10
Other	35	58	Various
Total	**314**	**755**	

In addition to the expiration of power supply contracts through 2010, PSE anticipates the loss of some hydro and combustion turbine resources, and NUG contracts by 2012. PSE will lose 102 aMW of energy by 2012 through the loss of the following hydro resources:

- Chelan County's PUD Rock Island 2 (48 aMW) in 2006
- Grant County's PUD Priest Rapids and Wanapam (54 aMW) by 2012

PSE will also lose its Whitehorn 2 & 3 combustion turbine in 2009, representing a loss of 134 MW.

From December 2011-2012, PSE's cogeneration NUG contracts expire, representing a loss of 498 aMW. Exhibit VIII-4 provides details on PSE's expiring NUG contracts.

Exhibit VIII-4
PSE NUG Contract Expiration

NAME	CONTRACT EXPIRATION	2003 ENERGY (AMW)
March Point I	12/31/2011	82
March Point II	12/31/2011	64
Tenaska	12/31/2011	224
Sumas	12/31/2012	128
Total		**498**

C. Single-Cycle Combustion Turbine Planning Considerations

PSE made a series of planning assumptions for its existing single-cycle combustion turbines (SCGTs), including:

- The SCGTs will be available to serve winter peak load requirements.
- The SCGTs will be used to "back up" lower than normal hydro generation.
- The SCGTs will serve as reserves for unit outages at other PSE generating facilities.
- The SCGTs provide a potential resource to "back up" intermittent wind generation.

In developing its electric load-resource outlook, PSE factored in key considerations regarding its existing SCGTs. First, PSE recognizes its existing SCGTs are 60-70 percent less fuel efficient than current combined cycle gas-fired generation technology. This factor magnifies the impact of market gas price risks and quantity of air emissions that would occur if PSE SCGTs were used for baseload energy purposes. Next, PSE acknowledges that the long-term, heavy use of SCGTs to serve baseload energy needs could increase non-fuel operating costs and may affect operational reliability. Moreover, PSE's existing permits limit the annual run time of the SCGTs. In regards to the SCGTs, PSE currently hedges its surplus summer capacity, reducing costs to customers. Further discussion of PSE's SCGTs can be found in Appendix E.

D. Dispatch Modeling of Loads

To quantity its load resource outlook, PSE simulated the dispatch of its existing resources to serve the forecasted loads over the 20-year planning period. PSE made a series of assumptions regarding its dispatch practices and use of gas-fired generation in its determination of the long-run outlook for energy over the 20-year planning period. The results included the simulation of the hourly dispatch versus hourly loads in AURORA. During hours that supply exceeds load, the dispatch modeling reflects sales to the spot market. During hours that load exceeds supply, the dispatch modeling shows PSE purchasing from the spot market.

The economic dispatch results were then adjusted to reflect planning assumptions for PSE's SCGTs and its combined cycle gas-fired resources. Consistent with the discussion in C above, the results were modified to exclude baseload energy generated from the SCGTs. In addition, to reflect the baseload capability of its greater efficiency combined cycle generation resources, PSE modified the results to include the full baseload energy capabilities of its cogeneration resources. Exhibit VIII-5 provides the fuel efficiency of PSE's SCGTs and Exhibit VIII-6 provides the fuel efficiency of PSE's cogeneration resources.

Exhibit VIII-5
Fuel Efficiency of PSE's Simple-Cycle Combustion Turbines

NAME	PLANT CAPACITY (MW)	FUEL EFFICIENCY ASSUMPTIONS
Frederickson	141	27%
Fredonia 1 & 2	202	29%
Fredonia 3 & 4	108	32%
Whitehorn 2 & 3	134	28%

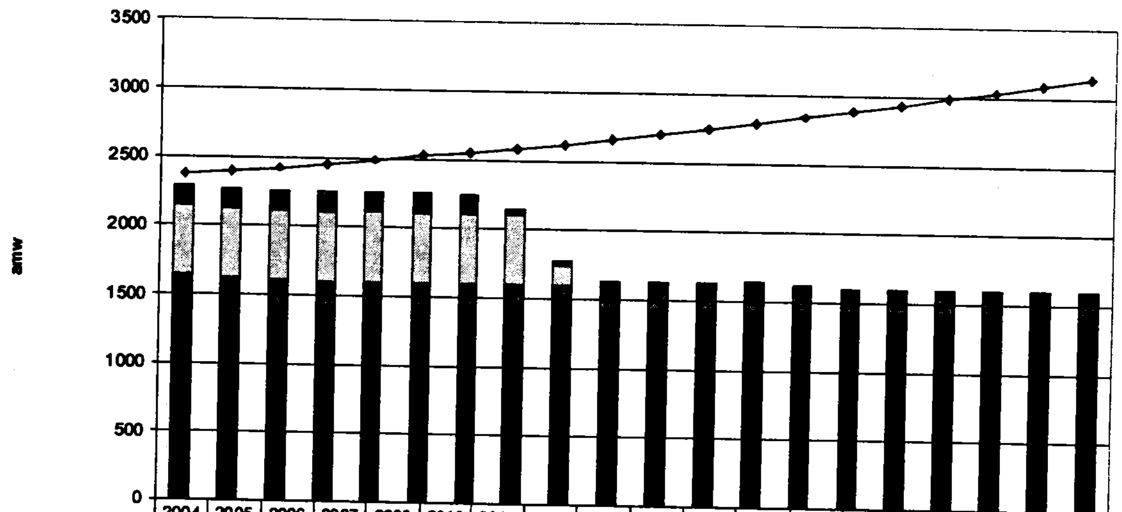
Exhibit VIII-6
Fuel Efficiency of PSE's Cogeneration Resources

NAME	PLANT CAPACITY (MW)	FUEL EFFICIENCY ASSUMPTIONS
Encogen	170	38%
March Point	148	40%
Tenaska	224	40%
Sumas	128	42%

E. Electric Load-Resource Outlook – Energy

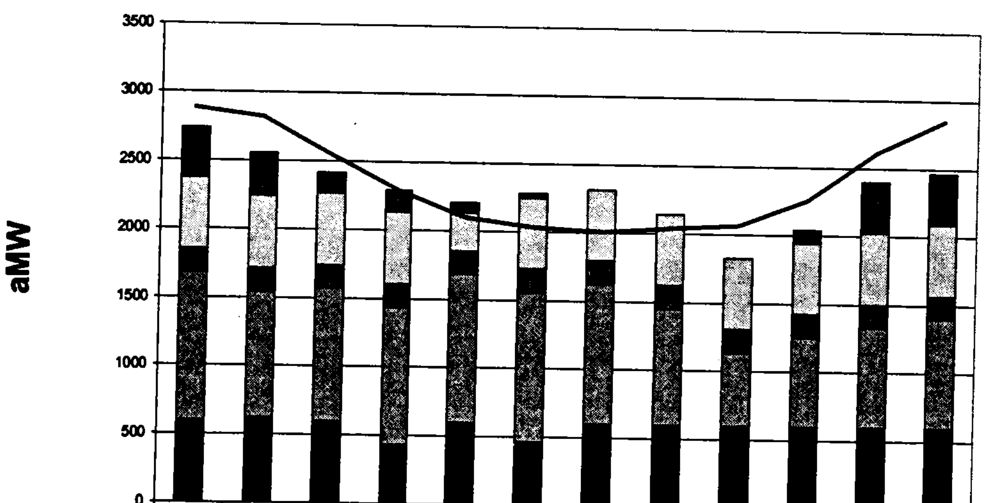
Exhibit VIII-7 provides PSE's annual energy load-resource balance from 2004-2023. Exhibits VIII-8 and VIII-9 provide a monthly view of PSE's energy needs in 2004 and 2013. On an annual basis, PSE has an existing gap of 90 aMW between its load forecast and existing resources. As illustrated by Exhibit VIII-8, the shape of this need illustrates the greatest deficit during the winter months, and little or no deficit during the summer months. By 2013, PSE has an existing gap of 1,548 aMW. As Exhibit VIII-9 illustrates, by 2013 the load-resource outlook has changed so that PSE has a significant deficit not only in the winter, but in the summer as well. For additional information on PSE's monthly energy load-resource outlook, please see Appendix F.

Exhibit VIII-7
Annual Load-Resource Outlook



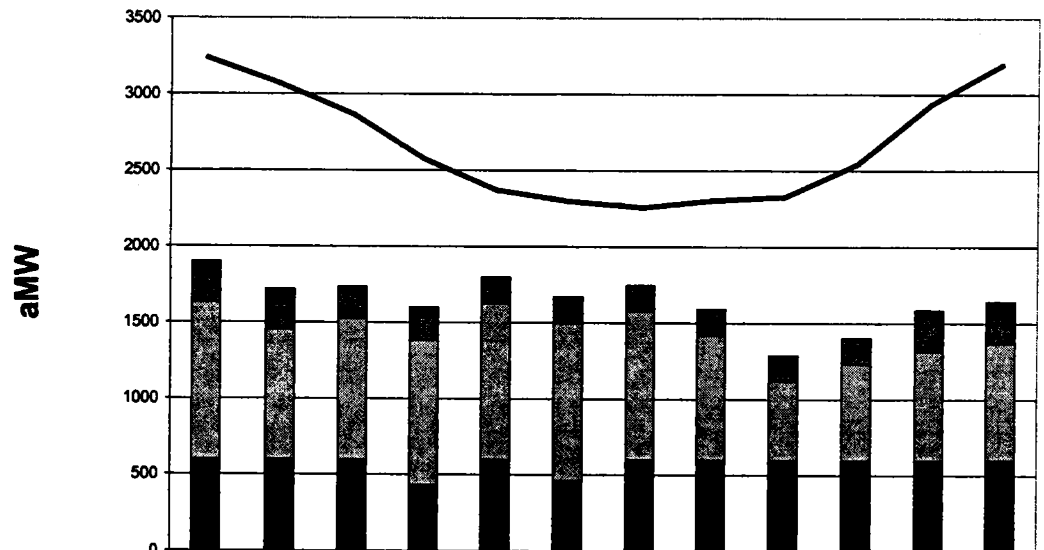
	2004	2005	2006	2007	2008	2010	2011	2012	2013	2014	2015	2016	2017	2018	2020	2021	2022	2023
Contracts	139.8	140.4	144.3	150	150.9	142.1	40.16	38.26	33.6	33.42	32.99	33.55	16.8	-8.12	-8.005	-7.919	-7.849	-7.778
NUGs	505.2	505.2	505.2	505.2	505.2	505.2	505.2	133	0	0	0	0	0	0	0	0	0	0
Encogen	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170	170
Hydro	897.3	876.1	863.4	856.4	858.8	856.4	856.4	858.8	856.4	856.4	856.4	858.8	856.4	856.4	858.8	856.4	856.4	856.4
Colstrip	574.7	573.1	573.1	573.1	574.7	573.1	573.1	574.7	573.1	573.1	573.1	574.7	573.1	573.1	574.7	573.1	573.1	573.1
Load	2377	2397	2426	2457	2490	2553	2586	2618	2660	2705	2750	2796	2843	2890	2989	3038	3089	3140

Exhibit VIII-8
2004 Monthly Energy Load-Resource Outlook



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	358	316	151	162	68	29	(79)	(75)	(85)	95	377	376
NUGs	526	526	526	526	281	526	526	526	526	526	526	526
Encogen	170	170	170	170	170	170	170	170	170	170	170	170
Hydro	1,085	924	974	1,002	1,090	1,092	1,026	852	536	652	732	800
Colstrip	598	619	598	433	598	464	598	598	598	598	598	598
Load	2,891	2,823	2,552	2,292	2,101	2,038	2,010	2,042	2,069	2,261	2,614	2,854

Exhibit VIII-9
2013 Monthly Energy Load-Resource Outlook



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Contracts	98	93	40	44	0	5	(10)	(19)	(26)	(20)	100	102
Encogen	170	170	170	170	170	170	170	170	170	170	170	170
Hydro	1,033	857	926	952	1,027	1,031	977	822	521	635	718	771
Colstrip	598	598	598	433	598	464	598	598	598	598	598	598
Load	3,234	3,064	2,864	2,569	2,368	2,295	2,255	2,305	2,326	2,541	2,932	3,192

F. Electric Load-Resource Outlook – Capacity

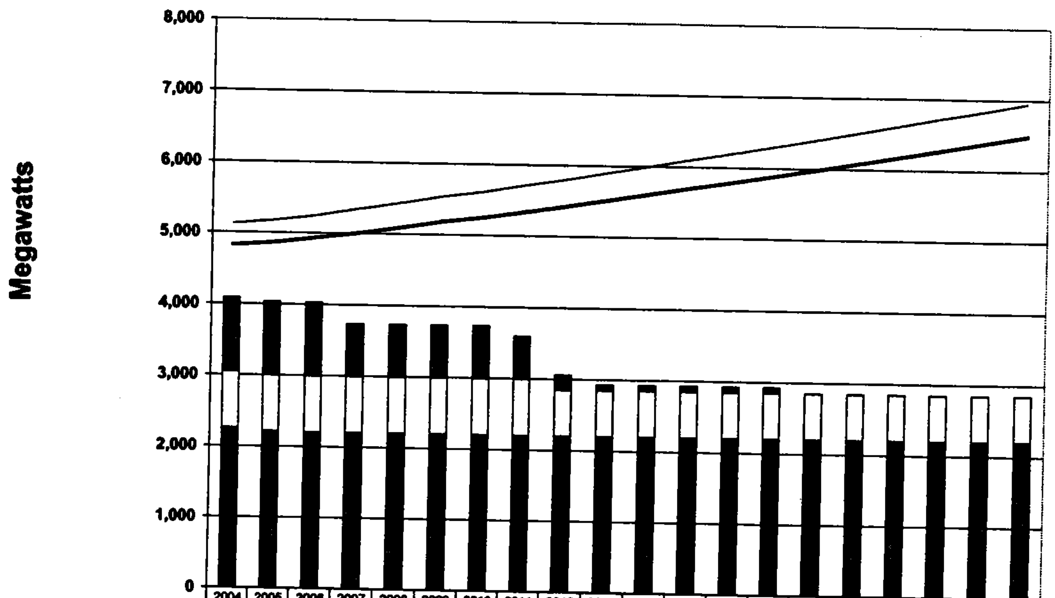
There is currently a deficit between PSE's existing capacity and its expected peak load.. As the power supply and NUG contracts expire, this situation intensifies. Exhibit VIII-10 provides PSE's annual capacity balance for 2002-2023.

G. Summary

For many utilities, load growth represents the primary driver in their load-forecast outlook. In contrast, PSE faces the current loss of existing resources, with further losses anticipated over the next 10 years, in addition to load growth in its service territory. By 2012, PSE loses some of its current hydro and combustion turbine resources, in addition to the expiration of power supply and NUG contracts. Other chapter highlights include:

- PSE anticipates its electric load to grow from 2,377 aMW in 2004 by 238 aMW to 2,660 aMW in 2013. By 2023, PSE has an anticipated electric load of 3,140 aMW.
- PSE anticipates its expected winter peak to grow from 4,819 MW in 2004 by 695 MW to 5,514 MW in 2013. By 2023, PSE has an expected winter peaking need of 6,490 MW.

Exhibit VIII-10
PSE's Annual Winter Peak Load and Resources (2004-2023)



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Contracts	515	515	515	221	221	221	219	85	85	80
NUGs	520	520	520	520	520	520	520	520	127	0
Encogen + CTs	793	793	793	793	793	793	793	793	650	650
Colstrip	646	646	646	646	646	646	646	646	646	646
Hydro	1,610	1,565	1,553	1,553	1,553	1,553	1,553	1,553	1,553	1,553
Expected Peak Load + Op. Res.	5,126	5,172	5,244	5,345	5,436	5,536	5,610	5,709	5,800	5,901
Expected Peak Load	4,819	4,862	4,929	5,004	5,089	5,182	5,251	5,336	5,421	5,514

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Contracts	80	80	80	80	-2	-2	-2	-2	-2	-2
NUGs	0	0	0	0	0	0	0	0	0	0
Encogen + CTs	650	650	650	650	650	650	650	650	650	650
Colstrip	646	646	646	646	646	646	646	646	646	646
Hydro	1,553	1,553	1,553	1,553	1,553	1,553	1,553	1,553	1,553	1,553
Expected Peak Load + Op. Res.	6,001	6,101	6,200	6,300	6,406	6,513	6,620	6,728	6,837	6,951
Expected Peak Load	5,608	5,702	5,794	5,888	5,983	6,081	6,182	6,282	6,384	6,490

- By 2010, PSE will lose 314 aMW of energy and 755 MW of capacity through the expiration of power supply contracts.
- PSE's loss of hydro resources by 2012 will decrease its load resources by 102 aMW.
- The loss of PSE's Whitehorn combustion turbine will decrease its load resource by 134 MW.
- The expiration of PSE's NUG contracts in 2011-2012 will deplete PSE's resources by 498 aMW.
- PSE simulated the dispatch of its existing resources to serve the forecast load over the 20-year period to quantify its load resource outlook.
- For planning purposes, PSE is reserving its simple cycle combustion turbines (SCGTs) for several purposes including serving winter peak load requirements, as reserves for unit outages at other facilities, and to back up hydro in low years. In addition, the SCGTs may be a resource to "back up" intermittent wind resources.

- However, for planning purposes, the load-resource outlook reflects the full availability of its higher efficiency combined cycle gas-fired generation resources. PSE's SCGTs have poorer fuel efficiencies than current combined cycle technology and limited run-time due to existing permits.
- For planning purposes, PSE reflects the full baseload capacity of its combined cycle resources.

IX

IX. NEW ELECTRIC RESOURCE OPPORTUNITIES

Chapter VII provided an overview of PSE's existing resources – including existing conservation and efficiency programs and generation supply resources. Chapter IX looks forward by examining resource opportunities, beginning with new possible conservation and efficiency initiatives. Next, this chapter describes renewable and thermal resource opportunities. Section D examines other resource alternatives such as fuel conversion, conservation voltage reduction, distributed generation and demand management. The chapter ends with a discussion of electric and gas transmission considerations.

A. Conservation and Efficiency

The amount of conservation and efficiency in the Company's resource portfolio depends heavily upon actions and decisions made by consumers, policies set by government agencies, and customer feedback related to current programs and offerings. As part of the current effort to develop new supply curves, PSE is reviewing new and emerging measures anticipated to become cost-effective over the next 5 to 10 years. In the residential sector, there will likely be increased emphasis on high-efficiency appliances, lighting, duct sealing, better controls and higher efficiency windows. Within the commercial sector, HVAC and lighting loads greatly influence energy use. For HVAC, higher-efficiency equipment, better control schemes, variable speed devices, demand controlled ventilation and circulation systems, and increased attention to commissioning and O&M offer the most promise. Lighting possibilities include improvement to fluorescent technology, advanced lighting design, layout and controls, retail display fixtures, and daylighting. Industrial processes tend to be site-specific, with potential efficiency opportunities at both the input and output stages. Higher-efficiency motor and pump speed controls, and sensors to modulate energy use represent efficiency opportunities at the input stage, while waste heat recovery could enhance the output stage. Certain lighting technology improvements, including high-bay lighting also show significant potential.

PSE has agreed to work closely with the NWPPC in their development of Regional Conservation Supply Curves for the Fifth Regional Power Plan, with work on the estimates underway. PSE expects to receive results during the second quarter of 2003. Currently, residential sector models are nearly completed, with data collection and model development efforts underway for the commercial sector. The industrial analysis will likely begin during March 2003. PSE plans to use the Power Council's methodology and many of the same conservation measure data inputs, applied to PSE's customer base, end-use composition and forecasts. PSE anticipates the completion of this work by May 2003. As the additional conservation supply curve resource potential becomes available, PSE will update the Least Cost Plan with the updated information for the August 30, 2003 update filing. PSE will rely upon the conservation supply curves and program experience, coupled with information and recommendations of the Conservation Resources Advisory Group (CRAG), to update its conservation targets for 2004 and beyond.

B. Renewable Resources

Wind

A wind generation site typically must have a capacity of 100 mw or greater in order to achieve reasonable economies of scale. Generally, individual generators produce 1.5 megawatts, however, based on recent project proposals, turbines of 2 mw and greater have been introduced. Wind's primary economic benefit stems from its avoidance of the volatility characterizing the fuel market. However, wind availability often proves volatile. Typical average capacity for a wind project is 30-35 percent, with a range of output from zero to 100 percent. Raw wind energy needs to be either small enough to be absorbed into the control area without adversely affecting operations, or have firming from a dispatch able resource.

Wind energy projects currently operate under a unique business model. The developer identifies the site and procures the necessary permits. The developer then contracts with a utility for the energy, which allows the developer to obtain bank financing. Subsequently, the developer sells the project to a larger entity that can benefit from the federal tax credit. O & M can be contracted back to the developer or another qualified entity. Currently, the federal tax credit proves critical to the economic viability of wind power projects.

Much of the wind power development in the Northwest has taken place along the Columbia River, outside of PSE's territory. Power from this area requires a transmission wheel for the full capacity. The power can be delivered to Mid-C either raw, or firmed and shaped. The PSE service territory extends into Kittitas County along the I-90 corridor. There are some wind power developments under consideration which could interconnect directly to PSE transmission lines; however, upgrades would be necessary due to the finite nature of transmission capacity. Appendix G contains more detailed information on wind technology.

Biomass

Biopower, or biomass-to-electric power generation, has proven itself as a viable electric-generation option in the United States. Currently, the technology has 10 GW of installed capacity – the largest source of non-hydro renewable electricity. Of this amount, 7 GW stems from the forest-product industry and agricultural-industry residues, with about 2.5 GW of municipal solid waste generation capacity and 0.5 GW of other capacity such as landfill gas-based production. The electricity produced from biomass serves baseload power needs. The Public Utility Regulatory Policy Act of 1978 (PURPA) provided a primary driver for growth of this technology.

Today's capacity utilizes direct-combustion boiler/steam turbine technology. The average biopower plant has a capacity of 20 MW, with the largest plant at 75 MW. The plants have an average biomass-to-electricity efficiency rate of 20 percent. Typically, biomass plants produce electricity at 8 to 12 cents/kwh. Biopower research and development has focused on technology alternatives such as co-firing with coal, gasification and direct-fired combustion technologies. The fuel for biopower plants appears to be plentiful, however, the industry still lacks an adequate infrastructure for obtaining the fuels and demonstrated technology to combust or gasify the fuels. Supporters of biomass believe the issues of global climate change and implementation of the Clean Air Act provide opportunities for further development and commercialization of the biopower industry. Appendix G contains more detailed information on biomass energy resources.

Geothermal

Friction in the Earth's core from continental plates shifting beneath each other and the decay of radioactive elements occurring naturally in small rocks produces geothermal energy. The two principal categories of geothermal energy for electric generation technology include hydrothermal resources and hot dry rock (HDR) resources. Technological advances during the last century have made the location and drilling of hydrothermal resources possible. The energy can be piped to steam or hot water to the surface, with heat used directly for space heating, aquaculture or industrial processes, or converted into electricity. Hydrothermal resources are considered shallow resources (less than 3,000 meters below the Earth's surface) and contain hot water, steam or a combination of hot water and steam. HDR resources have little permeability, with primary locations in deep masses of rock.

National research and development programs for geothermal energy focus their efforts primarily on trying to make hydrothermal resources more commercially cost-effective. Through this effort, supporters of geothermal energy intend to improve generic geothermal technology to a point that will make HDR exploitation more economically feasible. Predominately the higher quality resources can be found in the western United States, including Alaska and Hawaii. At this point, development of hydro resources has only occurred in California, Nevada, Utah and Hawaii. Appendix G contains more detailed information on geothermal energy resources.

Solar

Solar photovoltaic modules (or photovoltaics or PV") are solid-state devices which convert sunlight into direct-current electricity. This technology had recent origins with the invention of Bell Labs' silicon solar cell in 1954. The technology power man-made earth satellites in the late 1950s, and continued use by the U.S. space program advanced this technology. For the past 30 years, private/public collaborative efforts in the U.S., Europe and Japan have focused on solar technologies. The Department of Energy estimates that current annual global module production exceeds 100 MW. Supporters of PV tout the technology's benefits as its simplicity, versatility and low-environmental impact. The cost of the technology and the lack of adequate sunlight in certain regions represent this technology's major drawbacks. Appendix G contains more detailed information on PV technologies.

C. Thermal Resources

Natural Gas Combined Cycle Gas Turbines

Combined cycle turbines comprise most of the new generation proposed and under development in the Northwest. The typical plant design uses one to three gas turbine generators (about 250 mw each) in combination with a steam turbine of 20-60 MW. A heat recovery system captures heat from the gas turbines through a heat recovery system to create the steam for the secondary steam turbine system. Additional peaking capacity can be achieved with duct-firing when gas combustion augments the heat recovery system to create more steam energy. A new combined cycle gas turbine could be located in or near PSE's service territory. The plant's primary need is access to natural gas which can be delivered via the Northwest Pipeline or PSE's system. Local generation provides an economic benefit by minimizing the need for long distance high voltage transmission. Local generation may require upgrades in the water and sewer infrastructure in addition to possible upgrades of the gas lines and transmission and distribution systems. Appendix G contains more detailed information on combined cycle turbine technology.

Simple Cycle Gas Turbines

Simple cycle turbines prove less efficient than combined cycle generators. Simple cycle turbines serve peaking and backup needs due to their operational flexibility as they can be shut down and started up more quickly. In the long run, simple cycle machines can be adapted with a heat recovery system and the plant can be converted into a combined cycle plant for baseload needs. Appendix G contains more detailed information on simple cycle gas turbines.

Tenaska Assessment

PSE retained Tenaska, Inc. in 2002 to evaluate the prospects of PSE building new generation. In its report, Tenaska identified potential sites, provided cost estimates for various technologies and sizes, and estimated a benchmark to compare with other resource alternatives. Tenaska's report is presented in Appendix H.

Coal

Currently 25 percent of PSE's energy comes from part ownership of coal plants in Colstrip, Montana. Economic and environmental issues make development of new coal burning plants west of the Cascades unlikely. Developers of new coal plants focus on "mine mouth" operations to avoid the expense of shipping the coal. Mine mouth generation implies greater expense and reliance on high voltage transmission.

Typically, coal generation serves baseload need with a large capacity factor. The plants are relatively large, 400 mw or greater, to benefit from the economies of scale. The capital cost of coal generation is higher than that for large natural gas-fueled plants; however coal costs less on a per mmbtu basis. Appendix G contains more detailed information on the further development of coal resources.

D. Other Resource Opportunities

Demand Response

Demand management programs offer another potential electric resource opportunity for PSE. Two key demand response programs include Time-of-Use programs and demand-responsive rate options such as Critical Peak Pricing.

Time-of-Use Rate Program. PSE's Time-of-Use rate program began in May of 2001 for approximately 300,000 residential customers. During this time, the western energy crisis was occurring. Under PSE's program, customers were provided financial incentives to shift their electric consumption to off-peak times of the day in an effort to reduce energy supply costs as well as other system costs. The total length of the pilot program for residential customers extended over 15 months. This program included an "opt-off" mechanism whereby customers could choose to exit the program. Over the first year of the pilot program less than one percent of customers chose to voluntarily leave the program; during the last few months of the program about eight percent of customers chose to leave the pilot program. All of the customers on the pilot had been receiving time-of-use consumption information regarding their energy use for nearly six months prior to being placed on time-of-use rates (this was part of PSE's Personal Energy Management information program). During the course of the pilot program a group of tens of thousands of customers continued to receive individualized time-of-use consumption information. This group proved to be a useful sample to compare to the customers on actual time-of-use rates as well as customers on traditional "flat" rates..

PSE continued the pilot into 2002. By the summer of 2002, the energy crisis of the previous year had subsided, with less volatile market prices. As a result of the settlement of the Company's recent general rate case, a few changes were made to the program, effective July 1, 2002. These included a reduction in the differential between on- and off-peak prices charged to customers and a provision to collect many of the incremental costs of the program from it participants as a result of these changes. In the fall of 2002, a majority of the residential customers were paying slightly more on time-of-use rates than they would have on flat rates. During these last few months of the program about eight percent of customers chose to leave the pilot.

- ***Quantitative Analysis of Load Impacts by the Brattle Group***. The Brattle Group conducted a quantitative analysis of energy load shifting between time periods by customers participating in the Time-of-Use rate program. The analysis covered the months of June 2001 through June 2002. The Brattle Group statistically compared actual consumption under the Time-of-Use rate program with the consumption that would have been used if the program participants continued to be charged the current flat rate and received time-of-use consumption data on an information-only basis.

The Brattle Group's analysis revealed that the load analysis results indicate that significant shifting behavior occurred throughout the course of the pilot program. On average, Time-of-Use rate customers decreased their usage by about 5.5% in the more expensive morning peak period and decreased their usage by about 5.0% in the more expensive evening peak period. The Time-of-Use rate customers decreased their usage between 2% and 3% during the mid-day period when prices were the same as the flat rate. Energy use increased by about 5.3% during the lowest price period (Economy) in effect at night and all day Sunday (and NERC Holidays). The Brattle Group estimated that during the winter this shifting effect helped move over 30 aMW off of PSE's peak demand. The analysis confirmed that the strong shifting behavior persisted over a period of more than twelve months despite many changes in several exogenous factors during the same time period. The price-elasticity exhibited by PSE's residential customers is consistent with the response of other residential customers on various other time-of-use programs.

The Brattle Group also conducted an analysis of whether the Time-of-Use customers consumed less energy than customers who were not on the Time-of-Use rates and customers who had access to time-of-use consumption information. The Brattle Group termed this the "conservation effect[1]." The Brattle Group's analysis indicates that there was some conservation effect for the customers on Time-of-Use rates. However, no consensus exists among external stakeholders as to the degree or existence of this "conservation effect." On average, the Brattle Group estimated that Time-of-Use rate customers consistently conserved one percent more electricity than flat-rate customers. While the overall conservation effect for all customers did decrease over the course of the pilot program the Time-of-Use customers appeared to continue to conserve one percent more than customers on flat rates. The analysis indicates, that while some variations existed in the conservation effect across various housing types, the estimated overall effect of a time-of-use rate applied to all of PSE's residential customers appeared to be a one percent effect of more conservation. The Brattle Group's analysis tends to confirm that some conservation behavior persisted over a period of more than twelve months despite many changes in several exogenous factors during the same time period.

[1] *"Conservation" is defined to include behavioral changes as well as efficiency improvements or equipment upgrades (e.g. installing more efficient lighting). Time-of-use customers reported conservation actions as well as efficiency upgrades.

- ***Participant Survey and Customer Advisory Panels.*** The Company conducted a survey of 821 time-of-use rate customers during the month of July 2001. Customers at this time were overwhelmingly supportive of the program and were please with their ability to manage and control their energy use, and reduce their bills. In addition, the Company requested customers to participate on customer advisory panels. More than 120 customers responded to PSE's request and in July and August of 2001, three Customer Advisory panels held four weekly meetings. There were 16 participants on each panel and each member spent 12 hours studying and debating the program. Recruitment and panel selection practices made every attempt to have a wide-representation of PSE's customer sectors. As a result the panels included seniors, working and stay-at-home customers, as well as disabled, low and fixed income customers, all at various education levels. The panel results were consistent with the survey results PSE had received which showed broad support and understanding for time-of-use programs.

- ***Current Collaborative Study.*** Currently, a collaborative group is studying the cost-effectiveness of the time-of-use rate program. Demand-side programs, including time-of-use rate programs, must demonstrate that they both improve resource efficiency and reduce total resource costs. This analysis intends to utilize standard practice methodology, a methodology developed in 1983 to evaluate demand-side programs and projects. The methodology looks at costs and benefits from multiple perspectives, thereby determining the beneficiaries of the program and level of benefit. The test results depend on the interplay between avoided costs, prices and program costs. Currently, the Company and a collaborative group of stakeholders are running a variety of scenarios and conducting the program analysis using Charles Rivers Associates to model the cost-effectiveness of this program under these standard practice tests.

Critical Peak Pricing Products. PSE is considering the implementation of Critical Peak Pricing products. This type of demand response product would likely be cost-effective for a wide variety of customer classes and rate schedules, but would first be offered to the industrial and commercial customers .Critical Peak Pricing products have similar characteristics to standard time-of-use products, with the difference being, on several days (10 to 15 days) of the year, during the peak hours, customers pay a higher energy charge. As with the price variation on time-of-use time periods, the prices during those "critical peak" hours would be known to the customer in advance, the prices would be in the tariffs, and would not change over the short term. Customers would be notified of those critical peak days at least one day before. Customers would know the cost of electricity during the next day's peak time period, thus they could make the appropriate decision to reduce their electric load in response to the known price signal. Since these customer are already on a base time-of-use pricing plan, they would be familiar with the definition of on-peak hours. By being limited to a finite number of days (10 to 15 days) for a critical peak period, customers have an increased ability to plan and respond to this price signal. The Company's widespread deployment of AMR technology and infrastructure across its service territory several years ago makes this type of product possible to implement. Through this program, PSE would seek to increase the overall awareness of all customers to the benefits of peak load reduction through conservation, load reduction, and load shifting.

Fuel Conversion

The option of end-user fuel-switching from electricity to natural gas represents a potential cost-effective new resource opportunity. In the residential sector, this generally means converting space heating for forced air systems and water heating in existing homes. For homes with electric baseboard heat, the conversion would include to either a gas hydronic system or adding ductwork to change to a forced air system. For homes with electric heat pumps, cost-effectiveness of converting to a primary gas furnace would likely require a case by case review. Once customers receive gas on-site, they may wish to convert certain electric appliances, including cooking appliances, dryers and fireplaces. For apartment units, PSE would need to understand costs and effectiveness of "transforming" today's standard market practice of using electric baseboard or room heaters to natural gas, from the builder/developer perspective, the tenant's perspective, and the utility infrastructure and metering costs.

In the commercial sector, cost-effective fuel-switching would likely require that the conversion be done concurrently with existing equipment replacement, potentially limiting the rate at which this potential resource may be acquired. All electric packaged HVAC units can be replaced with gas heating/electric cooling systems. Similarly electric boilers can be converted to a gas boiler, although the cost of converting electric chillers to gas chillers currently carries a high cost.

PSE has not assessed an economic savings potential for fuel-switching from the customer or the total resource cost perspectives. The current pilot project will help determine technical cost and performance data, and give some appreciation for consumer issues and concerns. Regulatory treatment of costs and revenues for both electricity and natural gas should be reviewed. On a per customer basis, lost electric margin can be high with fuel-switching because of the large reduction in electric sales volume from converting space and water heat (and possibly other appliances). At the same time, there will be additional margins created on the gas side. Line extension policies will need review to accommodate the added costs of extending gas service. In addition, PSE would need to seek clarification of accounting treatment for financial incentives paid by the electric rider and/or shared with the gas tracker for the conversion of heating load to PSE gas service within the joint fuel service territory.

Distributed Generation

Distributed generation has been touted as a resource solution for a wide variety of applications, addressing both supply needs and electricity distribution planning issues. Conceptually, distributed generation offers a host of benefits, including improved customer service and reliability, superior distribution asset utilization, alleviation of transmission constraints, and creating environmental benefits, among others. Nationally, the downturn in distributed generation developments can largely be attributed to the decline in momentum for retail choice, a temporary excess of generation that has come on-line over this time period, and the slower than predicted decline in the costs of different distributed generation technologies. While distributed generation can be used to address needs in both gas and electricity supply planning, this section focuses primarily on the latter. (For further discussion on facilities system planning issues, refer to Chapter VI).

A broad array of distributed generation technologies have been introduced to the market. Estimates regarding the volume of distributed generation found around the U.S. range from 34 GW to 75 GW depending on the assumptions used to define distributed generation. Distributed generation can either be located on a customer's premises with the majority of output being used on-site or it can be located along a utility's distribution system, typically within a substation. In some cases, distributed generation can be located on areas of the system just beyond the existing transmission and distribution system (e.g., wind might be viable in a wind resource area that lacks sufficient infrastructure). Individual units range from less than a megawatt up to 50 MW. Most installations exceed $500/kW for their installation, with some still exceeding $1,000/kW.

Specific technology types include:

- ***Fuel Cells*** – Presently, fuel cell technology has not matured, with the technology still in its infancy. Capital costs tend to be prohibitively high with minimal fuel costs and minimal emissions. Fuel cells have a quiet and low temperature process, with strong green power appeal.

- ***Micro Turbines*** – Micro turbine technology is still in the development phase. Cost data has been varied, and expected near-term cost reductions have not been realized. A continuing need exists to understand manufacturers contract cost structures.

- ***Mini Turbines*** – Mini turbines consist of modular capability conducive to incremental additions. This technology provides good power quality and uninterrupted supply, with strong load following and grid support applications. Other benefits include low noise levels and a small footprint. Mini turbines have multi-fuel capabilities, however, they experience poor heat rates, a condition not likely to vastly improve.

- ***Reciprocating Engines*** – This technology utilizes a proven design, used today as a typical backup source for critical applications. However, reciprocating engines have complicated and expensive maintenance requirements resulting from a high number of sealed and lubricated moving parts. They rely upon a batch-based fuel supply, mostly diesel oil and have numerous emission problems such as C, NO_x, SO_2, CO_2, and C_xH_y, in addition to noise issues.

Conservation Voltage Reduction (CVR)

Conservation Voltage Reduction (CVR) offers another potential source for addressing PSE's resource gap in the future. The Northwest Energy Efficiency Alliance[2] (NEEA) is conducting a pilot project throughout the Northwest region on CVR, relying upon a recently approved $2.8 million budget through 2005. CVR adheres to the principle that local distribution service voltage can be reduced on certain circuits, with certain end-use loads, to provide energy savings benefits on the customer side of the meter, and, to a lesser degree, on the utility side of the meter.

[2] NEEA receives funding for its programs from electric utilities throughout the region, including PSE (contributing 10.3 percent of funding to this organization).

The benefits of CVR include electric energy savings on non-thermostatically controlled loads, primarily lighting, motors and appliances. Significant savings from demand reduction may also be realized, with a decrease in system energy losses (transformers and lines). With reduced voltage, the system could have more contingency backup capability. Some utilities that have experimented with CVR report reduced customer complaints for high or low voltage, improved voltage quality, and lower customer energy bills. CVR likely could increase the life of end-use appliances. The implementation of CVR requires significant equipment and software costs, development of CVR engineering tools, in addition to ongoing metering and monitoring of distribution system operations. Existing distribution engineering procedures and policies, included safety and customer service levels would need to be modified.

As detailed in Chapter XVI, PSE intends to continue its participation in a regional pilot as a demonstration utility. This allows the Company to work through issues related to CVR, to substantiate energy and demand benefits, and to work toward development of implementation guidelines and approaches.

E. Resource Opportunity Consideration – Transmission

Transmission issues must be considered when evaluating new resource options for several reasons. First, siting new generating resources at certain locations may create new constraints or aggravate existing constraints on one or more portions of the transmission system; and siting new generating resources at other locations may relieve existing congestion on the transmission system. Second, siting new generating resources at different locations can affect the cost of transmission to PSE and therefore affect the resulting costs for new resources. For example, new generation opportunities at locations that would allow direct interconnection with PSE's central or southern transmission system would not require payment of transmission charges for use of the BPA system, and may improve power flows within the PSE transmission system.

PSE Transmission System Constraints

Puget owns transmission facilities in its control area and, in connection with the Colstrip generating facility, in Montana. Puget's control area transmission system is composed primarily of 115 kV facilities, operated in parallel with the Bonneville Power Administration (BPA) main transmission grid. BPA's facilities mainly consist of 500 kV and 230 kV transmission facilities. While Puget's system may have capacity for new generation in certain locations, transmission constraints on BPA's system may not permit additional generation in or around Puget's control area without new construction by BPA or Puget. Puget's control area transmission system constraints arise from thermal limitations, while its Montana facilities have stability limitations. The following information on specific PSE transmission constraints is from PSE's FERC 715 filing:

- ***Whatcom County*** – Puget has a 230-115 kV transformer at Portal Way Substation and a Portal Way-Arco Central 115 kV line in Whatcom County. Under high Canadian transfers, high local generation, and low local load conditions, these facilities can overload during outage conditions.

- ***Whatcom County - Skagit County*** – Puget has two 115 kV lines between these two counties, the Bellingham-Sedro Woolley Nos. 3 & 4 lines, and owns 50 percent of the transfer rights on a double circuit 230 kV line. PSE operates these lines in parallel with two BPA 500 kV transmission lines. BPA and Puget use those lines to transfer power to and from Canada and the Northwest. When imports from Canada are high, an outage on one of the BPA lines can cause sufficient additional loading of Puget's 115 kV lines causing them to reach their thermal limits. Furthermore, Puget currently uses all of its thermal transmission capacity in its Nos. 3 & 4 115 kV lines, and its transfer rights on the 230 kV lines to transfer its share of Canadian power, and power from its generation resources in Whatcom County to Skagit County.

- ***Mid-Columbia Area - Puget Sound Area*** – Puget has a 230 kV line and a 115 kV line running between the Mid-Columbia and Puget Sound areas. BPA has agreed with Puget that the two lines have a combined capacity of 450 MW. However, due to the amount of output from generation resources that Puget has under contract in the Mid-Columbia area and elsewhere, Puget has its transmission capacity on the two lines already fully utilized. Puget has had to contract with BPA for an additional 1136 MW of transmission capacity between these two areas.

- ***Internal King County*** – Power transfers to and from Canada affect Puget's 230 and 115 kV system through King County. Outages on BPA's system could result in overloads on Puget and BPA's system to such an extent that the transfers from and to Canada must be curtailed below the full ratings. Puget facilities that are most often affected include the Bothell-

Sammamish 230 kV line, Beverly-Cottage Brook 115 kV, Cottage Brook-Snoqualmie 115 kV and the Sammamish 230-115 kV transformers.

- ***King County - Kitsap County*** – Puget has a single 115 kV line running between King County and Kitsap County. This line must be operated with one end open because outages on BPA's would otherwise cause the line to be thermally overloaded. In addition, there are several problems within the Kitsap County system. In the event of an outage among one of the three transmission lines from BPA's Kitsap substation that serve Puget's load and the U.S. Navy's load in Kitsap County, the remaining two transmission lines could be overloaded. Finally, Puget has two transmission lines between its Bremerton substation and its Foss Corner substation in Kitsap County. An outage of one of these two lines could result in the remaining line becoming overloaded.

- ***Pierce County – Thurston County*** – Puget has two 115 kV lines, and one 57.5 kV line between Pierce and Thurston Counties. These and other BPA lines can overload following an outage of a BPA 500 kV line that is in a parallel path with them. To mitigate the amount of overloading, large blocks of generation north of this path are tripped when the 500 kV line outage occurs. For the highest transfers, the 57.5 kV line may trip due to overload. These lines and BPA 230 kV lines limit the transfers that can reliably be accommodated between these counties.

- ***BPA Paul Substation - Puget Tono Substation Interconnection*** – Puget's interconnection with the Paul Substation has a thermal rating of 400 MW, and BPA has a contract with BPA for an additional 100 MW of transmission capacity.

- ***Colstrip Transmission System*** – PacifiCorp, Northwestern, Avista, Portland General Electric Company, and PSE jointly own the Colstrip transmission facilities located in Montana. The capacity of these facilities is fully utilized to transfer Colstrip Project output to points west of Montana. The Colstrip transmission facilities limitations arise from stability limits.

F. Resource Opportunity Consideration – Gas Transmission Capacity

The availability and cost of gas transmission (pipeline) capacity represents another resource-specific consideration. Three pipelines primarily serve the Pacific Northwest:

- ***Duke Energy Gas Transmission-Canada (formerly Westcoast Pipeline)*** receives supplies in northern British Columbia for delivery in southern B.C. and to the US border at Sumas, Washington. From this point, a dedicated project-controlled short-haul pipe or service provided by a LDC (Local Distribution Company) utility can be used to deliver supplies to a power-plant site in Whatcom County.

- ***Williams Companies' Northwest Pipeline*** can make deliveries to locations along the I-5 corridor in western Washington and Oregon. Gas delivered by Northwest originates from B.C. (via Westcoast at Sumas) or from the Rocky Mountain states. Project dedicated laterals or service provided by a LDC utility could be used to move gas to locations not immediately adjacent to the pipeline.

- ***PG&E Gas Transmission-Northwest*** serves eastern Washington and Oregon with supplies originating in Alberta. Project dedicated laterals or service provided by a LDC (Local Distribution Company) utility can be used to move gas to locations not immediately adjacent to the pipeline.

Pipelines will generally expand their systems (both mainline and laterals) to deliver additional gas when requested by customers willing to sign binding contracts. Recent trends suggest, however, that new capacity will be priced at the higher of rolled-in or incremental cost. For example, Northwest's Evergreen Expansion project, which will add capacity from Sumas to Chehalis WA. is expected to be priced at over 40 cents per dekatherm. This is significantly more than the 32-cent price of existing capacity. Such incremental pricing will provide great incentive for new generation loads to seek synergies with other users to more fully utilize existing capacity.

The cost to construct and operate a pipeline lateral or the payments to an LDC (needed to deliver gas to a power plant off the mainline) must be weighed against the cost of additional electric transmission needed to move the plant closer to the pipeline. Expansions by pipelines generally require a 2-3 year lead-time, but often, small amounts of surplus capacity can be consolidated to bridge to the availability of the new capacity.

Capacity additions by both Westcoast and Northwest in 2003 are expected to increase the capacity to deliver B.C.-originated gas to western Washington in the amount of about 200,000

Dth/day. Sponsors of the many proposed, but not completed, power plants have contracted the majority of this capacity.

G. Summary

PSE has a wide variety of available electric resource opportunities to balance its load-resource outlook. Conservation, renewable and thermal resources, and other alternatives such as demand response programs, fuel conversions, distributed generation and conservation voltage reduction offer potential opportunities. Other chapter highlights include:

- As part of the current effort to develop new supply curves, PSE is reviewing new and emerging measures anticipated to become cost-effective over the next 5 to 10 years.
- Resource supply alternatives include renewable resources such as wind, biomass, solar and geothermal energy, while thermal resources options focus on gas-fired and coal sources.
- Fuel conversion, the switching of end-users from electricity to gas, represents a potential cost-effective efficiency resource opportunity.
- Conservation voltage reduction, another potential new resource opportunity, involves reducing local distribution service voltage on certain circuits, with certain end-use loads, to provide energy savings.
- Distributed generation consists of several technologies – fuel cells, micro turbines, mini-turbines and reciprocating engines – that provide near-term opportunities for electric resource needs.
- PSE considers demand response programs such as its recent time-of-use program or critical peak pricing products as another option for meeting electric resource needs. Currently, PSE is participating in a collaborative effort to examine time-of-use scenarios and conduct program analysis.
- Transmission constraints – including thermal limitations in PSE's control area and stability limitations around Colstrip – add to the cost and time frame of building new generation and increase the cost of delivering energy from facilities not directly interconnected with PSE's system.
- Additions in 2003 to gas transmission capacity will increase delivery of 200,000 Dth/day, however, much of this capacity has been contracted by sponsors of pending power plants.

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X. ELECTRIC PORTFOLIO ANALYSIS

Chapter X describes the analysis process and assumptions PSE used in determining its long-term electric resource strategy for the 20-year planning period. The chapter begins with an overview of the eight planning levels considered in the analysis process. Next, PSE outlines its need for new resources, including both electric and capacity. The next portion of the chapter focuses on the various stages of PSE's analysis process. Since PSE's previous Least Cost Plan, the Company has significantly revised and updated its analytical process. Section D provides the key objectives guiding the analytical process, details on each of the major analytical stages and major input assumptions. Section E focuses on the probability analysis of several risk factors, including natural gas and power market prices, hydro generation, and the correlation between gas prices, power prices and hydro. This discussion responds to the August 2001 request by the Washington Utility and Transportation Commission (WUTC) for PSE to specifically address probabilistic analysis of risk factors in its next Least Cost Plan. Next, this chapter addresses other uncertainties accounted for in the analysis process, including a scenario analysis of market prices, retail load growth scenarios, emission regulations and the wind production tax credit. The chapter ends with a discussion of estimates of incremental conservation.

A. Portfolio Planning Levels

As will be discussed more fully in Chapter XI, many areas of the country prescribe capacity and reserve margins to guide utility planning efforts. Although this may be the case in some regions, neither the state of Washington nor the Western Systems Coordinating Council (WSCC) specify a sufficiency standard for resource planning. In the absence of a regulatory standard, PSE considers a wide spectrum of possible planning levels for both energy and capacity. As Exhibit X-1 illustrates, PSE examined eight different planning levels, ranging from a "do nothing" level to an extremely conservative level.

Exhibit X-1
Planning Level Summary

PLANNING LEVEL	ENERGY	CAPACITY
Do Nothing	Current deficit grows with demand	Current deficit grows with demand
Status Quo	2003 deficit level maintained	2003 deficit level maintained
Level A1	Meets Nov-Feb customer needs	2003 deficit level maintained
Level A2	Meets Nov-Feb customer needs	Meets 19 Degree F hour at SEA-TAC
Level B1	Meets highest deficit month needs	Meets 23 Degree F hour at SEA-TAC
Level B2	Meets highest deficit month needs	Meets 16 Degree F hour at SEA-TAC
Level C1	Meets the highest deficit month, plus 10% of the deficit	Meets 13 Degree F hour at SEA-TAC
Level C2	All months are at least 110% of the total monthly load	Meets 13 Degree F hour at SEA-TAC

Under the "Do Nothing" planning level, PSE allows the current energy and capacity deficit to grow with demand, and adds no new resources. The status quo level maintains the deficit level for energy and capacity at 2003 levels. In addition to these first two levels, PSE examines a mix of four energy and four capacity levels. The four various energy levels include:

- ***Meet Nov-Feb Customer Needs (levels A1 and A2).*** This energy planning level averages the energy deficit on an aMW basis for the months of November through February – generally the highest energy deficit months.
- ***Meet Highest Deficit Month (levels B1 and B2).*** This energy planning level meets the highest deficit on a monthly basis, with the highest deficit month occurring generally in December.
- ***Meet Highest Deficit Month + 10 percent (level C1).*** This energy planning level first meets the highest deficit on a monthly basis and then adds 10 percent of the highest month's deficit. Again, the highest deficit month occurs in December.
- ***All Months Meet 110 percent of Load (level C2.)*** This energy planning level ensures that PSE meets all deficits, plus 10 percent of the total customer load on a monthly basis.

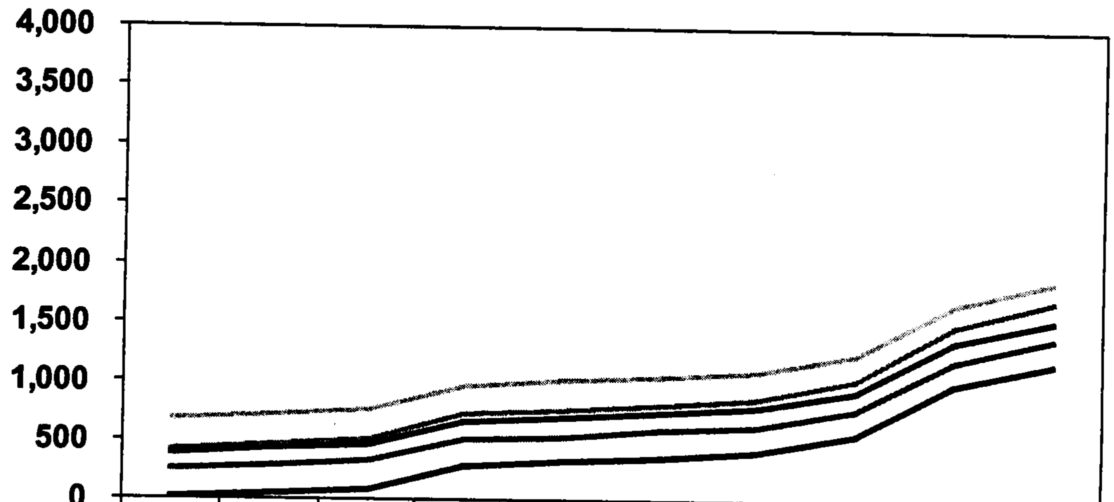
PSE also examines four different capacity planning levels. These various levels of capacity meet needs based on weather observed at the Seattle-Tacoma International Airport (SEA-TAC). These four levels include:

- 23 Degree F hour at SEA-TAC
- 19 Degree F hour at SEA-TAC
- 16 Degree F hour at SEA-TAC
- 13 Degree F hour at SEA-TAC

B. PSE Need for New Resources

After determining the various planning levels to be examined, PSE assessed the planning impact at each different level, for both energy and capacity. As Exhibit X-2 illustrates, the need for energy varies widely among planning levels. Under the status quo, PSE has an energy need of 10 aMW in 2004, growing to 1,176 aMW by 2013. Under the most stringent standard, PSE has a need of 674 aMW in 2004, growing to 1,874 aMW by 2013.

Exhibit X-2
Energy Planning Level Impact

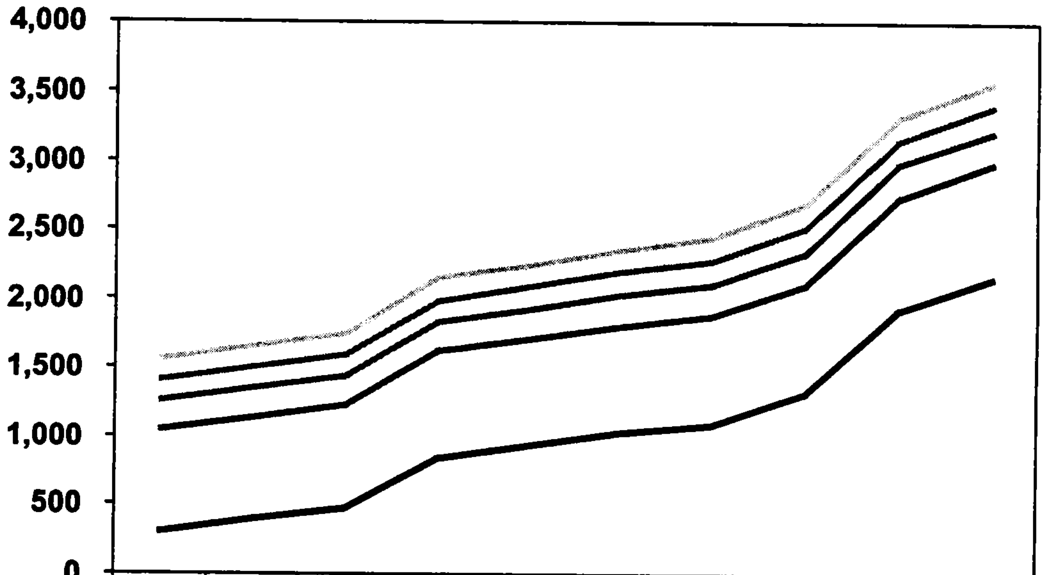


	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Status Quo	10	50	88	287	327	369	416	558	991	1,176
Level A1, 2	255	283	330	512	536	592	630	772	1,196	1,395
Level B1, 2	385	425	462	662	701	743	791	933	1,365	1,551
Level C1	423	468	509	728	772	818	870	1,026	1,502	1,706
Level C2	674	717	757	961	1,004	1,050	1,102	1,248	1,684	1,874

Exhibit X-3 provides a summary of PSE's capacity needs at the various planning levels. Under the status quo level, PSE has a need for 307 MW of capacity, increasing to 2,156 MW by 2013.

Under the most conservative planning level, PSE has a need for 1,558 MW in 2004, growing to 3,562 MW by 2013.

Exhibit X-3
Capacity Planning Level Impact



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Status Quo	307	395	473	843	927	1,021	1,091	1,310	1,930	2,156
Level B1	1,042	1,134	1,217	1,612	1,703	1,803	1,879	2,112	2,739	2,971
Level A2	1,249	1,342	1,428	1,827	1,921	2,025	2,104	2,341	2,971	3,208
Level B2	1,403	1,499	1,586	1,988	2,084	2,192	2,272	2,512	3,145	3,385
Level C1, 2	1,558	1,655	1,745	2,148	2,248	2,358	2,441	2,684	3,319	3,562

C. Portfolio Construction

After defining the eight planning levels, and the energy and capacity needs at each level, PSE constructed portfolios for the analysis process. This section describes the steps included in the construction of the portfolio, including determining technology mixes, general portfolio construction rules and applicable seasonal shaping techniques.

Resource Technology Mixes

PSE considered a broad range of resource technologies in the Least Cost Process analysis, including gas combined cycle (CCGT), gas simple cycle (SCGT), coal-fired steam and wind.

The Company assumed the wind resources as those described in the Cascades & Inland profile developed by the NPCC. PSE considered several other technologies, including many discussed in Chapter IX., but excluded these resources for a variety of reasons. Although PSE considered solar, the high capital cost associated with current technology and the incompatible weather conditions of the Northwest made this an undesirable choice. The Company considered biomass and geothermal resources, but rejected these options due to the current project-specific nature of these opportunities. Although the Company did not include biomass and geothermal resources in the generic Least Cost Plan analysis, PSE realizes these technologies provide a possibility of cost and environmental benefits and will continue to monitor market opportunities related to these technologies.

From the list of resources to be included in the Least Cost Plan analysis, PSE developed several technology mixes for analysis under a host of conditions. The following list describes the resource mixes considered in the Least Cost Plan analysis.

- ***All Gas.*** This portfolio mix meets the energy requirements of the various planning levels with CCGT resources. Duct Firing and SCGT resources meet the capacity requirements of the various planning levels.
- ***All Coal.*** This portfolio mix meets the energy requirements of the various planning levels with coal-fired steam resources. SCGT resources meet the capacity requirements of the various planning levels.
- ***Gas and Coal.*** This portfolio mix meets the energy requirements of the various planning levels with CCGT and coal-fired steam resources, with a mix of approximately two-thirds gas and the remaining coal. Duct Firing and SCGT resources meet the capacity requirements of the various planning levels.
- ***All Wind.*** This portfolio mix meets the energy requirements of the various portfolios entirely with wind resources. Duct Firing and SCGT resources meet the capacity requirements of the various planning levels.
- ***5% Wind, Gas and Coal.*** This portfolio mix uses wind to meet five percent of customer load by 2013. PSE meets the remainder of the energy requirements of the various planning levels with CCGT and coal-fired steam resources, with a mix of approximately two-thirds gas and one-third coal. Duct Firing and SCGT resources meet the capacity requirements of the various planning levels.

- ***10% Wind, Gas and Coal.*** This portfolio mix uses wind to meet 10 percent of customer load by 2013. PSE meets the remainder of the energy requirements of the various planning levels with CCGT and coal-fired steam resources, with a mix of approximately two-thirds gas and one-third coal. Duct Firing and SCGT resources meet the capacity requirements of the various planning levels.
- ***2% Wind and Gas.*** This portfolio mix uses wind to meet two percent of customer load by 2013. PSE meets the remainder of the energy requirements of the various planning levels with CCGT resources. Duct Firing and SCGT resources meet the capacity requirements of the various planning levels.
- ***5% Wind and Gas***. This portfolio mix uses wind to meet five percent of customer load by 2013. PSE uses the remainder of the energy requirements of the various planning levels with CCGT resources. Duct Firing and SCGT resources meet the capacity requirements of the various planning levels are met with.
- ***10% Wind and Gas.*** This portfolio mix uses wind to meet 10 percent of customer load by 2013. PSE meets the remainder of the energy requirements of the various planning levels with CCGT resources. Duct Firing and SCGT resources meet the capacity requirements of the various planning levels.

General Portfolio Construction Rules

PSE employed several "rules" to guide the portfolio construction of portfolios. These rules and their rationale include:

- ***New coal-fired generating facilities would not be developed and on-line before 2006.*** Practical opportunities for the acquisition of coal resources are not available until at least 2006. While possible attractive PPA opportunities exist, these specific opportunities do not fit within the generic analysis associated with this Least Cost Plan.
- ***New System Exchange resources will be added after 2006***. PSE currently has a contract with PGE for 300 MW of system exchange that expires in 2006. PSE has a north-south intertie limit of 400 MW leaving 100 MW which PSE does not intend on using for additional system exchange resources. The shaping discussion following this section more fully describes the assumptions surrounding system exchanges.
- ***No wind resources are added until 2005***: Given the state of various projects in the region, PSE finds it improbable that wind resources could be brought online prior to 2005. When meeting the technology mix wind standards (2 percent, 5 percent, 10

percent by 2013), PSE makes the additions evenly throughout the planning horizon to reach the 2013 target.

- ***Duct Firing is always added to CCGTs***: Whenever PSE adds a CCGT resource, whether with full or partial rights to power, duct firing is added at a rate of 13.5 percent of the capacity of the CCGT. As a generic capacity resource, duct firing has superior cost and heat rate benefits than the generic SCGT resource. PSE bases it 13.5 percent assumption on the average of the projects reviewed by Tenaska (see Appendix H).
- ***Resources will be shaped.*** As discussed in the following section, PSE will shape resources by one of three methods – joint ownership, forward capacity sales and system exchange.

Seasonal Exchanges

PSE employed several seasonal shaping techniques in constructing its portfolios. The first method, Joint Ownership, applies to base load resources and effectively sells the right to the power from the resource to a third party for a specified time block in the year. The energy need profile for PSE shows that for several years, until the NUG contracts expire, PSE does not need energy in the summer. While summer spot sales of new CCGT resources may potentially be more lucrative than joint ownership, the summer exposure introduces un unacceptable level of risk. PSE makes the following specific assumptions for joint ownership in its generic Least Cost Plan analysis:

- The jointly-owned resource will be a CCGT; the Duct Firing associated with the CCGT is not jointly-owned.
- The third party has an entitlement to power from May through August as PSE has surplus delivery during these months until the NUG contracts expire at the end of the decade.
- PSE and the other party will split the CCGT capital cost of $645/kW on a market price-weighted basis. Thus, PSE would pay slightly less than two-thirds (for the power 8 out of the 12 months of the year) of the capital cost as the power prices in the summer lead to a higher price-weighted share of the cost for the other party.
- The two parties will split the fixed costs on a time-of-use basis, therefore, PSE would pay two-thirds with the other party paying the remainder.
- The other party will have responsibility for all fixed costs during the period in which they receive the power.

This Joint Ownership scenario could also be characterized as PSE having full ownership of the facility and selling the summer power forward through a long-term contract. Since the market for this type of contract is not known in a generic sense, the Joint Ownership approach intends to approximate the recovery of the exact full cost of the resource. Actual market conditions and potentially different market views held by the other party may drive different results in the practical application of this shaping technique.

The second shaping technique addresses seasonal SCGT capacity sales. The generic nature of the Least Cost Plan analysis process limits capacity resources primarily to SCGTs. PSE's capacity and energy need profile have similarities on a monthly basis, primarily that both needs occur in the winter months. The market prices in the Washington/Oregon region show price peaks in the summer driven by California's summer peaking markets. These higher market prices in the summer lead to economic dispatch of the SCGTs into the market and not for native load. SCGTs left exposed to spot market conditions in the summer lead to high levels of volatility. The combination of a lack of capacity need in the summer and the exposure to extreme volatility from summer spot sales leads PSE to assume that all incremental SCGT capacity will be sold forward at a cost equal to the full-fixed cost, plus a return. PSE assumes the capacity will be sold forward for the months of May through October.

System Exchanges are the last method of shaping employed in the generic Least Cost Plan analysis. PSE constructed system exchanges using the following assumptions:

- New system exchange transaction opportunities are limited by the existence of the PGE 300 MW contract and the North/South 400 MW transmission limit.
- Portfolios will be constructed such that the months where PSE provides system energy do not violate the energy planning level.
- The system exchange profile is similar to the Joint Ownership profile, with PSE taking energy from September through April, and providing system energy from May through August.
- System exchange capacity only apply to peak times (i.e., standard 6 by 16 hour profile).

Adhering to the planning levels limits the possible amount of system exchange to a little over 125 MW in the 10-year planning horizon.

D. Analysis Process

This section focuses on the analysis process used by PSE to develop its Least Cost Plan. Since PSE's previous Least Cost Plan, the company has significantly revised and updated its analytical process. Section D begins with a description of the five key objectives driving PSE's Least Cost Plan analytical process. Next, PSE provides detail on each of the major analytical process stages. For a more detailed overview of PSE's modeling process, please see Appendix I.

Analytical Process Objectives

Since its previous Least Cost Plan, PSE significantly revised and updated its analytical process for this Least Cost Plan. In part, this process seeks to address comments that were received following PSE's previous Least Cost Plan. Moreover, PSE revised its process to reflect and respond to major changes that have occurred, and continue to occur in the energy utility industry. Accordingly, PSE designed its new analytical process to provide a rigorous, yet flexible, approach for meeting the following objectives:

- Comprehensive analysis of long-term energy resource planning issues and alternatives, using consistent methods and assumptions.
- Explicit assessment of key uncertainties, including probabilistic analysis of major risk factors and associated tradeoffs.
- Formulation and testing of a broad variety of potential resource portfolios.
- Use of defined criteria to guide the analysis and to provide results that facilitate open, well-documented decision-making that includes both quantitative and qualitative factors.
- A responsive, iterative process that promotes timely, useful results at each major stage and ultimately results in full integration of energy supply resources and demand-side management.

Analytical Process Stages

To accomplish the analytical objectives (including balancing tradeoffs among them), PSE has organized the Least Cost Plan analytical process to proceed in several stages, as illustrated in Exhibit X-4.

Exhibit X-4
Major Stages in the Least Cost Plan Analytical Process

1.	Development of Major Input Assumptions and Forecasts
2.	Forecast of Market Prices for Electricity in the Pacific Northwest
3.	Determination of PSE's Need for New Resources
4.	Resource Portfolio Screening Analysis
5.	Integrated Analysis Using Updated Conservation Resource Estimates

Stage One: Development Of Basic Input Assumptions And Forecasts. The first stage of PSE's Least Cost Plan analytical process consisted of developing the basic input assumptions and forecasts for use in the modeling process. Major input assumptions for the analysis included:

- ***Retail Customer Electric Load Forecasts*** – In order to determine the need for resources over the 20-year planning period, PSE made assumptions regarding the size of the retail customer loads. These forecasts, including the base case and alternate scenario forecasts of energy and peak demands, are presented in Chapter V of this report.
- ***Existing Power Supply Resources*** – Along with making assumptions on the number of retail customers, PSE identified its existing power supply resources. In addition, the Company gathered information about costs and other characteristics of available new resources. Chapter VII discusses PSE's existing electric resources and Chapter IX details potential new resources.
- ***Natural Gas Market Price Forecast*** – The price of natural gas drives power costs, making a forecast of market prices for natural gas an essential analysis element. PSE assumed base case gas price projections based upon a long-term forecast of market prices for natural gas at Sumas produced by the PIRA Energy Group in January 2003. Exhibit X-5 and Exhibit X-6 provide the results of the PIRA Energy Group's gas price forecast. The prices for 2003 and 2004 reflect forward market prices as of fall 2002, and are changed from the PIRA forecast for those two years.

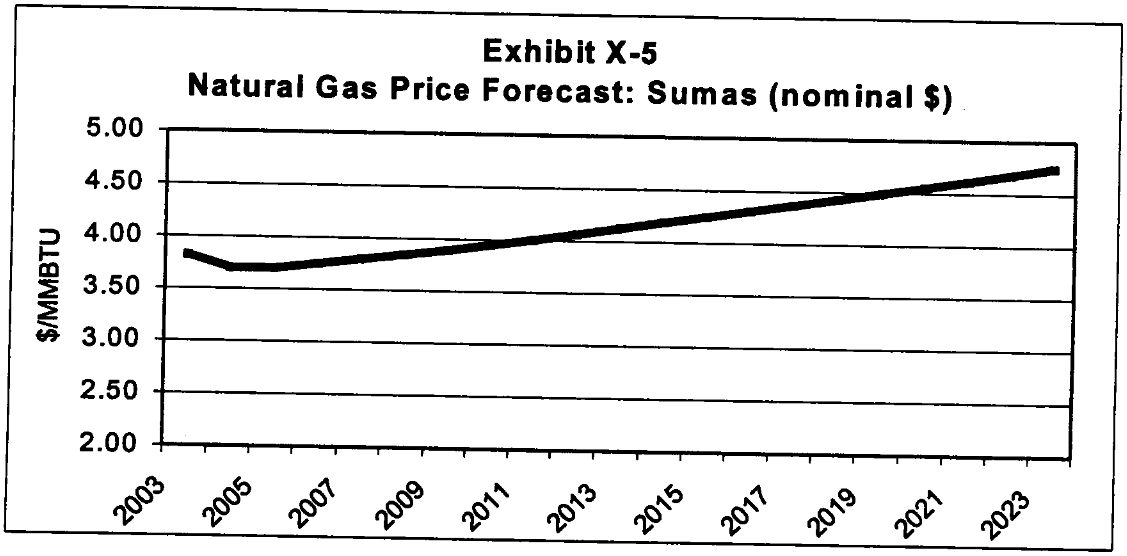


Exhibit X-6
Long-Term Forecast of Market Prices for Natural Gas at Sumas
(Nominal Dollars per MMBtu)

YEAR	PRICE
2003	3.83
2004	3.70
2005	3.70
2006	3.75
2007	3.80
2008	3.85
2009	3.90
2010	3.95
2011	4.01
2012	4.07
2013	4.13
2014	4.19
2015	4.25
2016	4.31
2017	4.37
2018	4.43
2019	4.49
2020	4.55
2021	4.62
2022	4.68
2023	4.75

- ***Wholesale Electric Market Prices*** – Input assumptions about market prices for wholesale electric supplies represents another key variable for the resource analysis. Stage Two of the analytical process addresses the preparation of the market electricity price forecast.

Stage Two: Forecasts Of Market Prices For Electricity In The Pacific Northwest. To develop the base case projection of market prices for electricity, PSE prepared a region-wide market forecast using the AURORA model to simulate long-run market prices for wholesale power supply in the Western Electric Coordinating Council area, including prices at the Mid-Columbia trading hub.

EPIS, Inc., located near Portland, Oregon, developed, and owns and licenses the Aurora model. AURORA is a nationally recognized energy market simulation model used by numerous clients of EPIS, including BPA and the Northwest Power Planning Council. The use of AURORA by these and other Northwest entities has resulted in an extensive review of the methodology and data used in the model. This regional review by Northwest players proves to be especially important due to the large role that hydroelectric generation plays in the region. For further information about the AURORA model, please refer to the EPIS website at www.epis.com.

A number of assumptions drove the AURORA-based forecast of market prices for wholesale power supply. These assumptions included forecasts of regional load growth, completion of new generating resources currently under construction, costs and operating characteristics of new resources, costs of capital (including debt, equity and capitalization ratios) and the types of entities (investor-owned utilities, publicly-owned utilities and non-utility developers) that may develop new generating resources. In addition, the analysis used the PIRA forecast of natural gas prices. Appendix J provides further detail about these assumptions. Exhibits X-7 and X-8 summarize results from the forecast of Mid-Columbia power supply prices.

Exhibit X-7
Forecast of Annual Average Mid-Columbia Wholesale Power Price
Nominal Dollars per Megawatt-Hour

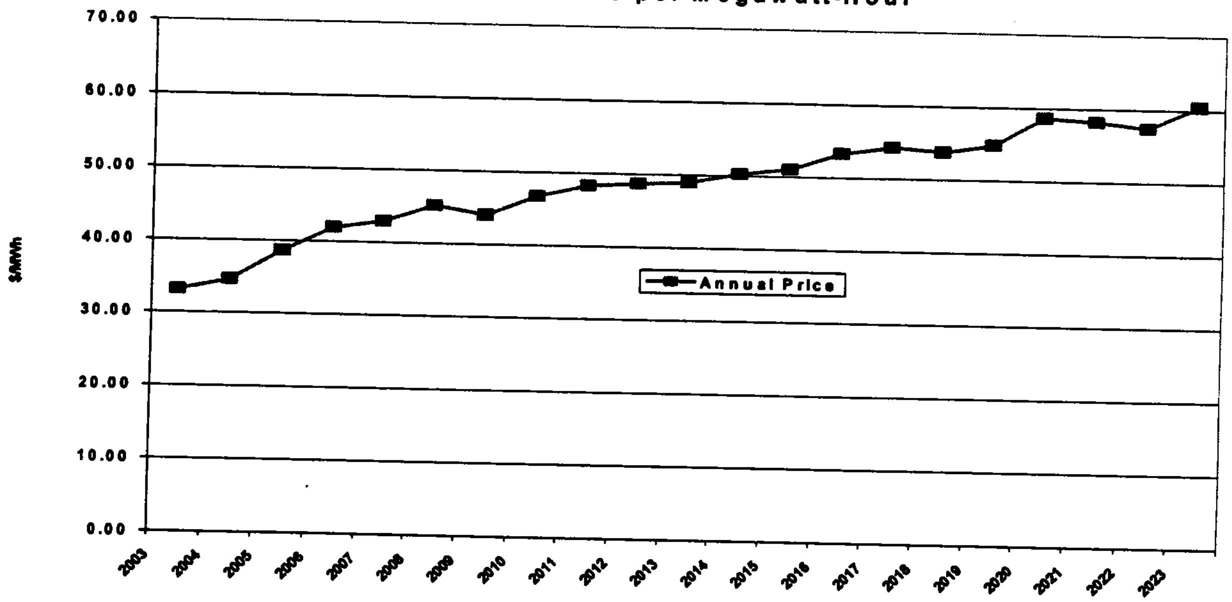


Exhibit X-8
Results of AURORA Forecast of Wholesale Markets Power Supply Prices
(Annual Average)
Nominal Dollars per Megawatt-Hour

YEAR	PRICE
2003	33.16
2004	34.60
2005	38.67
2006	41.91
2007	42.94
2008	45.17
2009	44.01
2010	46.78
2011	48.31
2012	48.72
2013	48.97
2014	50.28
2015	51.06
2016	53.36
2017	54.31
2018	53.81
2019	54.83
2020	58.64
2021	58.22
2022	57.43
2023	60.46

Stage Three: Determination Of PSE's Need For New Electric Resources. The third stage of PSE's resource analysis process focused on determining PSE's need for new resources. The magnitude of PSE's projected need for new resources, including the growth over time and the seasonal "shape" of the need for new resources, has direct implications for the amount of new resources that PSE should acquire. It also impacts the types (e.g., energy and capacity) of resources PSE should acquire and at what points in time it should be making new resource acquisitions. In other words, PSE's need for new energy and capacity resources represents one of the most important drivers for development of the Company's electric resource strategy.

- ***Need for New Electric Energy Resources***. Accordingly, PSE performed a detailed assessment of its need for new electric resources, beginning with the energy component. PSE also used the AURORA model to prepare this portion of the analysis. However, rather than simulating the overall regional market (as done to produce the market power price forecast described above), the analysis at this stage focused specifically on simulating the use of PSE's existing portfolio of electric resources to serve its customers' forecasted retail electric loads.

  PSE used the AURORA model to determine how much of the retail customer energy requirements (net of new conservation energy savings accumulating at a rate of an additional 15 aMW each year) would be met by cost-effective use of PSE's existing portfolio (net of expiring contracts and other resource losses as they are scheduled to occur over the 20-year planning horizon). The amounts of the shortfalls and the ability of the existing portfolio to serve the forecasted loads were then computed for each time period in the planning horizon. These shortfalls, or energy deficits, represent PSE's need for new resources.

  Key inputs to this portion of the analysis included the assumptions described in earlier sections of this chapter, including the market price forecasts for natural gas and electricity.

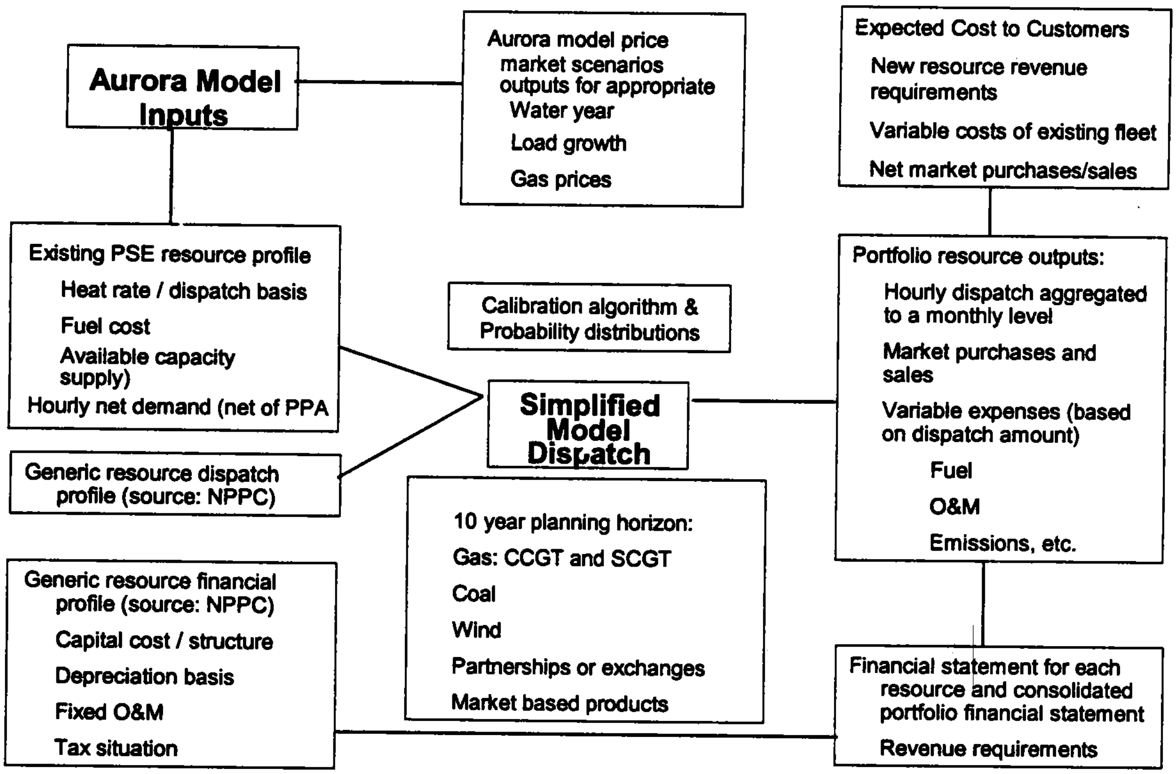
  It is important to note that the AURORA model results to determine PSE's need for new energy resources include projections of energy produced on an economic basis from PSE's existing co-generation and simple-cycle combustion turbine facilities (i.e., during periods when market prices for power are higher than combustion turbine operating costs, including market prices for natural gas). However, the AURORA results indicate that the majority of the energy generation from PSE's combustion turbines would occur during summer months when other existing resources in the portfolio prove sufficient to serve PSE's retail customer loads and PSE would be making surplus power sales from its portfolio. As a result, the combustion turbine generation amounts included in the results do not significantly affect PSE's need for new energy resources. Since PSE's combustion turbines play a critically important role in providing generating capacity to help meet winter peak loads, it is important not to assume that they can also be used extensively to meet energy requirements during those same winter months.

Section B of this chapter provided an overview of PSE's need for new energy and capacity resources at the eight planning levels. Chapter XI provides analysis results – including the planning level guided PSE's long-term resource strategy and the resultant need for energy and capacity resources.

Stage Four: Resource Portfolio Screening Analysis. In order to screen the portfolios constructed for analysis (see Section C), PSE developed a dispatch model which provides MWh and variable costs for each resource considered by PSE. The model dispatches existing and potential new PSE resources against hourly power prices from AURORA for the Washington/Oregon region. The dispatch model relies upon the same inputs to AURORA for plant profiles and demands. As described more fully in Section E of this chapter, the dispatch model uses Crystal Ball Monte Carlo simulation to perform probabilistic risk analysis.

PSE uses the MWh and variable cost results from the dispatch model, in conjunction with fixed cost assumptions, to derive a "bottom up" revenue requirement for each new resource under consideration. For each new resource, the model generates a financial summary, including an income statement, a cash flow summary and an approximation of regulatory asset base. Then, the financial data from each new resource are consolidated. Next, the model develops the comparative incremental cost to customers for a particular resource portfolio by combining the variable cost of dispatch from the existing dispatchable PSE fleet, the cost of market purchases and the revenue requirements from the new resource portfolio over a 20-year period. Finally, the net present value (NPV) of the 20-year strip of incremental costs to customers is calculated at PSE's pre-tax Weighted Average Cost of Capital (WACC). Exhibit X-9 provides a schematic view of PSE's portfolio screening model.

Exhibit X-9
Portfolio Screening Analysis



Stage Five – Integrated Analysis Using updated Conservation Resource Estimates. Under the settlement agreement reached in PSE's last General Rate Case in 2002, the parties agreed to a schedule for the development of updated conservation resource assessments in or shortly after May 2003. As described in Chapter 16, PSE will use these results to conduct additional load-resource analysis during the second half of 2003, including more complete integration of the analysis of both supply-side and demand-side resource alternatives. The results of this analysis will be in PSE's August 2003 Least Cost Plan update.

E. Probabilistic Analysis of Risk Factors

Following PSE's previous Least Cost Plan, the WUTC issued a comment letter, dated August 21, 2001, directing PSE to include probabilistic risk analysis in its next Least Cost Plan filing. PSE developed its Least Cost Plan screening model to assess uncertainties through probabilistic Monte Carlo modeling. The LCP screening model employs Crystal Ball™ as the Monte Carlo analysis tool. The Monte Carlo analysis considers three uncertainty factors:

- Market prices for natural gas

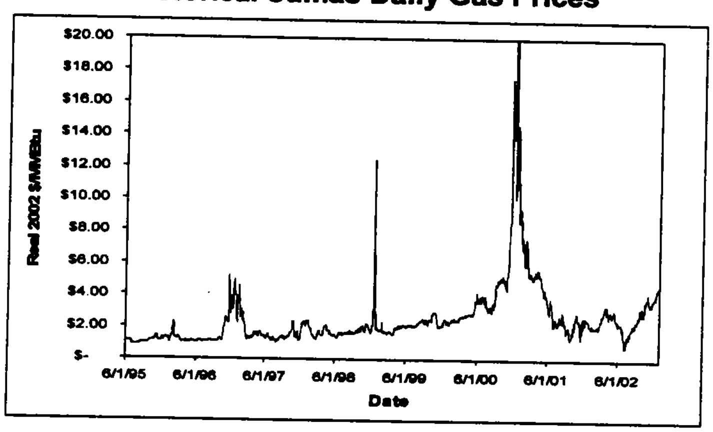
- Market prices for power
- Hydroelectric generation availability

For each of the uncertainty factors, the Monte Carlo analysis requires two pieces of information – the distribution of possible outcomes for each uncertainty factor, and the correlation between the uncertainty factors. This section addresses the development of these inputs to the Monte Carlo analysis. The distributions associated with the uncertainty factors were developed using historical data and will be dealt with separately, while PSE based the correlation factors on historical information and will address these factors collectively. The historical data sets span June 1995 to December 2002, based on daily data points. The individual data sets were aligned to assure no gaps or holes existed in the data set.

Market prices for natural gas

Historically, market prices for natural gas exhibit a high degree of volatility. Exhibit X-10 illustrates the Sumas index data set used for natural gas prices.

Exhibit X-10
Historical Sumas Daily Gas Prices

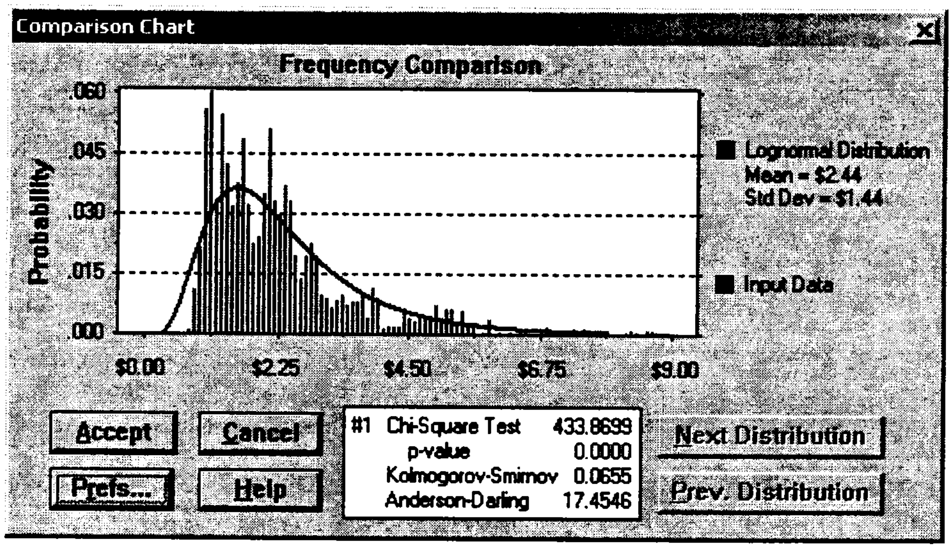


Source: Gas Daily

The Sumas gas index revealed a few days during the 2000 - 2001 period in which the price for natural gas exceeded $20/MMBtu. In the development of the distribution of prices based on this historical data set, PSE set a cap for gas prices at $20/MMBtu. For any days in which the price exceeded this level, PSE set that day's price to $20/MMBtu.

Using Crystal Ball™ the historical data set of real 2002 $/MMBtu data points can be curve-fit to a number of distributions. The lognormal distribution ranks highest and is displayed in Exhibit X-11.

Exhibit X-11
Historical Sumas Daily Gas Price Distribution



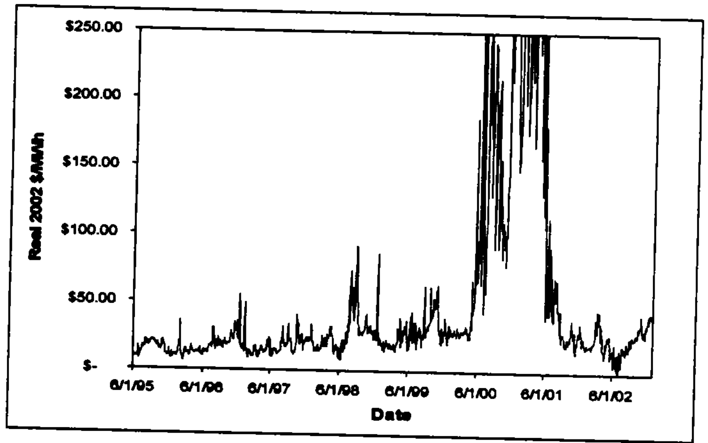
The mean of this data set is $2.44/MMBtu (real 2002$), with a standard deviation of $1.44/MMBtu. These values translate to a coefficient of variability of 59 percent (standard deviation as a percent of the mean). PSE applied this measure of gas price volatility is applied to the gas prices in the screening model on an annual basis, with this annual volatility applied evenly across the monthly gas price profile used in the model.

Market prices for power

Historical power prices show even greater volatility than gas prices. Exhibit X-12 provides the data set used for power prices, with the Mid-Columbia hub as the index.

Exhibit X-12

Historical Mid-Columbia Power Prices



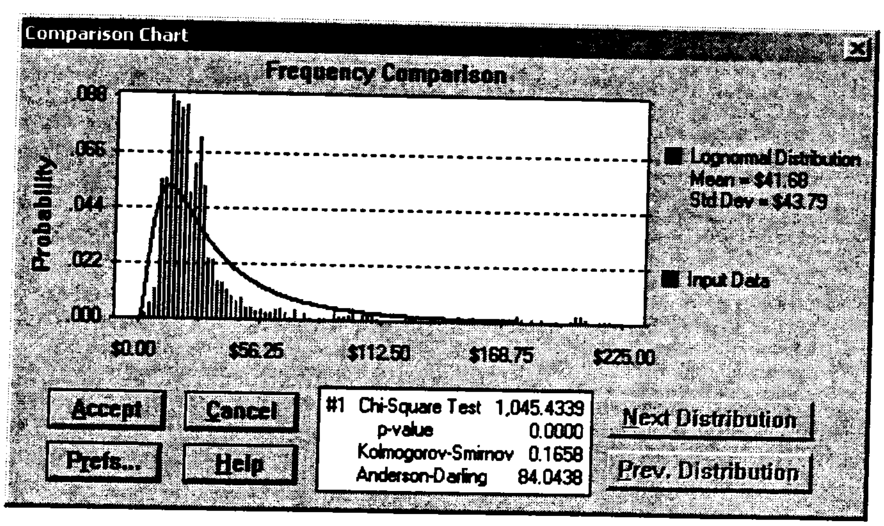
Source: MegaWatt Daily

The Mid-Columbia power index revealed several days during the 2000 - 2001 time period in which the price for power exceeded $250/MWh. In the development of the distribution of prices based on this historical data set, PSE set a cap for power prices at $250/MWh. For any days in which the price exceeded this level, PSE set that day's price to $250/MWh.

Using Crystal Ball™ the historical data set of real 2002 $/MWh data points can be curve-fit to a number of distributions. Exhibit X-13 displays lognormal distribution which ranked highest.

Exhibit X-13

Historical Sumas Daily Gas Price Distribution



The mean of this data set is $41.68/MWh (real 2002 $), and the standard deviation is $43.79/MWh. These values translate to a coefficient of variability of 105 percent (standard deviation as a percent of the mean). Similar to gas prices, the screening model applies the power price volatility on an annual basis. The annual volatility factor is applied equally to the Aurora hourly price profile. Since the power prices are represented on an hourly basis, the concern of "double counting" volatility arose. The Aurora hourly price profile already has an equivalent 30 percent coefficient of variability built into it due to hourly price fluctuation. The annual volatility factor used in the screening model therefore has the 30 percent netted from the 105 percent to yield an annual coefficient of variability of 75 percent.

Hydroelectric generation

PSE based the variability of hydroelectric generation on the 40-year (1948-1988) NWPP hydro availability data set. The 10 facilities owned by PSE are divided into two systems – the Western System and the Mid-Columbia System. The NWPP has projected the availability of each of these 10 hydroelectric facilities for each of the 40 years of hydrological data in its data set. Each facility has an associated mean and standard deviation availability. In order to "roll up" the statistics on each facility into the two systems detailed above, PSE calculated the MW weighted average standard deviation. Exhibits X-14 and X-15 illustrate these facilities, their associated capacity, and coefficient of variability.

Exhibit X-14
Western Hydroelectric System

Plant	40-year SD (% of mean)	MW
Upper Baker	12.1%	104.90
Lower Baker	14.4%	79.00
White River	12.1%	62.50
Puget Small Plants	9.4%	69.65
Weighted Avg SD	12.1%	

Exhibit X-15
Columbia River Hydroelectric System

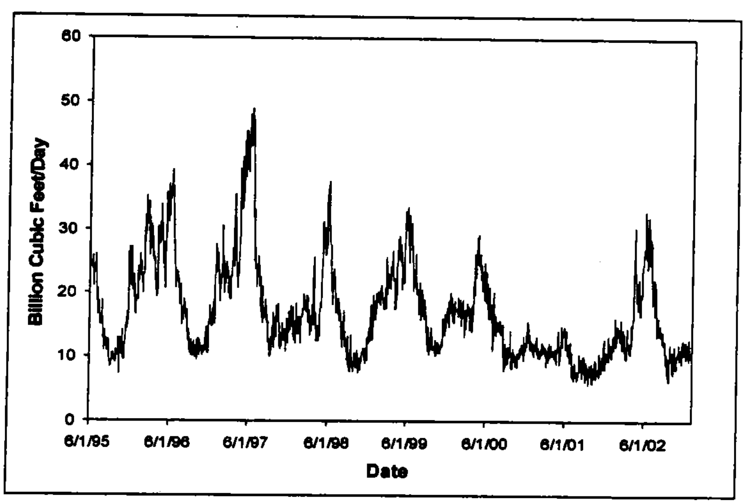
Plant	40-year SD (% of mean)	MW
Wells	9.9%	262.92
Rocky Reach	9.9%	492.67
Rock Island 1	4.5%	163.08
Wanapum	4.5%	106.49
Priest Rapids	7.8%	72.96
Rock Island 2	7.8%	173.95
Weighted Avg SD	8.3%	

As Exhibits X-14 and X-15 illustrate, the distribution for each of the hydroelectric systems is assumed to be normal.

Correlation between Power, Gas, and Hydroelectric Availability

In order to correlate both power and gas to hydroelectric availability, PSE needed to chose a proxy for hydroelectric availability. The NWPP data detailed by the availability distribution on ends in 1988, and sufficient data on gas or power prices does not go back this far back in order to allow for a determination of a good statistical relationship. PSE chose the daily river flow at the Dalles, as shown in Exhibit X-16.

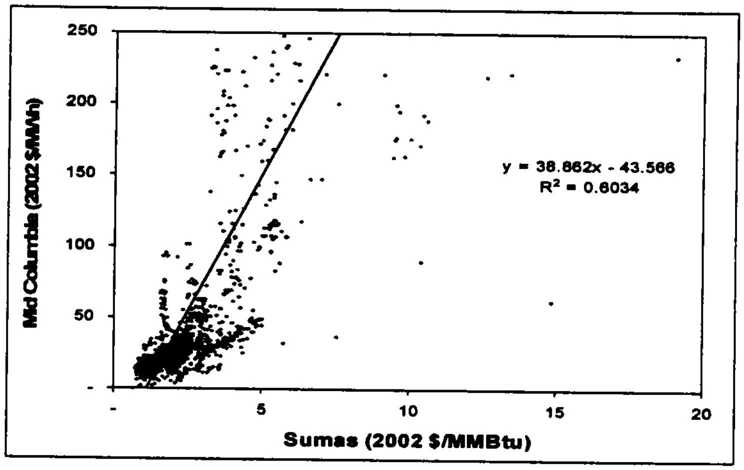
Exhibit X-16
Volumetric River Flow at The Dalles



Source: US Geological Survey

PSE now has three consistent sets of data for gas, power, and hydroelectric availability. The assessment of correlation between these three factors began with an analysis of the level of determination between the data sets. Variation in gas prices account for a significant portion of the variation in power prices. Exhibit X-17 illustrates this relationship and demonstrates a coefficient of determination (R-squared) of close to 60 percent.

Exhibit X-17
Power Price as a Function of Gas Price



Similarly, PSE examined the level of variation in both power and gas prices as a result of variation in hydroelectric availability (Dalles River flow). Exhibits X-18 and X-19 portray this relationship.

Exhibit X-18
Power Price as a Function of Dalles River Flow

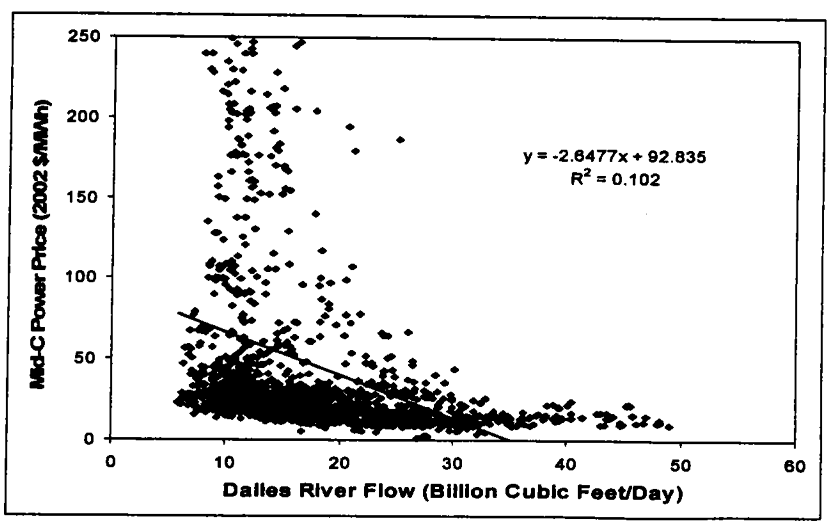
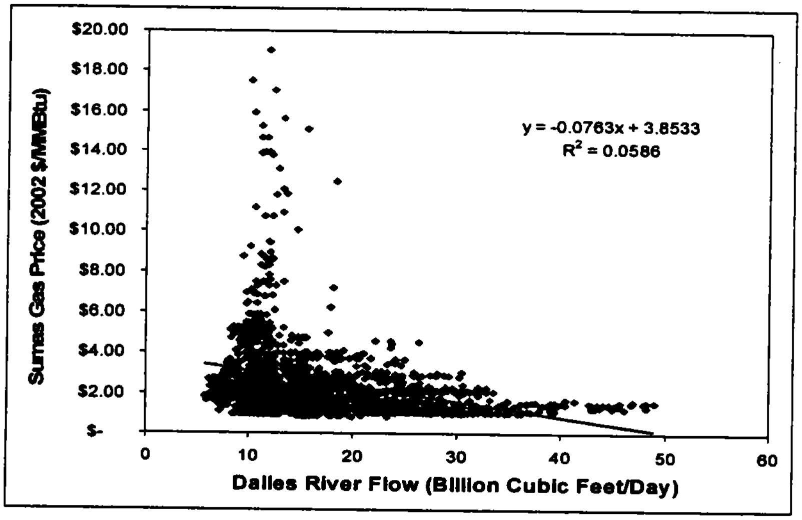


Exhibit X-19
Gas Price as a Function of Dalles River Flow



These exhibits characterize both of these relationships as negative, thus higher river flow drives lower power and gas prices, but the level of determination is quite small.

It should be noted that Crystal Ball™ treats the uncertainty factors as independent variables, and therefore, requires correlation coefficients as inputs to relate power, gas and hydroelectric availability to each other. Excel™ was used to calculate the correlation coefficients between the three uncertainty variables. Exhibit X-20 shows the results of these calculations.

Exhibit X-20
Correlation Coefficients

	Mid C ($/MWh)	*Sumas Gas ($/MMBtu)*	*Dalles (Cf/Day)*
Mid C ($/MWh)	1.00		
Sumas Gas ($/MMBtu)	0.67	1.00	
Dalles (Cf/Day)	(0.32)	(0.24)	1.00

As expected, gas and power have a high and positive correlation. Again, as expected, power/gas and hydroelectric availability have a somewhat lower and negative correlation.

Since two hydroelectric systems were modeled, PSE assumes the correlation coefficient between the two systems to be one. Lastly, there is no inter-year correlation within each uncertainty factor for all three

F. Other Uncertainties

In addition to performing probabilistic risk analysis, PSE examined other uncertainties impacting the modeling process. PSE examined market price uncertainty utilizing scenario analysis. In addition, PSE examined retail load growth scenarios; emissions such as sulfur dioxide, nitrous oxides and carbon dioxide; and the wind production tax credit.

Market Price Uncertainty

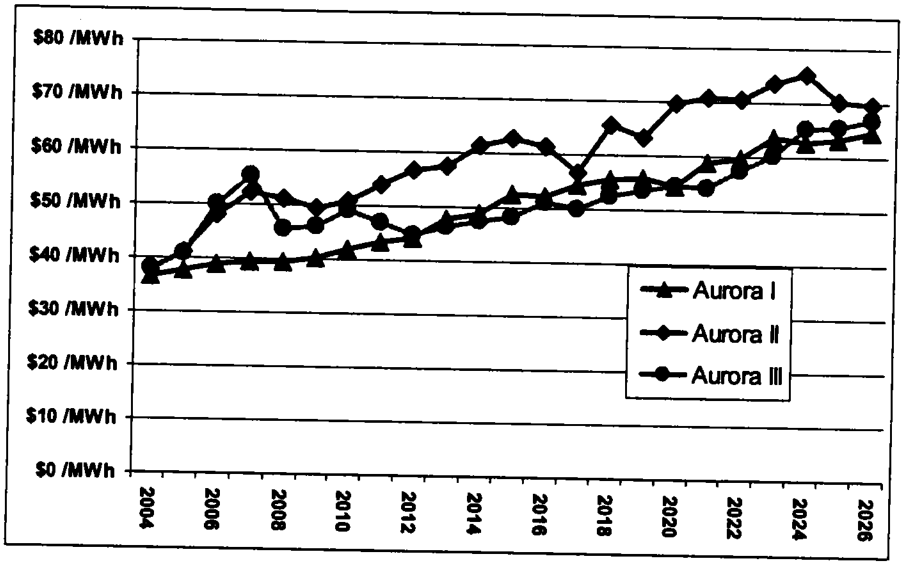
As detailed earlier, PSE performed the initial AURORA run ("AURORA I") using input assumptions similar to those used by the Northwest Power Planning Council (NWPPC). The NWPPC assumes fairly low cost-of-capital, especially considering the current financial state of many IPP's and regional utilities. This was reflected in dispatch case "AURORA I", and, in combination with the assumption of perfect foresight by the developer in the AURORA model approach, which generally leads to well-supplied modeled marketplace.

In recognition that merchant developers and others currently face higher costs of capital than assumed in "AURORA I", PSE developed another case ("AURORA II") with the general assumption of 50 percent higher capital costs in the marketplace. However, the assumption of perfect foresight could not be changed. Market prices resulting from this run were substantially higher than those in the previous run, which is readily explained by the higher degree of scarcity of capital. In this case, PSE did not adjust other assumptions such as fuel cost and load growth from AURORA I.

With AURORA I and II as bounds, PSE performed a third analysis, incorporating the currently high cost of capital to most developers in the short-term (for two years) but then reverting to the lower capital cost assumed in AURORA I. In other words, "AURORA III" recognizes the ongoing market difficulties facing developers and investor-owned utilities and assumes a return to normalcy within two years.

It is important to note that PSE assumed a generation technology-dependent lag time for resource additions after the two years of high capital cost for "AURORA III", specifically one year for SCGT, two years for CCGT, and five years for coal plants. PSE did this to reflect construction and some development time necessary for each technology after the availability of cheaper capital resumes. Exhibit X-21 provides an overview of market prices under the three scenarios.

Exhibit X-21
AURORA Market Price Scenarios



AURORA III, reflecting current capital constraints, assumes a trend back toward historical financial market conditions, with short-term prices similar to levels seen in AURORA II. As time progresses and the effects of the current capital problems disappear, these price levels fall to levels similar to AURORA I.

Clearly with the uncertainty in the today's market, it proves to be useful to approach power market prices with a range of reasonable scenarios. While PSE believes it has a solid range of probable outcomes, PSE is unable to assign firm probabilities to these cases individually. These three cases utilized a scenario-based approach, rather than a probabilistic perspective, serving the Least Cost Plan effort by narrowing down cost-effective and risk-minimizing approaches to PSE's resource situation. PSE believes that under the current market conditions, AURORA III serves as a more likely forecast than AURORA I and II.

Retail Load Growth

The model allows for different load growth scenarios to be considered. The base case assumes 1.4 % long term average annual growth rate. The high growth rate considered is 1.7% while the low growth rate is 1.1% over the 20 years of the study. These scenarios are based on different fundamental determinants of demand such as population, employment, inflation and productivity. This band width is designed to capture the range of forecasted sales, likely to fall within 50% probability. The high growth rate scenario results in about 70 aMW in 2010 over the base case, while the low growth rate scenario results in about 60 aMW lower demand by 2010.

Emissions

The screening model allows for the analysis of emissions output. The incremental cost of emissions can be included in the dispatch basis of the existing and new facilities. Currently, emissions are not included in the dispatch basis, but are captured as an after-dispatch variable cost. Exhibit X-22 provides the model emission rate assumptions for the existing PSE fleet and for new resources.

Exhibit X-22
Screening Model Emission Rate Assumptions

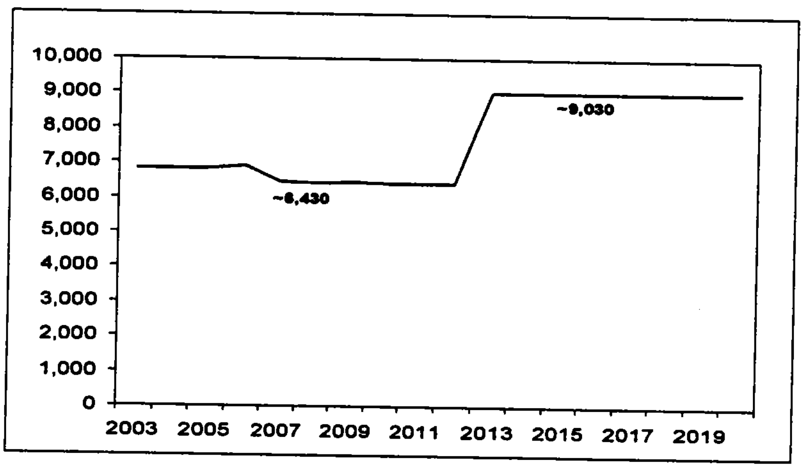
Emission rate (T/GWh)	SO2	NOX	CO2	Source
Fredonia 1&2	-	0.00002	582.00	PSE
Frederickson 1&2	0.00080	0.03900	582.00	NPPC Generic
Fredonia 3&4	0.00080	0.03900	582.00	PSE
Whitehorn 2&3	0.000003	0.00002	582.00	PSE
Colstrip 1&2	2.27613	2.09048	1,119.24	EPA
Colstrip 3&4	0.50220	2.19521	1,097.69	EPA
Encogen (Dispatchable)	0.00200	0.03900	411.00	NPPC Generic
March Point 1&2 (Dispatchable)	0.00200	0.03900	411.00	NPPC Generic
Sumas	0.00200	0.03900	411.00	NPPC Generic
Tenaska	0.00200	0.03900	411.00	NPPC Generic
CCGT (Generic)	0.00200	0.03900	411.00	NPPC Generic
SCGT (Generic)	0.00080	0.05523	582.00	NPPC Generic
Coal (Generic)	0.38200	0.35000	1,012.00	NPPC Generic

These emission rates serve as the basis for the calculation of emission expense associated with generation at a particular facility. The generic resources assume state-of- the-art emission controls; such as flue gas desulphurization (FGD), selective catalytic reducers (SCR), and burner controls. The remainder of this section addresses the current emission regulations applicable to PSE to as well as potential future regulations for each pollutant and for CO_2.

- ***Sulfur Dioxide.*** Currently SO_2 regulations apply to existing and future PSE plants. A market-based allowance trading system exists to implement these regulations. Affected utility units receive an allocation of allowances based on their historic fuel consumption and a specific emissions rate. Each allowance permits a unit to emit one ton of SO_2 during or after a specified year. For each ton of SO_2 emitted in a given year, PSE must retire one allowance.

These regulations currently apply to PSE. The Company receives an allocation of allowances. Exhibit X-23 details the total allowances issued to PSE through 2020:

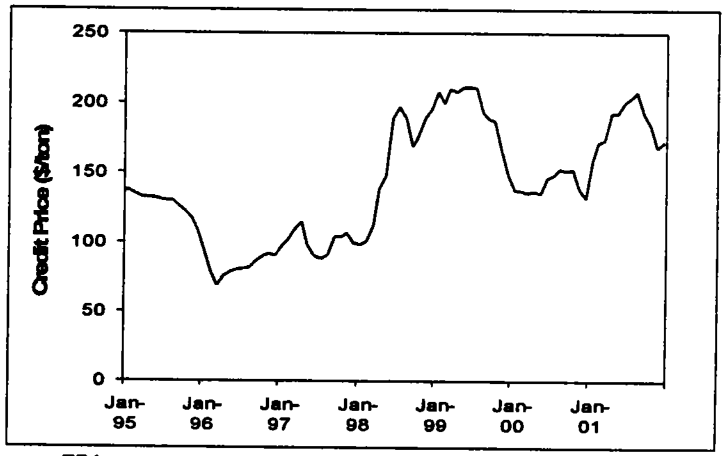
Exhibit X-23
PSE SO_2 Allowances



Source: EPA

A forward market for SO_2 credits exists. As a simplification, the screening model assumes SO_2 credits cost $200/ton and do not escalate going forward. Exhibit X-24 provides an overview of the market for SO_2 credits.

Exhibit X-24
Historical Sulfur Dioxide Credit Prices ($/ton)



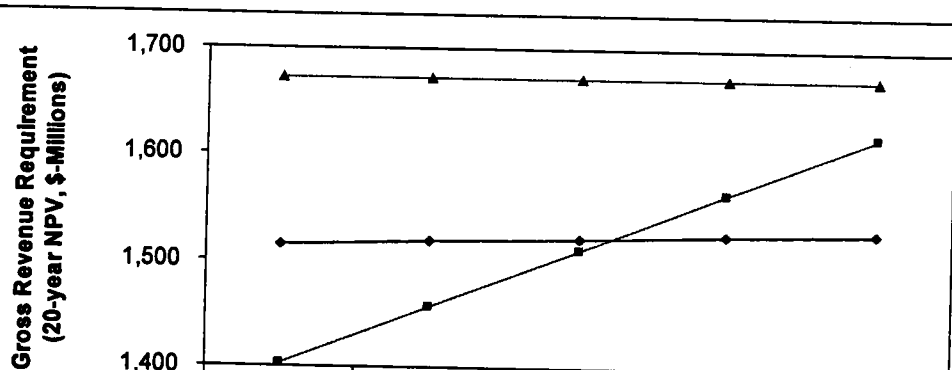
Source: EPA

As referenced in Chapter II, Planning Issues, and provided in more detail in Appendix K, Environmental Risk Assessment, several pieces of legislation have been introduced in the U.S. Congress which could change the regulations governing SO_2 emissions.

- ***Nitrous Oxide (NO_X).*** NO_X mitigation regulations currently do not apply to PSE. However, other parts of the country are subject to NO_X mitigation regulations. These regulations could be a proxy for what may eventually apply in the western United States. Appendix K provides detailed description of current and potential future regulations.

These potential NO_X regulations would impact the economics of the set of supply resources under consideration in this Least Cost Plan. Exhibit X-25 shows the impact of a range of NO_X credit prices on the relative cost of wind, coal and CCGT resources:

Exhibit X-25
Impact of NO_X Credit Prices on Generation Technologies



	-	2,500	5,000	7,500	10,000
CCGT	1,515	1,518	1,522	1,525	1,529
Coal	1,402	1,456	1,510	1,564	1,618
Wind	1,673	1,673	1,673	1,673	1,673

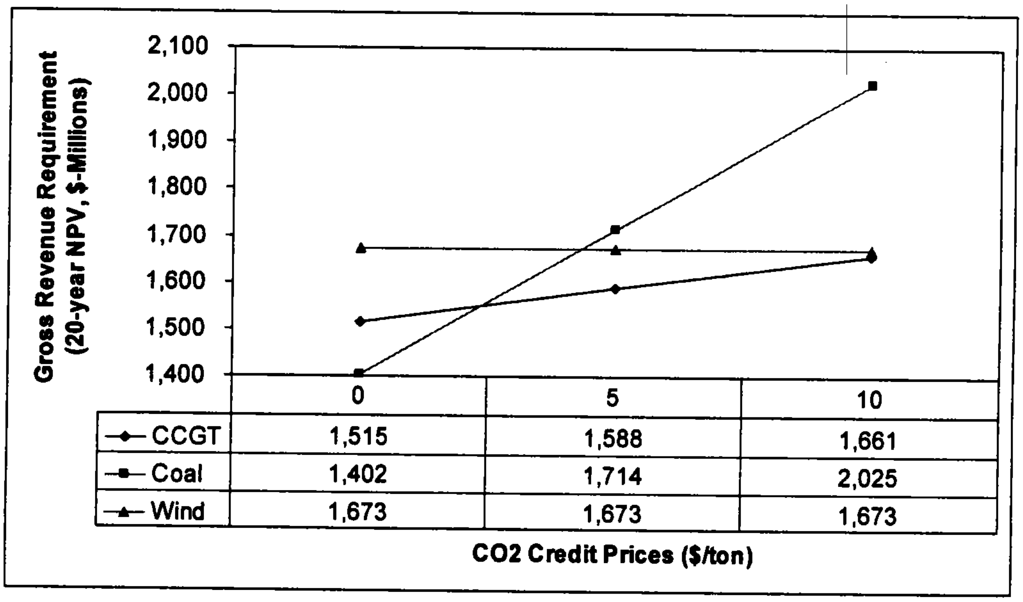
NOX Credit Prices ($/ton)

The analysis in Exhibit X-25 assumes that 500 MW (energy equivalent for wind) of each technology is installed in 2004, with NO_X regulations also becoming effective in 2004. While this represents an aggressive assumption, it demonstrates a "maximum" effect across the technologies. As the implementation of the NO_X regulations is pushed into the future, the "crossover" points occur at higher NO_X credit values. The comparison metric is a 20-year NPV of the gross revenue requirements including all fixed and variable expenses plus a return.

- ***Carbon Dioxide Legislation.*** Currently, power plants in the U.S. are not subject to CO_2 regulations. However, as detailed in Appendix K, several legislative proposals have been introduced during the current U.S. Congress which seek to implement CO_2 requirements.

  The introduction of CO_2 reduction regulations would change the economics of the supply resources that PSE is considering. Exhibit X-26 shows the impact of CO_2 reduction regulations that would employ a cap-and-trade system:

Exhibit X-26
Impact of CO_2 Credit Prices on Generation Technologies



	0	5	10
CCGT	1,515	1,588	1,661
Coal	1,402	1,714	2,025
Wind	1,673	1,673	1,673

The analysis in Exhibit X-26 assumes that 500 MW (energy equivalent for wind) of each technology is installed in 2004, with CO_2 regulations also becoming effective in 2004. While this represents an aggressive assumption, it demonstrates a "maximum" effect across the technologies. As the implementation of the CO_2 regulations is pushed into the future, the "crossover" points occur at higher CO_2 credit values (e.g. if the regulations is instituted in 2008, the crossover for coal and gas moves from ~$3/ton to ~$6/ton). The comparison metric is a 20-year NPV of the gross revenue requirements including all fixed and variable expenses plus a return.

- ***Mercury.*** As Exhibit X-22 illustrates, PSE does not include emission assumptions regarding mercury for its screening model. As detailed further in Appendix K, some legislation that has been introduced in the U.S. Congress has restrictions on mercury and could be a factor for future consideration.

Wind Production Tax Credits

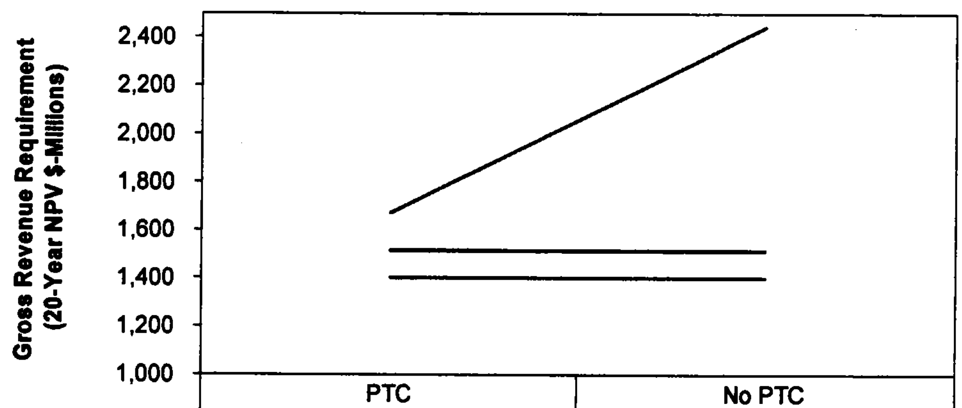
In 1992, Congress signed the Energy Policy Act into law, which included enactment of a Production Tax Credit (PTC) under Section 45 of the Internal Revenue Code of 1986. This credit was available to corporate entities building new renewable energy production facilities such as solar, biomass, wood chip, geothermal and wind power production plants. At its inception, the tax credit equaled $0.015 per kWh. The PTC value has increased each year by the official rate of inflation and applies to the first 10 years of operation of the equipment. The current PTC rate is approximately $0.019 per kWh.

The credit applies to new renewable energy facilities placed into commercial service after enactment of the law, and prior to the latest deadline, December 31, 2003. On March 9, 2002, Congress signed the Job Creation and Worker Assistance Act of 2002 into law. Section 603 of the Act extended the production tax credit for wind, retrospectively, from December 31, 2001 to December 31, 2003.

Currently, the future of the PTC remains uncertain although a number of pending Congressional bills propose extension of the PTC beyond 2003. Until the future of the PTC becomes clear, the pressure on developers to begin projects this year in order to take advantage of the PTC will be significant. After that time, without an extension of the PTC, the economic outlook for new wind developments would be highly uncertain, especially in relation to wind facilities utilizing the PTC, and other conventional resource options.

Despite the uncertainty over the PTC's extension, PSE continues to examine cost-effective means of incorporating wind into the Company's portfolio under conditions with and without the PTC beyond December 2003. While the PTC makes wind investment more attractive from a cost perspective, it does not represent the only decision point for the Company. As with any resource alternative the Company considers, reliability and flexibility continue to be important variables taken into the decision making process. Given this, PSE realizes an extension of the PTC would not only make wind a more attractive resource alternative over the next several years, but it would also encourage developers to maximize the efficiency and reliability of their projects since the PTC is structured on a per-unit-of-production basis. Without the PTC, it could be argued that turbine availability, operating costs and production performance would not be as optimal as in an environment where the PTC remained in place. Regardless of the eventual resolution of the PTC issue, the current uncertainty does not support near-term growth of wind resource within the industry. Exhibit X-27 provides an analysis of the effect of the PTC on wind economics. For the purposes of the Least Cost Plan, PSE assumed that for any new wind resource, a production tax credit of $18/MWh would apply for the first 10 years of service. For more details on the PTC, please refer to Appendix K.

Exhibit X-27
Impact of PTC on Wind Economics



	PTC	No PTC
CCGT	1,515	1,515
Coal	1,402	1,402
Wind	1,673	2,442

G. Estimates of Incremental Conservation

The model utilizes the most recent forecast of load for its analysis. The current demand includes 15 aMW of conservation per year for 10 years, consistent with terms agreed in the last General Rate Case. From this base case the analysis considers an additional 5 aMW of conservation per year for the next 10 years. A more precise incremental change to conservation will be a product of the Conservation process which will be integrated into the Least Cost Plan in the August 2003 update.

The additional conservation is first applied at the sales forecast level. The forecast incorporating the additional conservation is then converted from billed sales to actual load, commonly called GPI for generation, purchase and interchange. (See Appendix C for further discussion.) The annual billed sales forecast is first increased to account for the transmission and distribution losses, and then shaped among the twelve months. The load is shaped hourly based on recent historical loads developed in the last General Rate Case. Since the load is shaped hourly it results in the incremental conservation being shaped to take into account seasonal differences and peak capacity needs.

The decremented load forecast is incorporated into the portfolio screening model. The quantity of new baseload resources required to meet energy needs is reduced from the base case which results in a lower capital expenditure. The level of additional peaking resources is also reduced, relatively greater than the base load, since capacity needs are assumed to grow faster than energy needs.

H. Summary

Since PSE filed its last Least Cost Plan, the Company has significantly updated and improved the analytical process for determining its least-cost electric resource strategy. Most significantly, PSE has incorporated probabilistic analysis of key risk factors such as the market prices for gas and power, hydro availability and the correlation between these three factors with its analytical process. Other key highlights of this chapter include:

- In absence of a regional or state regulatory requirement on sufficiency standards for resource planning, PSE examined eight planning levels. These levels ranged from a "do nothing" approach assuming PSE's current energy and capacity deficit grows with demand, to a planning level requiring energy in all months to be at 110 percent of the total monthly load and capacity needs to meet a 13-degree F hour at SEA-TAC.
- At these planning levels, energy needs in 2004 ranged from 10 to 674 aMW, growing to 1,176 to 1,874 aMW by 2013.
- For capacity, the possible capacity needs in 2004 ranged from 307 to 1,558 MW, increasing to 2,156 to 3,562 MW in 2013.
- PSE constructed portfolios consisting of a mix of gas, coal and wind resources. Specific construction rules regarding availability of new resources guided the construction of the portfolios. In addition, three methods of seasonal shaping were utilized in the portfolio construction.
- The first step of PSE's resource analysis process consisted of developing basic inputs and assumptions such as retail customer and electric loads, existing power supply resources, natural gas price forecast and wholesale electricity market prices.
- PSE developed a dispatch model which provides MWh and variable costs for each resource considered by PSE in order to screen the various portfolios.
- PSE used the dispatch model results to derive a "bottom up" revenue requirement for each new resource. The revenue requirement, the variable cost and the cost of market purchased were used to develop a net present value (NPV) of the 20-year strip of incremental costs for each portfolio.

- After regional updated conservation assessments become available in May 2003, PSE will update its analysis with conservation resource estimates for an August 2003 filing to the WUTC.
- In addition to performing probabilistic risk analysis, PSE modeled two alternative scenarios for market power prices. Moreover, PSE examined other uncertainties such as retail load growth scenarios, emission impacts and the impact of the possible expiration of the wind production tax credit in December 2003.